9111 Jollyville Road | Suite 255 | Austin, TX 78759 | P (512) 349-5800 | F (512) 233-0803
trinityconsultants.com

Trinity Consultants

January 22, 2013

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
Delaware Basin JV Gathering LLC, Avalon Mega CGF
Loving County, Texas
Customer Number (CN): 603815879, Regulated Entity Number (RN): TBD

Dear Mr. Robinson:

Delaware Basin JV Gathering LLC (DBJVG) proposes to construct a gas processing facility near Mentone in Loving County, Texas (Avalon Mega Central Gathering Facility [CGF]). The primary Standard Industrial Classification code of the proposed Avalon Mega CGF is 1321 (Natural Gas Liquids). DBJVG is registered under Texas Commission on Environmental Quality (TCEQ) Customer Reference Number CN603815879. The Avalon Mega CGF has not yet been assigned a TCEQ Regulated Entity Number (RN).

The proposed Avalon Mega CGF will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements. 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 Avalon Mega CGF will be a new major source with respect to nitrogen oxides (NO_x) and carbon monoxide (CO). The project will also trigger PSD review based on significant emission rates for volatile organic compounds (VOC), sulfur dioxide (SO_2), particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}), and particulate matter with an aerodynamic diameter of 2.5 microns or less ($PM_{2.5}$). Therefore, a separate PSD application for all non-GHG pollutants is being submitted to the TCEQ under a separate cover.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call me at (512) 349-5800 or Mr. JD Holt, DBJVG, at (832) 636-2721.

Sincerely,

TRINITY CONSULTANTS

Melissa Dakas
Managing Consultant

Attachments

cc: Air Permits Initial Review Team (APIRT), TCEQ Austin
Ms. Lorinda Gardner, TCEQ Region 7 Midland
Mr. Charles Griffie, Delaware Basin JV Gathering LLC
Mr. Jason Zapalac, Delaware Basin JV Gathering LLC
Mr. JD Holt, Delaware Basin JV Gathering LLC

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GREENHOUSE GASES

Delaware Basin JV Gathering LLC> Avalon Mega CGF

Prepared By:

Jason Zapalac, Delaware Basin JV Gathering LLC
JD Holt, Delaware Basin JV Gathering LLC

DELAWARE BASIN JV GATHERING LLC
1201 Lake Robbins Drive
The Woodlands, TX 77380
(832) 636-4911
Fax: (832) 636-5446

Melissa Dakas – Managing Consultant

TRINITY CONSULTANTS
12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661-8100

Project 124401.0095

Trinity Consultants

Environmental solutions delivered uncommonly well

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

Delaware Basin JV Gathering LLC (DBJVG) is proposing to construct a gas processing facility near Mentone in Loving County, TX (Avalon Mega Central Gathering Facility [CGF]). The primary Standard Industrial Classification code of the proposed Avalon Mega CGF is 1321 (Natural Gas Liquids). DBJVG is registered under Texas Commission on Environmental Quality (TCEQ) Customer Reference Number CN603815879. The Avalon Mega CGF has not yet been assigned a TCEQ Regulated Entity Number (RN).

Loving County is currently designated as being attainment/unclassifiable for all criteria pollutants. Air emissions from the Avalon Mega CGF project are subject to the jurisdiction of both the U.S. Environmental Protection Agency (EPA) and the TCEQ. Greenhouse Gas (GHG) emissions from the Avalon Mega CGF are subject to the jurisdiction of the EPA under authority asserted in Texas through its Federal Implementation Plan (FIP) for the regulation of GHGs. All non-GHG emissions are subject to the jurisdiction of the TCEQ. Accordingly, DBJVG is submitting applications to both agencies to obtain the requisite authorizations to construct.

1.1. PROPOSED PROJECT

The Avalon Mega CGF will be designed to treat up to 200 million standard cubic feet per day (MMscfd) of sweet natural gas in six (6) identical processing trains. The Avalon Mega CGF will consist of inlet separation facilities, amine treating units, glycol dehydration units, thermal oxidizers, and supporting equipment. The main processes at the Avalon Mega CGF will include the following:

> Inlet separation to separate liquids from the inlet gas
> Removal of carbon dioxide (CO_2) from natural gas through amine treating
> Removal of water from natural gas through glycol dehydration
> Compression of natural gas by natural gas fired compressors
> Pipeline loading of high-pressure condensate liquids
> Truck loading of low-pressure condensate and produced water liquids

The proposed Avalon Mega CGF will include the following emissions sources:

> Amine Units (6)
> Triethylene glycol (TEG) Dehydrators (6)
> Compressor Engines (12)
> Diesel Emergency Power Generators (6)
> Thermal Oxidizers (6)
> Process Flares (3)
> Truck Loading Operations
> Produced Water Tanks (6)
> Planned Maintenance, Start-up, and Shutdown (MSS) activities
> Equipment Leak Fugitives

1.2. PERMITTING CONSIDERATIONS

The DBJVG Avalon Mega CGF site is located in Loving County, Texas. Loving County is currently classified as being attainment/unclassified for all criteria pollutants.[1] Based on the current classification, the Prevention of Significant Deterioration (PSD) regulations define a stationary source as a major source if it emits or has the potential to emit (PTE) either of the following:

- 250 tons per year (tpy) or more of any PSD pollutant; or
- 100 tpy or more of any PSD pollutant if the facility belongs to one of the 28 listed PSD major facility categories.

The natural gas production facility does not belong to one of the 28 listed PSD sources categories; therefore the major source threshold is 250 tons per year (tpy) or more of any criteria PSD pollutant. The Avalon Mega CGF will be a major source (greater than 250 tpy) with respect to nitrogen oxides (NO_x) and carbon monoxide (CO). According to EPA's "major for one, major for all" PSD policy, if a site is major for a regulated pollutant or GHGs, then the remaining regulated pollutants need to be compared to the Significant Emission Rates (SERs; i.e., 40 tpy for NO_x, sulfur dioxide (SO_2), and volatile organic compounds (VOC), 100 tpy for CO, 25 tpy for particulate matter (PM), 15 tpy for particulate matter with an aerodynamic diameter of 10 microns or less [PM_{10}], and 10 tpy for particulate matter with an aerodynamic diameter of 2.5 microns or less [$PM_{2.5}$]) when determining PSD applicability for these pollutants. Based on the potential to emit calculations, the project will also trigger PSD review based on significant emission rates for VOC, SO_2, PM_{10}, and $PM_{2.5}$. In the Tailoring Rule[2], the U.S Environmental Protection Agency (EPA) established a major source threshold of 100,000 tons per year (tpy) of Carbon Dioxide equivalent (CO_2e) emissions and an SER of 75,000 tpy for emissions of Greenhouse Gases (GHG). DBJVG has determined that the GHG emissions from the proposed project will exceed the major source threshold. Therefore, the proposed action represents a new major NSR project with respect to GHG emissions and the aforementioned criteria pollutants.

With the 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.[3] Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority asserted in Texas through its FIP for the regulation of GHGs. Accordingly, DBJVG is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct.

1.3. PERMIT APPLICATION

All required supporting documentation for the permit application is provided in the following sections. 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 supporting documentation. The Biological Assessment, Cultural Resources, and National Historic Preservation Act Analysis Reports will be submitted under a separate cover.

---

[1] Per 40 CFR §81.344 (Effective April 5, 2005).
[2] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[3] 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).

2. TCEQ FORM PI-1

Texas Commission on Environmental Quality
Form PI-1 General Application for
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: Delaware Basin JV Gathering LLC		
Texas Secretary of State Charter/Registration Number (if applicable):		
B. Company Official Contact Name: Charles Griffie		
Title: Operations Manager		
Mailing Address: 1201 Lake Robbins Drive		
City: The Woodlands	State: TX	ZIP Code: 77380
Telephone No.: (832) 636-1000	Fax No.: (832) 636-5446	E-mail Address: Charles.Griffie@anadarko.com
C. Technical Contact Name: JD Holt		
Title: Sr. Staff EHS Representative		
Company Name: Delaware Basin JV Gathering LLC		
Mailing Address: 1201 Lake Robbins Drive		
City: The Woodlands	State: TX	ZIP Code: 77380
Telephone No.: (832) 636-2721	Fax No.: (832) 636-8042	E-mail Address: JD.Holt@anadarko.com
D. Site Name: Avalon Mega CGF		
E. Area Name/Type of Facility: Gas Processing Facility		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Liquids		
Principal Standard Industrial Classification Code (SIC): 1311		
Principal North American Industry Classification System (NAICS): 211111		
G. Projected Start of Construction Date: 11/25/2013		
Projected Start of Operation Date: 8/1/2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: From the intersection of Hwy 302 and Loving County Road 300 in Mentone, Texas, travel north 14 miles on Co Rd 300. Turn left(west) on lease road and travel approx. 1 mile.		
City/Town: Mentone	County: Loving	ZIP Code: 79754
Latitude (nearest second): 31° 54' 7.97" N	Longitude (nearest second): 103° 42' 52.17" W	

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

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): CN603815879	
L. Regulated Entity Number (RN): TBD	
II. General Information	
A. Is confidential information submitted with this application? If Yes, mark each confidential page confidential in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.	☐ YES ☒ NO
C. Number of New Jobs: 20	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
State Senator: Carlos . resti	District No.: 19
State Representative: Pete P. Gallego	District No.: 74
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested.	
☒ Initial ☐ Amendment ☐ Revision (30 TAC 116.116(e) ☐ Change of Location ☐ Relocation	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)*	
☒ Construction ☐ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Plant-Wide Applicability Limit	
☒ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source	
☐ 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.4.0		☐ 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
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP
☒ To be Determined		☐ None

III.	**Type of Permit Action Requested *(continued)***	
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. ***(check all that apply)***	
☐ GOP Issued	☐ GOP application/revision application submitted or under APD review	
☐ SOP Issued	☐ SOP application/revision application submitted or under APD review	
IV.	**Public Notice Applicability**	
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☒ YES ☐ NO
If Yes, list the affected state(s) and/or Class I Area(s).		
List: Carlsbad Caverns National Park		
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):***	
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NOx):		
Particulate Matter (PM):		
PM 10 microns or less (PM10):		
PM 2.5 microns or less (PM2.5):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants not listed above: Greenhouse Gases - See Appendix C of Permit Application		

TCEQ

V. Public Notice Information *(complete if applicable)*		
A. Public Notice Contact Name: JD Holt		
Title: Sr Staff EHS Representative		
Mailing Address: 1201 Lake Robbins Drive		
City: The Woodlands	State: TX	ZIP Code: 77380
B. Name of the Public Place: Loving County Courthouse		
Physical Address *(No P.O. Boxes)*: 100 Bell Street		
City: Mentone	County: Loving	ZIP Code: 79754
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: Skeet Lee Jones		
Mailing Address: 100 Bell Street		
City: Mentone	State: TX	ZIP Code: 79754
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? ***(For Concrete Batch Plants)***		☐ YES ☐ NO
Presiding Officers Name(s):		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located.		
Chief Executive: Skeet Lee Jones		
Mailing Address: 100 Bell Street		
City: Mentone	State: TX	ZIP Code: 79754
Name of the Indian Governing Body:		
Mailing Address:		
City:	State:	ZIP Code:

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

V. Public Notice Information *(complete if applicable) (continued)*	
C. Concrete Batch Plants, PSD, and Nonattainment Permits	
3. Provide the name, mailing address of the chief executive and Indian Governing Body; and identify the Federal Land Manager(s) for the location where the facility is or will be located. *(continued)*	
Name of the Federal Land Manager(s):	
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?	
VI. Small Business Classification *(Required)*	
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?	☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?	☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?	☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?	☐ YES ☒ NO
VII. Technical Information	
A. The following information must be submitted with your Form PI-1 ***(this is just a checklist to make sure you have included everything)***	
1. ☒ Current Area Map	
2. ☒ Plot Plan	
3. ☐ Existing Authorizations	
4. ☒ Process Flow Diagram	
5. ☒ Process Description	
6. ☒ Maximum Emissions Data and Calculations	
7. ☒ Air Permit Application Tables	
a. ☒ Table 1(a) (Form 10153) entitled, Emission Point Summary	
b. ☒ Table 2 (Form 10155) entitled, Material Balance	
c. ☒ Other equipment, process or control device tables	
B. Are any schools located within 3,000 feet of this facility?	☐ YES ☒ NO

VII.	**Technical Information**			
C.	Maximum Operating Schedule:			
Hour(s): 24	Day(s): 365	Week(s): 52	Year(s): 1	
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

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.*	
C.	Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?	☒ YES ☐ NO
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO

X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If Yes, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: $ 75,000
Paid online?	☐ YES ☒ NO
Company name on check: WGR Asset Holding Company	
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:	Charles Griffie
Signature:	*Original Signature Required*
Date:	12/10/2012

PRINT FORM RESET FORM

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 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 603815879		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:*

10. Mailing Address:							
	City		**State**		**ZIP**		**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)*
( ) -		( ) -

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)*

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)*

Avalon Mega CGF

24. Street Address of the Regulated Entity: *(No P.O. Boxes)*							
	City		State		ZIP		ZIP + 4
25. Mailing Address:	1201 Lake Robbins Drive Tower						
	City	The Woodlands	State	TX	ZIP	77380	ZIP + 4
26. E-Mail Address:	JD.Holt@anadarko.com						

27. Telephone Number	28. Extension or Code	29. Fax Number *(if applicable)*
(832) 636-1000		(832) 636-5446

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)
1311		211111	

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

Oil and Gas Production Facility

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

35. Description to Physical Location:	From the intersection of Hwy 302 and Loving County Road 300 in Mentone, Texas, travel north 14 miles on Co Rd 300. Turn left (west) on lease road and travel approx. 1 mile. Arrive at facility.

36. Nearest City	County	State	Nearest ZIP Code
Mentone	Loving	TX	79754

37. Latitude (N) In Decimal:	31.9		38. Longitude (W) In Decimal:	103.7	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
31	54	13	103	42	46

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:	Melissa Dakas	41. Title:	Managing Consultant
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(512) 349-5800		(512) 233-0803	mdakas@trinityconsultants.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.

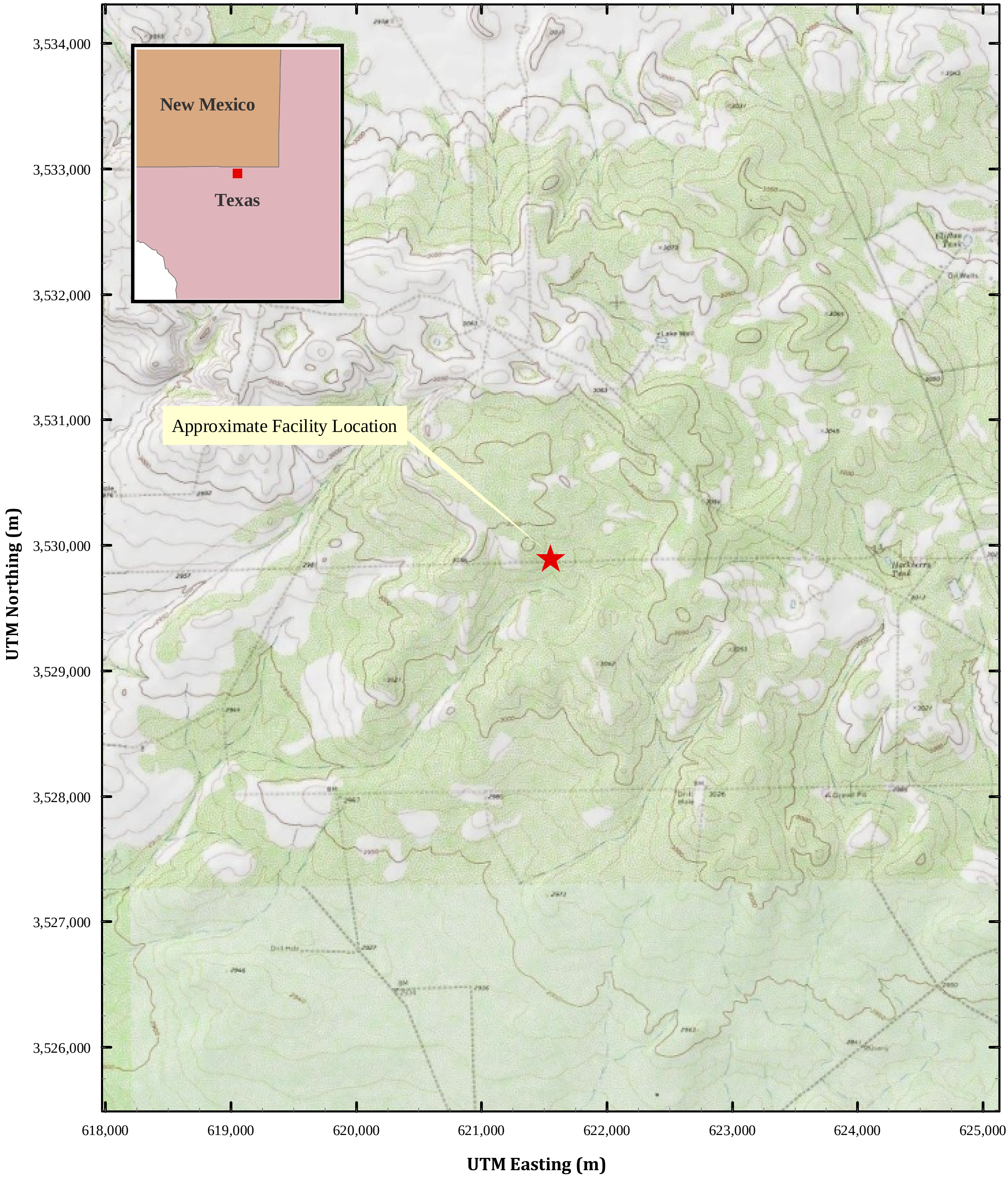
(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Delaware Basin JV Gatherin LLC	Job Title:	Operations Manager
Name *(In Print)*:	Charles Griffie	Phone:	(832) 636-1000
Signature:	Charles Griffie	Date:	12/10/2012

4. AREA MAP

The proposed Avalon Mega CGF will be located in Loving County, TX. 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 site and extends out at least 3,000 feet from the property line in all directions. The map depicts the fence line/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. Area Map
Anadarko Mega CGF
Loving County, Texas

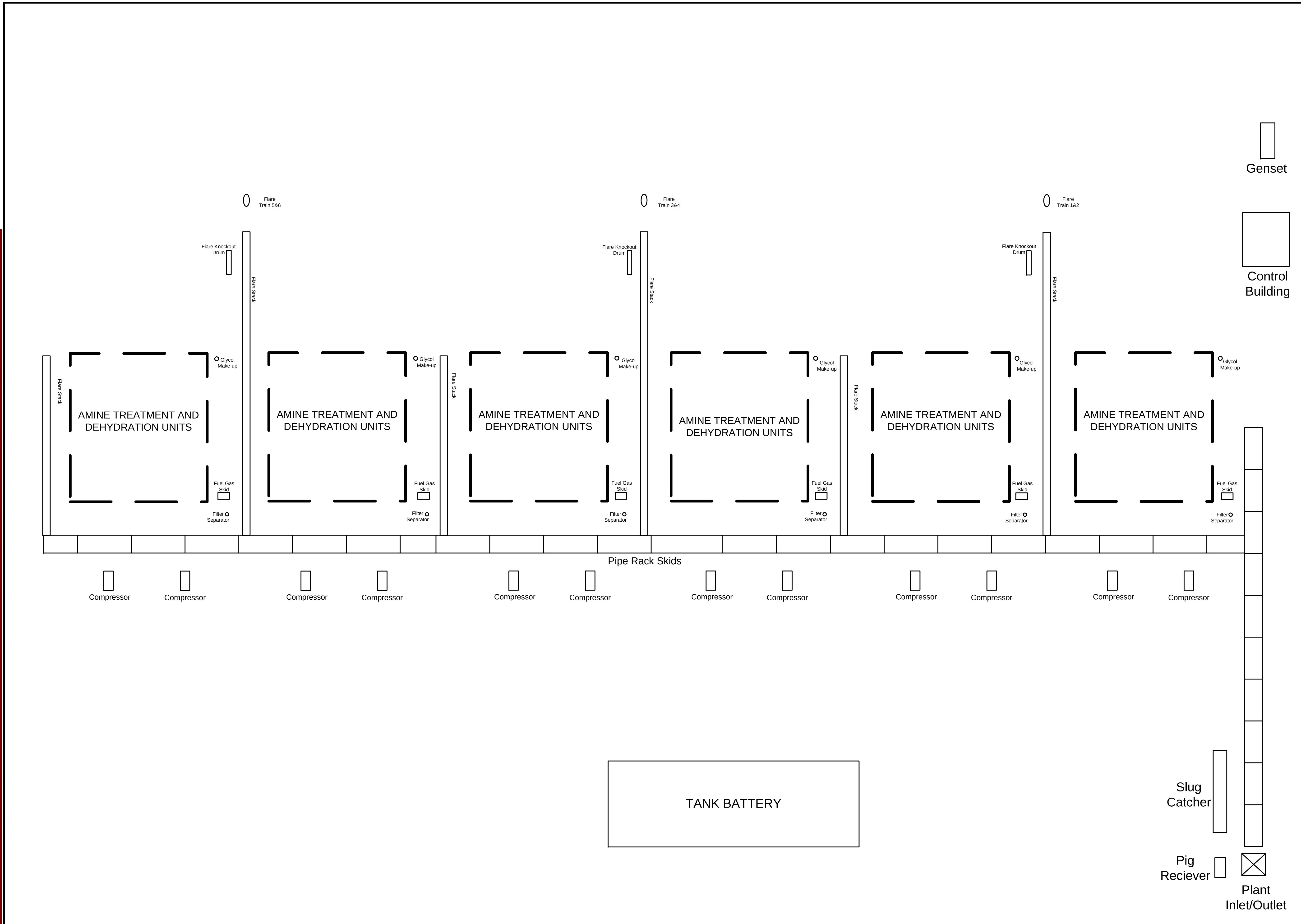


Coordinates reflect UTM projection Zone 13, NAD83.

Trinity Consultants

5. PLOT PLAN

The following figure depicts the site plan for the proposed Avalon Mega CGF.



PFD NOMENCLATURE

STREAMS	CONTROLS

NOTES

FOR INFORMATION ONLY

REVISIONS

REV.	DESCRIPTION	DRWN	CHKD	APPRV	DATE
A	ISSUED FOR INFORMATION				

PROJECT INFORMATION

DRAWN BY :

DATE:

AEC JOB NO.

CLIENT FILE NO.

AFE / P.O. NO.

audubon
Total Flexibility. Total Solutions.
Audubon Engineering
10205 Westheimer Rd.
Suite 600
Houston, Texas 77042
281-669-0590

AVALON PLOT PLAN (DRAFT)

DWG. NO. REV.

6. PROCESS DESCRIPTION & PROCESS FLOW DIAGRAM

The proposed Avalon Mega CGF will be composed of six identical processing trains with the combined ability to process 200 MMscfd of field gas.

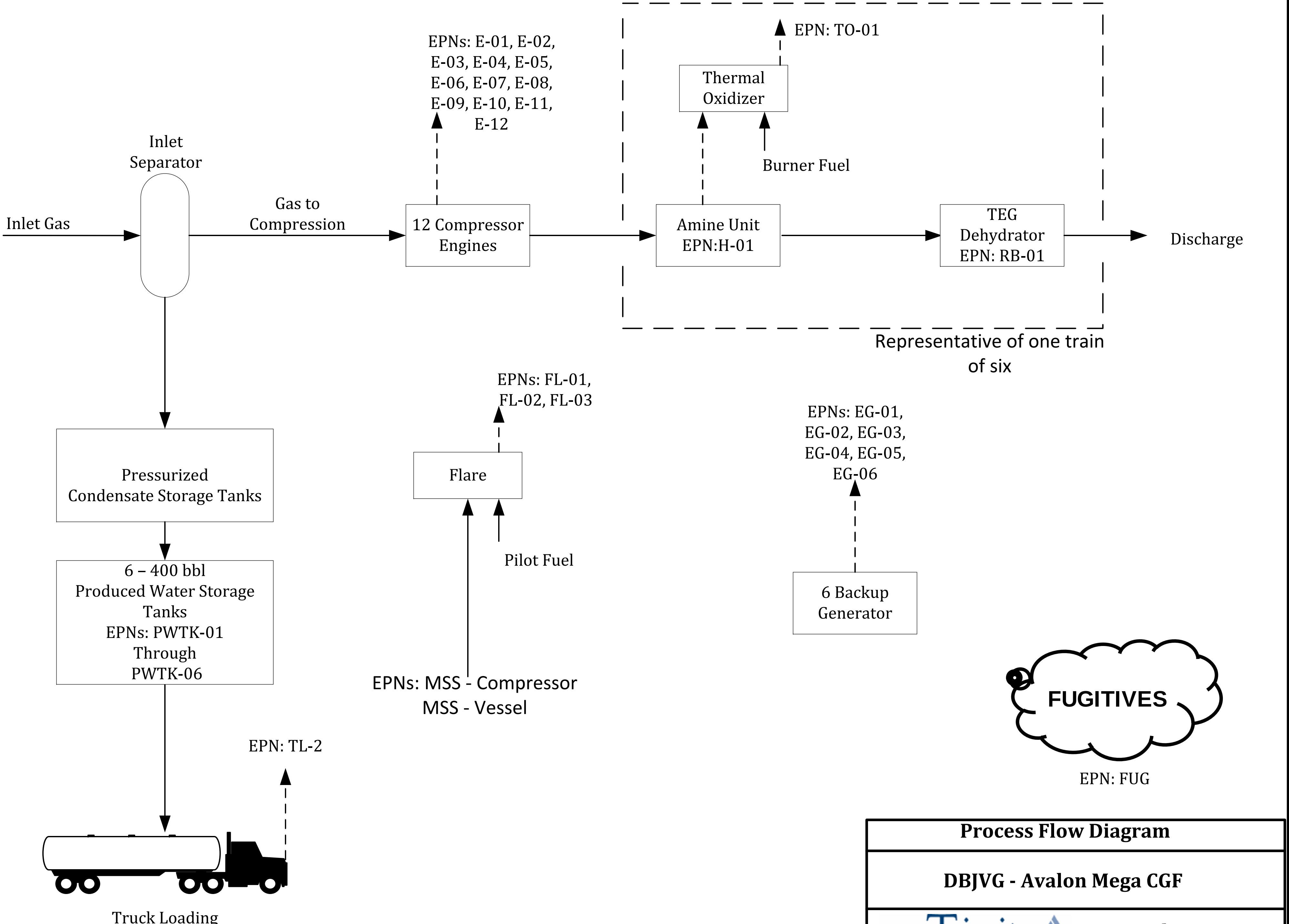
Natural gas entering the Avalon Mega CGF is first sent through a single inlet separator skid to separate liquids from the inlet gas. The resulting liquids are sent to atmospheric produced water tanks (EPNs: PWTK-1, PWTK-2, PWTK-3, PWTK-4, PWTK-5, and PWTK-6) and pressurized condensate storage tanks prior to being loaded to tanker trucks for shipment off-site (EPN: TL-2). The daily maximum liquid production is estimated to be 200 barrels of condensate and 200 barrels of water. The emissions from the produced water storage tanks will be vented to the atmosphere.

The separated gas is compressed by twelve Caterpillar G3612 engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12). The compressed inlet gas is then sent to a series of six identical trains for treatment. Each train is equipped with an amine unit for CO_2 removal and a TEG dehydrator for water removal. The amine units (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06) and TEG dehydrators (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06) are equipped with reboilers to promote better separation. The amine still vents are controlled by a thermal oxidizer (EPNs: TO-01, TO-02, TO-03, TO-04, TO-05, and TO-06) and the flash tank emissions are recycled back into the fuel gas system. The TEG dehydrator still vent and flash tank emissions from both units are recycled back into the fuel gas system for the facility.

Additional process emissions at the site result from fugitive emissions (EPN: FUG), and routine maintenance, startup, and shutdown (MSS) emissions from the compressor blowdowns (EPN: MSS-compressors), vessel blowdowns (EPN: MSS-vessel), and pigging operations (EPN: MSS-pigging). The compressor and vessel blowdown emissions are controlled by flares (EPNs: FL-01, FL-02, FL-03), one flare per two trains.

The facility will include six diesel-fired emergency generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06). Each engine will be operated less than 100 hours per year for routine testing, maintenance, and inspection purposes only.

Emissions from the proposed equipment are discussed in the following section of this application.



Process Flow Diagram

DBJVG - Avalon Mega CGF

Trinity Consultants

November 2012
124401.0095

This section summarizes the GHG emission calculation methodologies and provides emission calculations for the proposed GHG emission sources:

The following sources of GHG emissions are included in the emission calculations provided in Appendix C:

- Twelve Caterpillar G3612 Engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12);
- Six amine reboilers (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06);
- Six amine still vents routed to thermal oxidizers (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, and TO-6);
- Six TEG dehydrator reboilers (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06);
- Three flares (EPNs: FL-01, FL-02. FL-03);
- Six produced water storage tanks (EPNs: PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, and PWTK-06);
- Six emergency generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06);
- Produced water truck loading (EPN: TL-2);
- Site-wide fugitive emissions (EPN: FUG); and
- Site-wide MSS emissions (EPNs: MSS-compressors, MSS-vessel, and MSS-pigging).

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

According to 40 CFR Section (§)52.21(b)(49)(ii), PSD applicability for GHG emissions is determined based on GHG emissions on a carbon dioxide equivalent basis (CO_2e), as calculated by multiplying the mass of each of the six regulated GHGs by the gas' associated Global Warming Potential (GWP).[4] The GWP value for each GHG proposed to be emitted from the project is listed in the following table.

Table 7.1-1. 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:

$$\text{CO}_2\text{e Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)$$
$$= \text{CO}_2\text{ Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{CO}_2\text{ GWP} + \text{CH}_4\text{ Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{CH}_4\text{ GWP}$$
$$+ \text{N}_2\text{O Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{N}_2\text{O GWP}$$

[4] 40 CFR Part 98, Subpart A, Table A-1.

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

Emissions of CO_2, CH_4, and N_2O are estimated using the methodologies outlined in EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR Part 98) or a mass balance approach, as detailed in the remainder of this section.

7.1. COMPRESSOR ENGINES

The project will include twelve natural gas-fired compressor engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12). Combustion of natural gas will result in 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 40 CFR Part 98 Subpart C for stationary fuel combustion sources and as shown in the following table. [5]

Table 7.1-2. 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	2.2E-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 engines. 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 compressor engines:

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

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

7.2. THERMAL OXIDIZER

The thermal oxidizers (EPNs: TO-01, TO-02, TO-03, TO-04, TO-05, and TO-06) will be used to control emissions from the still vents associated with the amine units. Emissions of CO_2, CH_4, and N_2O from the thermal oxidizers will result from the combustion of pipeline quality natural gas in the pilot and the combustion of waste vent gas from the amine units.

[5] 40 CFR 98 Subpart C, Tables C-1 and C-2.

Emissions from pilot gas combustion are estimated using the methodologies described below, the design pilot gas flow rate, and the natural gas fuel analysis.

GHG emissions from combustion of amine unit waste streams are estimated based on methodologies in 40 CFR Part 98 Subpart W for petroleum and natural gas systems.

Pilot Gas Fuel 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:

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

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

Amine Still Vent Emissions

Controlled hourly emission rates for CO_2 and CH_4 from the thermal oxidizer are estimated using the ProMax output for the waste stream resulting from the amine still vent and the guaranteed destruction efficiency. The ProMax simulation output file is provided in Appendix A for reference.

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

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Output}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency}(\%)/100]$$

Hourly N_2O emission rates are estimated using Equation W-40 in 40 CFR Part 98 Subpart W for combustion units that combust process vent gas, as shown in the following equation:[6]

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

The process gas 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.

---

[6] 40 CFR §98.233(z)(2)(vi).

In addition to emissions from combusted CO_2, CH_4, and N_2O, GHG emissions will result from the conversion of carbon atoms in the waste streams 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 Part 98 Subpart W.[7] 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):

$$\text{Converted } CO_2 \text{ Hourly Emission Rate} = \text{Output}\left(\frac{\text{lb}}{\text{hr}}\right) \text{ x Carbon Count x Destruction Rate Efficiency } (\%)/100$$

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

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

7.3. TEG DEHYDRATOR REBOILERS

The TEG dehydrators are equipped with reboilers (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06). Fuel combustion associated with the heating of the reboilers will result in emissions of GHG pollutants. Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the reboiler. 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 glycol dehydrator reboilers:

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

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

7.4. AMINE UNIT REBOILERS

The amine units are equipped with reboilers (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06). Fuel combustion associated with the heating of the reboilers will result in emissions of GHG pollutants. Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the reboiler. 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 amine unit reboilers:

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

[7] 40 CFR §98.233(z)(2)(iii).

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

7.5. FLARES

The Avalon Mega CGF will include three flares (EPNs: FL-01, FL-02, and FL-03), one flare per two trains, to control MSS emissions and emergency releases. Emissions of CO_2, CH_4, and N_2O from the flares will result from the combustion of pipeline quality natural gas in the pilot and the combustion of gas streams from the compressor and vessel blowdowns during MSS activities.

Emissions from pilot gas combustion are estimated using the methodologies described below, the design pilot gas flow rate, and the natural gas fuel analysis.

Pilot Gas Fuel Emissions

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the flare pilot. 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:

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

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

MSS Activity Emissions

Emissions from compressor and vessel blowdowns (EPNs: MSS-compressors and MSS-vessel) are estimated by determining the volume of gas per blowdown and the gas speciation. GHG emissions will result from the conversion of carbon atoms in the waste streams 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 Part 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):

$$\begin{aligned} &CO_2 \text{ Hourly Emission Rate} \\ &\quad = \text{Volume (scf) x } 379.4\left(\frac{\text{lbmol}}{\text{scf}}\right) \text{ x Molecular Weight}\left(\frac{\text{lb}}{\text{lbmol}}\right) \text{ x \% } CO_2 \\ &\quad / \text{ Hours of Operation (hr) x Carbon Count x Destruction Rate Efficiency (\%)}/100 \end{aligned}$$

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

[8] 40 CFR §98.233(z)(2)(iii).

Controlled Annual Emission Rate (tpy)

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

7.6. FUGITIVE COMPONENTS

Process fugitive GHG emissions result from leaking piping components such as valves and flanges (EPN: FUG).

Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment, 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.[9] DBJVG has selected to implement the 28 VHP Monitoring Program; therefore, these control efficiencies are applied to the equipment leak fugitive calculations. Additionally, DBJVG will monitor flanges using quarterly organic vapor analyzer (OVA) monitoring at the same leak definition for valves, resulting in the same control efficiency applied to flanges as is applied to valves.

Hourly Emissions

Hourly emissions of GHG from traditional fugitive components (i.e., valves and flanges) 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:

Hourly Emission Rate (lb/hr)

$$= \text{TCEQ Emission Factor}\left(\frac{\text{lb}}{\text{hr-comp}}\right) \times \text{ Number of Components (\# comp)}$$
$$\times \text{ Compound Content (wt \%)} \times \big(1 - 28\text{ VHP Control Factor(\%)}\big)$$

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:

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

7.7. FUGITIVE MSS ACTIVITIES

Fugitive CO_2 and CH_4 emissions will occur from maintenance, startup and shutdown activities due to pigging operations (EPN: MSS-pigging) which vent to the atmosphere. Fugitive emissions from the MSS activities are calculated using the following equations:

---

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

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Annual Gas Mass}\left(\frac{\text{lb}}{\text{yr}}\right) \times \frac{1}{\text{Annual Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right)} \times \text{Component Mass Percent (\%)}$$

Annual CO_2 and CH_4 emission rates from fugitive MSS activities are estimated based on the annual amount of gas released during pigging operations using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Annual Gas Mass}\left(\frac{\text{lb}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

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

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
E-01	E-01	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-02	E-02	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-03	E-03	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-04	E-04	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-05	E-05	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
E-06	E-06	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-07	E-07	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-08	E-08	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-09	E-09	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-10	E-10	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
E-11	E-11	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
E-12	E-12	Compressor, Caterpillar G3612	CO_2	3126	13691
			CH_4	0.06	0.26
			N_2O	<0.01	0.03
			CO_2e	3129	13705
EG-01	EG-01	Emergency Generator 1	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-02	EG-02	Emergency Generator 2	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-03	EG-03	Emergency Generator 3	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
EG-04	EG-04	Emergency Generator 4	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-05	EG-05	Emergency Generator 5	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
EG-06	EG-06	Emergency Generator 6	CO_2	1281	64.07
			CH_4	0.05	<0.01
			N_2O	0.01	<0.01
			CO_2e	1286	64.29
H-01	H-01	Amine Unit #1 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-02	H-02	Amine Unit #2 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
H-03	H-03	Amine Unit #3 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-04	H-04	Amine Unit #4 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-05	H-05	Amine Unit #5 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
H-06	H-06	Amine Unit #6 Reboiler	CO_2	4676	20479
			CH_4	0.09	0.39
			N_2O	<0.01	0.04
			CO_2e	4680	20499
TO-1	TO-1	Thermal Oxidizer 1	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
TO-2	TO-2	Thermal Oxidizer 2	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-3	TO-3	Thermal Oxidizer 3	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-4	TO-4	Thermal Oxidizer 4	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-5	TO-5	Thermal Oxidizer 5	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
TO-6	TO-6	Thermal Oxidizer 6	CO_2	20058	87853
			CH_4	0.11	0.50
			N_2O	0.05	0.22
			CO_2e	20076	87932
RB-01	RB-01	Glycol Dehydrator #1 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
RB-02	RB-02	Glycol Dehydrator #2 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-03	RB-03	Glycol Dehydrator #3 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-04	RB-04	Glycol Dehydrator #4 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-05	RB-05	Glycol Dehydrator #5 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769
RB-06	RB-06	Glycol Dehydrator #6 Reboiler	CO_2	175	768
			CH_4	<0.01	0.01
			N_2O	<0.01	<0.01
			CO_2e	176	769

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
FL-01	FL-01	Flare #1	CO_2	35.51	156
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	35.54	156
FL-02	FL-02	Flare #2	CO_2	35.51	156
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	35.54	156
FL-03	FL-03	Flare #3	CO_2	35.51	156
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	35.54	156

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:		Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Avalon Mega CGF**			Customer Reference No.	**CN603815879**

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)
FUG	FUG	Fugitive Emissions	CO_2	<0.01	<0.01
			CH_4	<0.01	<0.01
			CO_2e	<0.01	<0.01
PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	Produced Water Tanks	CO_2	<0.01	<0.01
			CH_4	<0.01	0.01
			CO_2e	0.06	0.30
TL-2	TL-2	Produced Water Truck Loading	CH_4	<0.01	<0.01
			CO_2e	<0.01	<0.01
MSS-compressors	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	CO_2	10.63	9.95
			CH_4	0.18	0.17
			CO_2e	14.39	13.47
MSS-vessel	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	CO_2	48.22	0.40
			CH_4	0.81	<0.01
			CO_2e	65.27	0.54
MSS-pigging	MSS-pigging	MSS- Pigging Operations	CO_2	0.43	<0.01
			CH_4	0.01	<0.01
			CO_2e	0.68	<0.01

9. FEDERAL NEW SOURCE REVIEW REQUIREMENTS

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

- Nonattainment New Source Review (NNSR)
- Prevention of Significant Deterioration (PSD)

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 NSR permit application.

9.1. NNSR APPLICABILITY REVIEW

The Avalon Mega CGF facility will be located in Loving County, Texas, which has been designated as attainment area for all criteria pollutants. Under EPA and TCEQ rules, sites located in areas that are designated in attainment of the National Ambient Air Quality Standards (NAAQS) for a criteria pollutant are potentially regulated under the PSD program if they are considered major sources. Major source thresholds are defined in 40 CFR §52.21 (b)(1)(i). The Avalon Mega CGF will be considered a major source under PSD and therefore, not subject to NNSR permitting requirements.

9.2. PSD APPLICABILITY REVIEW

The proposed Avalon Mega CGF will be a new major source with respect to GHG emissions and subject to PSD permitting requirements under the GHG Tailoring Rule[10]. In the Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources and a major modification threshold of 75,000 tpy CO_2e for existing major sources. DBJVG has determined that the GHG emissions from the proposed project will exceed 100,000 tpy. With a final action published in May 2011, EPA promulgated a FIP to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications.[11] Therefore, GHG emissions from the proposed project are subject to the jurisdiction of the EPA under authority asserted in Texas through the aforementioned FIP.

As shown in the TCEQ application, the facility's emissions of non-GHG criteria pollutants will also exceed the PSD major source thresholds (i.e. > 250 tpy of NO_x and CO). Therefore, the proposed project will be subject to PSD permitting requirements for non-GHG criteria emissions and the project is subject to the jurisdiction of the TCEQ for major source NSR permitting of such emissions. Accordingly, DBJVG is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct.

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

[11] 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).

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 in 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:

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

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[12], this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr).[13] Furthermore, EPA’s guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling average.[14]

---

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

[13] 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).

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

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.[15] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases and not a single pollutant.[16] 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:

> *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.*[17]

DBJVG 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 Avalon Mega CGF, 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. DBJVG has provided 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. To assist applicants and regulators with the

---

[15] 40 CFR §52.21(b)(12)

[16] 40 CFR § 52.21(b)(49)(i)

[17] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, June 3, 2010.*

case-by-case process, in 1990 EPA issued a Draft Manual on New Source Review permitting which included a "top-down" BACT analysis.

> *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.*[18]

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.[19]

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."*[20]

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*

[18] Draft NSR Manual at B-2. "The NSR Manual has been used an a guidance document in conjunction with new source review workshops and training, and as a simple 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 be this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen 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)

[19] 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.

[20] As quoted in Sierra Club v. U.S. EPA (97-1686).

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.[21]

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 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.

On March 27, 2012, the EPA Administrator signed proposed Standards of Performance for GHG Emissions for Electric Utility Generating Units by adding Subpart TTTT to 40 CFR Part 60 (NSPS Subpart TTTT). This proposed NSPS is not applicable to the emission sources included in this application.

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.

[21] 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.

EPA's March 2011 GHG Permitting Guidance generally directed that a BACT review for GHGs should be done in the same manner as it is done for any other regulated pollutant.[22] 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.[23] DBJVG has provided this information in Section 6 of this application.
- 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.[24] Because the project's GHG emissions are dominated by the compressor engines, amine reboilers, and the amine units via the thermal oxidizers, this BACT analysis focuses mainly on these predominant sources of CO_2e from the project.

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.

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

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

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1.[25] For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. DBJVG proposes the use of pipeline quality natural gas only for all combustion equipment associated with the proposed project. 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.

---

[22] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, page 17.

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

[24] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, page 31.

[25] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, page 24.

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 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."[26]

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".[27] 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."[28] 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,

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

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

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

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."[29]

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 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.

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.

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 Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule 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, DBJVG proposes only long-term averaging periods (i.e. 365 day rolling average) for each 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 estimated emissions increase of GHGs from the proposed project will be greater

[29] *PSD and Title V Permitting Guidance for Greenhouse Gases.* March 2011, pages 42-43.

than 100,000 tpy on a CO_2e basis primarily due to the removal of CO_2 from the field gas in the amine units and the combustion of natural gas in the compressor engines and amine reboilers.

Potential emissions of GHGs from the proposed project will result from the following emission units:

- Twelve Caterpillar G3612 Engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12);
- Six amine reboilers (EPNs: H-01, H-02, H-03, H-04, H-05, and H-06);
- Six amine still vents routed to thermal oxidizers (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, and TO-6);
- Six TEG dehydrator reboilers (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, and RB-06);
- Three flares (EPNs: FL-01, FL-02. FL-03);
- Six emergency generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06); and
- Site-wide fugitive emissions (EPN: FUG).

DBJVG is also proposing to construct six produced water storage tanks (EPNs: PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, and PWTK-06), and to conduct produced water truck loading operations (EPN: TL-2). However, based on the characteristics of the produced water tank contents; the GHG emissions from these sources have been determined to be negligible and emission for these operations are not included in this GHG PSD BACT analysis. In addition, GHG emissions from small emission sources such as MSS activities are not included in the BACT analysis. GHG emissions from these negligible sources will be minimized through the employment of work practices.

The emission calculations provided in Section 7 and Appendix C include a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed Avalon Mega CGF. 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)[30]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Industrial Boilers* (hereafter referred to as GHG BACT Guidance for Boilers)[31]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry* (hereafter referred to as GHG BACT Guidance for Refineries)[32]

[30] 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

[31] 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

[32] 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

10.4. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is a summary of BACT for the control of GHG emissions from the proposed Avalon Mega CGF 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. DBJVG 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 Avalon Mega CGF

EPN	Description	Proposed BACT Limit
E-1 through E-12	Caterpillar G3612 Compressor Engines	13,705 tpy CO_2e per engine
H-01 through H-06 and RB-1 through RB-6	Amine Reboilers and TEG Dehydrator Reboilers	3,822 lb CO_2/MMscf (per train)
TO-1 through TO-6	Amine Still Vent Routed to a Thermal Oxidizer	Work Practices
FL-1, FL-2, and FL-3	Flares	Work Practices
EG-01, EG-02, EG-03, EG-04, EG-05, and EG-06	Emergency Generators	Work Practices
FUG	Fugitive Emissions	Work Practices

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

The new 200 MMscfd Avalon Mega CGF will be designed and constructed using new or updated energy efficient equipment. The plant was designed with heat and process integration in mind for increased energy efficiency. Where feasible, the facility utilizes available process streams to transfer heat which reduces combustion heating requirements in the process. Equipment (vessels), piping, and components in hot service to will be designed to prevent heat lose to the atmosphere from equipment containing hot streams.

The facility will recycle the flash gas from the amine units and flash gas and still vent from the TEG reboiler back to the fuel gas system instead of sending these vents to a control device. The recycling of this material will reduce the amount of natural gas required to fuel the facility's combustion sources and will avoid the formation of additional GHG from combusting this material in a control device.

Process control instrumentation and pneumatic components will be operated using compressed air rather than fuel gas or off-gas; therefore, no GHG emissions will be emitted to the atmosphere from these components. The plant will be built using new, state-of-the-art equipment and process instrumentation and controls. DBJVG operating and maintenance policies will maintain all equipment according to manufacturer specifications in order to keep all equipment operating efficiently.

Table 10.4-2. 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, and 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, and 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 Oxidizers and Flares	
Fuel quality analysis and fuel handling	• Monitor fuel quality • Periodic fuel sampling and analysis • Fuel handling practices • DBJVG will use clean and treated field gas as fuel	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. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed project following the EPA's five-step "top-down" BACT process. DBJVG is proposing the use of good combustion practices for all combustion sources at the proposed facility.

11.1. AMINE UNIT STILL VENT

The amine units at the Avalon Mega CGF will be used to remove CO_2 in order to meet pipeline specifications for transportation of the natural gas. Because the amine unit is designed to remove CO_2 from the inlet gas stream, the generation of CO_2 is inherent to the process, and any reduction of the CO_2 emissions by process changes would reduce the process efficiency. This would result in a greater CO_2 content in the natural gas that would eventually be emitted. The process-based CO_2 emissions emitted from the amine still vents are calculated based on the estimated flow rate and gas composition of the waste gas.

11.1.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration (CCS);
- Flare;
- Thermal Oxidizer;
- Condenser;
- Proper Design and Operation; and
- Use of Tank Flash Gas Recovery Systems.

11.1.1.1. Carbon Capture and Sequestration

DBJVG engaged the Wood Group Mustang (WGM) to conduct research and analysis to determine the technical feasibility of CO_2 capture and transfer from the Avalon Mega CGF Facility. Since most of the CO_2 emissions from the proposed project are generated from the amine units, the study was designed to evaluate potential options to capture and transfer to an existing pipeline.

Based on the results of these studies, capture and transfer of CO_2 from the amine units is technically feasible. The study evaluated the potential options for capture and transfer of CO_2 from the Avalon Mega CGF (located near Mentone in Loving County, TX) to nearby CO_2 pipelines. The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer.

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

11.1.1.2. Flare

The use of a flare can only reduce the CH_4 emissions contained in the Avalon Mega CGF stripped amine acid gases. The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Controlling the amine still vent streams with a flare would also require significant supplemental fuel to increase the heating value of the waste gases to the point that it can be effectively combusted in a flare at 300 Btu/ft^3. This will create collateral CO_2 and CH_4 emissions from the additional combustion of the fuel gas and increase the overall CO_2e emissions from this control device. Flares have a destruction efficiency rate (DRE) of 98% for VOCs and 99% for compounds containing no more than 3 carbons and that contain no elements other than carbon and hydrogen, including CH_4. Additionally, the flare requires the use of a continuous pilot ignition system or equivalent that results in additional GHG emissions from natural gas combustion in the pilot. The combustion of the supplemental fuel and pilot fuel result in an overall increase in the net CO_2e emissions from this source.

11.1.1.3. Thermal Oxidizer

Another option to reduce the CH_4 emitted from the Avalon Mega CGF facility is to send stripped amine acid gases to a thermal oxidizer (TO). The TO is also an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions, the control of CH_4 in the process gas at the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. A regenerative thermal oxidizer (RTO) has a high efficiency heat recovery. This allows the facility to recover heat from the exhaust stream, reducing the overall heat input of the plant. In general, TOs have destruction and removal efficiency (DRE) greater than of 99% for all VOC and HAP compounds, which is more efficient than a typical flare. In contrast with a flare, which requires the use of supplemental fuel to increase the waste gas heating value as well as a constant pilot, a RTO only uses a minimal amount of natural gas to get up to the optimum temperature for combustion resulting in lower use of supplemental fuel and lower GHG emissions.

11.1.1.4. Condenser

Condensers are supplemental emissions control that reduces the temperature of the still column vent vapors on amine units to condense water and VOCs, including CH_4. The condensed liquids are then collected for further treatment or disposal. The reduction efficiency of the condensers is variable and depends on the type of condenser and the composition of the waste gas, ranging from 50-98% of CH_4 emissions.

11.1.1.5. Proper Design and Operations

The amine unit will be new or updated equipment installed on site. New or updated equipment has better energy efficiency, hence reducing the GHGs emitted during combustion. The amine unit will operate at a minimum circulation rate with consistent amine concentrations. By minimizing the circulation rate, the equipment avoids pulling out additional VOCs and GHGs in the amine streams, which would increase VOC and GHG emissions into the atmosphere.

11.1.1.6. Use of Tank Flash Gas Recovery Systems

The amine units will be equipped with flash tanks. The flash tanks will be used to recycle off-gases formed as the pressure of the rich glycol/rich amine streams drops to remove lighter compounds in the stream prior to entering the reboiler. These off-gases are recycled back into the plant for reprocessing, instead of venting to the atmosphere or combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

11.1.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

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

The control options for minimizing GHG emissions from the amine still vent are ranked below:

Rank	Control Technology	Estimated CO_2e Reduction	Reduction Details	Reference
1	Carbon Capture and Sequestration	80%	Reduction of all GHGs.	Report of the Interagency Task Force on Carbon Capture and Storage issued by EPA August 2010 Section III.A.2 Status of Capture Technology
2	Proper Design and Operation	1% - 10%	Reduction of all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
3	Condenser	< 0.25%	Reduction of CH_4 in acid gas and dehydrate waste gas.	Vendor Data
4	Use of Tank Flash Gas Recovery Systems	< 0.25%	Reduction of CH_4 in flash gas only.	Hard piped back into the system
5	Thermal Oxidizer	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas combustion	Vendor Data
6	Flare	--	Reduction in acid gas CH_4. Increase in CO_2 due to acid gas, supplemental fuel, and pilot gas combustion.	http://www.tceq.texas.gov/permitting/air/guidance/newsourcereview/flares/ and vendor data

11.1.4. 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 Sequestration.

The exhaust from the amine still vent contains a high concentration of CO_2 (90%) as shown in the ProMax simulation output included in Appendix A; however additional processing of the exhaust gas will be required to implement CCS. The vent gas contains VOC and HAP impurities. The vent gas must undergo separation (removal of other pollutants from gas), capture, and compression. Once the CO_2 stream is treated, it can be controlled from this project in one of the following ways:

- Sequestered in a geological formation
- Use in Enhanced Oil Recovery (EOR)
- Transported to an existing CO_2 pipeline

A study of the risks associated with long-term geologic storage of CO_2 places those risks on par with the underground storage of natural gas or acid-gas[33]. The liability of underground CO_2 storage, however, is less understood. A recent publication from MIT states that "The characteristics (of long term CO_2 storage) pose a challenge to a purely private solution to liability" (de Figueiredo, M., 2007. The Liability of Carbon Dioxide Storage, Ph.D. Thesis, MIT Engineering). Based on the location of the proposed Avalon Mega CGF, there are other demonstrated and cost effective options for CO_2 control; therefore the liability associated with sequestration in geologic formations and long-term environmental impact uncertainty remove this CCS option from further consideration.

The Avalon Mega CGF is approximately 12 miles from the existing Kinder Morgan CO_2 pipeline network. The Kinder Morgan pipeline network provides CO_2 for various uses, including EOR. Therefore the evaluation of transferring the Avalon Mega CGF CO_2 to an existing pipeline network includes both the options of transporting the CO_2 to an existing pipeline and using the gas for EOR. The CO_2 Sales Definition Study conducted by WGM to determine the financial and environmental impacts of implementing CCS through transporting the CO_2 to an existing pipeline network evaluates the financial feasibility of both options.

DBJVG, through the WGM study, reviewed the feasibility to recover CO_2 for use in for enhanced oil recovery in the area or transported via CO_2 pipeline for sale to other users in various parts of the area or state. This study determined that the Avalon Mega CGF is capable of producing 1217 tons (1104 metric tons) of CO_2 at a maximum natural gas production rate of 200 MM SCFD and with a CO_2 level of 11% in the produced gas. For the baseline facility design, the CO_2 is exhausted into the atmosphere through thermal oxidizers to insure all VOC and HAP impurities are destroyed.

The primary purpose of the Avalon Mega CGF amine units is to remove the CO_2 in the acid gas stream to meet the pipeline specification; therefore the amine still vent is a very high CO_2 concentrated stream (90%). While the amine still vent has a high CO_2 content, additional processing of the exhaust gas will be required to meet the specifications of the Kinder Morgan pipeline. These include separation (removal of other pollutants from the vent 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. Compressing the captured CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall power plant system. Published studies estimate energy penalties in the range of 15% to 30% for CCS. This would also mean that up to 30% more fuel will be consumed, 30% more CO_2 will be produced at the facility, and 30% more criteria pollutant emission (NO_x, CO, VOC, PM, SO_2) would be generated. This would result in significant negative environmental and energy impacts.

Specifically, the amine vent stream must be dehydrated by using a DEG glycol dehydrator to reduce the water content. The water content is the most critical parameter due to the corrosion associated with CO_2 stream with water. The H_2S levels in the natural gas are low, typically expected to be between 4 and 12 ppm for the gas processed at Avalon Mega CGF. The concentrated H_2S levels in the amine unit still vent are expected to range between 40 and 120 ppm. The H_2S will be removed via treating unit using one of several available processes. For this study we have used a Sulfatreat™ catalytic process. Since the H_2S levels are low, the catalyst usage will be low in the Sulfatreat system. The spent catalyst is environmentally safe and can be easily disposed of via landfill or sold for fertilizer. The series of treatment processes would result in a CO_2 product of approximately 99.8%.

[33] Benson, S. 2006. CARBON DIOXIDE CAPTURE AND STORAGE, Assessment of Risks from Carbon Dioxide Storage in Deep Underground Geological Formations. Lawrence Berkley National Laboratory

The CO_2 will be collected from the Avalon Mega CGF facility in a 4" pipeline and the gathering lines will feed a 6" pipeline. The pipeline will transport the gas to the Kinder Morgan pipeline for transport to market. The collection headers total length is 10 miles. The pipeline is assumed to be 12 miles.

The WGM study determined the total initial capital cost of the equipment and infrastructure required to capture, compress, treat, and transfer the CO_2 to the Kinder Morgan pipeline approximately is $44,065,000.00, with annual operating costs of $1,826,000. These costs were provided in the WGM study in a formal CAPEX Estimate Study for the Avalon Mega CGF project. The overall estimated cost of CCS implementation represents the sum of the individual cost factors. The overall cost of the Avalon Mega CGF project is an initial capital investment of approximately $117,000,000 with annual operating costs of $8,000,000. As shown in Appendix D, the estimated cost of CCS implementation at the Avalon Mega CGF is $17.04/ton removed of CO_2. The total annualized cost of the CCS over a ten year lifespan is approximately $8,083,230 compared to an annualized cost of the project of $24,614,000. The implementation of CCS represents an additional 33% cost to the project on an annual basis. As such, DBJVG contends that CCS is economically infeasible control technology option and eliminates CCS from further review under this BACT analysis.

11.1.5. Step 5 – Select BACT for the Amine Unit Still Vent

DBJVG proposes to utilize a well-designed and operated TO to treat the amine unit acid gas stream. The additional design elements and work practices as BACT for the amine still vent in place of a numerical BACT limit:

- Condenser;
- Use of a Thermal Oxidizer;
- Use of Tank Flash Gas Recovery Systems; and
- Proper Design and Operation.

The TO produces no significant additional GHG emissions beyond what is already present in the acid gas stream. Specific monitoring and work practices for the TO are found in section 11.2.5 of this BACT analysis.

11.2. THERMAL OXIDIZER

Each thermal oxidizer (EPNs: TO-1 through TO-6) at Avalon Mega CGF are designed to destroy, through combustion, the process waste gas produced by the amine units, and has a fuel firing rate of 9 MMBtu/hr when firing natural gas. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas routed to the TO.

CO_2 emissions from burning waste gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the TO and the burner fuel. CO_2 emissions emitted from the TO are based on the amount of carbon-containing gases produced from the amine unit. In addition, minor amounts of CH_4 emissions are emitted from the TO due to incomplete combustion of CH_4.

The TO is an example of a control device for which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of VOCs, HAPs and specifically CH_4 in the process gas to the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to the waste gas even though it will form additional CO_2 emissions.[34] The TO has a destruction and removal efficiency of a least 99% for VOCs and HAPs.

The following sections present a BACT evaluation for GHG emissions from combustion of burner gas and amine still vent gas released to the TOs.

11.2.1. 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;
- Proper Design;
- Low Carbon Fuel Selection; and
- Good Combustion, Operating, and Maintenance Practices.

11.2.1.1. Carbon Capture and Sequestration

The viability of CCS has been discussed previously in Section 11.1 and is not considered a viable option at this time. The emission units evaluated in this BACT analysis section are the TO burners only. The employment of CCS for the amine units still vent were deemed economically infeasible as discussed in Section 11.1.4. Therefore controlling these minimal emissions generated from the TO burners is also economically infeasible.

11.2.1.2. Proper Design

Good TO design can be employed to destroy any HAPs, VOCs and CH_4 entrained in the waste gas from the amine unit. Good TO design includes flow measurement and monitoring/control of waste gas heating values.

11.2.1.3. Low Carbon Fuel Selection

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

11.2.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the TO. Good combustion practices also include proper maintenance and tune-up of the TO at least annually per the manufacturer's specifications as outlined in Table 10.4-2.

---

[34] 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.

11.2.2. Step 2 – Eliminate Technically Infeasible Options

As discussed above, the burners are the unit of interest in this section; therefore, the use of CCS is technically infeasible as illustrated in Section 11.1.4.

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

The control options for minimizing GHG emissions from the TO are ranked below:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Proper Design	1% - 10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
3	Good Combustion, Operating, and Maintenance Practices	1% - 10%	Reduction in all GHGs.	EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

11.2.4. Step 4 – Evaluate Most Effective Control Options

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

11.2.5. Step 5 – Select BACT for the TO

DBJVG proposes the following design elements and work practices as BACT for the TO:

- Proper Design;
- Low Carbon Fuel Selection; and
- Good combustion, Operating, and Maintenance Practices.

Compliance with work practices and requested monitoring and recordkeeping requirements are noted below:

- The TOs are designed to combust low-VOC concentration waste gas from the amine vent streams.
- For burner combustion, the natural gas fuel usage (scf) will be recorded using a flow meter.
- Each thermal oxidizer shall have an initial performance test, and annual compliance testing, to verify destruction and removal efficiency (DRE) as represented in the application.
- Waste gas will be sampled and analyzed on an annual basis for composition. The sampled data will be used to calculate GHG emissions to show compliance with the limits specified in this application.
- GHG emissions shall be calculated, on a monthly basis, using equations as demonstrated in this application.
- The flowrate of the waste gas combusted will be measured and recorded using a flow meter.
- Periodic maintenance will help maintain the efficiency of the thermal oxidizer and will be performed at a minimum annually or more frequently as recommended by the manufacturer specifications.
- DBJVG will install a temperature monitor in the combustion chamber to record the combustion temperature.

- DBJVG would like to base the minimum combustion temperature to be determined during the initial performance test. DBJVG will maintain that temperature at all times when processing waste gases from the amine units in the thermal oxidizer to ensure proper destruction and removal efficiency. DBJVG will install and maintain a temperature recording device with an accuracy of ± 0.75 percent of the temperature being measured expressed in degrees Celsius.

11.3. COMPRESSOR ENGINES

GHG emissions from the proposed engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12) include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The following section presents BACT evaluations for GHG emissions from the proposed engines.

11.3.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/fuel ratio controllers; and
- Efficient Engine Design.

11.3.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from each engine 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 engines, CCS would involve post combustion capture of the CO_2 from the engines 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 similar engines, 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

---

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

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]

11.3.1.2. Fuel Selection

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

11.3.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the engines. Good combustion practices also include proper maintenance and tune-up of the engine at least annually per the manufacturer's specifications as outlined in Table 10.4-2.

11.3.1.4. Air/fuel ratio controllers

Air/fuel ratio controllers minimize methane emissions from reciprocating engines. 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 and reduce the amount of energy required to heat the stream and, therefore, reduce the CO_2e emissions. Please note because these engines are equipped with the ultra-lean burn technology, air/fuel ratio controllers are inherent to the process in the engines.

11.3.1.5. Efficient Engine Design and Selection

To select the most efficient engine for the Avalon Mega CGF project the following factors were taken into account: site layout square footage, operational fluctuations and flexibility, emissions performance, and energy efficiency.

To meet the compression needs of this project, larger engines with high horsepower ratings are required to move the large amounts of gas at the facility. Engine manufacturers such as Ajax, Cummins, and Arrow do not manufacture engines that could handle the compression needs of the Avalon Mega CGF. The two engine manufacturers with engines large enough to meet the needs of the facility are Waukesha and Caterpillar.

Except for one extremely large engine model that is not readily available in the United States, Waukesha engines generally utilize rich burn technology to burn fuel in the engine combustion chamber. Rich burn is an inherently inefficient combustion process that results in increased fuel usage compared to lean burn engines. Therefore, the Waukesha engines were eliminated from consideration due to their inefficient rich burn design. The engine selection process then focused on energy efficient lean burn technology offered by Caterpillar engines.

Caterpillar manufactures a large engine, the CAT CTM series engine, that is similar in size to the very large lean burn Waukesha engine, but it is also not readily available for this application. In addition, this larger engine does not allow for sufficient operational flexibility in the case of declining fields, shut-in wellsites, and other potential impacts on engine load. Caterpillar offers three engine models that could satisfy all the needs of this project: the G3608LE,

---

[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

G3612LE, and G3616LE. The "LE" in the model names means low emission, so these engines also have lower levels of criteria pollutants, which meet the criteria PSD-BACT requirements. The following table compares the three available Caterpillar engines evaluated for this project.

Table 11.3-1. Efficiency Comparison of Caterpillar Engines

Model	Horsepower Rating (HP)	# of Engines Required to meet Compression Needs of Avalon Mega CGF	BSFC @ 100%	BSFC @ 50%
G3608LE	2370	19	6791	7785
G3612LE	3550	12	6791	7684
G3616LE	4735	10	6766	7728

The G3616LE engine is slightly more fuel efficient than the G3612LE engine at full load. However, due to the operational concerns mentioned previously, it is more likely that these engines, if used at this facility, would be operating closer to 50% load than 100% load. This would result in a severe increase in fuel consumption for this engine model, and prevent sufficient operational flexibility for the site.

A G3608LE is just as fuel efficient as the G3612LE; however, several more engines would be required for the site to be able to meet its compression needs. This would result in more maintenance costs, more land required, and likely increased lubricating oil consumption as well, which combine to make this engine model a poor choice for this site.

Therefore, due to these factors, the G3612LE is the most optimum solution for a fuel efficient natural gas fired engine. There is insufficient grid capacity for electrical engines to be operated at this facility, and natural gas is a cleaner burning fuel than other sources.

11.3.2. Step 2 – Eliminate Technically Infeasible Options

As discussed below, CCS is deemed technically infeasible for control of GHG emissions from the engines. All other control options are technically feasible.

11.3.2.1. 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 engines 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.[38] A detailed CCS evaluation was provided in Section 11.1.4

[38] 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.

for the 90% CO_2 stream from the amine still vents. These emission units, by comparison, emit CO_2 in small and more diluted quantities. In addition, the CO_2 concentration in the flue gas stream is approximately 4.6%. 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. The use of solid sorbents and membranes are considered to be in the research and development phase. Implementing CCS on the engine flue gas streams would require considerable additional gas processing equipment to separate the CO_2 from the exhaust. The low purity and concentration of CO_2 in the engines' exhaust means that the per ton cost of removal and storage will be much higher than the public data estimates for much larger carbon rich fossil fuel facilities due to the loss of economies of scale. Even using low-side published estimates for CO_2 capture and storage of $256 per ton for equipment with similar flue gas characteristics such as a new natural gas combined cycle turbine, assuming a conservative $6/MBtu gas price (Anderson, S., and Newell, R. 2003. Prospects for Carbon Capture and Storage Technologies. Resources for the Future. Washington DC) means added cost to the project over $42,059,654 per year. The equipment to treat the engine exhaust to separate the CO_2 would cost as much as all the treatment equipment and pipeline required for only the amine still vents. 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.

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

With elimination of CCS as a control option, the following remain as technically feasible control options for minimizing GHG emissions from the engines:

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/fuel ratio controllers; and
- Efficient Engine Design.

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

11.3.4. 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.

11.3.5. Step 5 – Select BACT for the Engines

DBJVG proposes the following design elements and work practices as BACT for the engines:

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/fuel ratio controllers; and
- Efficient Engine Design.

DBJVG proposes the CO_2e emission limits for the engines:

- For each engine (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12): 13,705 short tons of CO_2e per year per engine

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 Appendix C 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.

Compliance with the requested BACT limits will be demonstrated through the following operational, monitoring and recordkeeping requirements:

- All compressor engines will be equipped with lean-burn with low NO_x technology and oxidation catalysts, and will be operated using good combustion practices.
- All engines will be tuned once per year, or more frequently, per manufacturer recommendations.
- CO_2 emitted from the engines will be calculated on a monthly basis using equation C-2a in 40 CFR Part 98 Subpart C.
- CH_4 and N_2O emissions will be calculated on a monthly basis using the default CH_4 and N_2O emission factors contained in Table C-2, equation C-9a of 40 CFR Part 98, and the measured actual heat input (HHV).
- The CO_2e emissions will be calculated on a 12-month rolling average, based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
- Fuel for the Compressor Engines shall be limited to natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf).
- The high heat value (HHV) of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6).
- The fuel combusted in the compressor engines will be measured and recorded using an operational nonresettable elapsed flow meter. Flow meters will be calibrated annually.

11.4. AMINE AND TEG DEHYDRATOR REBOILERS

GHG emissions from the proposed reboilers (EPNs: H-01 through H-06 and RB-1 through RB-6) include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The reboilers include the six amine unit and six TEG dehydrator reboilers. The following section presents BACT evaluations for GHG emissions from the proposed reboilers.

11.4.1. Step 1 – Identify All Available Control Technologies

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

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

11.4.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from each reboiler 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 each reboiler, CCS would involve post combustion capture of the CO_2 from the reboiler stack 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 on similar equipment, 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.[39] 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.[40] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[41]

11.4.1.2. Low Carbon Fuel Selection

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

11.4.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the reboilers. Good combustion practices also include proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications as outlined in Table 10.4-2.

---

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

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

41 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

11.4.1.4. Combustion Air 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. [42]

11.4.1.5. 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.

11.4.1.6. Efficient Heater Design

Efficient design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since DJBVG is proposing to install new equipment, these reboilers will be designed to optimize combustion efficiency. Additionally, the amine units and TEG dehydrator have been designed to minimize heat duty and require less fuel to treat inlet gas.

11.4.2. 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.

11.4.2.1. 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.[43] 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.

11.4.2.2. 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.

---

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

[43] *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.

11.4.3. 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:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Efficient Heater Design	10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry
3	Good Combustion, Operating, and Maintenance Practices	1% - 10%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 5.1.1.5 Improved Maintenance
4	Combustion Air Controls	1% - 3%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures for the Petroleum Refinery Industry

11.4.4. 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.

11.4.5. Step 5 – Select BACT for the Reboilers

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

- Low Carbon Fuel Selection;
- Efficient Heater Design;
- Good Combustion, Operating, and Maintenance Practices; and
- Combustion Air Controls.

DJVBG proposes the combined CO_2 emission limit, expressed in lb CO_2/MMscf, for each train that contains one amine and one TEG dehydrator reboiler as follows:

EPN	Description	Proposed BACT Limit
H-01 and RB-01	Train 1	3,822 lb CO_2/MMscf
H-02 and RB-02	Train 2	3,822 lb CO_2/MMscf
H-03 and RB-03	Train 3	3,822 lb CO_2/MMscf
H-04 and RB-04	Train 4	3,822 lb CO_2/MMscf
H-05 and RB-05	Train 5	3,822 lb CO_2/MMscf
H-06 and RB-06	Train 6	3,822 lb CO_2/MMscf

Where:

$$\left(4{,}676\frac{lb}{hr}+175\frac{lb}{hr}\right)\div 30.461\frac{MMscf}{day}\times 24\frac{hr}{day}=3{,}822\frac{CO_2e\quad lb}{MMscf}$$

These proposed emission limits are based on the plant design outlet flowrate of 30.461 MMSCFD per train and the maximum potential to emit (lb/hr) of the amine unit and TEG dehydrator reboilers.

Compliance with these emission limits will be demonstrated by monitoring plant inlet volume and performing calculations consistent with the calculations included in Appendix C of this application.

Compliance with the requested BACT limits demonstrated through the following operational, monitoring and recordkeeping requirements:

- CO_2 emitted from the engines will be calculated on a monthly basis using equation C-2a in 40 CFR Part 98 Subpart C.
- CH_4 and N_2O emissions will be calculated on a monthly basis using the default CH_4 and N_2O emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the measured actual heat input (HHV).
- The CO_2e emissions will be calculated on a 12-month rolling average, based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
- The high heat value (HHV) of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6).
- The fuel combusted in the reboilers will be measured and recorded using an operational nonresettable elapsed flow meter. Flow meters will be calibrated annually.
- The reboilers will be tuned for thermal efficiency on an annual basis.

11.5. FLARES

The flares at the Avalon Mega CGF 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 emitted from the flare 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.[44]

The following sections present a BACT evaluation for GHG emissions from combustion of pilot gas.

11.5.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;
- Low Carbon Fuel Selection;
- Flare Gas Recovery;
- Good Combustion, Operating, Maintenance Practices; and
- Good Flare Design.

11.5.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 11.1.

11.5.1.2. Low Carbon 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.

11.5.1.3. 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.

11.5.1.4. 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.

---

[44] 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.

11.5.1.5. 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, blower controls, and monitoring/control of waste gas heating value.

11.5.2. 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.

11.5.2.1. 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.

11.5.2.2. 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 Avalon Mega CGF 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.

11.5.3. 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:

Rank	Control Technology	Estimated Reduction	Reduction Details	Reference
1	Low Carbon Fuel Selection	28% (Natural Gas Versus No. 2 Fuel Oil)	Reduction in all GHGs.	40 CFR Part 98 Subpart C, Table C-1
2	Good Flare Design	1% - 15%	Reduction in all GHGs.	Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry issued by EPA October 2010 Section 3.0 Summary of GHG Reduction Measures Table 1 Summary of GHG Reduction Measures

				for the Petroleum Refinery Industry
3	Good Combustion, Operating, Maintenance Practices	1% - 10%	Reduction in all GHGs.	EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

11.5.4. 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.

11.5.5. Step 5 – Select BACT for the Flares

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

- Low Carbon Fuel Selection;
- Good Combustion, Operating, Maintenance Practices; and
- Good Flare Design.

The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. Compliance with work practices is noted below:

- Flare shall have a minimum destruction and removal efficiency (DRE) of 98% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W §98.233(n).
- The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring.
- An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
- DBJVG proposes to limit MSS activities and flaring events to minimize GHG emissions from this source.
- DBJVG proposes the implementation of good combustion practices noted in their initial application.

11.6. EMERGENCY GENERATORS

The proposed project will comprise six 1214-bhp diesel fired emergency generators. The emergency generators will be limited to 100 hours of operation per year for purposes of maintenance and testing. CO_2 emissions from the diesel engines are produced from the combustion of hydrocarbons present in the diesel fuel. CH_4 emissions result from incomplete combustion of hydrocarbons present in the diesel fuel. N_2O emissions from diesel-fueled units form solely as a byproduct of combustion. The engines are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage or natural gas supply curtailments.

The following sections present a BACT evaluation of GHG emissions from the emergency generator engines.

11.6.1. Step 1 - Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;

11.6.1.1. Carbon Capture and Sequestration

CCS is not considered an available control option for emergency equipment that operates on an intermittent basis and must be immediately available during plant emergencies without the constraint of starting up the CCS process.

11.6.1.2. Fuel Selection

The only technically feasible fuel for the emergency generators is diesel fuel. While natural gas-fueled emergency generators may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the emergency generators since they will need to be used in the event of an emergency, when natural gas supplies may be interrupted.

11.6.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices, as specified in Table 10.4-2, are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the emergency engines at least annually per the manufacturer's specifications.

11.6.2. Step 2 - Eliminate Technically Infeasible Options

Due to the fact that the emergency generators will operate less than 100 hours per year in non-emergency service, and because their stack gases are low in volume and CO_2 mass rate, capture and segregation of CO_2 for sequestration has not been demonstrated. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis. As explained above, the only technically feasible fuel for the emergency generators is diesel fuel. All other control technologies are considered feasible.

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

DBJVG will select emergency generators with high fuel combustion efficiency and will implement good combustion, operating, and maintenance practices to minimize GHG emissions.

11.6.4. Step 4 - Evaluate Most Effective Control Options

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

11.6.5. Step 5 - Select CO_2 BACT for Emergency Generators

Based on the selection of a fuel efficient emergency generators and implementing good combustion, operating and maintenance practices as described in Table 10.4-2, DBJVG will meet BACT through work practices. Further, these new engines will be subject to the federal New Source Performance Standard (NSPS) for Stationary Compression Ignition Internal Combustion Engines (40 CFR Part 60, Subpart IIII), such that specific emissions standards for various pollutants must be met during normal operation, such that the engines will meet or exceed BACT.

11.7. 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 included in the proposed project include traditional components such as valves and flanges.

11.7.1. 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.

11.7.1.1. 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.

11.7.1.2. Air-Driven Pneumatic Controllers

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

11.7.1.3. LDAR Programs

Instrumented monitoring is effective for identifying leaking CH_4, and although it cannot detect CO_2, it can detect CO_2 if it is a minor component in a highly concentrated hydrocarbon stream. 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). [45] The following table demonstrated the control efficiencies for TCEQ's various LDAR Programs:

Table 11.6-1. TCEQ Control Efficiencies for LDAR Programs

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

Equipment/Service	28M	28RCT	28VHP	28MID	28LAER	AVO
Valves						
Gas/Vapor	75%	97%	97%	97%	97%	97%
Light Liquid	75%	97%	97%	97%	97%	97%
Heavy Liquid	0%	0%	0%	0%	0%	97%
Pumps						
Light Liquid	75%	75%	85%	93%	93%	93%
Heavy Liquid	0%	0%	0%	0%	0%	93%
Flanges/Connectors						
Gas/Vapor	30%	30%	30%	30%	97%	97%
Light Liquid	30%	30%	30%	30%	97%	97%
Heavy Liquid	30%	30%	30%	30%	30%	97%
Compressors	75%	75%	85%	95%	95%	95%
Relief Valves (Gas/Vapor)	75%	97%	97%	97%	97%	97%
Open-ended Lines	75%	97%	97%	97%	97%	97%
Sampling Connections	75%	97%	97%	97%	97%	97%

11.7.1.4. 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.

11.7.1.5. AVO Monitoring Program

Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids in the piping components are expected to have discernible 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.

11.7.1.6. 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.

11.7.2. 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.

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

11.7.3.1. Air-Driven Pneumatic Controllers

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

11.7.3.2. LDAR Programs

A small amount of GHG may be emitted via piping equipment leaks (i.e., due to CO_2 and methane in the gas streams). It is infeasible to capture GHG emissions from fugitive sources such as piping leaks. However, fugitive GHG emissions can be reduced by utilizing a leak detection and repair (LDAR) program. There are many structured LDAR programs that have been developed as part of state and federal rulemaking and BACT.

LDAR programs are designed to control VOC emissions and vary in stringency. LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing a high content of methane.

The TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000*. Table 5 displays the State BACT recommendations based on the uncontrolled fugitive emission rates.

Table 11.6-2. TCEQ BACT Summary for Fugitive VOC Emissions

Uncontrolled Annual Fugitive VOC Emission Rate	Best Available Control Technology
< 10 tpy	May not require monitoring
10 tpy ≤ x < 25 tpy	28M
≥ 25 tpy	28VHP

The uncontrolled VOC annual fugitive emissions are greater than 25 tpy for the Avalon Mega CGF and therefore, the selection of the TCEQ's 28VHP program is the minimum required for VOC BACT.

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). [46]

11.7.3.3. 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.

11.7.3.4. 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 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.

11.7.3.5. High Quality Components

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

11.7.4. Step 4 – Evaluate Most Effective Control Options

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

11.7.5. Step 5 – Select BACT for Fugitive Emissions

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane and CO_2. The total estimated fugitive CO_2 and methane emissions as CO_2e have a very minor contribution to the proposed facility's total GHG emissions. DBJVG will be implementing the 28MID LDAR program to minimize emissions from piping fugitive leaks. While this operational practice is designed to reduce VOC emissions, it has a collateral effect on GHG emissions.

DBJVG evaluated the existing LDAR programs for the purpose of the control of fugitive VOC emissions. Table 11.6-1 is a summary of the TCEQ's LDAR programs and the control efficiencies that may be achieved with each. The selection of the 28 MID LDAR program was considered appropriate to meet the requirements of the project. As shown in Table 11.6-1, the 28LAER LDAR program is one of the TCEQ's most stringent LDAR programs, developed to satisfy LAER requirements in ozone non-attainment areas. The project is located in Loving County, currently classified as being attainment/unclassified for all criteria pollutants. As such, the use of the 28LAER LDAR program was not appropriate.

In addition, DBJVG proposes to run on compressed air for instrument control. No process gas will be utilized or vented for these applications. Additionally, DBJVG will monitor flanges using quarterly OVA monitoring at the same leak

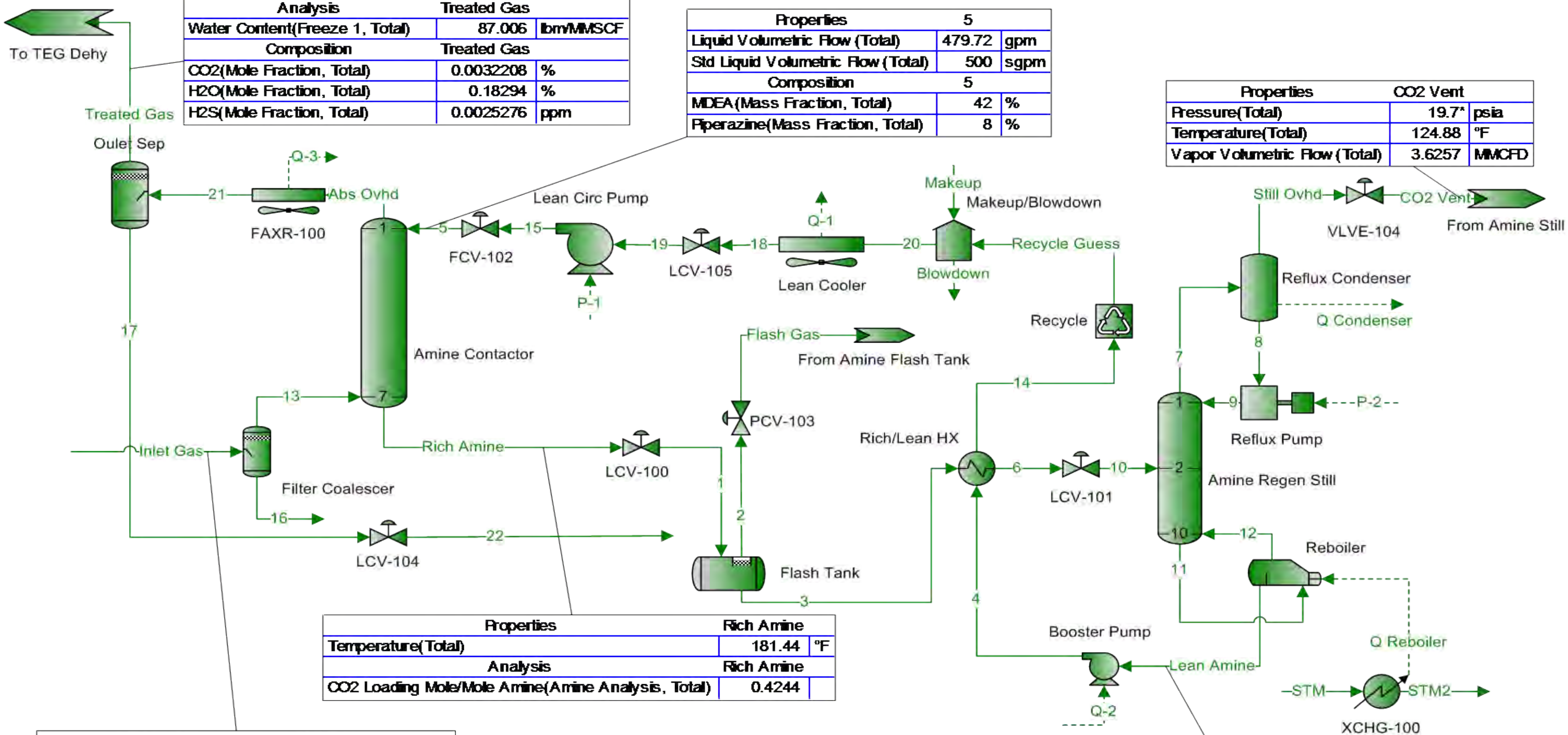
[46] TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

definition for valves, resulting in the same control efficiency applied to flanges as is applied to valves. DBJVG 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.

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

PROMAX® Simulation Output

35 MMSCFD Anadarko Avalon CGF - Amine Unit



Properties	Treated Gas	
Temperature(Total)	120	°F
Std Vapor Volumetric Flow (Total)	30.631	MMSCFD
Analysis	Treated Gas	
Water Content(Freeze 1, Total)	87.006	lbm/MMSCF
Composition	Treated Gas	
CO2(Mole Fraction, Total)	0.0032208	%
H2O(Mole Fraction, Total)	0.18294	%
H2S(Mole Fraction, Total)	0.0025276	ppm

Properties	5	
Liquid Volumetric Flow (Total)	479.72	gpm
Std Liquid Volumetric Flow (Total)	500	sgpm
Composition	5	
MDEA (Mass Fraction, Total)	42	%
Piperazine(Mass Fraction, Total)	8	%

Properties	CO2 Vent	
Pressure(Total)	19.7*	psia
Temperature(Total)	124.88	°F
Vapor Volumetric Flow (Total)	3.6257	MMCFD

Properties	Rich Amine	
Temperature(Total)	181.44	°F
Analysis	Rich Amine	
CO2 Loading Mole/Mole Amine(Amine Analysis, Total)	0.4244	

Properties	Inlet Gas	
Pressure(Total)	1164.7*	psia
Temperature(Total)	100*	°F
Std Vapor Volumetric Flow (Total)	35*	MMSCFD
Analysis	Inlet Gas	
Water Content(Freeze 1, Total)	213.19	lbm/MMSCF
Composition	Inlet Gas	
CO2(Mole Fraction, Total)	11.51*	%
H2S(Mole Fraction, Total)	10.01*	ppm

Analysis	Lean Amine	
CO2 Loading Mole/Mole Amine(Amine Analysis, Total)	0.022205	

Names	Units	Q Reboiler
Energy Rate	Btu/h	2.643e+007

Process Streams		To Thermal Oxidizer	1	2	3	4
Composition	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Total	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Mole Fraction		%	%	%	%	%
H2O		10.3553	10.9085	9.49484	0.554138	35.9227
N2		0.0345614	0.185745	0.000114708	0.267659	0.721918
CO2		83.7502	32.9674	90.3304	0.0160488	0.00276046
H2S		0.00727027	0.00243244	0.00786953	2.69607E-06	8.22996E-07
C1		4.68150	46.1690	0.123352	62.1990	50.6693
C2		0.670837	6.57193	0.0304932	16.4604	5.89653
C3		0.269415	2.12669	0.00874517	10.3670	2.91980
iC4		0.0309403	0.206090	0.000739009	1.30335	0.400189
nC4		0.0880801	0.606430	0.00283051	3.84786	1.06057
iC5		0.0224782	0.0658097	0.000127609	1.30248	0.413070
nC5		0.0296215	0.101196	0.000272503	1.62772	0.526135
nC6		0.0245413	0.0564729	0.000148575	1.15017	0.518810
nC7		0.0142966	0.0109513	1.43399E-05	0.499618	0.370632
nC8		0.0118829	0.00858853	1.65010E-05	0.280084	0.328115
nC9		0.00884087	0.0102446	5.61792E-05	0.122871	0.247590
MDEA		0.000182361	0.00223409	2.75698E-13	1.28678E-05	0.00162203
TEG		3.14808E-06	0	0	0.000709080	1.21597E-06
Piperazine		3.20890E-05	0.000327283	5.65714E-14	0.000830195	0.000293985
Mass Flow		lb/h	lb/h	lb/h	lb/h	lb/h
H2O		983.422	61.3121	816.544	0.230853	105.335
N2		5.10380	1.62339	0.0153395	0.173390	3.29168
CO2		19429.8	452.661	18977.1	0.0163329	0.0197738
H2S		1.30617	0.0258640	1.28030	2.12480E-06	4.56533E-06
C1		395.907	231.080	9.44644	23.0744	132.306
C2		106.334	61.6530	4.37697	11.4455	28.8589
C3		62.6260	29.2578	1.84083	10.5712	20.9562
iC4		9.47989	3.73715	0.205042	1.75179	3.78591
nC4		26.9871	10.9968	0.785338	5.17175	10.0333
iC5		8.54923	1.48136	0.0439502	2.17308	4.85084
nC5		11.2661	2.27789	0.0938536	2.71573	6.17859
nC6		11.1485	1.51833	0.0611197	2.29205	7.27705
nC7		7.55172	0.342359	0.00685917	1.15769	6.04481
nC8		7.15541	0.306080	0.00899777	0.739843	6.10048
nC9		5.97732	0.409932	0.0343954	0.364418	5.16857
MDEA		0.114553	0.0830578	1.56828E-10	3.54585E-05	0.0314601
TEG		0.00249215	0	0	0.00246243	2.97220E-05
Piperazine		0.0145705	0.00879524	2.32611E-11	0.00165363	0.00412165

Molar Flow	lbmol/h	lbmol/h	lbmol/h	lbmol/h	lbmol/h
H2O	54.5882	3.40334	45.3251	0.0128143	5.84699
N2	0.182191	0.0579506	0.000547577	0.00618955	0.117504
CO2	441.492	10.2855	431.206	0.000371123	0.000449309
H2S	0.0383255	0.000758900	0.0375664	6.23459E-08	1.33956E-07
C1	24.6787	14.4043	0.588840	1.43834	8.24724
C2	3.53634	2.05038	0.145564	0.380642	0.959754
C3	1.42023	0.663508	0.0417464	0.239734	0.475244
iC4	0.163103	0.0642982	0.00352777	0.0301397	0.0651371
nC4	0.464317	0.189201	0.0135118	0.0889807	0.172624
iC5	0.118494	0.0205320	0.000609161	0.0301195	0.0672338
nC5	0.156150	0.0315721	0.00130083	0.0376407	0.0856368
nC6	0.129370	0.0176190	0.000709248	0.0265975	0.0844446
nC7	0.0753650	0.00341670	6.84535E-05	0.0115535	0.0603263
nC8	0.0626411	0.00267954	7.87699E-05	0.00647687	0.0534060
nC9	0.0466049	0.00319623	0.000268180	0.00284135	0.0402992
MDEA	0.000961323	0.000697015	1.31609E-12	2.97565E-07	0.000264011
TEG	1.65952E-05	0	0	1.63973E-05	1.97919E-07
Piperazine	0.000169158	0.000102109	2.70052E-13	1.91980E-05	4.78507E-05
Volumetric Flow	**ft^3/h**	**ft^3/h**	**ft^3/h**	**ft^3/h**	**ft^3/h**
H2O	21794.2	516.577	14274.6	1.63537	2487.30
N2	73.5058	8.95611	0.174831	0.801810	50.4645
CO2	176976	1569.28	136532	0.0472183	0.191884
H2S	15.3461	0.115301	11.8795	7.86927E-06	5.70684E-05
C1	9935.99	2213.98	187.515	184.346	3534.45
C2	1417.42	311.965	46.0901	47.8756	409.625
C3	567.287	100.211	13.1592	29.7007	202.312
iC4	64.9383	9.64506	1.10738	3.68548	27.6600
nC4	184.724	28.3303	4.23738	10.8520	73.2236
iC5	46.9928	3.05167	0.190257	3.61871	28.4434
nC5	61.8825	4.68965	0.405896	4.51952	36.2170
nC6	51.0478	2.59511	0.220056	3.14338	35.5974
nC7	29.6100	0.498854	0.0211197	1.34417	25.3440
nC8	24.5251	0.388225	0.0241938	0.741875	22.3580
nC9	18.1677	0.459135	0.0818998	0.319593	16.8290
MDEA	0.370623	0.0988273	3.95918E-10	3.45310E-05	0.109112
TEG	0.00634860	0	0	0.00190990	8.09296E-05
Piperazine	0.0660665	0.0147307	8.27019E-11	0.00224564	0.0198558

Process Streams		To Thermal Oxidizer	1	2	3	4
Properties	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Total	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Property	**Units**					
Temperature	°F	129.374	181.734	124.877	135.177	167.263
Pressure	psig	1.00405	30.0041	5.00405	35	1.00405
Std Vapor Volumetric Flow	MMSCFD	4.80113	0.284150	4.34768	0.0210612	0.148242
Mass Density	lb/ft^3	0.0997472	0.180004	0.131142	0.211466	0.0489547
Molecular Weight	lb/lbmol	39.9747	27.5257	41.5026	26.7602	20.9038
Compressibility		0.995342	0.993039	0.993840	0.985149	0.996426
Specific Gravity		1.38022	0.950386	1.43297	0.923958	0.721752
Molar Flow	lbmol/h	527.153	31.1991	477.365	2.31247	16.2766
CpCv Ratio		1.28297	1.26116	1.28780	1.19507	1.24417
Dynamic Viscosity	cP	0.0160654	0.0149080	0.0162093	0.0109312	0.0127245

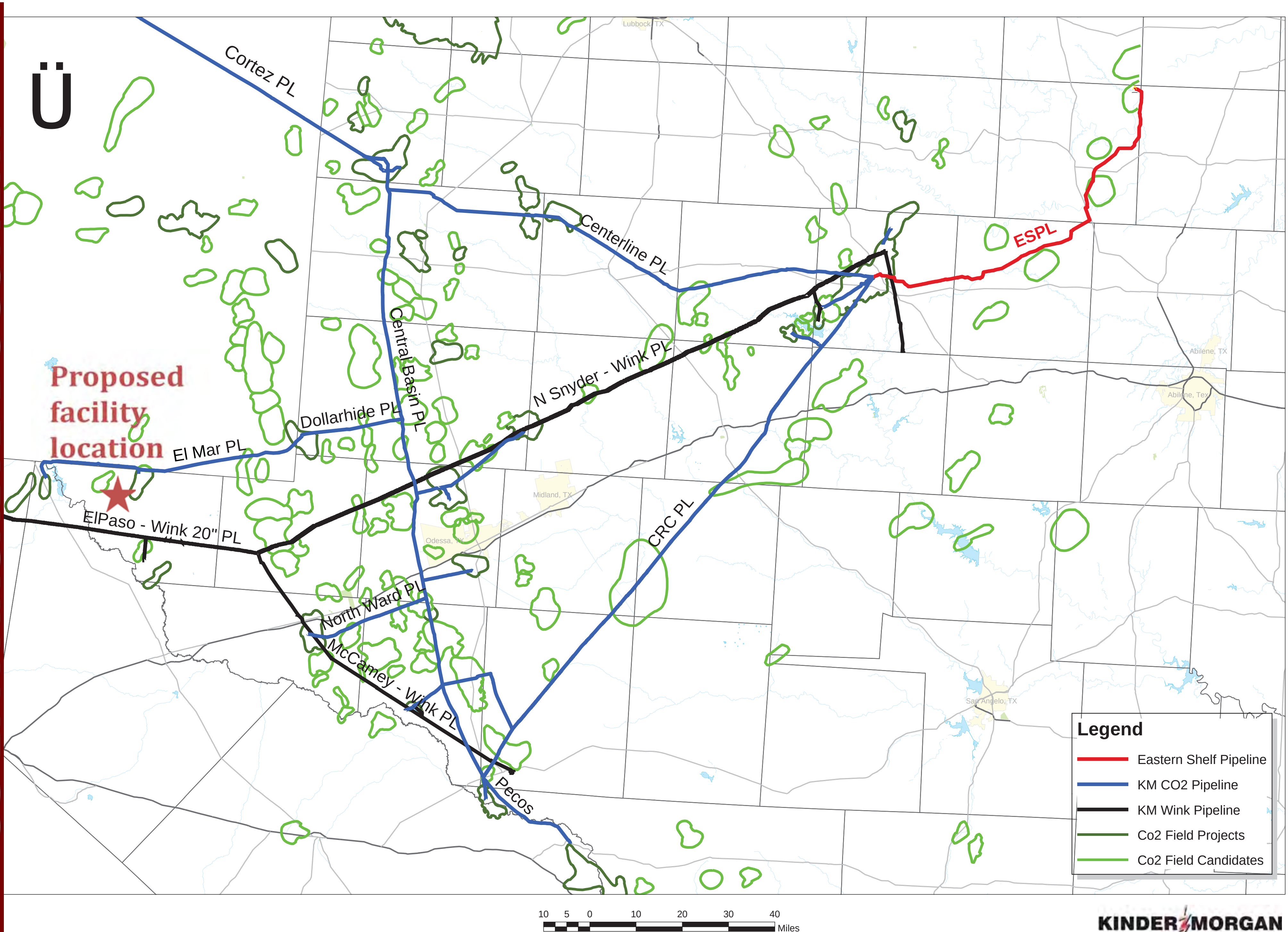
Process Streams		To Thermal Oxidizer	1	2	3	4
Composition	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Vapor	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Mole Fraction		%	%	%	%	%
H2O		10.3553	10.9085	9.49484	0.554138	35.9227
N2		0.0345614	0.185745	0.000114708	0.267659	0.721918
CO2		83.7502	32.9674	90.3304	0.0160488	0.00276046
H2S		0.00727027	0.00243244	0.00786953	2.69607E-06	8.22996E-07
C1		4.68150	46.1690	0.123352	62.1990	50.6693
C2		0.670837	6.57193	0.0304932	16.4604	5.89653
C3		0.269415	2.12669	0.00874517	10.3670	2.91980
iC4		0.0309403	0.206090	0.000739009	1.30335	0.400189
nC4		0.0880801	0.606430	0.00283051	3.84786	1.06057
iC5		0.0224782	0.0658097	0.000127609	1.30248	0.413070
nC5		0.0296215	0.101196	0.000272503	1.62772	0.526135
nC6		0.0245413	0.0564729	0.000148575	1.15017	0.518810
nC7		0.0142966	0.0109513	1.43399E-05	0.499618	0.370632
nC8		0.0118829	0.00858853	1.65010E-05	0.280084	0.328115
nC9		0.00884087	0.0102446	5.61792E-05	0.122871	0.247590
MDEA		0.000182361	0.00223409	2.75698E-13	1.28678E-05	0.00162203
TEG		3.14808E-06	0	0	0.000709080	1.21597E-06
Piperazine		3.20890E-05	0.000327283	5.65714E-14	0.000830195	0.000293985

Mass Flow	lb/h	lb/h	lb/h	lb/h	lb/h
H2O	983.422	61.3121	816.544	0.230853	105.335
N2	5.10380	1.62339	0.0153395	0.173390	3.29168
CO2	19429.8	452.661	18977.1	0.0163329	0.0197738
H2S	1.30617	0.0258640	1.28030	2.12480E-06	4.56533E-06
C1	395.907	231.080	9.44644	23.0744	132.306
C2	106.334	61.6530	4.37697	11.4455	28.8589
C3	62.6260	29.2578	1.84083	10.5712	20.9562
iC4	9.47989	3.73715	0.205042	1.75179	3.78591
nC4	26.9871	10.9968	0.785338	5.17175	10.0333
iC5	8.54923	1.48136	0.0439502	2.17308	4.85084
nC5	11.2661	2.27789	0.0938536	2.71573	6.17859
nC6	11.1485	1.51833	0.0611197	2.29205	7.27705
nC7	7.55172	0.342359	0.00685917	1.15769	6.04481
nC8	7.15541	0.306080	0.00899777	0.739843	6.10048
nC9	5.97732	0.409932	0.0343954	0.364418	5.16857
MDEA	0.114553	0.0830578	1.56828E-10	3.54585E-05	0.0314601
TEG	0.00249215	0	0	0.00246243	2.97220E-05
Piperazine	0.0145705	0.00879524	2.32611E-11	0.00165363	0.00412165
Molar Flow	**lbmol/h**	**lbmol/h**	**lbmol/h**	**lbmol/h**	**lbmol/h**
H2O	54.5882	3.40334	45.3251	0.0128143	5.84699
N2	0.182191	0.0579506	0.000547577	0.00618955	0.117504
CO2	441.492	10.2855	431.206	0.000371123	0.000449309
H2S	0.0383255	0.000758900	0.0375664	6.23459E-08	1.33956E-07
C1	24.6787	14.4043	0.588840	1.43834	8.24724
C2	3.53634	2.05038	0.145564	0.380642	0.959754
C3	1.42023	0.663508	0.0417464	0.239734	0.475244
iC4	0.163103	0.0642982	0.00352777	0.0301397	0.0651371
nC4	0.464317	0.189201	0.0135118	0.0889807	0.172624
iC5	0.118494	0.0205320	0.000609161	0.0301195	0.0672338
nC5	0.156150	0.0315721	0.00130083	0.0376407	0.0856368
nC6	0.129370	0.0176190	0.000709248	0.0265975	0.0844446
nC7	0.0753650	0.00341670	6.84535E-05	0.0115535	0.0603263
nC8	0.0626411	0.00267954	7.87699E-05	0.00647687	0.0534060
nC9	0.0466049	0.00319623	0.000268180	0.00284135	0.0402992
MDEA	0.000961323	0.000697015	1.31609E-12	2.97565E-07	0.000264011
TEG	1.65952E-05	0	0	1.63973E-05	1.97919E-07
Piperazine	0.000169158	0.000102109	2.70052E-13	1.91980E-05	4.78507E-05

Volumetric Flow	ft^3/h	ft^3/h	ft^3/h	ft^3/h	ft^3/h
H2O	21794.2	516.577	14274.6	1.63537	2487.30
N2	73.5058	8.95611	0.174831	0.801810	50.4645
CO2	176976	1569.28	136532	0.0472183	0.191884
H2S	15.3461	0.115301	11.8795	7.86927E-06	5.70684E-05
C1	9935.99	2213.98	187.515	184.346	3534.45
C2	1417.42	311.965	46.0901	47.8756	409.625
C3	567.287	100.211	13.1592	29.7007	202.312
iC4	64.9383	9.64506	1.10738	3.68548	27.6600
nC4	184.724	28.3303	4.23738	10.8520	73.2236
iC5	46.9928	3.05167	0.190257	3.61871	28.4434
nC5	61.8825	4.68965	0.405896	4.51952	36.2170
nC6	51.0478	2.59511	0.220056	3.14338	35.5974
nC7	29.6100	0.498854	0.0211197	1.34417	25.3440
nC8	24.5251	0.388225	0.0241938	0.741875	22.3580
nC9	18.1677	0.459135	0.0818998	0.319593	16.8290
MDEA	0.370623	0.0988273	3.95918E-10	3.45310E-05	0.109112
TEG	0.00634860	0	0	0.00190990	8.09296E-05
Piperazine	0.0660665	0.0147307	8.27019E-11	0.00224564	0.0198558

Process Streams		To Thermal Oxidizer	1	2	3	4
Properties	Status:	Solved	Solved	Solved	Solved	Solved
Phase: Vapor	From Block:	MIX-100	From Amine Flash Tank	From Amine Still	From Glycol Flash Tank	From Glycol Still Vent
	To Block:	--	MIX-100	MIX-100	MIX-100	MIX-100
Property	Units					
Temperature	°F	129.374	181.734	124.877	135.177	167.263
Pressure	psig	1.00405	30.0041	5.00405	35	1.00405
Std Vapor Volumetric Flow	MMSCFD	4.80113	0.284150	4.34768	0.0210612	0.148242
Mass Density	lb/ft^3	0.0997472	0.180004	0.131142	0.211466	0.0489547
Molecular Weight	lb/lbmol	39.9747	27.5257	41.5026	26.7602	20.9038
Compressibility		0.995342	0.993039	0.993840	0.985149	0.996426
Specific Gravity		1.38022	0.950386	1.43297	0.923958	0.721752
Molar Flow	lbmol/h	527.153	31.1991	477.365	2.31247	16.2766
CpCv Ratio		1.28297	1.26116	1.28780	1.19507	1.24417
Dynamic Viscosity	cP	0.0160654	0.0149080	0.0162093	0.0109312	0.0127245

Map of Nearest CO_2 Pipeline



KINDER MORGAN

GHG Emission Calculations

GHG EMISSION CALCULATIONS FOR ENGINES

Combustion Engines (EPNs: E-01, E-02, E-03, E-04, E-05, E-06, E-07, E-08, E-09, E-10, E-11, and E-12)

Combustion Sources of GHG Emissions

Parameter	Units	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612	Compressor, Caterpillar G3612
EPN	-	E-01	E-02	E-03	E-04	E-05	E-06	E-07	E-08	E-09	E-10	E-11	E-12
Rated Capacity (HHV) [1]	MMBtu/hr	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74	26.74
Hours of Operation per Year [2]	hrs/yr	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760
Natural Gas Potential Throughput [3]	scf/yr	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600	192,807,600
Fuel Gas High Heat Value (HHV) [4]	MMBtu/scf	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03

[1] Estimated Maximum Heat Input (MMBtu/hr) = Fuel Consumption (HHV) (Btu/bhp-hr) x Engine Power (bhp) x (1 MMBtu/1,000,000 Btu)
Estimated Maximum Heat Input (MMBtu/hr) = 7,533 (Btu/bhp-hr) x 3,550 (bhp) x (1 MMBtu/ 1,000,000 Btu) = 26.74 MMBtu/ hr
[2] Annual hours of operation assumed to be maximum hours per year. This includes hours for MSS emissions.
[3] Natural gas throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value
[4] High heating value per site specfic gas analysis

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Emission Factors for Natural Gas

Parameter [1]	Value	Units
Fuel Consumption (LHV)	6,791	Btu/bhp-hr
Fuel Consumption (HHV)	7,533	Btu/bhp-hr
Engine Power	3,550	bhp

[1] Per engine specification sheet.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1, 2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
E-01	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-02	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-03	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-04	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-05	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-06	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-07	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-08	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-09	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-10	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-11	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
E-12	Compressor, Caterpillar G3612	Natural Gas	Tier I	13,691.29	0.26	0.03	13,704.72	3,125.87	0.06	5.90E-03	3,128.93
			Total	**164,295.52**	**3.10**	**0.31**	**164,456.66**	**37,510.39**	**0.71**	**0.07**	**37,547.18**
			Total CO_2e Emissions [4]	**-**	**-**	**-**	**164,456.66**	**-**	**-**	**-**	**37,547.18**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.
Annual Emissions (tons/yr) = Natural Gas Potential Throughput (scf/yr) x Natural Gas High Heat Value (MMBtu/scf) x Emission Factor (kg CO_2/MMBtu) x 2.205 (lb/kg) / 2,000 (lb/ ton)

Example CO_2 Annual Emission Rate (tons/yr) = $\frac{192{,}807{,}600 \text{ scf}}{\text{yr}} \times \frac{0.0012 \text{ MMBtu}}{\text{scf}} \times \frac{53.020 \text{ kg CO2}}{\text{MMBtu}} \times \frac{2.205 \text{ lb}}{\text{kg}} \times \frac{\text{ton}}{2{,}000 \text{ lb}} = \frac{13691.29 \text{ tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{13691.29 \text{ tons}}{\text{yr}} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{\text{yr}}{8{,}760 \text{ hr}} = \frac{3125.87 \text{ lbs}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

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

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO_2e Annual Emission Rate (tons/yr) = $\frac{13691.29 \text{ tons}}{\text{yr}} \times 1 + \frac{0.26 \text{ tons}}{\text{yr}} \times 21 + \frac{0.03 \text{ tons}}{\text{yr}} \times 310 = \frac{13704.72 \text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

GHG EMISSION CALCULATIONS FOR EMERGENCY GENERATORS

Emergency Generators (EPNs: EG-01, EG-02, EG-03, EG-04, EG-05, EG-06)

Emergency Generator GHG Emissions

Parameter	Units	Emergency Generators
EPN	-	EG-01, EG-02, EG-03, EG-04, EG-05, EG-06
Rated Capacity (HHV) [1]	MMBtu/hr	7.86
Hours of Operation per Year [2]	hrs/yr	100
#2 Fuel Oil Potential Throughput [3]	gal/yr	5,695
#2 Fuel Oil High Heat Value (HHV) [4]	MMBtu/gal	0.138

[1] Estimated Maximum Heat Input (MMBtu/hr) = Fuel Consumption (HHV) (Btu/bhp-hr) x Engine Power (bhp) x (1 MMBtu/1,000,000 Btu)

Estimated Maximum Heat Input (MMBtu/hr) = 130,984 (Btu/min) x 60 (min/hr) x (1 MMBtu/ 1,000,000 Btu) = 7.86 MMBtu/ hr

[2] Annual hours of operation assumed to be maximum hours per year. This includes hours for MSS emissions.

[3] Throughput is based on heat capacity of the unit, hours of operation and the fuel's high heating value

[4] High heating value Per 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.

GHG Emission Factors for #2 Distillate Diesel

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	73.960	kg CO_2/MMBtu
CH_4 [2]	0.003	kg CH_4/MMBtu
N_2O [2]	0.0006	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Distillate Fuel Oil No. 2.

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Petroleum Fuels.

GHG Emission Factors for #2 Distillate Diesel

Parameter [1]	Value	Units
Fuel Consumption (LHV)	122,961	Btu/min
Fuel Consumption (HHV)	130,984	Btu/min
Engine Power	1,214	bhp

[1] Per engine performance data sheet.

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Tier Used	Annual Emissions [1,2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
EG-01	Emergency Generator 1	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-02	Emergency Generator 2	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-03	Emergency Generator 3	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-04	Emergency Generator 4	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-05	Emergency Generator 5	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
EG-06	Emergency Generator 6	#2 Fuel Oil	Tier I	64.07	2.60E-03	5.20E-04	64.29	1,281.45	0.05	0.01	1,285.76
			Total	**384.43**	**0.02**	**0.00**	**385.73**	**7,688.68**	**0.31**	**0.06**	**7,714.57**
			Total CO_2e Emissions [4]	**-**	**-**	**-**	**385.73**	**-**	**-**	**-**	**7,714.57**

[1] CO_2 emissions from #2 Fuel Oil combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions for #2 Fuel Oil combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = #2 Fuel Oil Potential Throughput (scf/yr) x #2 Fuel Oil High Heat Value (MMBtu/scf) x Emission Factor (kg CO_2/MMBtu) x 2.205 (lb/kg) / 2,000 (lb/ ton)

Example CO_2 Annual Emission Rate (tons/yr) = $\frac{5695 \text{ gal}}{\text{yr}} \times \frac{0.138 \text{ MMBtu}}{\text{gal}} \times \frac{73.960 \text{ kg CO2}}{\text{MMBtu}} \times \frac{2.205 \text{ lb}}{\text{kg}} \times \frac{\text{ton}}{2{,}000 \text{ lb}} = \frac{64.07 \text{ tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{64.07 \text{ tons}}{\text{yr}} \times \frac{2{,}000 \text{ lb}}{\text{ton}} \times \frac{\text{yr}}{100 \text{ hr}} = \frac{1281.45 \text{ lbs}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

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

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO_2e Annual Emission Rate (tons/yr) = $\frac{64.07 \text{ tons}}{\text{yr}} \times 1 + \frac{0.003 \text{ tons}}{\text{yr}} \times 21 + \frac{0.0005 \text{ tons}}{\text{yr}} \times 310 = \frac{64.29 \text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Amine Reboiler (EPNs: H-01, H-02, H-03, H-04, H-05, H-06)

Amine Reboiler Combustion Emissions - Greenhouse Gases

Parameter	Units	Amine Unit Reboilers
EPN	-	H-01, H-02, H-03, H-04, H-05, H-06
Rated Capacity	MMBtu/hr	40
Annual hours of Operation	hr/yr	8,760

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Potential Emission Calculations

			Annual Emissions [1, 2] (tons/yr)				Hourly Emissions [3] (lb/hr)			
EPN	Description	Fuel Type	CO_2	CH_4	N_2O	CO_2e [4]	CO_2	CH_4	N_2O	CO_2e [4]
H-01	Amine Unit #1 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-02	Amine Unit #2 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-03	Amine Unit #3 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-04	Amine Unit #4 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-05	Amine Unit #5 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
H-06	Amine Unit #6 Reboiler	Natural Gas	20,479	0.39	0.04	20,499	4,676	0.09	0.01	4,680
		Total	**122,873.83**	**2.32**	**0.23**	**122,994**	**28,053.39**	**0.53**	**0.05**	**28,081**
		Total CO_2e Emissions [4]	**-**	**-**	**-**	**122,994**	**-**	**-**	**-**	**28,081**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Emission Factor (kg CO2/MMBtu) x Hours of Operation (hr/yr) x 2.205 (lb/kg) / 2,000 (lb/ ton)

Example CO2 Annual Emission Rate (tons/yr) = $\frac{40.00\text{ MMBtu}}{\text{hr}} \times \frac{53.020\text{ kg CO2}}{\text{MMBtu}} \times \frac{2.205\text{ lb}}{\text{kg}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\text{ lb}} = \frac{20{,}479\text{ tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{20{,}479\text{ tons}}{\text{yr}} \times \frac{2{,}000\text{ lb}}{\text{ton}} \times \frac{\text{yr}}{8{,}760\text{ hr}} = \frac{4{,}676\text{ lb}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

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

CO_2e Annual Emission Rate (tons/yr) = CO_2 Emission Rate (tons/yr) x CO_2 GWP + CH_4 Emission Rate (tons/yr) x CH_4 GWP + N_2O Emission Rate (tons/yr) x N_2O GWP

Example CO2e Annual Emission Rate (tons/yr) = $\frac{20{,}479\text{ tons}}{\text{yr}} \times 1 + \frac{0.39\text{ tons}}{\text{yr}} \times 21 + \frac{3.86\text{E-02 tons}}{\text{yr}} \times 310 = \frac{20{,}499\text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO_2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

GHG EMISSION CALCULATIONS FOR THERMAL OXIDIZER

TO (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, TO-6)

TO Emissions - Greenhouse Gases - Amine Acid Gas Combustion

Parameter	Units	Thermal Oxidizer 1	Thermal Oxidizer 2	Thermal Oxidizer 3	Thermal Oxidizer 4	Thermal Oxidizer 5	Thermal Oxidizer 6
EPN	-	TO-1	TO-2	TO-3	TO-4	TO-5	TO-6
Rated Capacity [1]	MMBtu/hr	9	9	9	9	9	9
Maximum Process Vent Gas Flowrate [2]	MMscfd (wet)	4.35	4.35	4.35	4.35	4.35	4.35
Fuel Gas High Heat Value (HHV)	MMBtu/scf	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03	1.215E-03
Annual hours of Operation	hr/yr	8,760	8,760	8,760	8,760	8,760	8,760
Thermal Oxidizer Reduction Efficiency (DRE)	%	99%	99%	99%	99%	99%	99%

[1] Scaled up from Avalon CGF #2 facility with an added safety factor of 20%.

[2] Maximum process vent gas flowrates obtained from ProMax output da 64.88888889

GHGs Emission Calculations - Process Vent Gas

EPN	Description	Fuel Type	Uncontrolled Emissions [1] (lb/hr) CO_2	CH_4	Ethane	Propane	Butanes [2]	Pentanes +
TO-1	Thermal Oxidizer 1	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-2	Thermal Oxidizer 2	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-3	Thermal Oxidizer 3	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-4	Thermal Oxidizer 4	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-5	Thermal Oxidizer 5	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
TO-6	Thermal Oxidizer 6	Natural Gas	18,977.15	9.45	4.38	1.84	0.99	0.25
		Total	**113,862.89**	**56.68**	**26.26**	**11.05**	**5.94**	**1.50**

[1] Uncontrolled emission rates from ProMax output data.

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

Carbon Atoms per VOC Compound

Compound	Number of Carbon Atoms	Molecular Weight of Component (lb/lbmol)	Carbon Weight (%)
Carbon Dioxide	1	44.10	27.2%
Methane	1	16.04	74.8%
Ethane	2	30.07	79.8%
Propane	3	44.10	81.6%
Butanes	4	58.12	82.6%
Pentanes +	5	72.15	83.2%

CO_2 Conversion Emission Calculations - Process Vent Gas

EPN	Description	Converted to CO_2 [1] (lb/hr) CH_4	Ethane	Propane	Butanes	Pentanes +	Total Converted CO_2 (lb/hr)
TO-1	Thermal Oxidizer 1	9.35	8.67	5.47	3.92	1.23	28.64
TO-2	Thermal Oxidizer 2	9.35	8.67	5.47	3.92	1.23	28.64
TO-3	Thermal Oxidizer 3	9.35	8.67	5.47	3.92	1.23	28.64
TO-4	Thermal Oxidizer 4	9.35	8.67	5.47	3.92	1.23	28.64
TO-5	Thermal Oxidizer 5	9.35	8.67	5.47	3.92	1.23	28.64
TO-6	Thermal Oxidizer 6	9.35	8.67	5.47	3.92	1.23	28.64

[1] 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) = Total Uncontrolled Emissions (lb/hr) x DRE (%) x # Carbons

Example CH_4 Converted to CO_2 Hourly Emission Rate (lb/hr) = $\frac{09.45 \text{ lb}}{\text{hr}} \times 99\,\% \times \frac{1 \text{ Carbon Atom}}{\text{Molecule } CH_4} = \frac{09.35 \text{ lb}}{\text{hr}}$

GHG EMISSION CALCULATIONS FOR THERMAL OXIDIZER

TO (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, TO-6)

GHG Emission Factors for Natural Gas - Pilot Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for

[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for

GHG Potential Emission Calculations - Pilot Gas

			Annual Emissions [1, 2] (tons/yr)				Hourly Emissions [3] (lb/hr)			
EPN	Description	Fuel Type	CO_2	CH_4	N_2O	CO_2e [4]	CO_2	CH_4	N_2O	CO_2e [4]
TO-1	Thermal Oxidizer 1	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-2	Thermal Oxidizer 2	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-3	Thermal Oxidizer 3	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-4	Thermal Oxidizer 4	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-5	Thermal Oxidizer 5	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
TO-6	Thermal Oxidizer 6	Natural Gas	4,607.77	0.09	0.01	4612.29	1,052.00	0.02	0.002	1,053.03
		Total	**27,646.61**	**0.52**	**5.21E-02**	**27,673.73**	**6,312.01**	**1.19E-01**	**1.19E-02**	**6,318.20**
		Total CO_2e Emissions [4]	**-**	**-**	**-**	**27,673.73**	**-**	**-**	**-**	**6,318.20**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.

[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Annual Hours of Operation (hr/yr) x Emission Factor (kg CO2/MMBtu) x 2.205 (lb/kg) / 2,000 (lb/ton)

Example CO_2 Annual Emission Rate (tpy) =	9.0 MMBtu / hr	8,760 hr / yr	53.020 kg CO2 / MMBtu	2.205 lb / kg	ton / 2,000 lb	=	4,608 tons / yr

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) =	4,607.77 tons / yr	yr / 8,760 hr	2,000 lb / ton	=	1052.00 lb / hr

kg to lb conversion 2.20 lb/kg

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

CO2e Annual Emission Rate (tons/yr) = CO2 Emission Rate (tons/yr) x CO2 GWP + CH4 Emission Rate (tons/yr) x CH4 GWP + N2O Emission Rate (tons/yr) x N2O GWP

Example CO2e Annual Emission Rate (tons/yr) =	4,607.77 tons / yr	1	+	0.09 tons / yr	21	+	8.69E-03 tons / yr	310	=	4,612 tons / yr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

TO (EPNs: TO-1, TO-2, TO-3, TO-4, TO-5, TO-6)
GHG Potential Emission Calculations

			Hourly Emissions (lb/hr)				Annual Emissions [5, 6] (tons/yr)			
EPN	**Description**	**Fuel Type**	**CO_2 [1]**	**CH_4 [2]**	**N_2O [3]**	**CO_2e [4]**	**CO_2**	**CH_4**	**N_2O**	**CO_2e [4]**
TO-1	Thermal Oxidizer 1	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-2	Thermal Oxidizer 2	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-3	Thermal Oxidizer 3	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-4	Thermal Oxidizer 4	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-5	Thermal Oxidizer 5	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
TO-6	Thermal Oxidizer 6	Natural Gas	20,058	0.11	0.05	20,076	87,853	0.50	0.22	87,932
		Total	**120,346.75**	**0.69**	**0.30**	**120,455.10**	**527,118.77**	**3.00**	**1.33**	**527,593.33**
		Total CO_2e Emissions [4]	**-**	**-**	**-**	**120,455**	**-**	**-**	**-**	**527,593**

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

[2] CH_4 from controlled CH_4 emissions.

[3] 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) + Pilot Gas N_2O Emissions (lb/hr)

Example Hourly Emission Rate for N_2O (lb/hr) =	4.35 MMscf	1 day	10^6 scf	1.235E-03 MMBt	1.00E-04 kg	2.2046 lb	+	0.002 lb	=	0.05 lb
	day	24 hrs	1 MMscf	scf	MMBtu	kg		hr		hr

[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) =	20,057.79 lb	1	+	0.11 lb	21	+	0.05 lb	310	=	20,076 lb
	hr			hr			hr			hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

[5] Annual Emission Calculations (tpy) = Hourly Emission Calculations (lb/hr) x Hours of Operation per year (hrs/yr) / Conversion (lbs/ton)

Example CO2e Annual Emission Rate (tons/yr) =	20,075.85 lb	8,760 hr	tons	=	87,932 tons
	hr	yr	2,000 lb		yr

lb to kg conversion 2.20 lb/kg

TEG Dehydrator Reboiler (EPNs: RB-01, RB-02, RB-03, RB-04, RB-05, RB-06)

TEG Dehydrator Reboiler Combustion Emissions - Greenhouse Gases

Parameter	Units	Glycol Dehydrator Reboilers
EPN	-	RB-01, RB-02, RB-03, RB-04, RB-05, RB-06
Rated Capacity	MMBtu/hr	1.5
Annual hours of Operation	hr/yr	8,760

GHG Emission Factors for Natural Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-

GHG Potential Emission Calculations

EPN	Description	Fuel Type	Annual Emissions [1, 2] (tons/yr) CO_2	CH_4	N_2O	CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	CH_4	N_2O	CO_2e [4]
RB-01	Glycol Dehydrator #1 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-02	Glycol Dehydrator #2 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-03	Glycol Dehydrator #3 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-04	Glycol Dehydrator #4 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-05	Glycol Dehydrator #5 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
RB-06	Glycol Dehydrator #6 Reboiler	Natural Gas	768	1.45E-02	1.45E-03	769	175	3.31E-03	3.31E-04	176
		Total	**4,607.77**	**0.09**	**8.69E-03**	**4,612**	**1,052.00**	**1.98E-02**	**1.98E-03**	**1,053**
		Total CO_2e Emissions [4]	-	-	-	**4,612**	-	-	-	**1,053**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Emission Factor (kg CO2/MMBtu) x Hours of Operation (hr/yr) / 1,000 (lb/ton)

Example CO2 Annual Emission Rate (tons/yr) = $\frac{1.50\ \text{MMBtu}}{\text{hr}} \times \frac{53.020\ \text{kg CO2}}{\text{MMBtu}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{2.205\ \text{lb}}{\text{kg}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} = \frac{768\ \text{tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 1,000 (lb/ton) x 2.20 (lb/kg) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{768\ \text{tons}}{\text{yr}} \times \frac{2{,}000\ \text{lb}}{\text{ton}} \times \frac{\text{yr}}{8{,}760\ \text{hr}} = \frac{175\ \text{lb}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

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

CO2e Annual Emission Rate (tons/yr) = CO2 Emission Rate (tons/yr) x CO2 GWP + CH4 Emission Rate (tons/yr) x CH4 GWP + N2O Emission Rate (tons/yr) x N2O GWP

Example CO2e Annual Emission Rate (tons/yr) = $\frac{768\ \text{tons}}{\text{yr}} \times 1 + \frac{1.45\text{E-}02\ \text{tons}}{\text{yr}} \times 21 + \frac{1.45\text{E-}03\ \text{tons}}{\text{yr}} \times 310 = \frac{769\ \text{tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Tanks (EPNs:PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06)

Parameter [1]	Units	Water Tanks 1-6
EPN	-	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06
FIN	-	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06
Maximum Process Vent Gas Flowrate	MMscfd	3.98E-02
Annual hours of Operation	hr/yr	8,760

[1] Scaled up from Anadarko Avalon CGF #2 facility.

[2] Obtained from E&P Tanks output for storage tanks.

EPN	FIN	Description	Uncontrolled Emissions [1] (lb/hr)			Uncontrolled Emissions [1] (tpy)		
			CO_2	CH_4	CO_2e	CO_2	CH_4	CO_2e
PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	PWTK-01, PWTK-02, PWTK-03, PWTK-04, PWTK-05, PWTK-06	Produced Water Tanks 1-6	0.000	0.003	0.063	0.001	0.014	0.295
		Total	**0.00E+00**	**3.00E-03**	**0.06**	**1.00E-03**	**0.01**	**0.30**

[1] Produced Water Tanks emissions assumed 1% Condensate. Uncontrolled emissions for Condensate Tanks were determined using E&P Tanks. Condensate tanks are pressurized, and consequently do not actually emit GHGs.

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Flares (EPNs: FL-01, FL-02, FL-03)

Parameter [1]	Units	Flares
EPN	-	FL-01, FL-02, FL-03
FIN	-	FL-01, FL-02, FL-03
Pilot Gas Fuel Flowrate per flare	scf/hr	250
Pilot Gas Fuel flowrate	scf/yr	2,190,000
High Heat Value (HHV) [2]	MMBtu/scf	1.22E-03
Annual hours of Operation	hr/yr	8,760
Flare Reduction Efficiency (DRE) [3]	%	98.0

[1] Scaled up from Anadarko Avalon CGF #2 facility.
[2] Obtained from E&P Tanks output for storage tanks.
[3] Flare Reduction Efficiency (generic) is 98% per TCEQ Flares Guidance.

GHG Emission Factors for Natural Gas - Pilot Gas

Pollutant	Emission Factor	Emission Factor Units
CO_2 [1]	53.020	kg CO_2/MMBtu
CH_4 [2]	0.001	kg CH_4/MMBtu
N_2O [2]	0.0001	kg N_2O/MMBtu

[1] Emission factors from 40 CFR Part 98, Subpart C, Table C-1 for Natural Gas.
[2] Emission factors Per 40 CFR Part 98, Subpart C, Table C-2 for Natural Gas.

GHG Potential Emission Calculations - Pilot Gas

EPN	FIN	Description	Fuel Type	Annual Emissions [1, 2] (tons/yr) CO_2	Annual CH_4	Annual N_2O	Annual CO_2e [4]	Hourly Emissions [3] (lb/hr) CO_2	Hourly CH_4	Hourly N_2O	Hourly CO_2e [4]
FL-01	FL-01	Flare #1	Natural Gas	155.51	0.003	0.0003	155.66	35.51	0.00	0.00	35.54
FL-02	FL-02	Flare #2	Natural Gas	155.51	0.003	0.0003	155.66	35.51	0.00	0.00	35.54
FL-03	FL-03	Flare #3	Natural Gas	155.51	0.003	0.0003	155.66	35.51	0.00	0.00	35.54
			Total	**466.54**	**0.01**	**8.80E-04**	**466.99**	**106.52**	**2.01E-03**	**2.01E-04**	**106.62**

[1] CO_2 emissions from Natural Gas combustion calculated per Equation C-1 and Tier I methodology provided in 40 CFR Part 98, Subpart C.
[2] CH_4 and N_2O emissions Natural Gas combustion calculated per Equation C-8 provided in 40 CFR Part 98, Subpart C.

Annual Emissions (tons/yr) = Rated Capacity (MMBtu/hr) x Annual Hours of Operation (hr/yr) x Emission Factor (kg CO2/MMBtu) x 2.205 (lb/kg) / 2000 (lb/ton)

Example CO_2 Annual Emission Rate (tpy) = $\frac{2{,}190{,}000\text{ scf}}{\text{yr}} \left| \frac{1.22\text{E-03 MMBtu}}{\text{scf}} \right| \frac{53.020\text{ kg CO2}}{\text{MMBtu}} \left| \frac{2.205\text{ lb}}{\text{kg}} \right| \frac{\text{ton}}{2{,}000\text{ lb}} = \frac{156\text{ tons}}{\text{yr}}$

[3] Hourly Emission rates (lb/hr) = Annual Emissions (tons/yr) x 2,000 (lb/ton) / 8,760 (hr/yr)

Example CO_2 Hourly Emission Rate (lbs/hr) = $\frac{155.51\text{ tons}}{\text{yr}} \left| \frac{\text{yr}}{8{,}760\text{ hr}} \right| \frac{2{,}000\text{ lb}}{\text{ton}} = \frac{155.66\text{ lb}}{\text{hr}}$

kg to lb conversion 2.20 lb/kg

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

CO2e Annual Emission Rate (tons/yr) = CO2 Emission Rate (tons/yr) x CO2 GWP + CH4 Emission Rate (tons/yr) x CH4 GWP + N2O Emission Rate (tons/yr) x N2O GWP

Example CO2e Annual Emission Rate (tons/yr) = $\frac{155.51\text{ tons}}{\text{yr}} \left| 1 \right. + \frac{2.93\text{E-03 tons}}{\text{yr}} \left| 21 \right. + \frac{2.93\text{E-04 tons}}{\text{yr}} \left| 310 \right. = \frac{156\text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

GHG EMISSION CALCULATIONS FOR TRUCK LOADING

Truck Loading Emission Factors

S = Saturation Factor [1]	P = True Vapor Pressure of Liquid Loaded (psia) [2]	M = Molecular Weight of Vapors (lb/lb-mole) [2]	T = Temperature of Bulk Liquid Loaded (°R) [2]	Hourly Loading Rate (gal/hr) [3]	Annual Loading Rate (gal/yr) [4]	Loading Loss (lb/1000 gal) [5]
0.6	3.4147	69	564.67	5,460	3,066,000	3.12

[1] The S-factor is based on submerged loading, dedicated normal.
[2] Worst case temperature assumed to be maximum ambient temperature for Loving, TX
[3] Hourly Loading Rate based on maximum capacity of loading truck in 1 hour.
[4] Annual Loading Rate based on proposed site-wide throughput of 200 bbl/day for each liquid.
[5] Based on Equation L_L = 12.46 * SPM/T from AP-42, Chapter 5, Section 5.2-4.

Proposed Hourly and Annual Emissions for Truck Loading

EPN	Source Name	Hourly Emissions (lb/hr) [1]	Annual Emissions (tons/yr) [2]
TL-2	Produced Water Truck Loading [3]	0.17	0.048
	Total CH_4 [4]	**0.17**	**0.05**
	Total CO_2e [5]	**3.58**	**1.00**

[1] Hourly Emissions (lb/hr) = Loading Losses (lb/1000 gal) x Hourly Loading Rate (gal/hr)

EPN TL-2 Hourly Emissions (lb/hr) = $\frac{3.12\text{ lb}}{1000\text{ gal}} \times \frac{5460\text{ gal}}{\text{hr}} \times 0.01$ = 0.17 lb/hr

[2] Annual Emissions (tpy) = Loading Losses (lb/1000 gal) x Annual Loading Rate (gal/yr) / 2000 (lb/ton)

EPN TL-2 Annual Emissions (tpy) = $\frac{0.17\text{ lb}}{1000\text{ gal}} \times \frac{3{,}066{,}000\text{ gal}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\text{ lb}}$ = $\frac{0.05\text{ tons}}{\text{yr}}$

[3] Assumed 1% of throughput is condensate. Multiply results by 0.01.
[4] Assumed all VOC is CH_4 for conservatism.
[5] CO_2e emissions based on GWPs for each greenhouse gas pollutant

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{0.17\text{ lb}}{\text{hr}} \times 21$ = 3.6 lb/hr

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

kg to lb conversion 2.204623 lb/kg

GHG EMISSION CALCULATIONS FOR PROPOSED FUGITIVES

Site-wide Fugitive Components (EPN: FUG)

Fugitive Counts and VOC Content

Stream	Valves	Flanges	Relief Valves	Open-ended Lines	Connectors	Other	CO_2 Content (Weight %) [1]	CH_4 Content (Weight %) [1]
Fuel Gas/Residue Gas	2780	2780	300	300	8340	200	21.81%	49.58%
Light Oil	950	950	30	100	2850	100	0.08%	0.11%

[1] Data obtained from representative gas analysis.

LDAR Control (%)

Stream	Valves	Flanges	Relief Valves	Open-ended Lines	Connectors	Other
Fuel Gas/Residue Gas	97%	30%	97%	97%	30%	0%
Light Oil	97%	30%	0%	97%	30%	0%

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

Oil and Gas Production Operations Emission Factors

Stream	Emission Factor [1] (lb/hr)/component					
	Valves	Flanges	Relief Valves	Open Ended Lines	Connectors	Other
Gas	0.00992	0.00086	0.0194	0.00441	0.00044	0.0194
Light Oil	0.0055	0.000243	0.0165	0.00309	0.000463	0.0165

[1] Oil and Gas Production emission factors obtained from TCEQ, Industrial Emissions Assessment Section, Components, RG-360, January 2005. For conservatism, it was assumed that components in CO_2 Service have the same emission factors as gas components.

Hourly GHG Emissions

Component	Stream	Hourly Emissions (lb/hr) [1]						
		Valves	Flanges	Relief Valves	Open Ended Lines	Connectors	Other	Total
CO_2	Gas	0.18	0.37	0.04	0.01	0.56	0.85	2.00
	Light Oil	0.03	0.04	0.11	0.00	0.20	0.36	0.74
CH_4	Gas	0.41	0.83	0.09	0.02	1.27	1.92	4.54
	Light Oil	0.00	0.00	0.00	0.0000	0.00	0.00	0.00
							Total CO_2	**2.74**
							Total CH_4	**4.55**
							Total CO_2e [2]	**98.23**

[1] Hourly Controlled CH_4 Emission Rate (lb/hr) = Oil and Gas Factor x Component Count x (%CH_4 content in LNG / 100)

Hourly Emission Rate for Valves from Gas Service (lb/hr) = $\frac{9.92\text{E-}03 \text{ lb}}{\text{hr-component}}$ | 2780 | $\frac{49.58\%}{100}$ | (1 - 0.97%) = 0.18 lb/hr

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

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{2.74 \text{ lb}}{\text{hr}}$ | 21 + $\frac{4.55 \text{ lb}}{\text{hr}}$ | 1 = $\frac{98.2 \text{ lb}}{\text{hr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Annual GHG Emissions

Component	Stream	Annual Emissions (tons/yr) [1]						
		Valves	Flanges	Relief Valves	Open Ended Lines	Connectors	Other	Total
CO_2	Gas	0.79	1.60	0.17	0.04	2.45	3.71	8.75
	Light Oil	0.15	0.15	0.47	0.01	0.88	1.58	3.24
CH_4	Gas	1.80	3.63	0.38	0.09	5.58	8.43	19.90
	Light Oil	0.00	0.00	0.00	0.00	0.00	0.01	0.02
							Total CO_2	**12.00**
							Total CH_4	**19.92**
							Total CO_2e [2]	**430.24**

[1] Annual Emissions (tons/yr) = Hourly Emissions (lb/hr) x 8,760 (hrs/yr) / 2204.623 (lb/tons)

Annual Emissions for Valves in Gas Service (tons/yr) = $\frac{0.18 \text{ lb}}{\text{hr}}$ | $\frac{8{,}760 \text{ hrs}}{\text{yr}}$ | $\frac{\text{ton}}{2{,}000 \text{ lb}}$ = 0.79 tons/yr

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

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

Example CO2e Emission Rate (tons/yr) = $\frac{12.00 \text{ tons}}{\text{yr}}$ | 1 + $\frac{19.92 \text{ tons}}{\text{yr}}$ | 21 = $\frac{430.2 \text{ tons}}{\text{yr}}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

lb to ton conversion 2,000.00 lb/ton

EMISSION CALCULATIONS FOR MSS ACTIVITIES

Site-wide Maintenance, Startup, and Shutdown (MSS) Emissions (EPN: MSS)

Compressor Blowdown VOC Emissions

Parameter [1]	Units	MSS - Compressor Blowdowns [2]	MSS - Vessel Blowdown	MSS- Pigging Operations [3]
EPN		MSS-compressors	MSS-vessel	MSS-pigging
FIN		FL-01, FL-02, FL-03	FL-01, FL-02, FL-03	MSS-pigging
Volume	scf	660,303	26,400	--
Mass	lb/yr	--	--	3244.63
Annual Hours of Operation	hrs/yr	1872	16.5	6
% CO_2	Wt %	4.56%	4.56%	0.08%
% CH_4	Wt %	59.98%	59.98%	0.11%
CO_2 Molecular Weight	lb/lb-mol	44.01	44.01	44.01
CH_4 Molecular Weight	lb/lb-mol	16.04	16.04	16.04
Flare Destruction Efficiency (DRE) [4]	%	98.0	98.0	0.0

[1] Scaled up from Anadarko Avalon CGF #2 facility.
[2] Assumed 12 compressor blowdown per month per engine for the compressor engines
[3] Scaled up from Anadarko Avalon #2 Facility, which assumed pounds per year based on engineering knowledge
[4] EPNs MSS-compressors and MSS-vessel routed to flare

GHGs Emission Calculations - Process Vent Gas

EPN	FIN	Description	Uncontrolled Emissions (lb/hr) CO_2	CH_4
MSS-compressors [1]	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	1.87	8.94
MSS-Vessel [1]	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	8.46	40.57
MSS-Pigging [2]		MSS- Pigging Operations	0.43	0.59
		Total	**10.76**	**50.11**

[1] Hourly Emissions (lb/hr) = Volume (scf/yr) * (lb-mol/379.4 scf) *Molecular Weight (lb/lb-mol) * Compound Wt % / Hours per year (hr/yr)

Hourly Emissions for CO_2 (lb/hr) = $\frac{660{,}303 \text{ scf}}{1 \text{ yr}} \cdot \frac{\text{lb-mol}}{379.4 \text{ scf}} \cdot \frac{44.01 \text{ lb}}{\text{lb-mol}} \cdot \frac{4.56\%}{1872 \text{ hr/yr}}$ = 1.87 lb/hr

[2] Hourly Emissions (lb/hr) = Pounds per Year (lb/yr) / Hours per Year (hr/yr) x Compound Wt%

Hourly Emissions for CO_2 (lb/hr) = $\frac{3244.63 \text{ lb}}{\text{yr}} \cdot \frac{\text{yr}}{6 \text{ hr}} \cdot 0.08\%$ = 0.43 lb/hr

Carbon Atoms per VOC Compound

Compound	Number of Carbon Atoms	Molecular Weight of Component (lb/lbmol)	Carbon Weight (%)
Carbon Dioxide	1	44.10	27.2%
Methane	1	16.04	74.8%
Ethane	2	30.07	79.8%
Propane	3	44.10	81.6%
Butanes	4	58.12	82.6%
Pentanes +	5	72.15	83.2%

EMISSION CALCULATIONS FOR MSS ACTIVITIES

CO_2 Conversion Emission Calculations - Process Vent Gas

EPN	FIN	Description	Converted to CO_2 [1] (lb/hr) CH_4
MSS-compressors	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	8.77
MSS-vessel	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	39.76
MSS-pigging	MSS-pigging	MSS- Pigging Operations	0
		Total	**48.53**

[1] 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) = Total Uncontrolled Emissions (lb/hr) x DRE (%) x # Carbons

Example CH_4 Converted to CO_2 Hourly Emission Rate (lb/hr) = $\frac{8.94\text{ lb}}{\text{hr}} \times 98\,\% \times \frac{1\text{ Carbon Atom}}{\text{Molecule }CH_4} = \frac{8.77\text{ lb}}{\text{hr}}$

GHG Potential Emission Calculations

EPN	FIN	Description	Hourly Emissions (lb/hr) CO_2	Hourly Emissions (lb/hr) CH_4	Annual Emissions [1] (tons/yr) CO_2	Annual Emissions [1] (tons/yr) CH_4
MSS-compressors	FL-01, FL-02, FL-03	MSS - Compressor Blowdowns	11	0.18	10	0.167
MSS-vessel	FL-01, FL-02, FL-03	MSS - Vessel Blowdown	48	0.81	0	0.007
MSS-pigging	MSS-pigging	MSS- Pigging	4.33E-01	1.19E-02	1.30E-03	3.57E-05
		Total	**59.29**	**1.00**	**10.35**	**0.17**
		Total CO_2e Emissions [2]	**-**	**80.34**	**-**	**14.01**

[1] Annual Emissions (tons/yr) = Hourly Emissions (lb/hr) *Hours per Year (hr/yr) / 2000 (lb/ton)

Annual Emissions (tons/yr) = $11 \times \frac{1872\text{ hr}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\text{ lb}} = \frac{9.95\text{ tons}}{\text{yr}}$

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

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

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{59.29\text{ lb}}{\text{hr}} \times 1 + \frac{1.00\text{ lb}}{\text{hr}} \times 21 = 80.34\text{ lb/hr}$

Per 40 CFR 98 - Mandatory Greenhouse Gas Reporting, Subpart A, Table A-1. Total CO2e emissions are calculated based on the following Global Warming Potentials.

CO_2	1
CH_4	21
N_2O	310

Conversion: lb to kg 2.204623 lb/kg

BACT Cost Analysis

Cost Estimation for Transfer of CO_2 via Pipeline - Amine Vent

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	12	miles
Average Diameter of Pipeline	6	inches
CO_2 emissions from vents	527,118.77	tons/year
CO2 capture efficiency	90%	
Captured CO_2	474,406.89	tons/year

CO_2 Transfer Cost Estimation[1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs			
Materials/Labor	$	$7,605,000.00	$7,605,000.00
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D + 29,788)	$527,000.00
Other Capital			
Gas Treatment Equipment and Labor	$	$35,933,000.00	$35,933,000.00
Operation & Maintenance (O&M)			
Fixed O&M per Year	$	$1,826,000.00	$1,826,000.00
		Total CCS Cost	$45,891,000.00

Amortized CCS Cost

Equipment Life (years)[2]	10
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.142
Total Capital Investment (TCI)	$44,065,000.00
Amortized Installation Cost (TCI*CRF)	$6,257,230.00
Total CCS Annualized Cost	**$8,083,230.00**
Total Annualized cost/ton CO_2	**$17.04**

Amortized Project Cost (without CCS)

Equipment Life[2]	10
Interest rate	0.07
Capital Recovery Factor (CRF)[3]	0.142
Total Capital Investment (TCI)	$117,000,000.00
Amortized Installation Cost (TCI*CRF)	$16,614,000.00
Annual Operating Cost Estimation	$8,000,000.00
Total Project Annualized Cost	**$24,614,000.00**

[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 2011 and DBJVG CO2 Sales Definition Study Aug. 16, 2012.
[2] Pipeline and Equipment life is estimated at 10 years due to the life cycle of the reservoir.
[3] Capital Recovery Fraction = Interest Rate x (1+ Interest Rate) ^ Pipeline Life) / ((1 + Interest Rate) ^ Pipeline Life - 1)
[4] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment