TITLE V RENEWAL
DCP OPERATING COMPANY, LP
ZIA II GAS PLANT

Prepared By:

Samuel Keen – Environmental Manager

DCP Operating Company, LP
2107 CityWest Blvd #600
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Adam Erenstein – Manager of Consulting Services

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March 2022

Project 223201.0018

Trinity Consultants
9400 Holly Ave NE, Bldg 3, Ste 300, Albuquerque, NM 87122 / P 505.266.6611 / **trinityconsultants.com**

March 7, 2022

Permit Programs Manager
NMED Air Quality Bureau
525 Camino de los Marquez Suite 1
Santa Fe, NM 87505-1816

RE: Application for Title V Renewal of Title V Permit P-270
DCP Operating Company, LP – Zia II Gas Plant

Permit Programs Manager:

DCP Operating Company, LP is submitting this application for a Title V renewal for its Zia II Gas Plant facility. This submittal is pursuant to 20.2.70.300.B.2 NMAC, which requires a Title V application to be submitted at least twelve months prior to the expiration of the current permit. Title V Permit P-270 expires on March 9, 2023.

The format and content of this application are consistent with the Bureau's current policy regarding Title V applications. Enclosed are two hard copies of the application, including an original certification and two discs containing the electronic files. Please feel free to contact either myself at (505) 266-6611 or aerenstein@trinityconsultants.com or Samuel Keen, Environmental Manager for DCP Operating Company, LP, at (713) 735-3978 or SEKeen@dcpmidstream.com if you have any questions regarding this application.

Sincerely,

Adam Erenstein
Manager of Consulting Services

Cc: Samuel Keen, P.E (DCP Operating Company, LP)
Trinity Project File 223201.0018

Mail Application To:		For Department use only:
New Mexico Environment Department Air Quality Bureau Permits Section 525 Camino de los Marquez, Suite 1 Santa Fe, New Mexico, 87505 Phone: (505) 476-4300 Fax: (505) 476-4375 www.env.nm.gov/aqb		AIRS No.:

Universal Air Quality Permit Application

Use this application for NOI, NSR, or Title V sources.

Use this application for: the initial application, modifications, technical revisions, and renewals. For technical revisions, complete Sections, 1-A, 1-B, 2-E, 3, 9 and any other sections that are relevant to the requested action; coordination with the Air Quality Bureau permit staff prior to submittal is encouraged to clarify submittal requirements and to determine if more or less than these sections of the application are needed. Use this application for streamline permits as well. See Section 1-I for submittal instructions for other permits.

This application is submitted as (check all that apply)**:** ☐ Request for a No Permit Required Determination (no fee)
☐ **Updating** an application currently under NMED review. Include this page and all pages that are being updated (no fee required).
Construction Status: ☐ Not Constructed ☑ Existing Permitted (or NOI) Facility ☐ Existing Non-permitted (or NOI) Facility
Minor Source: ☐ a NOI 20.2.73 NMAC ☐ 20.2.72 NMAC application or revision ☐ 20.2.72.300 NMAC Streamline application
Title V Source: ☐ Title V (new) ☑Title V renewal ☐ TV minor mod. ☐ TV significant mod. TV Acid Rain: ☐ New ☐ Renewal
PSD Major Source: ☐ PSD major source (new) ☐ minor modification to a PSD source ☐ a PSD major modification

Acknowledgements:
☑ I acknowledge that a pre-application meeting is available to me upon request. ☑ Title V Operating, Title IV Acid Rain, and NPR applications have no fees.
☐ $500 NSR application Filing Fee enclosed OR ☐ The full permit fee associated with 10 fee points (required w/ streamline applications).
☐ Check No.: in the amount of
☑ I acknowledge the required submittal format for the hard copy application is printed double sided 'head-to-toe', 2-hole punched (except the Sect. 2 landscape tables is printed 'head-to-head'), numbered tab separators. Incl. a copy of the check on a separate page.
☑ I acknowledge there is an annual fee for permits in addition to the permit review fee: www.env.nm.gov/air-quality/permit-fees-2/.
☐ This facility qualifies for the small business fee reduction per 20.2.75.11.C. NMAC. The full $500.00 filing fee is included with this application and I understand the fee reduction will be calculated in the balance due invoice. The Small Business Certification Form has been previously submitted or is included with this application. (Small Business Environmental Assistance Program Information: www.env.nm.gov/air-quality/small-biz-eap-2/.)

Citation: Please provide the **low level citation** under which this application is being submitted: **20.2.70.300.B.(2) NMAC**
(e.g. application for a new minor source would be 20.2.72.200.A NMAC, one example for a Technical Permit Revision is 20.2.72.219.B.1.b NMAC, a Title V acid rain application would be: 20.2.70.200.C NMAC)

Section 1 – Facility Information

Section 1-A: Company Information

		AI # if known (see 1st 3 to 5 #s of permit IDEA ID No.): 32800	Updating Permit/NOI #: P-270
1	Facility Name: Zia II Gas Plant	Plant primary SIC Code (4 digits): 1311	
		Plant NAIC code (6 digits): 211111	
a	Facility Street Address (If no facility street address, provide directions from a prominent landmark): From Loco Hills, NM head east on US-82 E/Lovington Hwy for 6 miles. Turn right onto NM-529/Bermuda Rd and continue for 7 miles. Turn right onto Co Rd 126/Co Rd 126A/Maljamar Rd and continue for 11 miles. Turn right onto Co Rd 126/Lusk Rd and follow for 1 mile. Turn left and arrive at the gas plant on the left side of the road after 0.3 miles.		

2	Plant Operator Company Name: DCP Operating Company, LP	Phone/Fax: 713-735-3978
a	Plant Operator Address: 2107 CityWest Blvd., #600, Houston, TX 77042	
b	Plant Operator's New Mexico Corporate ID or Tax ID: 036785	
3	Plant Owner(s) name(s): DCP Operating Company, LP	Phone/Fax: 713-735-3978
a	Plant Owner(s) Mailing Address(s): 2107 CityWest Blvd., #600, Houston, TX 77042	
4	Bill To (Company): DCP Operating Company, LP	Phone/Fax: 713-735-3978
a	Mailing Address: 2107 CityWest Blvd., #600, Houston, TX 77042	E-mail: SEKeen@dcpmidstream.com
5	☐ Preparer: ☑ Consultant: Adam Erenstein	Phone/Fax: 505-266-6611
a	Mailing Address: 9400 Holly Ave., Bldg. 3, Ste. 300, Albuquerque, NM 87122	E-mail: aerenstein@trinityconsultants.com
6	Plant Operator Contact: Samuel Keen	Phone/Fax: 713-735-3978
a	Address: 2107 CityWest Blvd., #600, Houston, TX 77042	E-mail: SEKeen@dcpmidstream.com
7	Air Permit Contact: Samuel Keen	Title: Environmental Engineer
a	E-mail: SEKeen@dcpmidstream.com	Phone/Fax: 713-735-3978
b	Mailing Address: 2107 CityWest Blvd., #600, Houston, TX 77042	
c	The designated Air permit Contact will receive all official correspondence (i.e. letters, permits) from the Air Quality Bureau.	

Section 1-B: Current Facility Status

1.a	Has this facility already been constructed? ☑ Yes ☐ No	1.b If yes to question 1.a, is it currently operating in New Mexico? ☑ Yes ☐ No
2	If yes to question 1.a, was the existing facility subject to a Notice of Intent (NOI) (20.2.73 NMAC) before submittal of this application? ☐ Yes ☑ No	If yes to question 1.a, was the existing facility subject to a construction permit (20.2.72 NMAC) before submittal of this application? ☑ Yes ☐ No
3	Is the facility currently shut down? ☐ Yes ☑ No	If yes, give month and year of shut down (MM/YY): N/A
4	Was this facility constructed before 8/31/1972 and continuously operated since 1972? ☐ Yes ☑ No	
5	If Yes to question 3, has this facility been modified (see 20.2.72.7.P NMAC) or the capacity increased since 8/31/1972? ☐Yes ☐No ☑N/A	
6	Does this facility have a Title V operating permit (20.2.70 NMAC)? ☑ Yes ☐ No	If yes, the permit No. is: P-270
7	Has this facility been issued a No Permit Required (NPR)? ☐ Yes ☑ No	If yes, the NPR No. is: N/A
8	Has this facility been issued a Notice of Intent (NOI)? ☐ Yes ☑ No	If yes, the NOI No. is: N/A
9	Does this facility have a construction permit (20.2.72/20.2.74 NMAC)? ☑ Yes ☐ No	If yes, the permit No. is: PSD-5217-M2R1
10	Is this facility registered under a General permit (GCP-1, GCP-2, etc.)? ☐ Yes ☑ No	If yes, the register No. is: N/A

Section 1-C: Facility Input Capacity & Production Rate

1	What is the facility's maximum input capacity, specify units (reference here and list capacities in Section 20, if more room is required)			
a	Current	Hourly: 9.6 MMscf	Daily: 230 MMscf	Annually: 83,950 MMscf
b	Proposed	Hourly: 9.6 MMscf	Daily: 230 MMscf	Annually: 83,950 MMscf

2	What is the facility's maximum production rate, specify units (reference here and list capacities in Section 20, if more room is required)			
a	Current	Hourly: 9.6 MMscf	Daily: 230 MMscf	Annually: 83,950 MMscf
b	Proposed	Hourly: 9.6 MMscf	Daily: 230 MMscf	Annually: 83,950 MMscf

Section 1-D: Facility Location Information

1	Section: 19	Range: 32E	Township: 19S	County: Lea County	Elevation (ft): 3,557
2	UTM Zone: ☐ 12 or ☑ 13			Datum: ☐ NAD 27 ☑NAD 83 ☐ WGS 84	
a	UTM E (in meters, to nearest 10 meters): 611,720 m E			UTM N (in meters, to nearest 10 meters): 3,612,340 m N	
b	**AND** Latitude (deg., min., sec.): 32° 38' 34.88" N			Longitude (deg., min., sec.): 103° 48' 31.92" W	
3	Name and zip code of nearest New Mexico town: Loco Hills, NM 88255				
4	Detailed Driving Instructions from nearest NM town (attach a road map if necessary): From Loco Hills, NM head east on US□82 E/Lovington Hwy for 6 miles. Turn right onto NM-529/Bermuda Rd and continue for 7 miles. Turn right onto Co Rd 126/Co Rd 126A/Maljamar Rd and continue for 11 miles. Turn right onto Co Rd 126/Lusk Rd and follow for 1 mile. Turn left and arrive at the gas plant on the left side of the road after 0.3 miles.				
5	The facility is 15 miles southeast of Loco Hills, NM.				
6	Status of land at facility (check one): ☐ Private ☐ Indian/Pueblo ☑ Federal BLM ☐ Federal Forest Service ☐ Other (specify)				
7	List all municipalities, Indian tribes, and counties within a ten (10) mile radius (20.2.72.203.B.2 NMAC) of the property on which the facility is proposed to be constructed or operated: **Counties:** Lea and Eddy; **Municipalities:** None; **Indian Tribes:** None				
8	**20.2.72** NMAC applications **only**: Will the property on which the facility is proposed to be constructed or operated be closer than 50 km (31 miles) to other states, Bernalillo County, or a Class I area (see www.env.nm.gov/aqb/modeling/class1areas.html)? ☐ Yes ☑ No (20.2.72.206.A.7 NMAC) If yes, list all with corresponding distances in kilometers: N/A				
9	Name nearest Class I area: Carlsbad Caverns National Park				
10	Shortest distance (in km) from facility boundary to the boundary of the nearest Class I area (to the nearest 10 meters): 72.8 km				
11	Distance (meters) from the perimeter of the Area of Operations (AO is defined as the plant site inclusive of all disturbed lands, including mining overburden removal areas) to nearest residence, school or occupied structure: 1,350 .				
12	Method(s) used to delineate the Restricted Area: Continuous Fencing "**Restricted Area**" is an area to which public entry is effectively precluded. Effective barriers include continuous fencing, continuous walls, or other continuous barriers approved by the Department, such as rugged physical terrain with steep grade that would require special equipment to traverse. If a large property is completely enclosed by fencing, a restricted area within the property may be identified with signage only. Public roads cannot be part of a Restricted Area.				
13	Does the owner/operator intend to operate this source as a portable stationary source as defined in 20.2.72.7.X NMAC? ☐ Yes ☑ No A portable stationary source is not a mobile source, such as an automobile, but a source that can be installed permanently at one location or that can be re-installed at various locations, such as a hot mix asphalt plant that is moved to different job sites.				
14	Will this facility operate in conjunction with other air regulated parties on the same property? ☒ No ☐ Yes If yes, what is the name and permit number (if known) of the other facility? N/A				

Section 1-E: Proposed Operating Schedule (The 1-E.1 & 1-E.2 operating schedules may become conditions in the permit.)

1	Facility **maximum** operating ($\frac{hours}{day}$): 24	($\frac{days}{week}$): 7		($\frac{weeks}{year}$): 52	($\frac{hours}{year}$): 8760	
2	Facility's maximum daily operating schedule (if less than 24 $\frac{hours}{day}$)?	Start: N/A	☐AM ☐PM	End: N/A		☐AM ☐PM
3	Month and year of anticipated start of construction: N/A – Facility is currently operating, and no construction is proposed.					

4	Month and year of anticipated construction completion: N/A – No construction is proposed in this application.
5	Month and year of anticipated startup of new or modified facility: N/A – No construction proposed in this application.
6	Will this facility operate at this site for more than one year? ☑ Yes ☐ No

Section 1-F: Other Facility Information

1	Are there any current Notice of Violations (NOV), compliance orders, or any other compliance or enforcement issues related to this facility? ☑ Yes ☐ No If yes, specify: Settlement Agreement AQB 20-64 (CO)		
a	If yes, NOV date or description of issue: 9/9/2021		NOV Tracking No: N/A
b	Is this application in response to any issue listed in 1-F, 1 or 1a above? ☐ Yes ☑ No If Yes, provide the 1c & 1d info below:		
c	Document Title: N/A	Date: N/A	Requirement # (or page # and paragraph #): N/A
d	Provide the required text to be inserted in this permit: N/A		
2	Is air quality dispersion modeling or modeling waiver being submitted with this application? ☐ Yes ☑ No		
3	Does this facility require an "Air Toxics" permit under 20.2.72.400 NMAC & 20.2.72.502, Tables A and/or B? ☐ Yes ☑ No		
4	Will this facility be a source of federal Hazardous Air Pollutants (HAP)? ☑ Yes ☐ No		
a	If Yes, what type of source? ☑ **Major** (☑ ≥10 tpy of any single HAP **OR** ☑ ≥25 tpy of any combination of HAPS) **OR** ☐ **Minor** (☐ <10 tpy of any single HAP **AND** ☐ <25 tpy of any combination of HAPS)		
5	Is any unit exempt under 20.2.72.202.B.3 NMAC? ☐ Yes ☑ No		
a	If yes, include the name of company providing commercial electric power to the facility: N/A Commercial power is purchased from a commercial utility company, which specifically does not include power generated on site for the sole purpose of the user.		

Section 1-G: Streamline Application **(This section applies to 20.2.72.300 NMAC Streamline applications only)**

1	☐ I have filled out Section 18, "Addendum for Streamline Applications." ☑ N/A (This is not a Streamline application.)

Section 1-H: Current Title V Information - Required for all applications from TV Sources

(Title V-source required information for all applications submitted pursuant to 20.2.72 NMAC (Minor Construction Permits), or 20.2.74/20.2.79 NMAC (Major PSD/NNSR applications), and/or 20.2.70 NMAC (Title V))

1	Responsible Official (R.O.) (20.2.70.300.D.2 NMAC): Randy Deluane	Phone: (713) 268-7488
a	R.O. Title: Vice President - Permian	R.O. e-mail: RCDeLaune@dcpmidstream.com
b	R. O. Address: 5718 Westheimer Road, Suite 1900, Houston, TX 77057	
2	Alternate Responsible Official (20.2.70.300.D.2 NMAC): Scot Millican	Phone: (575) 234-6441
a	A. R.O. Title: Asset Director - Permian	A. R.O. e-mail: SAMillican@dcpmidstream.com
b	A. R. O. Address:1925 Illinois Camp Rd, Artesia, NM 88210	
3	Company's Corporate or Partnership Relationship to any other Air Quality Permittee (List the names of any companies that have operating (20.2.70 NMAC) permits and with whom the applicant for this permit has a corporate or partnership relationship): N/A	
4	Name of Parent Company ("Parent Company" means the primary name of the organization that owns the company to be permitted wholly or in part.): N/A	
a	Address of Parent Company: N/A	

5	Names of Subsidiary Companies ("Subsidiary Companies" means organizations, branches, divisions or subsidiaries, which are owned, wholly or in part, by the company to be permitted.): N/A
6	Telephone numbers & names of the owners' agents and site contacts familiar with plant operations: N/A
7	Affected Programs to include Other States, local air pollution control programs (i.e. Bernalillo) and Indian tribes: Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B)? If yes, state which ones and provide the distances in kilometers: N/A

Section 1-I – Submittal Requirements

Each 20.2.73 NMAC (**NOI**), a 20.2.70 NMAC (**Title V**), a 20.2.72 NMAC (**NSR** minor source), or 20.2.74 NMAC (**PSD**) application package shall consist of the following:

Hard Copy Submittal Requirements:

1) One hard copy **original signed and notarized application package** **printed double sided** **'head-to-toe'** **2-hole punched** as we bind the document on top, not on the side; except Section 2 (landscape tables), which should be head-to-head. Please use **numbered tab separators** in the hard copy submittal(s) as this facilitates the review process. For NOI submittals only, hard copies of UA1, Tables 2A, 2D & 2F, Section 3 and the signed Certification Page are required. Please include a copy of the check on a separate page.

2) If the application is for a minor NSR, PSD, NNSR, or Title V application, include one working hard **copy** for Department use. This copy should be printed in book form, 3-hole punched, and **must be double sided**. Note that this is in addition to the head-to-to 2-hole punched copy required in 1) above. Minor NSR Technical Permit revisions (20.2.72.219.B NMAC) only need to fill out Sections 1-A, 1-B, 3, and should fill out those portions of other Section(s) relevant to the technical permit revision. TV Minor Modifications need only fill out Sections 1-A, 1-B, 1-H, 3, and those portions of other Section(s) relevant to the minor modification. NMED may require additional portions of the application to be submitted, as needed.

3) The entire NOI or Permit application package, including the full modeling study, should be submitted electronically. Electronic files for applications for NOIs, any type of General Construction Permit (GCP), or technical revisions to NSRs must be submitted with compact disk (CD) or digital versatile disc (DVD). For these permit application submittals, two CD copies are required (in sleeves, not crystal cases, please), with additional CD copies as specified below. NOI applications require only a single CD submittal. Electronic files for other New Source Review (construction) permits/permit modifications or Title V permits/permit modifications can be submitted on CD/DVD or sent through AQB's secure file transfer service.

Electronic files sent by (check one):

☑ CD/DVD attached to paper application

☐ secure electronic transfer. Air Permit Contact Name____________________________

Email______________________________

Phone number _______________________

a. If the file transfer service is chosen by the applicant, after receipt of the application, the Bureau will email the applicant with instructions for submitting the electronic files through a secure file transfer service. Submission of the electronic files through the file transfer service needs to be completed within 3 business days after the invitation is received, so the applicant should ensure that the files are ready when sending the hard copy of the application. The applicant will not need a password to complete the transfer. **Do not use the file transfer service for NOIs, any type of GCP, or technical revisions to NSR permits.**

4) Optionally, the applicant may submit the files with the application on compact disk (CD) or digital versatile disc (DVD) following the instructions above and the instructions in 5 for applications subject to PSD review.

5) If **air dispersion modeling** is required by the application type, include the **NMED Modeling Waiver** and/or electronic air dispersion modeling report, input, and output files. The dispersion modeling ***summary report only*** should be submitted as hard copy(ies) unless otherwise indicated by the Bureau.

6) If the applicant submits the electronic files on CD and the application is subject to PSD review under 20.2.74 NMAC (PSD) or NNSR under 20.2.79 NMC include,
   a. one additional CD copy for US EPA,
   b. one additional CD copy for each federal land manager affected (NPS, USFS, FWS, USDI) and,
   c. one additional CD copy for each affected regulatory agency other than the Air Quality Bureau.

   If the application is submitted electronically through the secure file transfer service, these extra CDs do not need to be submitted.

Electronic Submittal Requirements [in addition to the required hard copy(ies)]:

1) All required electronic documents shall be submitted as 2 separate CDs or submitted through the AQB secure file transfer service. Submit a single PDF document of the entire application as submitted and the individual documents comprising the application.

2) The documents should also be submitted in Microsoft Office compatible file format (Word, Excel, etc.) allowing us to access the text and formulas in the documents (copy & paste). Any documents that cannot be submitted in a Microsoft Office compatible

format shall be saved as a PDF file from within the electronic document that created the file. If you are unable to provide Microsoft office compatible electronic files or internally generated PDF files of files (items that were not created electronically: i.e. brochures, maps, graphics, etc,), submit these items in hard copy format. We must be able to review the formulas and inputs that calculated the emissions.

3) It is preferred that this application form be submitted as 4 electronic files (3 MSWord docs: Universal Application section 1 [UA1], Universal Application section 3-19 [UA3], and Universal Application 4, the modeling report [UA4]) and 1 Excel file of the tables (Universal Application section 2 [UA2]). Please include as many of the 3-19 Sections as practical in a single MS Word electronic document. Create separate electronic file(s) if a single file becomes too large or if portions must be saved in a file format other than MS Word.

4) The electronic file names shall be a maximum of 25 characters long (including spaces, if any). The format of the electronic Universal Application shall be in the format: "A-3423-FacilityName". The "A" distinguishes the file as an application submittal, as opposed to other documents the Department itself puts into the database. Thus, all electronic application submittals should begin with "A-". Modifications to existing facilities should use the core permit number (i.e. '3423') the Department assigned to the facility as the next 4 digits. Use 'XXXX' for new facility applications. The format of any separate electronic submittals (additional submittals such as non-Word attachments, re-submittals, application updates) and Section document shall be in the format: "A-3423-9-description", where "9" stands for the section # (in this case Section 9-Public Notice). Please refrain, as much as possible, from submitting any scanned documents as this file format is extremely large, which uses up too much storage capacity in our database. Please take the time to fill out the header information throughout all submittals as this will identify any loose pages, including the Application Date (date submitted) & Revision number (0 for original, 1, 2, etc.; which will help keep track of subsequent partial update(s) to the original submittal. Do not use special symbols (#, @, etc.) in file names. The footer information should not be modified by the applicant.

Table of Contents

Table 2-A: Regulated Emission Sources

Unit and stack numbering must correspond throughout the application package. If applying for a NOI under 20.2.73 NMAC, equipment exemptions under 2.72.202 NMAC do not apply.

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] Date of Construction/ Reconstruction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
C1-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00911	4735 hp	4735 hp	May-14 March-15	C1-E C1-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C1-C*	Compressor	Ariel	NA	F-46710	NA	N/A	October-14 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C2-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00912	4735 hp	4735 hp	May-14 March-15	C2-E C2-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C2-C*	Compressor	Ariel	NA	F-46929	NA	NA	October-14 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C3-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00915	4735 hp	4735 hp	June-14 March-15	C3-E C3-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C3-C*	Compressor	Ariel	NA	F-46790	NA	NA	January-15 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C4-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00918	4735 hp	4735 hp	June-14 March-15	C4-E C4-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C4-C*	Compressor	Ariel	NA	F-47105	NA	NA	January-15 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C5-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00917	4735 hp	4735 hp	June-14 March-15	C5-E C5-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C5-C*	Compressor	Ariel	NA	F-46800	NA	NA	October-14 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C6-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00913	4735 hp	4735 hp	June-14 March-15	C6-E C6-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C6-C*	Compressor	Ariel	NA	F-47007	NA	NA	October-14 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C7-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00916	4735 hp	4735 hp	June-14 March-15	C7-E C7-E	2020 0254	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C7-C*	Compressor	Ariel	NA	F-46617	NA	NA	October-14 March-15	N/A N/A		☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufacturer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classification Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
C8-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00914	4735 hp	4735 hp	June-14 March-15	C8-E C8-E	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C8-C*	Compressor	Ariel	NA	F-46687	NA	NA	November-14 March-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C9-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	BEN01006	2370hp	2370hp	June-14 March-15	C9-E C9-E	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C9-C*	Compressor	Ariel	NA	F-46794	NA	NA	March-15 November-14	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C10-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	BEN01001	2370hp	2370hp	June-14 March-15	C10-E C10-E	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	4SLB	N/A
C10-C*	Compressor	Ariel	NA	F-46690	NA	NA	December-14 March-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C11-C**	Screw Compressor	GEA FES	1210GLE	XC0344	NA	NA	2014 2015	N/A N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C12-C**	Screw Compressor	GEA FES	1210GLE	XC0355	NA	NA	2014 2015	N/A N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C13-C**	Screw Compressor	GEA FES	1210GLE	XC0348	NA	NA	2014 2015	N/A N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C14-C*	Compressor	Ariel	JGC/6	F-46848	NA	NA	2014 2015	N/A N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
C15-C*	Compressor	Ariel	JGC/6	F-47006	NA	NA	2014 2015	N/A N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
H1	Trim Reboiler Heater	Heatec	HCI-10010-40-D	HI-13-170	26.0 MMBtu/hr	26.0 MMBtu/hr	March-14 March-15	N/A H1	3100 0404	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
H3	Regeneration Gas Heater	Heatec	HCI-5010-40-G	HI-13-165	10.0 MMBtu/hr	10.0 MMBtu/hr	March-14 March-15	N/A H3	3100 0404	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
H4	Hot Oil Heater	OPF	OPF	J121104	99.0 MMBtu/hr	99.0 MMBtu/hr	2014 2015	N/A H4	3100 0404	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
H5	Hot Oil Heater	OPF	OPF	J131125	99.0 MMBtu/hr	99.0 MMBtu/hr	2014 2015	N/A H5	3100 0404	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
H6	TEG Regeneration Heater	Maxon	XPO-3	942556	3.5 MMBtu/hr	3.5 MMBtu/hr	2014 2015	N/A H6	3100 0404	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] Date of Construction/ Reconstruction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
FL1	Inlet Gas Flare	Zeeco	NA	FL-5100/24093	2.3 MMBtu/hr	2.3 MMBtu/hr	2014 2015	N/A FL1	3060 0904	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FL2	Acid Gas Flare	Zeeco	NA	FL-5200/24093	2.3 MMBtu/hr	2.3 MMBtu/hr	2014 2015	N/A FL2	3060 0904	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FL3	Lusk Emergency Flare	Flare King	NA	FL-201583	13 MMscf/d	13 MMscf/d	2014 2015	N/A FL-3	3100 0205	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
VCD1	Vapor Combustion Device	Zeeco	Zeeco	24895	3.6 MMBtu/hr	3.6 MMBtu/hr	2014 2015	VCD1 VCD1	3060 9903	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
Dehy	TEG Dehydrator	Enerflex	Enerflex	E001227	230 MMscfd	230 MMscfd	2014 2015	VCD1 VCD1	3100 0227	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TK-2100	Condensate Tank	Tank and Vessel Builders	NA	201429	1000 bbl	1000 bbl	2014 February-15	VCD1 VCD1	4040 0311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TK-2200	Condensate Tank	Tank and Vessel Builders	NA	201430	1000 bbl	1000 bbl	2014 February-15	VCD1 VCD1	4040 0311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TK-6100	Produced Water Tank	Palmer	NA	ST1046541	300 bbl	300 bbl	October-14 February-15	N/A N/A	4040 0311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
TK-6150	Produced Water Tank	Palmer	NA	ST1406066	300 bbl	300 bbl	October-14 February-15	N/A N/A	4040 0311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
L1	Truck Loadout	N/A	N/A	N/A	38,325,000 gal/yr	38,325,000 gal/yr	N/A N/A	VCD1 VCD1	4040 0250	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
HAUL	Paved Haul Roads	N/A	N/A	N/A	N/A	N/A	N/A N/A	N/A N/A	3108 8811	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FUG	Facility-Wide Fugitives	N/A	N/A	N/A	N/A	N/A	N/A N/A	N/A N/A	3108 8811	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
Amine	Amine Sweetening Unit	N/A	N/A	N/A	N/A	N/A	2014 2015	AGI1, AGI2, FL2 AGI1, AGI2, FL2	3100 0305	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
CT-1	Wet Surface Air Cooler	Niagara Blower Company	A4407SL	14-23717	131,500 lb/hr	131,500 lb/hr	2014 2015	N/A N/A	3060 0701	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
CT-2	Wet Surface Air Cooler	Niagara Blower Company	A4406	TBD	33,946 lb/hr	33,946 lb/hr	TBD TBD	N/A N/A	3060 0701	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
GEN-1	Diesel Generator (500 hrs/yr)	Cummins	DSFAC	B150793133	70 hp	70 hp	TBD TBD	N/A GEN-1	3100 0299	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
SSM (CB)	Compressor Blowdown SSM	N/A	N/A	N/A	N/A	N/A	N/A N/A	N/A N/A	3108 8811	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
SSM (PV)	Plant Venting SSM	N/A	N/A	N/A	N/A	N/A	N/A N/A	N/A N/A	3108 8811	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

[1] Unit numbers must correspond to unit numbers in the previous permit unless a complete cross reference table of all units in both permits is provided.
[2] Specify dates required to determine regulatory applicability.
[3] To properly account for power conversion efficiencies, generator set rated capacity shall be reported as the rated capacity of the engine in horsepower, not the kilowatt capacity of the generator set.
[4] "4SLB" means four stroke lean burn engine, "4SRB" means four stroke rich burn engine, "2SLB" means two stroke lean burn engine, "CI" means compression ignition, and "SI" means spark ignition

[5] Produced water tank TK-6100 is currently permitted as TK-G. Produced water tank TK-6150 is currently permitted as TK-H. These unit numbers are being updated in this application.

[6] Under normal operating conditions, the amine unit will not be a source of regulated emissions; emissions from the amine unit will be controlled 100% by the two AGI wells. In the event that one of the two AGI wells are inoperable due to maintenance or upset conditions, acid gas from the amine unit will be flared by Unit FL2 for limited periods.

* The compressor component is identified as a separate unit in this table for NSPS OOOO purposes; compressors are only a source of compressor blowdown SSM emissions.

** screw compressors are not subject to NSPS OOOO.

† These tanks are not a source of emissions. TK-D, TK-E, and TK-F are under blanket gas. TK-I and TK-J are pressurized tanks.

Table 2-B: Insignificant Activities[1] (20.2.70 NMAC) OR Exempted Equipment (20.2.72 NMAC)

All 20.2.70 NMAC (Title V) applications must list all Insignificant Activities in this table. All 20.2.72 NMAC applications must list Exempted Equipment in this table. If equipment listed on this table is exempt under 20.2.72.202.B.5, include emissions calculations and emissions totals for 202.B.5 "similar functions" units, operations, and activities in Section 6, Calculations. Equipment and activities exempted under 20.2.72.202 NMAC may not necessarily be Insignificant under 20.2.70 NMAC (and vice versa). Unit & stack numbering must be consistent throughout the application package. Per Exemptions Policy 02-012.00 (see http://www.env.nm.gov/aqb/permit/aqb_pol.html), 20.2.72.202.B NMAC Exemptions do not apply, but 20.2.72.202.A NMAC exemptions do apply to NOI facilities under 20.2.73 NMAC. List 20.2.72.301.D.4 NMAC Auxiliary Equipment for Streamline applications in Table 2-A. The List of Insignificant Activities (for TV) can be found online at http://www.env.nm.gov/aqb/forms/InsignificantListTitleV.pdf . TV sources may elect to enter both TV Insignificant Activities and Part 72 Exemptions on this form.

Unit Number	Source Description	Manufacturer	Model No.	Max Capacity	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5)	Date of Manufacture /Reconstruction[2]	For Each Piece of Equipment, Check Onc
			Serial No.	Capacity Units	Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Installation /Construction[2]	
TK-7015	Engine/Compressor Oil Tank	Willborn Bros	NA	1036	N/A	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7020	Amine Storage Tank with Blanket Gas	Palmer	NA	400	Not a regulated source of emissions.	11/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			ST1407196	bbl	List Item #1.a	2/1/2015	
TK-7025	Used Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7035	Jacket/Aux Water Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #1.a	2/1/2015	
TK-7045	Engine/Compressor Oil Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7050	R.O. Water Storage Tank	Palmer	NA	175	Not a regulated source of emissions.	2/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			OF1408083	bbl	List Item #1.a	2/1/2015	
TK-7055	Used Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	bbl	List Item #5	2/1/2015	
TK-7065	Jacket/Aux Water Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2015	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	bbl	List Item #1.a	2/1/2015	
TK-7070	R.O. Wastewater Tank	Palmer	NA	195	Not a regulated source of emissions.	2/1/2015	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			OF1408086	bbl	List Item #1.a	2/1/2015	
TK-7075	Compressor Crank Case Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7085	Used Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7095	Compressor Lubrication Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7105	Compressor Lubrication Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7115	Compressor Lubrication Oil Storage Tank	Willborn Bros	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	

Unit Number	Source Description	Manufacturer	Model No.	Max Capacity	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5)	Date of Manufacture /Reconstruction[2]	For Each Piece of Equipment, Check Onc
			Serial No.	Capacity Units	Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Installation /Construction[2]	
TK-7400	Refrigerant Compressor Lube Oil Storage Tank with Blanket Gas	Willborn Bros	NA	500	Not a regulated source of emissions.	8/1/2014	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/1/2015	
TK-7410	Used Refrigerant Compressor Oil Storage Tank	Willborn Bros	NA	500	Not a regulated source of emissions.	8/1/2014	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	2/15/2015	
TK-7500	H.M.O. Make-up Tank	Palmer	TBD	150	Not a regulated source of emissions.	2/1/2015	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			ST-1409494	bbl	List Item #1.a	3/1/2015	
TK-7600	Glycol Storage Tank	Palmer	TBD	150	Not a regulated source of emissions.	11/1/2014	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			ST-1406954	bbl	List Item #5	3/1/2015	
TK-7700	Methanol Storage Tank	Highland	NA	1500	Not a regulated source of emissions.	8/1/2014	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #1.a	2/1/2015	
TK-7750	Methanol Storage Tank	Highland	NA	1500	Not a regulated source of emissions.	8/1/2014	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #1.a	2/1/2015	
TK-7800	Methanol Storage Tank	Highland	NA	1036	Not a regulated source of emissions.	8/1/2014	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #1.a	2/1/2015	
TK-WATER	Raw Water Storage Tank	Power Pipe and Tank	NA	1000	Not a regulated source of emissions.	1/1/2015	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	bbl	List Item #1.a	2/1/2015	
TK-L1	Lusk Slop Tank	TBD	TBD	210	Not a regulated source of emissions.	TBD	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			TBD	bbl	List Item #5	TBD	
TK-L2	Lusk Methanol Tank	Palmer	NA	443	Not a regulated source of emissions.	9/1/1983	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			AT-2784	bbl	List Item #1.a	9/1/1983	
TK-3	Diesel Tank	N/A	NA	1000	Not a regulated source of emissions.	NA	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	List Item #5	5/1/2015	

[1] Insignificant activities exempted due to size or production rate are defined in 20.2.70.300.D.6, 20.2.70.7.Q NMAC, and the NMED/AQB List of Insignificant Activities, dated September 15, 2008. Emissions from these insignificant activities do not need to be reported, unless specifically requested.

[2] Specify date(s) required to determine regulatory applicability.

Table 2-C: Emissions Control Equipment

Unit and stack numbering must correspond throughout the application package. Only list control equipment for TAPs if the TAP's maximum uncontrolled emissions rate is over its respective threshold as listed in 20.2.72 NMAC, Subpart V, Tables A and B. In accordance with 20.2.72.203.A(3) and (8) NMAC, 20.2.70.300.D(5)(b) and (e) NMAC, and 20.2.73.200.B(7) NMAC, the permittee shall report all control devices and list each pollutant controlled by the control device regardless if the applicant takes credit for the reduction in emissions.

Control Equipment Unit No.	Control Equipment Description	Date Installed	Controlled Pollutant(s)	Controlling Emissions for Unit Number(s)[1]	Efficiency (% Control by Weight)	Method used to Estimate Efficiency
C1-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C1-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C2-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C2-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C3-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C3-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C4-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C4-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C5-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C5-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C6-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C6-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C7-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C7-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C8-E	Oxidation Catalyst	3/1/2015	CO, VOC, and HCHO	C8-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C9-E	Oxidation Catalyst	3/1/2015	CO and VOC	C9-E	94% CO, 52% VOC	Catalyst Mfg
C10-E	Oxidation Catalyst	3/1/2015	CO and VOC	C10-E	94% CO, 52% VOC	Catalyst Mfg
FL2	Emergency Acid Gas Flare	3/1/2015	H2S	Amine	98%	Eng Estimate
VCD1	Vapor Combustion Device	3/1/2015	VOC and HAPs	TK1, TK2, TK-C, TK-G, TK-H, L1, and Dehy	98%	Eng Estimate
AGI1, AGI2	AGI Wells	3/1/2015	H2S and CO2	Amine	100%	Eng Estimate
H6	TEG Regeneration Heater	3/1/2015	VOC and HAPs	Dehy	98%	Eng Estimate

[1] List each control device on a separate line. For each control device, list all emission units controlled by the control device.

Table 2-D: Maximum Emissions (under normal operating conditions)

☐ **This Table was intentionally left blank because it would be identical to Table 2-E.**

Maximum Emissions are the emissions at maximum capacity and prior to (in the absence of) pollution control, emission-reducing process equipment, or any other emission reduction. Calculate the hourly emissions using the worst case hourly emissions for each pollutant. For each pollutant, calculate the annual emissions as if the facility were operating at maximum plant capacity without pollution controls for 8760 hours per year, unless otherwise approved by the Department. List Hazardous Air Pollutants (HAP) & Toxic Air Pollutants (TAPs) in Table 2-I. Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		TSP[2]		PM10[2]		PM2.5[2]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
C1-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C2-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C3-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C4-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C5-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C6-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C7-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C8-E	5.22	22.86	28.71	125.74	6.58	28.80	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C9-E	2.61	11.44	14.37	62.93	3.29	14.42	0.23	0.99	0.16	0.99	0.16	0.99	0.16	0.99	-	-	-	-
C10-E	2.61	11.44	14.37	62.93	3.29	14.42	0.23	0.99	0.16	0.99	0.16	0.99	0.16	0.99	-	-	-	-
H1	1.27	5.58	2.14	9.38	0.14	0.61	0.37	1.64	0.19	0.85	0.19	0.85	0.19	0.85	-	-	-	-
H3	0.49	2.15	0.82	3.61	0.05	0.24	0.14	0.63	0.07	0.33	0.07	0.33	0.07	0.33	-	-	-	-
H4	5.94	26.02	4.06	17.78	0.53	2.34	1.43	6.25	0.74	3.23	0.74	3.23	0.74	3.23	-	-	-	-
H5	5.94	26.02	4.06	17.78	0.53	2.34	1.43	6.25	0.74	3.23	0.74	3.23	0.74	3.23	-	-	-	-
H6	0.17	0.75	0.29	1.3	0.019	0.083	0.050	0.22	0.026	0.11	0.026	0.11	0.026	0.11	-	-	-	-
FL1[3]	0.17	0.74	0.92	4.0	0.013	0.059	-	-	-	-	-	-	-	-	-	-	-	-
FL2[3]	0.16	0.68	0.84	3.7	0.013	0.059	-	-	-	-	-	-	-	-	-	-	-	-
FL3[3]	0.16	0.68	0.84	3.7	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
VCD1[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dehy[4]	-	-	-	-	48.38	211.89	-	-	-	-	-	-	-	-	-	-	-	-
TK-2100[4]	-	-	-	-	6.67	29.24	-	-	-	-	-	-	-	-	-	-	-	-
TK-2200[4]	-	-	-	-	6.67	29.24	-	-	-	-	-	-	-	-	-	-	-	-
TK-6100	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-
TK-6150	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-
L1[4]	-	-	-	-	-	114.51	-	-	-	-	-	-	-	-	-	-	-	-
HAUL	-	-	-	-	-	-	-	-	0.39	0.24	0.078	0.048	0.019	0.012	-	-	-	-
FUG	-	-	-	-	7.20	31.52	-	-	-	-	-	-	-	-	0.16	0.68	-	-
Amine[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	0.0075	0.033	0.00020	0.00088	2.07E-06	9.07E-06	-	-	-	-
CT-2	-	-	-	-	-	-	-	-	0.0040	0.017	0.00011	0.00046	1.09E-06	4.76E-06	-	-	-	-
GEN-1	0.51	0.13	0.58	0.14	0.027	0.0068	1.29E-06	3.24E-07	0.0460	0.01151	0.0460	0.01151	0.0460	0.01151	-	-	-	-
Totals	61.79	268.51	272.94	1193.10	129.46	682.04	7.48	32.77	5.03	20.98	4.71	20.74	4.65	20.70	0.16	0.68	-	-

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for TSP unless TSP is set equal to PM10 and PM2.5.

[3] FL1, FL2, and FL3 emissions are represented as pilot and purge only. Emissions associated with startup, shutdown, and maintenance from the flares will be covered under the requested SSM/M.

[4] Unit VCD1 combusts emissions from the condensate tanks (units TK-2100 and TK-2200), TEG Dehydrator non-condensables (unit Dehy) and Loadout (unit L1). Unit VCD1 will have no emissions in an uncontrolled scenario.

[5] Under normal operating conditions, the amine unit will not be a source of regulated emissions; emissions from the amine unit will be controlled 100% by the two AGI wells.

"-" Denotes emissions of this pollutant are not expected.

Table 2-E: Requested Allowable Emissions

Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or $1.41E^{-4}$).

Unit No.	NOx		CO		VOC		SOx		TSP[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
C1-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C2-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C3-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C4-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C5-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C6-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C7-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C8-E	5.22	22.86	0.54	2.36	2.04	8.92	0.45	1.97	0.31	1.37	0.31	1.37	0.31	1.37	-	-	-	-
C9-E	2.61	11.44	1.04	4.58	1.57	6.87	0.23	0.99	0.16	0.69	0.16	0.69	0.16	0.69	-	-	-	-
C10-E	2.61	11.44	1.04	4.58	1.57	6.87	0.23	0.99	0.16	0.69	0.16	0.69	0.16	0.69	-	-	-	-
H1	1.27	5.58	2.14	9.38	0.14	0.61	0.37	1.64	0.19	0.85	0.19	0.85	0.19	0.85	-	-	-	-
H3	0.49	2.15	0.82	3.61	0.054	0.24	0.14	0.63	0.075	0.33	0.075	0.33	0.075	0.33	-	-	-	-
H4	5.94	26.02	4.06	17.78	0.53	2.3	1.43	6.25	0.74	3.23	0.74	3.23	0.74	3.2	-	-	-	-
H5	5.94	26.02	4.06	17.78	0.53	2.3	1.43	6.25	0.74	3.23	0.74	3.23	0.74	3.2	-	-	-	-
H6	0.17	0.75	0.29	1.26	0.019	0.083	0.050	0.22	0.026	0.11	0.026	0.11	0.026	0.11	-	-	-	-
FL1[3]	0.17	0.74	0.92	4.02	0.013	0.059	-	-	-	-	-	-	-	-	-	-	-	-
FL2[3]	0.16	0.68	0.84	3.69	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
FL3[3]	0.16	0.68	0.84	3.69	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
VCD1[4]	0.24	1.06	0.20	0.89	1.76	7.71	-	-	-	-	-	-	-	-	-	-	-	-
Dehy[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-2100[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-2200[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-6100	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-
TK-6150	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-
L1[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HAUL	-	-	-	-	-	-	-	-	0.39	0.24	0.078	0.048	0.019	0.012	-	-	-	-
FUG	-	-	-	-	7.20	31.52	-	-	-	-	-	-	-	-	0.16	0.68	-	-
Amine[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	1.88E-03	8.25E-03	5.03E-05	2.20E-04	5.17E-07	2.27E-06	-	-	-	-
CT-2	-	-	-	-	-	-	-	-	9.89E-04	4.33E-03	2.64E-05	1.16E-04	2.72E-07	1.19E-06	-	-	-	-
GEN-1	0.51	0.13	0.58	0.14	0.027	0.0068	1.29E-06	3.24E-07	4.60E-02	1.15E-02	4.60E-02	1.15E-02	4.60E-02	1.15E-02	-	-	-	-
Totals	62.03	269.57	21.16	90.31	29.72	130.65	7.48	32.77	5.02	20.33	4.71	20.13	4.65	20.09	0.16	0.68	-	-

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for TSP unless TSP is set equal to PM10 and PM2.5.

[3] FL1, FL2, and FL3 emissions are represented as pilot and purge only. Emissions associated with startup, shutdown, and maintenance from the flares will be covered under the requested SSM/M.

[4] Unit VCD1 combusts emissions from the condensate tanks (units TK-2100 and TK-2200), TEG Dehydrator non-condensables (unit Dehy) and Loadout (unit L1). Unit VCD1 will have no emissions in an uncontrolled scenario.

[5] Under normal operating conditions, the amine unit will not be a source of regulated emissions; emissions from the amine unit will be controlled 100% by the two AGI wells.

"-" Denotes emissions of this pollutant are not expected.

Table 2-F: Additional Emissions during Startup, Shutdown, and Routine Maintenance (SSM)

☐ This table is intentionally left blank since all emissions at this facility due to routine or predictable startup, shutdown, or scehduled maintenance are no higher than those listed in Table 2-E and a malfunction emission limit is not already permitted or requested. If you are required to report GHG emissions as described in Section 6a, include any GHG emissions during Startup, Shutdown, and/or Scheduled Maintenance (SSM) in Table 2-P. Provide an explanations of SSM emissions in Section 6 and 6a.

All applications for facilities that have emissions during routine our predictable startup, shutdown or scheduled maintenance (SSM)[1], including NOI applications, must include in this table the Maximum Emissions during routine or predictable startup, shutdown and scheduled maintenance (20.2.7 NMAC, 20.2.72.203.A.3 NMAC, 20.2.73.200.D.2 NMAC). In Section 6 and 6a, provide emissions calculations for all SSM emissions reported in this table. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (https://www.env.nm.gov/aqb/permit/aqb_pol.html) for more detailed instructions. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		TSP[2]		PM10[2]		PM2.5[2]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
FL1	799.24	3.88	4,348.79	21.09	2,942.11	11.82	14,977.09	59.91	-	-	-	-	-	-	162.86	0.65	-	-
FL2	101.95	1.19	554.75	6.46	7.83	0.092	4,409.79	22.05	-	-	-	-	-	-	47.95	0.24	-	-
SSM (CB)	-	-	-	-	358.83	0.83	-	-	-	-	-	-	-	-	0.050	0.00011	-	-
SSM (PV)	-	-	-	-	1,499.96	12.03	-	-	-	-	-	-	-	-	7.27	0.058	-	-
Totals	901.19	5.06	4,903.54	27.55	4,808.74	24.77	19,386.88	81.96	-	-	-	-	-	-	218.13	0.95	-	-

[1] **For instance**, if the short term steady-state Table 2-E emissions are 5 lb/hr and the SSM rate is 12 lb/hr, enter 7 lb/hr in this table. If the annual steady-state Table 2-E emissions are 21.9 TPY, and the number of scheduled SSM events result in annual emissions of 31.9 TPY, enter 10.0 TPY in the table below.

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for TSP unless TSP is set equal to PM10 and PM2.5.

Table 2-G: Stack Exit and Fugitive Emission Rates for Special Stacks

☑ I have elected to leave this table blank because this facility does not have any stacks/vents that split emissions from a single source or combine emissions from more than one source listed in table 2-A. Additionally, the emission rates of all stacks match the Requested allowable emission rates stated in Table 2-E.

Use this table to list stack emissions (requested allowable) from split and combined stacks. List Toxic Air Pollutants (TAPs) and Hazardous Air Pollutants (HAPs) in Table 2-I. List all fugitives that are associated with the normal, routine, and non-emergency operation of the facility. Unit and stack numbering must correspond throughout the application package. Refer to Table 2-E for instructions on use of the "-" symbol and on significant figures.

Stack No.	Serving Unit Number(s) from Table 2-A	NOx		CO		VOC		SOx		TSP		PM10		PM2.5		☐ H_2S or ☐ Lead	
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
Totals:																	

Table 2-H: Stack Exit Conditions

Unit and stack numbering must correspond throughout the application package. Include the stack exit conditions for each unit that emits from a stack, including blowdown venting parameters and tank emissions. If the facility has multiple operating scenarios, complete a separate Table 2-H for each scenario and, for each, type scenario name here:

Stack Number	Serving Unit Number(s) from Table 2-A	Orientation (H-Horizontal V=Vertical)	Rain Caps	Height Above	Temp.	Flow Rate		Moisture by	Velocity	Inside Diameter (ft)
			(Yes or No)	Ground (ft)	(F)	(acfs)	(dscfs)	Volume (%)	(ft/sec)	
C1-E	C1	V	No	50	856	535.00	-	-	75.69	3.00
C2-E	C2	V	No	50	856	535.00	-	-	75.69	3.00
C3-E	C3	V	No	50	856	535.00	-	-	75.69	3.00
C4-E	C4	V	No	50	856	535.00	-	-	75.69	3.00
C5-E	C5	V	No	50	856	535.00	-	-	75.69	3.00
C6-E	C6	V	No	50	856	535.00	-	-	75.69	3.00
C7-E	C7	V	No	50	856	535.00	-	-	75.69	3.00
C8-E	C8	V	No	50	856	535.00	-	-	75.69	3.00
C9-E	C9-E	V	No	50	857	269.07	-	-	101.93	1.75
C10-E	C10-E	V	No	50	857	269.07	-	-	101.93	1.75
H1	H1	V	No	20	730	199.91	-	-	28.28	3.00
H3	H3	V	No	18	718	76.11	-	-	15.50	2.50
H4	H4	V	No	129	512	621.75	-	-	9.80	9.00
H5	H5	V	No	129	512	621.75	-	-	9.80	9.00
H6	H6	V	No	25	600	23.97	-	-	30.50	1.00
FL1	FL1	V	No	100	1832	227.27	-	-	65.62	2.10
FL2	FL2	V	No	150	1832	227.27	-	-	65.62	2.10
FL3	FL3	V	No	50	1832	35.49	-	-	65.60	0.83
VCD1	VCD1	V	No	30	1400	44.85	-	-	2.82	4.50
GEN-1	GEN-1	V	No	6.7	754	10.53	-	-	214.58	0.25

Table 2-I: Stack Exit and Fugitive Emission Rates for HAPs and TAPs

In the table below, report the Potential to Emit for each HAP from each regulated emission unit listed in Table 2-A, only if the entire facility emits the HAP at a rate greater than or equal to one (1) ton per year For each such emission unit, HAPs shall be reported to the nearest 0.1 tpy. Each facility-wide Individual HAP total and the facility-wide Total HAPs shall be the sum of all HAP sources calculated to the nearest 0.1 ton per year. Per 20.2.72.403.A.1 NMAC, facilities not exempt [see 20.2.72.402.C NMAC] from TAP permitting shall report each TAP that has an uncontrolled emission rate in excess of its pounds per hour screening level specified in 20.2.72.502 NMAC. TAPs shall be reported using one more significant figure than the number of significant figures shown in the pound per hour threshold corresponding to the substance. Use the HAP nomenclature as it appears in Section 112 (b) of the 1990 CAAA and the TAP nomenclature as it listed in 20.2.72.502 NMAC. Include tank-flashing emissions estimates of HAPs in this table. For each HAP or TAP listed, fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected or the pollutant is emitted in a quantity less than the threshold amounts described above.

Stack No.	Unit No.(s)	Total HAPs		Formaldehyde ☑ HAP or ☐TAP		Methanol ☑ HAP or ☐TAP		Acetaldehyde ☑ HAP or ☐TAP		Acrolein ☑ HAP or ☐TAP		Benzene ☑ HAP or ☐TAP		Toluene ☑ HAP or ☐TAP		Ethylbenzene ☑ HAP or ☐TAP		Xylenes ☑HAP or ☐TAP		n-Hexane ☑ HAP or ☐ TAP		2,2,4-Trimethylpentane ☑ HAP or ☐ TAP		Styrene ☑ HAP or ☐ TAP	
		lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
C1-E	C1-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C2-E	C2-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C3-E	C3-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C4-E	C4-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C5-E	C5-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C6-E	C6-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C7-E	C7-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C8-E	C8-E	0.75	3.3	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C9-E	C9-E	1.3	5.8	0.99	4.3	0.046	0.20	0.15	0.67	0.094	0.41	0.0081	0.035	0.018	0.079	0.00073	0.0032	0.0034	0.015	0.020	0.089	0.0046	0.020	0.00043	0.0019
C10-E	C10-E	1.3	5.8	0.99	4.3	0.046	0.20	0.15	0.67	0.094	0.41	0.0081	0.035	0.018	0.079	0.00073	0.0032	0.0034	0.015	0.020	0.089	0.0046	0.020	0.00043	0.0019
H1	H1	0.37	1.6	0.022	0.096	0.025	0.11	0.019	0.084	-	-	0.019	0.085	0.026	0.12	0.055	0.24	0.034	0.15	0.037	0.16	0.074	0.32	0.054	0.24
H3	H3	0.14	0.63	0.0084	0.037	0.0096	0.042	0.0074	0.032	-	-	0.0075	0.033	0.010	0.045	0.021	0.093	0.013	0.058	0.014	0.062	0.028	0.12	0.021	0.091
H4	H4	1.4	6.3	0.084	0.37	0.10	0.42	0.073	0.32	-	-	0.074	0.32	0.10	0.44	0.21	0.92	0.13	0.57	0.14	0.61	0.28	1.2	0.21	0.90
H5	H5	1.4	6.3	0.084	0.37	0.10	0.42	0.073	0.32	-	-	0.074	0.32	0.10	0.44	0.21	0.92	0.13	0.57	0.14	0.61	0.28	1.2	0.21	0.90
H6	H6	0.050	0.22	0.0029	0.013	0.0034	0.015	0.0026	0.011	-	-	0.0026	0.012	0.0036	0.016	0.0074	0.032	0.0046	0.020	0.0049	0.022	0.0100	0.044	0.0073	0.032
FL1[1]	FL1[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FL2[1]	FL2[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FL3[1]	FL3[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VCD1	VCD1	0.41	1.8	-	-	-	-	-	-	-	-	0.11	0.48	0.091	0.40	0.011	0.049	0.073	0.32	0.12	0.54	0.0058	0.026	-	-
N/A	Dehy[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	TK-2100[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	TK-2200[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	TK-6100	-	0.0044	-	-	-	-	-	-	-	-	*	0.0013	*	0.0014	*	9.4E-05	*	0.00039	*	0.0012	-	-	-	-
N/A	TK-6150	-	0.0044	-	-	-	-	-	-	-	-	*	0.0013	*	0.0014	*	9.4E-05	*	0.00039	*	0.0012	-	-	-	-
N/A	L1[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	HAUL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	FUG	0.64	2.8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amine[3]	Amine[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT-1	CT-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEN-1	GEN-1	0.050	0.012	0.049	0.012	-	-	0.00053	0.00013	6.4E-05	1.6E-05	0.00065	0.00016	0.00028	7.1E-05	-	-	0.00020	4.9E-05	-	-	-	-	-	-
FL1	FL1 SSM	259.4	1.0	-	-	-	-	-	-	-	-	3.9	0.016	4.6	0.018	1.06	0.0042	5.3	0.021	244.5	0.98	-	-	-	-
FL2	FL2 SSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	SSM (CB)	0.050	0.00011	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	SSM (PB)	7.3	0.058	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Totals:		279.8	58.5	2.9	12.3	1.0	4.4	2.8	12.2	1.6	7.0	4.3	1.9	5.1	2.1	1.6	2.3	5.7	2.0	245.3	4.5	0.76	3.3	0.50	2.2

"-" Denotes emissions of this pollutant are not expected.

[1] FL1, FL2, and FL3 emissions are represented as pilot and purge only. Emissions associated with startup, shutdown, and maintenance from the flares will be covered under the requested SSM/M.

[2] Unit VCD1 combusts emissions from the condensate tanks (units TK-2100 and TK-2200), TEG Dehydrator non-condensables (unit Dehy) and Loadout (unit L1). Unit VCD1 will have no emissions in an uncontrolled scenario.

[3] Under normal operating conditions, the amine unit will not be a source of regulated emissions; emissions from the amine unit will be controlled 100% by the two AGI wells.

Table 2-J: Fuel

Specify fuel characteristics and usage. Unit and stack numbering must correspond throughout the application package.

Unit No.	Fuel Type (low sulfur Diesel, ultra low sulfur diesel, Natural Gas, Coal, …)	Fuel Source: purchased commercial, pipeline quality natural gas, residue gas, raw/field natural gas, process gas (e.g. SRU tail gas) or other	Specify Units				
			Lower Heating Value	Hourly Usage	Annual Usage	% Sulfur	% Ash
C1-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C2-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C3-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C4-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C5-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C6-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C7-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C8-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C9-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	15.8 Mscf/hr	138.8 MMscf/yr	5 g S/100 scf	-
C10-E	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	15.8 Mscf/hr	138.8 MMscf/yr	5 g S/100 scf	-
H1	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	26.2 Mscf/hr	229.8 MMscf/yr	5 g S/100 scf	-
H3	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	10.1 Mscf/hr	88.4 MMscf/yr	5 g S/100 scf	-
H4	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	99.9 Mscf/hr	874.9 MMscf/yr	5 g S/100 scf	-
H5	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	99.9 Mscf/hr	874.9 MMscf/yr	5 g S/100 scf	-
H6	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	3.5 Mscf/hr	30.9 MMscf/yr	5 g S/100 scf	-
FL1	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	2.5 Mscf/hr	21.9 MMscf/yr	5 g S/100 scf	-
FL2	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	2.3 Mscf/hr	20.1 MMscf/yr	5 g S/100 scf	-
FL3	Natural Gas	Pipeline Quality Natural Gas	991 MMbtu/MMscf	2.3 Mscf/hr	20.1 MMscf/yr	5 g S/100 scf	-
VCD1	VOC*	VOC*	1513.3 MMBtu/MMscf	1.1 Mscf/hr	9.7 MMscf/yr	-	-
GEN-1	Diesel	Diesel	19,300 Btu/lb	0.7 scf/hr	345.7 scf/yr	15 ppm	-

* No additional or supplemental fuel is provided to the vapor combustion device. Instead, an igniter is activated by a pressure-sensing control system. The VOC emissions from the dehydrator, tanks, and loading is essentially the fuel.

Table 2-K: Liquid Data for Tanks Listed in Table 2-L

For each tank, list the liquid(s) to be stored in each tank. If it is expected that a tank may store a variety of hydrocarbon liquids, enter "mixed hydrocarbons" in the Composition column for that tank and enter the corresponding data of the most volatile liquid to be stored in the tank. If tank is to be used for storage of different materials, list all the materials in the "All Calculations" attachment, run the newest version of TANKS on each, and use the material with the highest emission rate to determine maximum uncontrolled and requested allowable emissions rate. The permit will specify the most volatile category of liquids that may be stored in each tank. Include appropriate tank-flashing modeling input data. Use additional sheets if necessary. Unit and stack numbering must correspond throughout the application package.

Tank No.	SCC Code	Material Name	Composition	Liquid Density (lb/gal)	Vapor Molecular Weight (lb/lb*mol)	Average Storage Conditions		Max Storage Conditions	
						Temperature (°F)	True Vapor Pressure (psia)	Temperature (°F)	True Vapor Pressure (psia)
TK-2100	40400311	Condensate	Hydrocarbons and Water	5.6	66	63.26	5.52	70.78	6.36
TK-2200	40400311	Condensate	Hydrocarbons and Water	5.6	66	63.26	5.52	70.78	6.36
TK-6100	40400311	Produced Water	Water plus trace hydrocarbons	8.3	18	72.26	0.40	86.25	0.63
TK-6150	40400311	Produced Water	Water plus trace hydrocarbons	8.3	18	72.26	0.40	86.25	0.63

Table 2-L: Tank Data

Include appropriate tank-flashing modeling input data. Use an addendum to this table for unlisted data categories. Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary. See reference Table 2-L2. Note: 1.00 bbl = 10.159 M3 = 42.0 gal

Tank No.	Date Installed	Materials Stored	Seal Type (refer to Table 2-LR below)	Roof Type (refer to Table 2-LR below)	Capacity		Diameter (M)	Vapor Space (M)	Color (from Table VI-C)		Paint Condition (from Table VI-C)	Annual Throughput (gal/yr)	Turn-overs (per year)
					(bbl)	(M^3)			Roof	Shell			
TK-2100	42064	Condensate	N/A	FX	1,000	159	6.096	2.43	tan	tan	Good	38,325,000	453.00
TK-2200	42064	Condensate	N/A	FX	1,000	159	6.096	2.43	tan	tan	Good	38,325,000	453.00
TK-6100	42064	Produced Water	N/A	FX	300	48	3.6576	2.43	tan	tan	Good	766,500	30.42
TK-6150	42064	Produced Water	N/A	FX	300	48	3.6576	2.43	tan	tan	Good	766,500	30.42

Table 2-L2: Liquid Storage Tank Data Codes Reference Table

Roof Type	Seal Type, Welded Tank Seal Type		Seal Type, Riveted Tank Seal Type		Roof, Shell Color	Paint Condition
	Mechanical Shoe Seal	**Liquid-mounted resilient seal**	**Vapor-mounted resilient seal**	**Seal Type**		
FX: Fixed Roof					**WH**: White	Good
IF: Internal Floating Roof	**A**: Primary only	**A**: Primary only	**A**: Primary only	**A**: Mechanical shoe, primary only	**AS**: Aluminum (specular)	Poor
EF: External Floating Roof	**B**: Shoe-mounted secondary	**B**: Weather shield	**B**: Weather shield	**B**: Shoe-mounted secondary	**AD**: Aluminum (diffuse)	
P: Pressure	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**C**: Rim-mounted secondary	**LG**: Light Gray	
					MG: Medium Gray	
					BL: Black	
					OT: Other (specify)	

Note: 1.00 bbl = 0.159 M^3 = 42.0 gal

Table 2-M: Materials Processed and Produced (Use additional sheets as necessary.)

Material Processed				Material Produced			
Description	**Chemical Composition**	**Phase (Gas, Liquid, or Solid)**	**Quantity (specify units)**	**Description**	**Chemical Composition**	**Phase**	**Quantity (specify units)**
Field Gas	Mixed hydrocarbons	Gas	230 MMscf/day	NGL	Mixed hydrocarbons	Liquid	35,561 bbl/day
				Condensate	Mixed hydrocarbons	Liquid	2,500 bbl/day
				Residue Gas	Mixed hydrocarbons	Gas	137 MMscf/day
				Produced Water	H_2O	Liquid	50 bbl/day

Table 2-N: CEM Equipment

Enter Continuous Emissions Measurement (CEM) Data in this table. If CEM data will be used as part of a federally enforceable permit condition, or used to satisfy the requirements of a state or federal regulation, include a copy of the CEM's manufacturer specification sheet in the Information Used to Determine Emissions attachment. Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary.

Stack No.	Pollutant(s)	Manufacturer	Model No.	Serial No.	Sample Frequency	Averaging Time	Range	Sensitivity	Accuracy
N/A - There will be no CEM equipment at this facility.									

Table 2-O: Parametric Emissions Measurement Equipment

Unit and stack numbering must correspond throughout the application package. Use additional sheets if necessary.

Unit No.	Parameter/Pollutant Measured	Location of Measurement	Unit of Measure	Acceptable Range	Frequency of Maintenance	Nature of Maintenance	Method of Recording	Averaging Time
N/A - There will be no PEM equipment at Zia II Gas Plant.								

Table 2-P: Greenhouse Gas Emissions

Applications submitted under 20.2.70, 20.2.72, & 20.2.74 NMAC are required to complete this Table. Power plants, Title V major sources, and PSD major sources must report and calculate all GHG emissions for each unit. Applicants must report potential emission rates in short tons per year (see Section 6.a for assistance). Include GHG emissions during Startup, Shutdown, and Scheduled Maintenance in this table. For minor source facilities that are not power plants, are not Title V, or are not PSD, there are three options for reporting GHGs 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHG as a second separate unit; OR 3) check the following box ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

		CO_2 ton/yr	N_2O ton/yr	CH_4 ton/yr	SF_6 ton/yr	PFC/HFC ton/yr[2]									Total GHG Mass Basis ton/yr[4]	Total CO_2e ton/yr[5]
Unit No.	**GWPs [1]**	**1**	**298**	**25**	**22,800**	**footnote 3**										
C1-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C2-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C3-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C4-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C5-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C6-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C7-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C8-E	**mass GHG**	16,023.9	0.030	0.30	-	-									16,024.2	
	CO_2e	16,023.9	9.0	7.5	-	-										16,040.4
C9-E	**mass GHG**	10,092.3	0.015	0.15	-	-									10,092.5	
	CO_2e	10,092.3	4.5	3.8	-	-										10,100.6
C10-E	**mass GHG**	10,092.3	0.015	0.15	-	-									10,092.5	
	CO_2e	10,092.3	4.5	3.8	-	-										10,100.6
H1	**mass GHG**	13,321.4	0.025	0.25	-	-									13,321.6	
	CO_2e	13,321.4	7.5	6.3	-	-										13,335.1
H3	**mass GHG**	5,123.6	0.010	0.10	-	-									5,123.7	
	CO_2e	5,123.6	2.9	2.4	-	-										5,128.9
H4	**mass GHG**	50,723.7	0.096	0.96	-	-									50,724.7	
	CO_2e	50,723.7	28.5	23.9	-	-										50,776.1
H5	**mass GHG**	50,723.7	0.10	0.96	-	-									50,724.7	
	CO_2e	50,723.7	28.5	23.9	-	-										50,776.1
H6	**mass GHG**	1,793.3	0.0034	0.034	-	-									1,793.3	
	CO2e	1,793.3	1.0	0.84	-	-										1,795.1
FL1	**mass GHG**	1,190.6	0.0024	8.5	-	-									1,199.1	
	CO_2e	1,190.6	0.71	212.6	-	-										1,403.9
FL2	**mass GHG**	1,095.3	0.0022	7.8	-	-									1,103.2	
	CO_2e	1,095.3	0.66	195.8	-	-										1,291.7
FL3	**mass GHG**	1,095.3	0.0022	7.8	-	-									1,103.2	
	CO_2e	1,095.3	0.66	195.8	-	-										1,291.7

	CO_2 ton/yr	N_2O ton/yr	CH_4 ton/yr	SF_6 ton/yr	PFC/HFC ton/yr[2]										Total GHG Mass Basis ton/yr[4]	Total CO_2e ton/yr[5]
GWPs [1]	**1**	**298**	**25**	**22,800**	**footnote 3**											
VCD1	**mass GHG**	1,908.3	0.0036	0.21	-	-									1,908.5	
	CO_2e	1,908.3	1.1	5.3	-	-										1,914.6
Dehy	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
TK-2100	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
TK-2200	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
TK-6100	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
TK-6150	**mass GHG**	-	-	-	-	-									-	
	CO2e	-	-	-	-	-										-
L1	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
HAUL	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
FUG	**mass GHG**	549.8	-	2001.5											2,551.3	
	CO_2e	549.8	-	50,037.5												50,587.3
Amine[6]	**mass GHG**	-	-	-	-	-									-	
	CO2e	-	-	-	-	-										-
CT-1	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
CT-2	**mass GHG**	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CO_2e	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GEN-1	**mass GHG**	28.3	0.00023	0.0011											28.3	
	CO2e	28.3	0.068	0.029												28.4
Startup, Shutdown, and Maintenance Emissions																
FL1	**mass GHG**	7,178.3	0.013	29.6											7,208.0	
	CO2e	7,178.3	3.8	740.2												7,922.4
FL2	**mass GHG**	2,044.0	0.00	13.6											2,057.6	
	CO_2e	2,044.0	1.3	340.6												2,385.9
SSM (CB)	**mass GHG**	0.0072	-	0.61											0.6	
	CO2e	0.0072	-	15.3												15.3
SSM (PV)	**mass GHG**	3.7	-	134.1											137.7	
	CO2e	3.7	-	3,351.6												3,355.3
Total	**mass GHG**														287,364.2	
	CO_2e															340,532.5

[1] **GWP** (Global Warming Potential): Applicants must use the most current GWPs codified in Table A-1 of 40 CFR part 98. GWPs are subject to change, therefore, applicants need to check 40 CFR 98 to confirm GWP values.

[2] For **HFCs** or **PFCs** describe the specific HFC or PFC compound and use a separate column for each individual compound.

[3] For each new compound, enter the appropriate GWP for each HFC or PFC compound from Table A-1 in 40 CFR 98.

[4] Green house gas emissions on a **mass basis** is the ton per year green house gas emission before adjustment with its GWP.

[5] **CO_2e** means Carbon Dioxide Equivalent and is calculated by multiplying the TPY mass emissions of the green house gas by its GWP.

[6] Under normal operating conditions, the amine unit will not be a source of regulated emissions; emissions from the amine unit will be controlled 100% by the two AGI wells. In the event that one of the two AGI wells are inoperable due to maintenance or upset conditions, acid gas from the amine unit will be flared by Unit FL2 for limited periods.

Section 3

Application Summary

The **Application Summary** shall include a brief description of the facility and its process, the type of permit application, the applicable regulation (i.e. 20.2.72.200.A.X, or 20.2.73 NMAC) under which the application is being submitted, and any air quality permit numbers associated with this site. If this facility is to be collocated with another facility, provide details of the other facility including permit number(s). In case of a revision or modification to a facility, provide the lowest level regulatory citation (i.e. 20.2.72.219.B.1.d NMAC) under which the revision or modification is being requested. Also describe the proposed changes from the original permit, how the proposed modification will affect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

The **Process Summary** shall include a brief description of the facility and its processes.

Startup, Shutdown, and Maintenance (SSM) routine or predictable emissions: Provide an overview of how SSM emissions are accounted for in this application. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

DCP Operating Company, LP (DCP) is submitting this application and the accompanying material to apply for a Title V Renewal (pursuant to 20.2.70.300.B(2) NMAC) to its current Title V Operating permit P270-M2 for the Zia II Gas Plant (Zia II).

The Zia II Gas Plant is a natural gas plant, SIC code 1311, located in Lea County, New Mexico, approximately 15 miles southeast of Loco Hills, NM. The plant is currently operating under NSR Permit PSD5217-M2R1 and Title V Operating permit P270-M2. Under these permits, the Zia II plant is permitted to process and treat 230 MMscf of natural gas per day.

This application seeks to incorporate the following changes:

Summary of Permitting Actions to be Incorporated

Permit	Date Issued	Application Type	Changes
PSD5217-M2R1	12/8/2021	NSR Technical Revision	Revise flare conditions per Settlement Agreement (No. AQB 20-64 (CO)) and Stipulated Final Compliance Order (Final Order) with NMED.

The Zia II Gas Plant is major source under the Prevention of Significant Deterioration (PSD) rules as currently permitted and will remain a major source after the modifications proposed. This facility will also remain a major source for operating permit purposes under Title V (20.2.70 NMAC).

Section 4

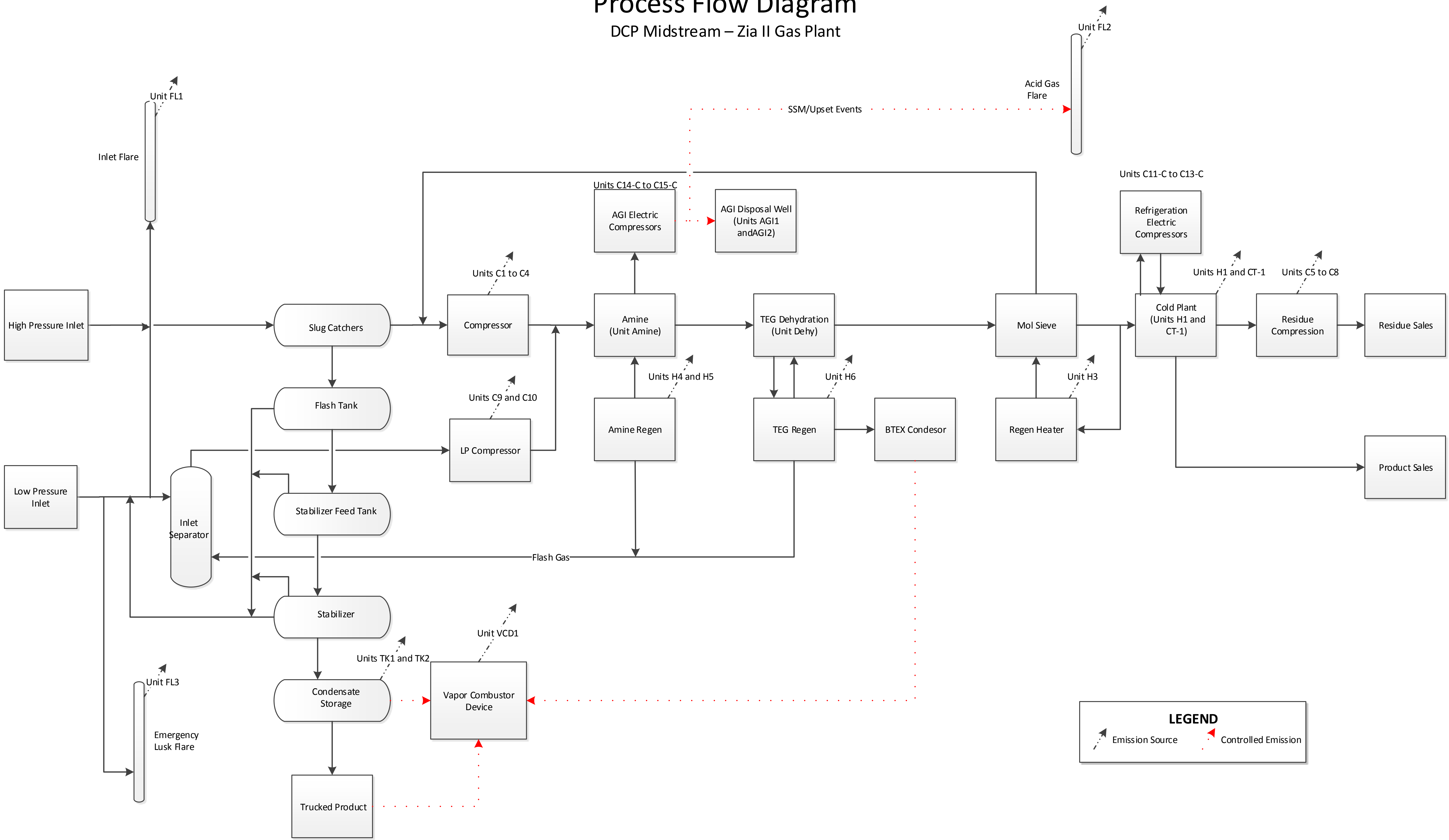
Process Flow Sheet

A **process flow sheet** and/or block diagram indicating the individual equipment, all emission points and types of control applied to those points. The unit numbering system should be consistent throughout this application.

A process flow diagram is attached.

Process Flow Diagram

DCP Midstream – Zia II Gas Plant



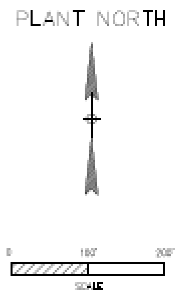
Trinity Consultants

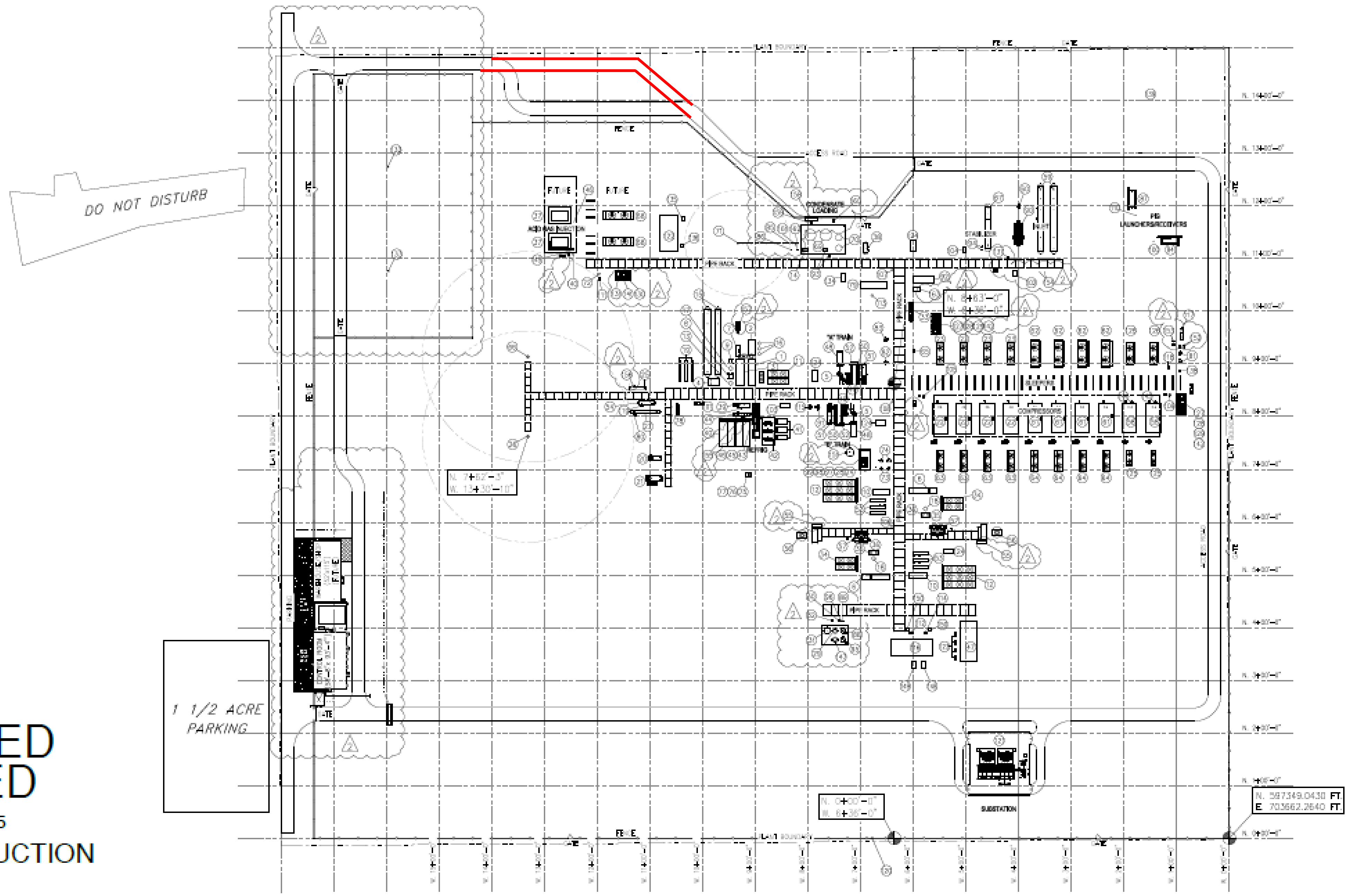
Section 5

Plot Plan Drawn To Scale

A **plot plan drawn to scale** showing emissions points, roads, structures, tanks, and fences of property owned, leased, or under direct control of the applicant. This plot plan must clearly designate the restricted area as defined in UA1, Section 1-D.12. The unit numbering system should be consistent throughout this application.

A plot plan is attached.





REVISED
ISSUED
JAN 23 2015
FOR CONSTRUCTION

NOTES:

REFERENCE DRAWINGS

NO.	TITLE

REVISIONS

NO.	FIRM	DATE	DESCRIPTION	BY	CHK.	APP.
0	F-518	05/14/14	ISSUED FOR CONSTRUCTION	MS3	MS3	JC
1	F-518	10/06/14	REVISED AS NOTED	CEG	MS3	JC
2	F-518	01/23/15	REVISED AS NOTED	SBO	MS3	JC

SAULSBURY INDUSTRIES
ENGINEERING SERVICES
TEXAS REGISTERED ENGINEERING
FIRM F-518

ENGINEERING RECORD

PROJ. MANAGER:	JC	SI JOB NUMBER:	9507
PROJ. ENGR:	JC	AFE NUMBER:	
PROJ. DESIGN:	MS3	WELD CODE:	

dcp Midstream

ZIA II GAS PLANT
200MM SCFD GAS PROCESSING FACILITY
PLOT PLAN

LEA COUNTY, NM

PLOT SCALE:	1"=100'-0"	DWG. NO. D-9507-C03-100	REV 2
FILE NAME:	C03-100		

\\eng\Jobs\DCP\9507 DCP Zia II Cryo Plant\03 ENGINEERING, DESIGN\3.4 Piping\3.4.3 Drawings - Plot Plans\C03-100 (1/23/2015 2:13:34 PM)

Section 6

All Calculations

Show all calculations used to determine both the hourly and annual controlled and uncontrolled emission rates. All calculations shall be performed keeping a minimum of three significant figures. Document the source of each emission factor used (if an emission rate is carried forward and not revised, then a statement to that effect is required). If identical units are being permitted and will be subject to the same operating conditions, submit calculations for only one unit and a note specifying what other units to which the calculations apply. All formulas and calculations used to calculate emissions must be submitted. The “Calculations” tab in the UA2 has been provided to allow calculations to be linked to the emissions tables. Add additional “Calc” tabs as needed. If the UA2 or other spread sheets are used, all calculation spread sheet(s) shall be submitted electronically in Microsoft Excel compatible format so that formulas and input values can be checked. Format all spread sheets and calculations such that the reviewer can follow the logic and verify the input values. Define all variables. If calculation spread sheets are not used, provide the original formulas with defined variables. Additionally, provide subsequent formulas showing the input values for each variable in the formula. All calculations, including those calculations are imbedded in the Calc tab of the UA2 portion of the application, the printed Calc tab(s), should be submitted under this section.

Tank Flashing Calculations: The information provided to the AQB shall include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., NOI, permit, or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis. If Hysis is used, all relevant input parameters shall be reported, including separator pressure, gas throughput, and all other relevant parameters necessary for flashing calculation.

SSM Calculations: It is the applicant’s responsibility to provide an estimate of SSM emissions or to provide justification for not doing so. In this Section, provide emissions calculations for Startup, Shutdown, and Routine Maintenance (SSM) emissions listed in the Section 2 SSM and/or Section 22 GHG Tables and the rational for why the others are reported as zero (or left blank in the SSM/GHG Tables). Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on calculating SSM emissions. If SSM emissions are greater than those reported in the Section 2, Requested Allowables Table, modeling may be required to ensure compliance with the standards whether the application is NSR or Title V. Refer to the Modeling Section of this application for more guidance on modeling requirements.

Glycol Dehydrator Calculations: The information provided to the AQB shall include the manufacturer’s maximum design recirculation rate for the glycol pump. If GRI-Glycalc is used, the full input summary report shall be included as well as a copy of the gas analysis that was used.

Road Calculations: Calculate fugitive particulate emissions and enter haul road fugitives in Tables 2-A, 2-D and 2-E for:
1. If you transport raw material, process material and/or product into or out of or within the facility and have PER emissions greater than 0.5 tpy.
2. If you transport raw material, process material and/or product into or out of the facility more frequently than one round trip per day.

Significant Figures:
A. All emissions standards are deemed to have at least two significant figures, but not more than three significant figures.
B. At least 5 significant figures shall be retained in all intermediate calculations.
C. In calculating emissions to determine compliance with an emission standard, the following rounding off procedures shall be used:
- **(1)** If the first digit to be discarded is less than the number 5, the last digit retained shall not be changed;
- **(2)** If the first digit discarded is greater than the number 5, or if it is the number 5 followed by at least one digit other than the number zero, the last figure retained shall be increased by one unit; **and**
- **(3)** If the first digit discarded is exactly the number 5, followed only by zeros, the last digit retained shall be rounded upward if it is an odd number, but no adjustment shall be made if it is an even number.
- **(4)** The final result of the calculation shall be expressed in the units of the standard.

Control Devices: In accordance with 20.2.72.203.A(3) and (8) NMAC, 20.2.70.300.D(5)(b) and (e) NMAC, and 20.2.73.200.B(7) NMAC, the permittee shall report all control devices and list each pollutant controlled by the control device regardless if the applicant takes credit for the reduction in emissions. The applicant can indicate in this section of the application if they chose to not take credit for the reduction in emission rates. For notices of intent submitted under 20.2.73 NMAC, only uncontrolled emission rates can be considered to determine applicability unless the state or federal Acts require the control. This information is necessary to determine if federally enforceable conditions are necessary for the control device, and/or if the control device produces its own regulated pollutants or increases emission rates of other pollutants.

STEADY-STATE EMISSIONS – UNCHANGED

The following units are not affected by the proposed changes in this application.

Engines (Units C1 to C10)
Emission factors for NO_x, CO, formaldehyde, and VOC are based on manufacturer guarantees. $PM/PM_{10}/PM_{2.5}$ emission factors are obtained from U.S. EPA AP-42 Section 3.2. SO_2 emissions were calculated based on a fuel sulfur content of 5 grains of sulfur per 100 standard cubic feet. HAP emissions, except for formaldehyde, are calculated using the GRI-HAPCalc program. The output for GRI-HAPCalc can be found in Section 7.1-6. The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).

The PM_{10} and $PM_{2.5}$ emission factors obtained from AP-42 Table 3.2-2 assume that all PM is less than 1.0 micrometer in diameter according to AP-42 Table 3.2-2, footnote i. Therefore, the PM_{10} and $PM_{2.5}$ emission factors are equivalent. Additionally, the emission factor for condensable PM is added to the PM_{10} (filterable) and $PM_{2.5}$ (filterable) emission factors so that all PM_{10} and $PM_{2.5}$ emissions are accounted for. Therefore, the sum of the PM_{10} (filterable) and PM condensable emission factors is used to estimate total PM_{10} and the sum of the $PM_{2.5}$ (filterable) and PM condensable emission factors are used to estimate total $PM_{2.5}$.

Hourly emission rates for NO_x, CO, formaldehyde, and VOC are based on the manufacturer-provided emission factors and a post control emission factor based on use of an oxidation catalyst. Manufacturer specification sheets for the engines and the proposed oxidation catalyst are included in Section 7.1 of this application. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following are example calculations for hourly and annual NO_x, CO, formaldehyde, and VOC emissions from the engines:

Unit Number	Uncontrolled NO_X Emission Factor		Uncontrolled CO Emission Factor		Uncontrolled VOC Emission Factor		Uncontrolled SO_2 Emission Factor		Uncontrolled TSP/PM10/$PM_{2.5}$ Emission Factor	
C1 to C8	0.5 g/hp-hr	Mfg Data (Section 7.1-1)	2.75 g/hp-hr	Mfg Data (Section 7.1-1)	0.63 g/hp-hr	Mfg Data (Section 7.1-2)	5 grain S per 100 scf	Sulfur content in natural gas	9.99E-03 lb/MMBtu	AP-42 Table 3.2-2 (Section 7.1-5)
C9 to C10	0.50 g/hp-hr	Mfg Data (Section 7.1-3)	2.75 g/hp-hr	Mfg Data (Section 7.1-3)	0.63 g/hp-hr	Mfg Data (Section 7.1-3)				
	Controlled NO_X Emission Factor		**Controlled CO Emission Factor**		**Controlled VOC Emission Factor**		**Controlled SO_2 Emission Factor**		**Controlled TSP/PM10/$PM_{2.5}$ Emission Factor**	
C1 to C8	0.50 g/hp-hr	Mfg Data (Section 7.1-1)	0.05 g/hp-hr	Mfg Data (Section 7.1-2)	0.20 g/hp-hr	Mfg Data (Section 7.1-2)	5 grain S per 100 scf	Sulfur content in natural gas	9.99E-03 lb/MMBtu	AP-42 Table 3.2-2 (Section 7.1-5)
C9 to C10	0.50 g/hp-hr	Mfg Data (Section 7.1-3)	0.2 g/hp-hr	Mfg Data (Section 7.1-4)	0.30 g/hp-hr	Mfg Data (Section 7.1-4)				

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Engine Rating (bhp)} \times \text{Emission factor}\left(\frac{\text{g}}{\text{bhp} - \text{hr}}\right) \times \left(\frac{1\ \text{lb}}{453.59\ \text{g}}\right)$$

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

Hourly emission rates for $PM/PM_{10}/PM_{2.5}$ are based on the AP-42 emission factors (lb/MMBtu), engine rating (bhp), and the heat rating (Btu/bhp-hr). Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following are example calculations for hourly and annual $PM/PM_{10}/PM_{2.5}$ emission rates from the engines:

$$\text{Hourly Emission Rate}\left(\frac{lb}{hr}\right) = \text{Engine Rating (bhp)} \times \text{Emission Factor}\left(\frac{lb}{MMbtu}\right) \times \text{Heat Rating}\left(\frac{btu}{bhp-hr}\right) \times \left(\frac{MMbtu}{10^6\,btu}\right)$$

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

Hourly emission rates for SO_2 are based on a fuel sulfur content of 5 grains of sulfur per a 100 standard cubic feet of gas. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following are example calculations for hourly and annual SO_2 emission rates from the engines:

$$SO_2\,\text{Emission Factor}\left(\frac{lb}{MMbtu}\right) = \left(\frac{5\text{ grains of Sulfur}}{100\text{ scf of gas}}\right) \times \left(\frac{1\ lb}{7000\text{ grains}}\right) \times \left(\frac{64\ lb\ SO_2}{32\ lb\ S}\right) \times \left(\frac{scf}{991\ btu}\right) \times \left(\frac{10^6\ btu}{MMbtu}\right)$$

$$\text{Hourly Emission Rate}\left(\frac{lb}{hr}\right) = \text{Engine Rating (bhp)} \times \text{Emission Factor}\left(\frac{lb}{MMbtu}\right) \times \text{Heat Rating}\left(\frac{btu}{bhp-hr}\right) \times \left(\frac{MMbtu}{10^6\,btu}\right)$$

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

The following are examples calculations for hourly and annual H_2SO_4 emission rates from the engines:

$$\text{Hourly Emission Rate}\left(\frac{lb}{hr}\right) = \text{Hourly } SO_2 \text{ Emissions}\left(\frac{lb}{hr}\right) \times 3\%\text{ Conversion to } H_2SO_4 \times \left(\frac{98.08\ lb\ H_2SO_4}{1\ lb-mol\ H_2SO_4}\right) \times \left(\frac{1\ lb-mol\ SO_2}{64.06\ lb\ SO_2}\right)$$

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

Generator (Unit GEN-1)
Emissions from the diesel generator engine were calculated using g/hp-hr manufacturer's data for NO_X, CO, VOC, and particulates. Emissions of SO2 are based on ultra-low sulfur diesel standard of 15 ppm sulfur. Greenhouse gas emissions were calculated using kg/MMBtu factors from 40 CFR 98 Subpart C, Tables C-1 and C-2. Emissions of hazardous air pollutants were calculated using lb/MMBtu emission factors from AP-42 Tables 3.3-1 and 3.3-2.

Heaters (Units H1, H3, and H6)
Emission factors for NO_x and CO are based on AP-42 Table 1.4-1 (July 1998). Because the firing rates of Units H1, H3, and H6 are less than 100 MMBtu/hr, the emission factors for small boilers are used. Units H1, H3, and H6 are low NO_x burner units. Emission factors for $PM/PM_{10}/PM_{2.5}$, and VOC are based on AP-42 Table 1.4-2 (July 1998). All PM (total, condensable, and filterable) is assumed to be less than 1.0 micrometer in diameter, according to AP-42 Table 1.4-2, footnote c. Therefore, the $PM/PM_{10}/PM_{2.5}$ emission factor is the sum of the filterable PM and condensable PM emission factors. SO_2 emissions were calculated based on a fuel sulfur content of 5 grains of sulfur per 100 standard cubic feet. Emissions of HAPs were calculated using GRI-HAPCalc. The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).

Hourly emission rates are based on the AP-42 emission factors (lb/MMscf), the average higher heating value for natural gas (MMBtu/MMscf), and the maximum heat input rate (MMBtu/hr). Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr.

Unit Number	Uncontrolled NOx Emission Factor		Uncontrolled CO Emission Factor		Uncontrolled VOC Emission Factor		Uncontrolled SO2 Emission Factor		Uncontrolled TSP/PM10/PM2.5 Emission Factor	
H1, H3, H6	50 lb/MMscf	AP-42 Table 1.4-1 (Section 7.2-1)	84 lb/MMscf	AP-42 Table 1.4-1 (Section 7.2-1)	5.5 lb/MMscf	AP-42 Table 1.4-2 (Section 7.2-1)	5 grain S per 100 scf	Sulfur content in natural gas	7.6 lb/MMscf	AP-42 Table 1.4-2 (Section 7.2-1)

Heaters (Units H4 and H5)
NO_x and CO emissions are based on manufacturer data for low NO_x burners. Because the firing rates of Units H4 and H5 are less than 100 MMBtu/hr, the emission factors for small boilers are used. VOC, TSP, PM_{10}, and $PM_{2.5}$ emissions are based on AP-42 Table 1.4-2 (July 1998). All PM (total, condensable, and filterable) is assumed to be less than 1.0 micrometer in diameter, according to AP-42 Table 1.4-2, footnote c. Therefore, the PM/PM_{10}/$PM_{2.5}$ emission factor is the sum of the filterable PM and condensable PM emission factors. SO_2 emissions were calculated based on a fuel sulfur content of 5 grains of sulfur per 100 standard cubic feet. Emissions of HAPs were calculated using GRI-HAPCalc. The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).

Hourly emission rates are based on the AP-42 emission factors (lb/MMscf), the average higher heating value for natural gas (MMBtu/MMscf), and the heater firing rate (MMBtu/hr). Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr.

Unit Number	Uncontrolled NOx Emission Factor		Uncontrolled CO Emission Factor		Uncontrolled VOC Emission Factor		Uncontrolled SO2 Emission Factor		Uncontrolled TSP/PM10/PM2.5 Emission Factor	
H4, H5	0.06 lb/MMBtu	Mfg Data (Section 7.2-2)	0.041 lb/MMBtu	Mfg Data (Section 7.2-2)	5.5 lb/MMscf	AP-42 Table 1.4-2 (Section 7.2-1)	5 grain S per 100 scf	Sulfur content in natural gas	7.6 lb/MMscf	AP-42 Table 1.4-2 (Section 7.2-1)

The following are example calculations for hourly and annual emission rates from the heaters at the facility:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{\text{Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right) \times \text{Firing Rate}\left(\frac{\text{MMbtu}}{\text{hr}}\right)}{\text{Average High Heating Value}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)}$$

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

Flares (Units FL1, FL2, and FL3)
Pilot and purge gas emissions of NO_x and CO are calculated using emission factors from AP-42 Table 13.5-1. Emissions of SO_2 and H_2S are considered negligible since the pilot fuel will be sweet natural gas and the purge gas analysis does not show any H_2S. Emissions of greenhouse gases are calculated using methodology from 40 CFR Subpart 98.233(n). Hourly throughputs for pilot and purge gas are taken from the manufacturer's guidelines. Pilot and purge gas emissions are calculated assuming year-round operation of the flare pilot and auto-ignition gas. Emissions during flaring events are accounted for under the SSM emissions detailed later in this section.

Unit Number	Uncontrolled NOx Emission Factor		Uncontrolled CO Emission Factor	
FL1, FL2, FL3	0.0680 lb/MMBtu	AP-42 Table 13.5-1	0.37 lb/MMBtu	AP-42 Table 13.5-1

The following are example calculations for hourly and annual NO_x and CO emission rates from the flares at the facility:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMbtu}}\right) \times \left[\text{Pilot Gas}\left(\frac{\text{MMbtu}}{\text{hr}}\right) + \text{Purge Gas}\left(\frac{\text{MMbtu}}{\text{hr}}\right)\right]$$

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

The following are example calculations for hourly and annual VOC emissions rates from the flares at the facility:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{\text{Mole\% of Gas} \times \left[\text{Pilot Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right) + \text{Purge Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right)\right] \times 10^6\left(\frac{\text{scf}}{\text{MMscf}}\right) \times 2.0\%\ \text{Uncombusted gas}}{\text{Specific Volume}\left(\frac{\text{scf}}{\text{lb}}\right)}$$

$$\text{Annual Emission Rate (tpy)} = \frac{\text{Mole\% of Gas} \times \left[\text{Pilot Gas}\left(\frac{\text{MMscf}}{\text{yr}}\right) + \text{Purge Gas}\left(\frac{\text{MMscf}}{\text{yr}}\right)\right] \times 10^6\left(\frac{\text{scf}}{\text{MMscf}}\right) \times 2.0\%\ \text{Uncombusted gas}}{\text{Specific Volume}\left(\frac{\text{scf}}{\text{lb}}\right) * 2000\left(\frac{\text{lb}}{\text{ton}}\right)}$$

Vapor Combustion Device (Unit VCD1)

The vapor combustion device (Unit VCD1) combusts VOC and HAP vapors from the condensate tanks (Units TK-2100 and TK-2200), dehydrator still vent (Unit Dehy), and loading (Unit L1). No additional or supplemental fuel is provided to the vapor combustion device. Instead, an igniter is activated by a pressure-sensing control system.

The VCD emission rates for NO_x and CO were calculated using AP-42 factors for external combustion sources from Tables 1.4-1 and 1.4-2. VOC and HAP emissions are based on 98% combustion of the total VOC and HAPs mass flow to the VCD1. No PM emissions are associated with the device since the unit is smokeless. VOC and HAP mass flow was determined from Tanks 4.09d, GlyCalc and using calculation methodology from AP-42 Section 5.2. SO_2 emissions are negligible due to negligible quantities of sulfur compounds in the combusted vapors.

Unit Number	Uncontrolled NOx Emission Factor		Uncontrolled CO Emission Factor		Uncontrolled VOC Emission Factor	
VCD1	100 lb/MMscf	Mfg Data (Section 7.2-2)	84 lb/MMscf	AP-42 Table 1.4-1 (Section 7.2-1)	385.8 tpy	Dehy VOC Emissions, Tank VOC Emissions, and Loading VOC Emissions

A calculated heat value for the VOC emissions sent to the VCD1 was used. This calculated heat value used the total VOC per stream sent to the VCD1 divided by the total mass sent to the VCD1. Below is a sample calculation of this ratio and a table showing the VOC mass flow pre and post VCD1 with their respective ratios:

$$\text{Dehy Mass Fraction} = \frac{\text{Dehy VOC Emissions (tpy)}}{\text{Total VOC Emission Sent to VCD1 (tpy)}}$$

$$\text{Calculated Heat Value}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right) = \text{Dehy Mass Fraction} \times \text{HHV of Dehy} + \text{Tanks Mass Fraction} \times \text{HHV of Tanks} + \text{Loading Mass Fraction} \times \text{HHV of Loading}$$

VOC Mass Flow Sent to VCD1

Source	Uncontrolled VOC Mass Flow Pre-VCD1 (TPY)	Controlled VOC Mass Flow Post-VCD1 (TPY)	Ratio*
TEG Dehydrator	211.9	4.24	0.55
Tank Working and Breathing Losses	59.3	1.19	0.15
Condensate Loading	114.5	2.29	0.30
Total VOC Emissions	369.2	7.4	

*VOC mass from each source divided by the total mass sent to the VCD.

The following are example calculations for hourly and annual NO_x, CO, and PM emissions rates from the VCD1 at the facility:

$$\text{Calculated Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right) = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right)$$

$$\times\left[\frac{\text{Dehydrator HHV}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)\times\text{TEG Ratio}}{\text{Average High Heating Value}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)} + \frac{\text{Tank HHV}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)\times(\text{Tank Working and Breathing Ratio} + \text{Condensate Loading Ratio})}{\text{Average High Heating Value}\left(\frac{\text{MMBtu}}{\text{MMscf}}\right)}\right]$$

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{\text{Total VOC Flowrate}\left(\frac{\text{scf}}{\text{hr}}\right)\times\text{Calculated Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right)}{10^6\left(\frac{\text{scf}}{\text{MMscf}}\right)}$$

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

The following are example calculations for hourly and annual VOC and HAP emissions rates from the VCD1 at the facility:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{\text{Total Emissions}\left(\frac{\text{ton}}{\text{yr}}\right)\times 2.0\ \%\ \text{of Uncombusted Gas}\ \times 2000\left(\frac{\text{lb}}{\text{ton}}\right)}{8760\ \frac{\text{hr}}{\text{yr}}}$$

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

Dehydrator (Unit Dehy)

Dehydrator emissions are calculated using GRI-GLYCalc 4.0. The glycol dehydrator system will have a reboiler and condenser associated with the unit. The TEG reboiler combustion emissions (Unit H6) are explained in the above heater section. The flash gas from the glycol flash tank will be re-routed to the low pressure inlet compression for recycling. Non-condensable/regenerator emissions are sent to the VCD1 for combustion. Please see Section 7.3-1 of the application for the GRI-GlyCalc 4.0 simulation.

Condensate Tanks (Units TK-2100 and TK-2200)

All post-tank emissions (working and breathing emissions) will be controlled by the vapor combustion device (Unit VCD1) which operates at a 98% control efficiency. Working and breathing emissions were calculated using TANKS 4.09d. The facility expects the condensate to be RVP 8. As a conservative assumption, RVP 10 speciation was used in the Tank 4.09d. No flash emissions are associated with the tanks. The condensate is stabilized before reaching the tanks. Condensate from the facility will be handled proportionately through one of two 1,000 bbl tanks. For the purposes of performing emission calculations, working and breathing losses were calculated assuming that 50% of total production is handled through a single tank. This approach was used to estimate tank emissions and tank turnovers to ensure a conservative estimate of potential emissions. HAPs were calculated using TANKS 4.09d with the default HAP speciation for RVP 10. Please see Section 7.5-1 of the application for the TANKS 4.09d simulation.

Water Tanks (Units TK-6100 and TK-6150)

Emissions for water tanks were conservatively estimated to assume one percent of produced water contains condensate. To estimate produced water storage tank emissions, condensate tank emissions were multiplied by one percent.

Truck Loading (Unit L1)

Loading emissions will be controlled by the vapor combustion device (Unit VCD1) which operates at a 98% control efficiency. VOC emissions for the condensate tank loading were estimated based on Equation 1 of AP-42 Section 5.2 (07/08). Annual HAP emissions were estimated by multiplying the HAP output from TANKS 4.09d by a ratio of working and breathing VOC losses to loadout VOC losses. Below is a sample HAP calculation:

$$\text{Benzene Emission Rate (tpy)} = \frac{\text{Total Loadout VOC (tpy)}}{\text{Total Tank VOC (tpy)}}\times\frac{\text{Benzene Tanks Output}\left(\frac{\text{lb}}{\text{yr}}\right)}{2000\ \frac{\text{lb}}{\text{ton}}}$$

The following are example calculations for hourly and annual VOC emission rates from condensate loading at the facility:

$$L_L = \frac{12.46 \times SPM}{T}$$

Where:

L_L = loading loss (lb/1,000 gal loaded)
S = saturation factor (from AP-42, Section 5.2, Table 5.2-1) = 0.6
P = true vapor pressure of loaded liquid (psia) = 70.78 °F (Tanks 4.09d)
M = molecular weight of vapor (lb/lb-mol) = 66 lb/lbmole (Tanks 4.09d)
T = temperature of bulk liquid (°R = °F + 460) = 6.3647 psia (Tanks 4.09d)

The following equations are used to estimate hourly and annual emission rates from the tank loading operations:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Loading Loss}\left(\frac{\text{lb}}{1{,}000\text{ gal}}\right) \times \text{ Maximum Hourly Throughput}\left(\frac{\text{gal}}{\text{hr}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Loading Loss}\left(\frac{\text{lb}}{1{,}000\text{ gal}}\right) \times \text{ Maximum Annual Throughput}\left(\frac{\text{gal}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

Water loading emissions are calculated by assuming VOC content for water tanks is be 1% for produced water.

Paved Haul Roads (Unit Haul)

Paved haul road emissions were estimated based on Equations 1 and 2 of AP-42 Section 13.2.1 (1/11). The following equations were used to estimate hourly and annual emission rates from the haul road operations:

$$\text{Emission Factor}\left(\frac{\text{lb}}{\text{VMT}}\right) = k \times (sL)^{0.91} \times (W)^{1.02}$$

Where:

VMT = Vehicle Miles Traveled
k, a, b = Empirical Constants (AP-42, Table 13.2.2-2)
W = Mean Vehicle Weight (tons)
p = Number of days in a year with at least 0.01 inches of precipitation
s= Surface Material Silt Content

The table below shows the hourly emission factors and annual wet day emission factors from the above equations used in the calculation of the haul roads.

	PM_{30} (lb/VMT)	PM_{10} (lb/VMT)	$PM_{2.5}$ (lb/VMT)
Hourly Emission Factors	0.20	0.039	0.010
Annual Wet Day Emission Factors	0.19	0.038	0.0092

VMT

Vehicle miles traveled is based on the length of road traveled on within the facility boundary. The length of the road is approximately 1,200 feet one way. Per trip each truck will travel approximately 0.5 miles.

W

The mean vehicle weight is calculated by averaging the weight of the empty vehicle (16 tons) per trip with the vehicle loaded weight (37.168 tons) per trip. Since the truck will be loaded only half of the trip, the average is calculated adding the empty weight of the vehicle to the loaded weight of the vehicle and dividing by two. A sample calculation is shown below:

$$\text{W (ton)} = \frac{\text{Empty Truck (ton)} + \text{Loaded Truck(ton)}}{2}$$

k

The table below show the empirical constants used in the calculation:

	k	
PM_{30}	0.011 lb/VMT	AP-42, Table 13.2.1-1
PM_{10}	0.0022 lb/VMT	
$PM_{2.5}$	0.00054 lb/VMT	

S
The surface silt content percent is from AP-42 Table 13.2.1-2. The ubiquitous baseline of 0.6 g/m^2 silt constant is used for the haul road.

p
The number of wet days per year is based off of AP-42 Figure 13.2.1-2. A conservative estimate of 60 wet days per year was used in the calculations.

The following equations are used to estimate hourly and annual emission rates from the haul road operations:

Hourly emission rate (lb/hr) = Hourly EF (lb/VMT) * VMT (mile/hr)

Annual emission rate (ton/yr) =Annual EF (lb/VMT) * VMT (mile/Trip) * Trips per year (Trip/yr) / 2000 (lb/tpy)

Wet Surface Air Cooler (Unit CT-1)
Emissions were estimated using methodology from AP-42 Section 13.4. The cooling tower water recirculation rate is from the Niagara Blower manufacturer's data. The uncontrolled circulating water flow percent drift is estimated based on AP-42 factors for induced draft cooling towers (Table 13.4-1). The controlled circulating water flow percent drift was established as a BACT requirement for cooling towers. The total dissolved solids content was estimated as 3,500 mg/l as a conservative measure. A particle size distribution was created using a Frisbie table.

An example calculation is shown below:

Hourly Uncontrolled TSP Emissions = Cooling water recirculation rate (gal/min) * Uncontrolled liquid drift (%) * Density of water (8.34 lb/gal) * Circulating water total dissolved solids (3,500 /10^6 ppm) * 60 min/hr * Mass % of TSP (PM_{30}) particulates

Facility Fugitives (Unit FUG)
Process fugitive emissions of VOC result from leaking components such as valves and flanges. Emissions from fugitive equipment leaks are calculated using fugitive component counts, the VOC content of each stream for which component counts are placed in service, and emission factors for each component type taken from the EPA Protocol for Equipment Leak Emission Estimates (11/95) Table 2-4. Table 2-4 can be found in Section 7.9-1 and the inlet gas analysis used in the calculations can be found in Section 7.4-1 and in the calculations attached to this section. The source counts are estimated based on similar DCP facilities. Please note the fugitive compressor count is 15. The facility has 10 fuel fired compressors and 5 electric compressors (3 associated with refrigeration and 2 associated with the AGI wells). DCP has added a 20% safety factor to the gas/vapor weight percent of VOC to account for variability of the gas. Also as a conservative estimate, DCP is assuming 100% VOC content in components in liquid service. The following is a table showing the emission factors used in the VOC fugitive calculations:

	Valves – Inlet Gas	Valves-Liquid	Relief Valves	Pump Seals	Flanges/ Connectors-Inlet Gas	Flanges/ Connectors-Liquid	Compressor Seals
Emission Factor (kg/hr/source)	4.5E-03	2.5E-03	8.8E-03	1.3E-02	3.9E-04	1.1E-04	8.8E-03

H_2S fugitive emission result from components in acid gas service. Emissions for fugitives are based on a screening value of 35 ppmv. In plant monitors H_2S monitors are set at 10 ppm. Therefore, DCP is conservatively estimating emission by assuming a screening value (correlated to leakage rate) for each component is 35 ppmv. Source counts are estimated from similar facility. Only 50% of the components in acid gas service should be in simultaneous service. This percentage is taken into account when calculating H_2S fugitive emissions for the facility. EPA Protocol for Equipment Leak Emission Estimates (11/95) Table 2-10 is used to calculate H_2S emissions from fugitives. The following is a table showing the leak rates used in the H_2S fugitive calculations.

	Valves	Pump Seals	Others	Connectors	Flanges	Open-ended Lines
Emission Factor (kg/hr/source)	3.25E-05	4.40E-04	1.10E-04	2.09E-05	5.61E-05	2.69E-05

HAPs emissions for fugitives are based on a weighted average of HAPs emissions in the total VOC emissions. Below is a sample calculation for HAPs fugitive emissions:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)=\frac{\text{Weight \% of HAP Emissions}\times\ \text{Safety Factor}\times\text{VOC Emission Rate}}{\text{Total Weight \% of VOC}}$$

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

The following equations were used to estimate hourly and annual VOC emissions:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)$$

$$=\text{EPA Emission Factor}\left(\frac{\text{kg}}{\text{hr-comp}}\right)\times\frac{2.20462\ \text{lb}}{\text{kg}}\times\text{Number of Components (\# comp)}\times\text{VOC Weight Percent (\% wt)}\times\text{Safety Factor}$$

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

The following equations were used to estimate hourly and annual H_2S emissions:

$$\text{Calculated Emission Factor}\left(\frac{\text{kg}}{\text{hr-comp}}\right)=\text{EPA Correlation Factor}\left(\frac{\text{kg}}{\text{hr}}\right)\times\ \text{Screening Value (ppmv)}^{X}$$

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)$$

$$=\text{EPA Emission Factor}\left(\frac{\text{kg}}{\text{hr-comp}}\right)\times\frac{2.20462\ \text{lb}}{\text{kg}}\times\text{Number of Components (\# comp)}\times\text{Components in Simultaneous Service (\%)}$$

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

(Please note the exponent in the screening value is provided in Table 2-10 of the EPA Protocol for Equipment Leak Emission Estimates (11/95))

Amine (Unit Amine)

The amine unit sour gas stream is completely controlled by two AGI wells (Units AGI1 and AGI2). Flash tank emissions are routed back to the low pressure inlet compression. The maximum sour gas produced from the Amine unit will be 13 MMscf/d. Each AGI well will handle 6.5 MMscf/d of sour gas. Under startup, shutdown, maintenance, and upset conditions, one AGI well will be offline at a time. During times when one of the AGI wells is down, the sour gas for the offline well will be sent to the acid gas flare (Unit FL2). There are no emissions, other than fugitives, when the amine sour gas is sent to the AGI wells. Fugitive emissions are accounted for under Unit FUG.

Methanol Tanks (Units TK-7700, TK-7750, TK-7800, and TK-L2)
***Not a regulated source of emissions**
Working and breathing emissions from the methanol tanks were calculated using TANKS 4.09d. There are no flashing emissions associated with methanol tanks. Emissions from the methanol tanks are less than half a ton per year.

SSM EMISSIONS- UNCHANGED

The following activities are not affected by the proposed changes in this application.

Flare SSM (unit FL1)
The plant flare is used for flaring during startup, shutdown, maintenance and upset conditions. The only steady state conditions associated with this flare are from the pilot and purge gas streams. SSM from the plant flare is due to various maintenance activities throughout the facility per manufacturer's recommended maintenance schedules. These maintenance activities include but are not limited to compressor catalyst changes, blowdowns for associated maintenance throughout the facility, instrumental calibrations and process safety device maintenance for process safety valves. The maximum volume of the gas sent to the flare is based on a plant rate 230 MMscf/day. The below values can also be found attached to this section in the plant flare (Unit FL1) calculation.

	Blowdown Events per Year	Duration per Event	Total Hours Flared	Volume Flared per hr	Volume Flared per Event	Volume Flared per Year	HHV of Flared Gas
FL1 Events	4.0 events/yr	2.0 hrs/event	8.0 hrs/yr	9,583,333 scf/hr	19,166,667 scf/event	76,667 Mscf/yr	1226.2 Btu/scf

The expected composition and maximum expected volumes of the gas are used as the basis of the flaring calculations. The SO_2 composition is based on a 98% molar conversion of H_2S to SO_2. NO_x and CO emissions for both scenarios are calculated using AP-42 Table 13.5-1 emission factors. VOC emissions are calculated from the VOC volume fraction of the inlet gas to the flare, the specific volume of the VOC fraction of the inlet gas, and a 98% destruction efficiency. The inlet gas analysis can be found in Section 7.4-1. The inlet gas analysis can also be found in the calculations. Emissions of greenhouse gases are calculated using methodology from 40 CFR Subpart 98.233(n).

Short-term emissions are based on the maximum flaring volume and heat content of the gas. Long term emissions are calculated based on the worst-case SSM duration and maximum volume and heat content. Please see the above table for maximum flaring and heat content of the gas. These values can also be found attached to this section in the calculations of Unit FL1.

Flare SSM (Unit FL2)
When one of the two AGI wells is inoperable due to maintenance or upset conditions, acid gas will be flared for limited periods at the acid gas flare. Below is a table that summarizes the acid gas events for the flare. The maximum sour gas produced from the Amine unit will be 13 MMscf/d. Each AGI well will handle 6.5 MMscf/d of sour gas. Under startup, shutdown, maintenance, and upset conditions, one AGI well will be offline at a time. During times when one of the AGI wells is down, the sour gas for the offline well (6.5 MMscf/day) will be sent to the acid gas flare.

	Events per Year	Duration per Event	Total Hours Flared	Volume Flared per hr	Volume Flared per Event	Volume Flared per Year	Targeted HHV*
FL2 Events	10.0 events/yr	1.0 hrs/event	10.0 hrs/yr	270,833 scf/hr	270,833 scf/event	2,708 Mscf/yr	850 Btu/scf

*The HHV of the acid gas flare is the targeted heat content of the gas after assist gas has been added to the stream

The expected composition and maximum expected volumes of the acid gas are used as the basis of the flaring calculations. The acid gas is expected to be relatively low heat content, so assist gas sufficient to raise the heat content of the flared gas may be added. The targeted heat content of the gas is shown in the above table.

The SO_2 composition is based on a 98% molar conversion of H_2S to SO_2. NO_x and CO emissions for both scenarios are calculated using AP-42 Table 13.5-1 emission factors. The acid gas analysis for the facility is attached in Section 7.4-2 and can also be seen in the calculation for the acid gas flare attached to this section. The acid gas analysis for the facility consists of 90% CO_2 and 10% H_2S. Emissions of greenhouse gases are calculated using methodology from 40 CFR Subpart 98.233(n).

Short term emissions are based on the assumed hourly maximum flaring volume, maximum H_2S content, and heat content of the gas. Long term emissions of H_2S and SO_2 are defined by an envelope bounded by the H_2S concentration and flare gas annual volume with assist gas. Long-term emissions are calculated based on the worst-case SSM duration, maximum flaring volume, maximum H_2S content, and heat content.

NO_x and CO emissions from the flare are directly proportional to the heat released in flaring, which in turn is the product of the volume of flared gas and the heat content of the gas. In a like manner, SO_2 emissions are proportional to volume of gas and H_2S content. All emission calculations include gas volume as one of the parameters.

The following equations were used to estimate hourly and annual NO_x and CO emission rates from the flares during SSM conditions:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMbtu}}\right) \times \left[\text{Pilot Gas}\left(\frac{\text{MMbtu}}{\text{hr}}\right) + \text{Purge Gas}\left(\frac{\text{MMbtu}}{\text{hr}}\right) + \text{Assist Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right) + \text{SSM Event}\left(\frac{\text{MMscf}}{\text{hr}}\right)\right]$$

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

The following equations were used to estimate hourly and annual H_2S emission rates from the flares during SSM conditions:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \frac{\text{Mole\% of Gas} \times \left[\text{Pilot Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right) + \text{Purge Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right) + \text{Assist Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right) + \text{SSM Event}\left(\frac{\text{MMscf}}{\text{hr}}\right)\right] \times 10^6\left(\frac{\text{scf}}{\text{MMscf}}\right) \times 2.0\%\text{ Uncombusted gas}}{\text{Specific Volume}\left(\frac{\text{scf}}{\text{lb}}\right)}$$

$$\text{Annual Emission Rate (tpy)} = \frac{\text{Mole\% of Gas} \times \left[\text{Pilot Gas}\left(\frac{\text{MMscf}}{\text{yr}}\right) + \text{Purge Gas}\left(\frac{\text{MMscf}}{\text{yr}}\right) + \text{Assist Gas}\left(\frac{\text{MMscf}}{\text{hr}}\right) + \text{SSM Event}\left(\frac{\text{MMscf}}{\text{hr}}\right)\right] \times 10^6\left(\frac{\text{scf}}{\text{MMscf}}\right) \times 2.0\%\text{ Uncombusted gas}}{\text{Specific Volume}\left(\frac{\text{scf}}{\text{lb}}\right) * 2000\left(\frac{\text{lb}}{\text{ton}}\right)}$$

The following equations were used to estimate hourly and annual SO_2 emission rates from the flares during SSM conditions:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = H_2S\text{ Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times 98\%\text{ Combustion of H2S} \times \frac{\text{Molecular Weight of }SO_2\,(64.0\text{ lb }SO_2)}{\text{Molecular Weight of }H_2S\,(34.1\text{ lb }H_2S)}$$

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

Venting SSM (Unit SSM (CB))

Emissions resulting from compressor blowdowns were calculated based on the total volume of gas released per event, the number of blowdown events per year, and the type of gas vented. A 15% safety factor was added to the annual volume of gas released as a conservative measure. The percent of VOC, HAP, H_2S, CO_2, and CH_4 in the inlet gas, residue gas, and propane is used to calculate the weight of each component released. An example calculation is shown below:

Maximum Uncontrolled Annual Emissions (tpy) = [Volume of Gas Vented (scf/yr)] x [MW of constituent (lb/lb-mol)] x [mol % speciated constituent] / [379.5 (scf/lb-mol)] / [2,000 (lb/ton)]

SSM (Plant Venting)
Emissions of plant venting during SSM are estimated based on process venting quantities and typical gas analysis. The estimated maximum volume of gas vented per hour is 879,000 ft^3. The estimated maximum volume of gas vented per year is $1.41*10^7$ ft^3. The emissions are calculated as follows:

Maximum Uncontrolled Annual Emissions (tpy) = [Volume of Gas Vented (scf/yr)] x [MW of constituent (lb/lb-mol)] x [mol % speciated constituent] / [379.5 (scf/lb-mol)] / [2,000 (lb/ton)

DCP Midstream, LP - Zia II Gas Plant

Emissions Summary

Emission Unit: All

Source Description: **DCP Midstream, LP - Zia II Gas Plant**

Maximum Uncontrolled Emissions																										
	NOx		CO		VOC		SOx		TSP		PM10		PM2.5		H_2S		Total HAPs		H_2SO_4		CO_2e	
Unit	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
C1-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C2-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C3-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C4-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C5-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C6-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C7-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C8-E	5.2	22.9	28.7	125.7	6.6	28.8	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	3.4	14.8	0.021	0.091	3,662	16,040
C9-E	2.6	11.4	14.4	62.9	3.3	14.4	0.23	1.0	0.16	1.0	0.16	1.0	0.16	1.0	-	-	1.7	7.4	0.010	0.046	2,306	10,101
C10-E	2.6	11.4	14.4	62.9	3.3	14.4	0.23	1.0	0.16	1.0	0.16	1.0	0.16	1.0	-	-	1.7	7.4	0.010	0.046	2,306	10,101
GEN-1	0.51	0.13	0.58	0.14	0.027	0.0068	1.3E-06	3.2E-07	0.0035	0.00086	0.0035	0.00086	0.0035	0.00086	-	-	0.050	0.012	5.9E-08	1.5E-08	113	28
H1	1.3	5.6	2.1	9.4	0.14	0.61	0.37	1.6	0.19	0.85	0.19	0.85	0.19	0.85	-	-	0.37	1.6	0.017	0.075	3,045	13,335
H3	0.49	2.1	0.82	3.6	0.054	0.24	0.14	0.63	0.075	0.33	0.075	0.33	0.075	0.33	-	-	0.14	0.63	0.0066	0.029	1,171	5,129
H4	5.9	26.0	4.1	17.8	0.53	2.3	1.4	6.2	0.74	3.2	0.74	3.2	0.74	3.2	-	-	1.4	6.3	0.066	0.29	11,593	50,776
H5	5.9	26.0	4.1	17.8	0.53	2.3	1.4	6.2	0.74	3.2	0.74	3.2	0.74	3.2	-	-	1.4	6.3	0.066	0.29	11,593	50,776
H6	0.17	0.75	0.29	1.3	0.019	0.083	0.050	0.22	0.026	0.11	0.026	0.11	0.026	0.11	-	-	0.050	0.22	0.0023	0.0101	410	1,795
FL1[1]	0.17	0.74	0.92	4.0	0.013	0.059	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321	1,404
FL2[1]	0.16	0.68	0.84	3.7	0.013	0.059	-	-	-	-	-	-	-	-	-	-	-	-	-	-	295	1,292
FL3[1]	0.16	0.68	0.84	3.7	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	295	1,292
VCD1[2]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dehy	-	-	-	-	48.4	211.9	-	-	-	-	-	-	-	-	-	-	19.8	86.8	-	-	20	87
TK-2100	-	-	-	-	6.7	29.2	-	-	-	-	-	-	-	-	-	-	0.15	0.64	-	-	-	-
TK-2200	-	-	-	-	6.7	29.2	-	-	-	-	-	-	-	-	-	-	0.15	0.64	-	-	-	-
TK-6100	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	0.0044	-	-	-	-
TK-6150	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	0.0044	-	-	-	-
L1	-	-	-	-	-	114.5	-	-	-	-	-	-	-	-	-	-	-	1.3	-	-	-	617
HAUL	-	-	-	-	-	-	-	-	0.39	0.24	0.078	0.048	0.019	0.0117	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	0.0075	0.033	0.00020	0.00088	2.1E-06	9.1E-06	-	-	-	-	-	-	-	-
FUG	-	-	-	-	7.2	31.5	-	-	-	-	-	-	-	-	0.16	0.68	0.64	2.8	-	-	-	50,587
SSM (FL1)	799.2	3.9	4348.8	21.1	2942.1	11.8	14977.1	59.9	-	-	-	-	-	-	162.9	0.65	-	-	-	-	*	7,922
SSM (FL2)	102.0	1.19	554.8	6.5	7.8	0.092	4409.8	22.0	-	-	-	-	-	-	48.0	0.24	-	-	-	-	*	2,386
SSM (CB)	-	-	-	-	358.8	0.83	-	-	-	-	-	-	-	-	0.050	0.00011	0.050	0.00011	-	-	6,641	15
SSM (PV)	-	-	-	-	1500.0	12.0	-	-	-	-	-	-	-	-	7.3	0.058	7.3	0.058	-	-	418,342	3,355
Steady-State Total	**61.8**	**268.5**	**272.9**	**1,193.1**	**129.5**	**682.0**	**7.5**	**32.8**	**5.0**	**21.0**	**4.7**	**20.7**	**4.6**	**20.7**	**0.16**	**0.68**	**54.7**	**240.5**	**0.34**	**1.5**	**62,764**	**325,642**
SSM Total	**901.2**	**5.1**	**4,903.5**	**27.6**	**4,808.7**	**24.8**	**19,386.9**	**82.0**	**-**	**-**	**-**	**-**	**-**	**-**	**218.1**	**0.95**	**7.314**	**5.8E-02**	**-**	**-**	**424,983.9**	**13,678.9**

DCP Midstream, LP - Zia II Gas Plant

Emissions Summary

Emission Unit: All

Source Description: **DCP Midstream, LP - Zia II Gas Plant**

	Maximum Controlled Emissions																									
	NOx		CO		VOC		SOx		TSP		PM10		PM2.5		H_2S		Total HAPs		H_2SO_4		CO_2e	
Unit	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
C1-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C2-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C3-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C4-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C5-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C6-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C7-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C8-E	5.2	22.9	0.54	2.4	2.0	8.9	0.45	2.0	0.31	1.4	0.31	1.4	0.31	1.4	-	-	0.75	3.3	0.021	0.091	3,662	16,040
C9-E	2.6	11.4	1.0	4.6	1.6	6.9	0.23	1.0	0.16	0.69	0.16	0.69	0.16	0.69	-	-	1.3	5.8	0.010	0.046	2,306	10,101
C10-E	2.6	11.4	1.0	4.6	1.6	6.9	0.23	1.0	0.16	0.69	0.16	0.69	0.16	0.69	-	-	1.3	5.8	0.010	0.046	2,306	10,101
GEN-1	0.51	0.13	0.58	0.14	0.027	0.0068	1.3E-06	3.2E-07	0.0035	0.00086	0.0035	0.00086	0.0035	0.00086	-	-	0.050	0.012	5.9E-08	1.5E-08	113	28
H1	1.3	5.6	2.1	9.4	0.14	0.61	0.37	1.6	0.19	0.85	0.19	0.85	0.19	0.85	-	-	0.37	1.6	0.017	0.075	3,045	13,335
H3	0.49	2.1	0.82	3.6	0.054	0.24	0.14	0.63	0.075	0.33	0.075	0.33	0.075	0.33	-	-	0.14	0.63	0.0066	0.029	1,171	5,129
H4	5.9	26.0	4.1	17.8	0.53	2.3	1.4	6.2	0.74	3.2	0.74	3.23	0.74	3.2	-	-	1.4	6.3	0.066	0.29	11,593	50,776
H5	5.9	26.0	4.1	17.8	0.53	2.3	1.4	6.2	0.74	3.2	0.74	3.23	0.74	3.2	-	-	1.4	6.3	0.066	0.29	11,593	50,776
H6	0.17	0.75	0.29	1.3	0.019	0.083	0.050	0.22	0.026	0.114	0.026	0.114	0.026	0.114	-	-	0.050	0.22	0.0023	0.0101	410	1,795
FL1[1]	0.17	0.74	0.92	4.0	0.013	0.059	-	-	-	-	-	-	-	-	-	-	-	-	-	-	321	1,404
FL2[1]	0.16	0.68	0.84	3.7	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	295	1,292
FL3[1]	0.16	0.68	0.84	3.7	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-	-	-	295	1,292
VCD1[2]	0.24	1.1	0.20	0.89	1.8	7.7	-	-	-	-	-	-	-	-	-	-	0.41	1.8	-	-	437	1,915
Dehy[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-2100[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-2200[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-6100	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	0.0044	-	-	-	-
TK-6150	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	0.0044	-	-	-	-
L1[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HAUL	-	-	-	-	-	-	-	-	0.39	0.24	0.078	0.048	0.019	0.0117	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	0.0019	0.0082	5.0E-05	2.2E-04	5.2E-07	2.3E-06	-	-	-	-	-	-	-	-
FUG	-	-	-	-	7.2	31.5	-	-	-	-	-	-	-	-	0.16	0.68	0.64	2.8	-	-	-	50,587
SSM (FL1)	799.2	3.9	4348.8	21.1	2942.1	11.8	14977.1	59.9	-	-	-	-	-	-	162.9	0.65	259.4	1.04	-	-	*	7,922
SSM (FL2)	102.0	1.19	554.8	6.5	7.8	0.092	4409.8	22.05	-	-	-	-	-	-	48.0	0.24	-	-	-	-	*	2,386
SSM (CB)	-	-	-	-	358.8	0.83	-	-	-	-	-	-	-	-	0.050	0.00011	0.050	0.00011	-	-	6,641	15
SSM (PV)	-	-	-	-	1500.0	12.0	-	-	-	-	-	-	-	-	7.3	0.058	7.3	0.058	-	-	418,342	3,355
Steady-State Total	**62.0**	**269.6**	**21.2**	**90.3**	**29.7**	**130.7**	**7.5**	**32.8**	**5.0**	**20.3**	**4.7**	**20.1**	**4.6**	**20.1**	**0.16**	**0.68**	**13.1**	**57.4**	**0.34**	**1.5**	**63,181.2**	**326,853.3**
SSM Total	**901.2**	**5.1**	**4,903.5**	**27.6**	**4,808.7**	**24.8**	**19,386.9**	**82.0**	**-**	**-**	**-**	**-**	**-**	**-**	**218.1**	**0.95**	**266.7**	**1.10**	**-**	**-**	**424,983.9**	**13,678.9**

NOTES

"" Indicates that an hourly limit is not appropriate for this operating situation and is not being requested.*

"-" Indicates emissions of this pollutant are not expected

[1] FL1, FL2, and FL3 emissions are represented as pilot and purge only. Emissions associated with startup, shutdown, and maintenance from FL1 and FL2 will be covered under the requested SSM/M.

[2] Unit VCD1 combusts emissions from the condensate tanks (units TK-2100 and TK-2200), TEG Dehydrator non-condensables (unit Dehy) and Loadout (unit L1). Unit VCD1 will have no emissions in an uncontrolled scenario.

[3] Emissions from units TK-2100, TK-2200, Dehy, and L1 are controlled by the vapor combustion device, unit VCD1. Controlled emissions for these units are included in unit VCD1 emissions.

[4] Unit Amine is not included here as 100% of emissions are sent to the two AGI wells (AGI1, AGI2). In the event that one of the two AGI wells are inoperable due to maintenance or upset conditions, acid gas from the amine unit will be flared by Unit FL2 for limited periods.

Maximum Controlled Emissions																						
	Formaldehyde		**Methanol**		**Acetaldehyde**		**Acrolein**		**Benzene**		**Toluene**		**Ethylbenzene**		**Xylenes**		**n-Hexane**		**2,2,4-Trimethylpentane**		**Styrene**	
Unit	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
C1-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C2-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C3-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C4-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C5-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C6-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C7-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C8-E	0.078	0.34	0.086	0.38	0.29	1.3	0.18	0.77	0.015	0.066	0.014	0.062	0.0014	0.0060	0.0063	0.028	0.038	0.17	0.0086	0.038	0.00082	0.0036
C9-E	0.99	4.3	0.046	0.20	0.15	0.67	0.094	0.41	0.0081	0.035	0.018	0.079	0.00073	0.0032	0.0034	0.015	0.020	0.089	0.0046	0.020	0.00043	0.0019
C10-E	0.99	4.3	0.046	0.20	0.15	0.67	0.094	0.41	0.0081	0.035	0.018	0.079	0.000731	0.0032	0.0034	0.015	0.020	0.089	0.0046	0.020	0.00043	0.0019
GEN-1	0.049	0.012	-	-	0.000532	0.000133	6.4E-05	1.6E-05	0.00065	0.00016	0.000284	7.1E-05	-	-	2.0E-04	4.94E-05	-	-	-	-	-	-
H1	0.022	0.096	0.025	0.11	0.019	0.084	-	-	0.019	0.085	0.026	0.12	0.055	0.24	0.034	0.15	0.037	0.16	0.074	0.32	0.054	0.24
H3	0.0084	0.037	0.0096	0.042	0.0074	0.032	-	-	0.0075	0.033	0.010	0.045	0.021	0.093	0.013	0.058	0.014	0.062	0.028	0.12	0.021	0.091
H4	0.084	0.37	0.10	0.42	0.073	0.32	-	-	0.074	0.32	0.10	0.44	0.21	0.92	0.13	0.57	0.14	0.61	0.28	1.2	0.21	0.90
H5	0.084	0.37	0.10	0.42	0.073	0.32	-	-	0.074	0.32	0.10	0.44	0.21	0.92	0.13	0.57	0.14	0.61	0.28	1.2	0.21	0.90
H6	0.0029	0.013	0.0034	0.015	0.0026	0.0113	-	-	0.0026	0.0115	0.0036	0.016	0.0074	0.032	0.0046	0.020	0.0049	0.022	0.0100	0.044	0.0073	0.032
FL1[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FL2[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FL3[1]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
VCD1[2]	-	-	-	-	-	-	-	-	0.11	0.48	0.091	0.40	0.011	0.049	0.073	0.32	0.12	0.54	0.0058	0.026	-	-
Dehy[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-2100[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-2200[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TK-6100	-	-	-	-	-	-	-	-	*	0.0013	*	0.0014	*	9.42E-05	*	0.000393	*	0.0012	-	-	-	-
TK-6150	-	-	-	-	-	-	-	-	*	0.0013	*	0.0014	*	9.42E-05	*	0.000393	*	0.0012	-	-	-	-
L1[3]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
HAUL	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUG	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SSM (FL1)	-	-	-	-	-	-	-	-	3.9	0.016	4.6	0.018	1.06	0.0042	5.3	0.021	244.5	0.98	-	-	-	-
SSM (FL2)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SSM (CB)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
SSM (PV)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Steady-State Total	**2.9**	**12.3**	**1.0**	**4.4**	**2.8**	**12.2**	**1.6**	**7.0**	**0.43**	**1.9**	**0.48**	**2.1**	**0.53**	**2.3**	**0.44**	**1.9**	**0.80**	**3.5**	**0.76**	**3.3**	**0.50**	**2.2**
SSM Total	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**3.89**	**0.016**	**4.59**	**0.018**	**1.06**	**0.0042**	**5.29**	**0.021**	**244.5**	**0.98**	**-**	**-**	**-**	**-**

NOTES

"" Indicates that an hourly limit is not appropriate for this operating situation and is not being requested.*

"-" Indicates emissions of this pollutant are not expected

[1] FL1, FL2, and FL3 emissions are represented as pilot and purge only. Emissions associated with startup, shutdown, and maintenance from FL1 and FL2 will be covered under the requested SSM/M.

[2] Unit VCD1 combusts emissions from the condensate tanks (units TK-2100 and TK-2200), TEG Dehydrator non-condensables (unit Dehy) and Loadout (unit L1). Unit VCD1 will have no emissions in an uncontrolled scenario.

[3] Emissions from units TK-2100, TK-2200, Dehy, and L1 are controlled by the vapor combustion device, unit VCD1. Controlled emissions for these units are included in unit VCD1 emissions.

[4] Unit Amine is not included here as 100% of emissions are sent to the two AGI wells (AGI1, AGI2). In the event that one of the two AGI wells are inoperable due to maintenance or upset conditions, acid gas from the amine unit will be flared by Unit FL2 for limited periods.

DCP Midstream, LP - Zia II Gas Plant

Caterpillar G3616

Emission Units:	C1-E to C8-E
Number of units:	8
Source Description:	Natural gas engine
Manufacturer:	Caterpillar
Model:	G3616
Type	4-stroke, lean burn natural gas engine
Control:	Oxidation Catalyst

Maximum Rating

	100%	75%	50%		
Rated hp	4735	3551	2368	hp	*Mfg data*
Heat Rate	6605	7061	7544	Btu/hp-hr	*Mfg data*
Fuel heat value	991	991	991	Btu/scf	*Residue Gas HHV*
Heat Input	31.27	25.07	17.86	MMBtu/hr	*Heat Rate * hp*
Fuel consumption	31.55	25.30	18.02	Mscf/hr	*Heat input / fuel heat value*
Annual fuel usage	276.4	221.6	157.9	MMscf/yr	*8760 hrs/yr operation*

Exhaust Parameters

Exhaust temp	856	897	974	deg F	*Mfg data*
Stack diameter	3.0	3.0	3.0	ft	*Eng Estimate*
Stack height	50	50	50	ft	*Eng Estimate*
Exhaust flow	32,100	25,615	18,637	acfm	*Mfg data*
Stack velocity	75.7	60.4	43.9	ft/s	*Exhaust flow / stack area*

Emissions Data

NO_X	0.50	0.50	0.50	g/hp-hr	*Mfg data*
CO	2.75	2.75	2.75	g/hp-hr	*Mfg data*
VOC	0.63	0.66	0.68	g/hp-hr	*Mfg data*
HCHO	0.26	0.28	0.31	g/hp-hr	*Mfg data*

Emission Calculations

Maximum Uncontrolled Emissions

NOx[1]	CO[1]	VOC[2]	SO_2[3]	PM[4]	H_2SO_4[9]	CO_2[5]	CH_4 as CO_2e[6]	N_2O as CO_2e[7]	Total HAPs[8]	
0.50	2.75	0.63								g/hp-hr
			0.0144	9.99E-03		116.98	0.0022	0.00022		lb/MMBtu
5.2	**28.7**	**6.6**	**0.45**	**0.31**	**0.021**	**3,658**	**1.7**	**2.1**	**3.4**	**lb/hr**
22.9	**125.7**	**28.8**	**2.0**	**1.4**	**0.091**	**16,024**	**7.5**	**9.0**	**14.8**	**tpy**
						14,537	6.8	8.2		tonnes/yr

Methanol[8]	Acetaldehyde[8]	Acrolein[8]	Benzene[8]	Toluene[8]	Ethylbenzene[8]	Xylenes[8]	n-Hexane[8]	2,2,4-Trimethylpentane[8]	HCHO[2]	Total Styrene[8]	
									0.26		g/hp-hr
											lb/MMBtu
0.09	**0.288**	**0.177**	**0.015**	**0.014**	**0.00137**	**0.0063**	**0.038**	**0.009**	**2.7**	**0.00082**	**lb/hr**
0.38	**1.26**	**0.77**	**0.07**	**0.062**	**0.006**	**0.028**	**0.17**	**0.038**	**11.9**	**0.0036**	**tpy**

DCP Midstream, LP - Zia II Gas Plant

Caterpillar G3616

Emission Units:	C1-E to C8-E
Number of units:	8
Source Description:	Natural gas engine
Manufacturer:	Caterpillar
Model:	G3616
Type	4-stroke, lean burn natural gas engine
Control:	Oxidation Catalyst

Maximum Controlled Emissions

NOx[1]	CO[2]	VOC[2]	SO_2[3]	PM[4]	H_2SO_4[9]	CO_2[5]	CH_4 as CO_2e[6]	N_2O as CO_2e[7]	Total HAPs[8]	
	98%	69%								Nominal % reduction
0.50	0.05	0.20								g/hp-hr
			0.0144	9.99E-03		116.98	0.0022	0.00022		lb/MMBtu
5.2	**0.54**	**2.04**	**0.45**	**0.31**	**0.021**	**3,658**	**1.7**	**2.1**	**0.75**	**lb/hr**
22.9	**2.36**	**8.9**	**2.0**	**1.4**	**0.091**	**16,024**	**7.5**	**9.0**	**3.3**	**tpy**
						14,537	6.85	8.164		tonnes/yr

Methanol[8]	Acetaldehyde[8]	Acrolein[8]	Benzene[8]	Toluene[8]	Ethylbenzene[8]	Xylenes[8]	n-Hexane[8]	2,2,4-Trimethylpentane[8]	HCHO[2]	Total Styrene[8]	
									98%		Nominal % reduction
									0.01		g/hp-hr
											lb/MMBtu
0.09	**0.29**	**0.18**	**0.02**	**0.014**	**0.00137**	**0.0063**	**0.0382**	**0.0086**	**0.08**	**0.00082**	**lb/hr**
0.38	**1.26**	**0.77**	**0.07**	**0.062**	**0.006**	**0.028**	**0.17**	**0.038**	**0.34**	**0.0036**	**tpy**

1 *Manufacturer specification sheet for Caterpillar 3616*

2 *Manufacturer specification sheet from catalyst*

3 *Based on 5 gr / 100 scf, nominal pipeline natural gas fuel*

4 *PM = TSP =* PM_{10} = $PM_{2.5}$*; AP-42, 3.2-2 (07/00)*

5 *40 CFR 98 Table C-1 Emission Factor for* CO_2: 53.06 (kg/mmBtu) ≡ 116.977 lb/MMBtu

6 *40 CFR 98 Table C-2 Emission Factor for* CH_4: 1E-03 (kg/mmBtu) ≡ 2.2046E-03 lb/MMBtu; GWP of CH4 = 25

7 *40 CFR 98 Table C-2 Emission Factor for* N_2O: 1E-04 (kg/mmBtu) ≡ 2.2046E-04 lb/MMBtu; GWP of N2O = 298

8 *Total HAPs = Total HAPS from GRI HAPCalc - GRI HAPCalc HCHO + Manufacturer HCHO*

9 *The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to* SO_3 *and that all of the* SO_3 *will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).*

$$H_2SO_4 \text{ Hourly Emissions (lb/hr)} = \frac{0.45 \text{ lb SO2}}{\text{hr}} \left| \; 0.03 \; \right| \frac{98.08 \text{ lb } H_2SO}{1 \text{ lb-mol } H_2SO} \left| \frac{1 \text{ lb-mol } SO_2}{64.06 \text{ lb } SO_2} \right. = 0.021 \text{ lb/hr}$$

Caterpillar G3608 LE

Emission Units:	C9-E to C-10E	
Number of units:	2	
Source Description:	Natural gas engine	
Manufacturer:	Caterpillar	
Model:	G3608 LE	DM8606-2
Type	4-stroke, lean burn natural gas engine	
Control:	Oxidation Catalyst	

Maximum Rating

	100%	75%		
Rated hp	2370	1778	hp	*Mfg data*
Heat Rate	6629	6914	Btu/hp-hr	*Mfg data*
Fuel heat value	991	991	Btu/scf	*Residue Gas HHV*
Heat Input	15.71	12.29	MMBtu/hr	*Heat Rate * hp*
Fuel consumption	15.85	12.40	Mscf/hr	*Heat input / fuel heat value*
Annual fuel usage	138.8	108.6	MMcf/yr	*8760 hrs/yr operation*

Exhaust Parameters

Exhaust temp	857	897	deg F	*Mfg data*
Stack diameter	1.83	1.83	ft	*Eng Estimate*
Stack height	50	50	ft	*Eng Estimate*
Exhaust flow	16,144	12,852	acfm	*Mfg data*
Stack velocity	101.9	81.1	ft/s	*Exhaust flow / stack area*

Emission Calculations

Maximum Uncontrolled Emissions

NOx[1]	CO[1]	VOC[1]	SO_2[3]	PM[4,8]	H_2SO_4[11]	CO_2[1]	CH_4 as CO_2e[6]	N_2O as CO_2e[7]	Total HAPs[10]	
0.50	2.75	0.63				441				g/hp-hr
			0.0144	9.99E-03			0.0022	0.00022		lb/MMBtu
2.6	**14.4**	**3.3**	**0.23**	**0.16**	**0.010**	**2304**	**0.87**	**1.0**	**1.7**	**lb/hr**
11.4	**62.9**	**14.4**	**1.0**	**0.69**	**0.046**	**10,092**	**3.8**	**4.5**	**7.4**	**tpy**
						9,156	3.44	4.1		tonnes/yr

Methanol[10]	Acetaldehyde[10]	Acrolein[10]	Benzene[10]	Toluene[10]	Ethylbenzene[10]	Xylenes[10]	n-Hexane[10]	2,2,4-Trimethylpentane[10]	HCHO[2]	Styrene[10]	
									0.26		g/hp-hr
											lb/MMBtu
0.046	**0.15**	**0.094**	**0.0081**	**0.018**	**0.00073**	**0.0034**	**0.020**	**0.0046**	**1.4**	**0.00043**	**lb/hr**
0.20	**0.67**	**0.41**	**0.035**	**0.079**	**0.0032**	**0.015**	**0.089**	**0.020**	**6.0**	**0.0019**	**tpy**

DCP Midstream, LP - Zia II Gas Plant

Caterpillar G3608 LE

Emission Units:	C9-E to C-10E	
Number of units:	2	
Source Description:	Natural gas engine	
Manufacturer:	Caterpillar	
Model:	G3608 LE	DM8606-2
Type	4-stroke, lean burn natural gas engine	
Control:	Oxidation Catalyst	

Maximum Controlled Emissions

NOx[1]	CO[2]	VOC[2]	SO_2[3]	PM[4,8]		CO_2[1]	CH_4 as CO_2e[6]	N_2O as CO_2e[7]	Total HAPs[10]		
	93%	52%									Nominal % reduction
0.50	**0.2**	**0.30**								g/hp-hr	Mfg Specs[2]
			0.0144	9.99E-03			0.0022	0.00022		lb/MMBtu	
2.6	**1.0**	**1.6**	**0.23**	**0.16**	**0.010**	**2,304**	**0.87**	**1.0**	**1.3**	**lb/hr**	
11.4	**4.6**	**6.9**	**1.0**	**0.69**	**0.046**	**10,092**	**3.8**	**4.5**	**5.8**	**tpy**	
						9,156	3.44	4.10		tonnes/yr	

Methanol[10]	Acetaldehyde[10]	Acrolein[10]	Benzene[10]	Toluene[10]	Ethylbenzene[10]	Xylenes[10]	n-Hexane[10]	2,2,4-Trimethylpentane[10]	HCHO[2]	Styrene[10]	
									0.19		Nominal % reduction
											g/hp-hr
											lb/MMBtu
0.046	**0.15**	**0.094**	**0.0081**	**0.018**	**0.00073**	**0.0034**	**0.020**	**0.0046**	**1.0**	**0.00043**	**lb/hr**
0.20	**0.67**	**0.41**	**0.035**	**0.079**	**0.0032**	**0.015**	**0.089**	**0.020**	**4.3**	**0.0019**	**tpy**

[1] *Manufacturer specification sheet for Caterpillar 3608*

[2] *Used specs from Zia facility spreadsheet from DCP, "SENM 200 mmcfd_v3.xlsx"*

[3] *Based on 5 gr / 100 scf, nominal pipeline natural gas fuel*

[4] *PM = TSP = PM_{10} = $PM_{2.5}$; AP-42, 3.2-2 (07/00)*

[5] *40 CFR 98 Table C-1 Emission Factor for CO_2*: 53.06 (kg/mmBtu) ≡ 116.977 lb/MMBtu

[6] *40 CFR 98 Table C-1 Emission Factor for CH_4*: 1E-03 (kg/mmBtu) ≡ 2.2046E-03 lb/MMBtu

[7] *40 CFR 98 Table C-2 Emission Factor for N_2O*: 1E-04 (kg/mmBtu) ≡ 2.2046E-04 lb/MMBtu

[8] *AP-42 Chapter 3.2*

[9] *NSPS JJJJ included as a reference to show that the catalyst reduces emissions below NSPS limits*

[10] *GRI HAPCalc 3.01*

[11] *The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).*

$$H_2SO_4 \text{ Hourly Emissions (lb/hr)} = \frac{0.23 \text{ lb SO2}}{\text{hr}} \times 0.05 \times \frac{98.08 \text{ lb } H_2SO_4}{1 \text{ lb-mol } H_2SO_4} \times \frac{1 \text{ lb-mol } SO_2}{64.06 \text{ lb } SO_2} = 0.010 \text{ lb/hr}$$

DCP Midstream, LP - Zia II Gas Plant

Diesel Generator

Make/Model:	Cummins		
Unit #	GEN-1		
Max HP, 100% Load:	70	hp	

Fuel Consumption

Fuel Type:	Diesel		
Fuel Usage:	5.1	gal/hr	Manufacturer's data
Fuel Usage:	35.955	lb/hr	gal/hr * lb/gal
Fuel Usage:	0.7	scf/hr	lb/hr */ lb/scf
Fuel Usage:	345.7	scf/yr	scf/hr * hr/yr
Annual Run Time:	500	hr/yr	
Fuel Consumption:	9913.3	Btu/bhp*hr	lb diesel/hr * BTU/lb diesel * 1/hp
Diesel Heating Value:	19300	Btu/lb	AP-42 Table 3.3-1
Density of diesel fuel:	52	lb/scf	
Density of diesel fuel:	7.05	lb/gal	AP-42 Appendix A
Diesel fuel sulfur:	15	ppm S	ULSD maximum
Heating Value:	1003600	Btu/scf	Btu/lb * lb/scf

Exhaust Parameters

Exhaust temp (Tstk):	754	°F	Mfg. data
Stack height:	6.7	ft	Engineering Judgment
Stack diameter:	0.25	ft	Engineering Judgment
Exhaust flow:	632.0	acfm	Mfg. data
Exhaust velocity:	214.6	ft/sec	Exhaust flow ÷ stack area

Manufacturer Emission Factors

Pollutant	g/kW-hr	**g/(hp*hr)**
NO_X[1]	4.465	3.3
VOC[1]	0.235	0.18
CO	5	3.7
PM / PM_{10} / $PM_{2.5}$	0.03	0.02
SO_2	N/A	N/A
Formaldehyde	N/A	N/A

[1] Assumed 5% VOC and 95% NO_X per CARB diesel policy on combined VOC and NO_X emission factors

Pollutant	Emission Factors				Potential Emissions	
	Manufacturer (g/hp-hr)	AP-42 (lb/MMBtu)	40 CFR 98 (kg/MMBtu)	15 ppm Fuel Sulfur[3] (g/scf)	lb/hr	ton/yr
NO_X	3.33	N/A	N/A	N/A	0.51	0.13
VOC	0.18	N/A	N/A	N/A	0.027	0.0068
CO	3.73	N/A	N/A	N/A	0.58	0.14
PM / PM_{10} / $PM_{2.5}$	0.02	N/A	N/A	N/A	0.0035	0.00086
SO_2	N/A	N/A	N/A	0.00085	1.3E-06	3.2E-07
CO_2	N/A	N/A	73.96	N/A	113.1	28.3
CH_4	N/A	N/A	0.003	N/A	0.0046	1.1E-03
N_2O	N/A	N/A	0.0006	N/A	0.00092	2.3E-04
H_2SO_4[2]	N/A	N/A	N/A	N/A	5.9E-08	1.5E-08
Formaldehyde	N/A	0.070	N/A	N/A	0.049	0.012
Benzene	N/A	9.33E-04	N/A	N/A	6.5E-04	1.6E-04
Toluene	N/A	4.09E-04	N/A	N/A	2.8E-04	7.1E-05
Xylenes	N/A	2.85E-04	N/A	N/A	2.0E-04	4.9E-05
Acetaldehyde	N/A	7.67E-04	N/A	N/A	5.3E-04	1.3E-04
Acrolein	N/A	9.25E-05	N/A	N/A	6.4E-05	1.6E-05

[2] *The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).*

[3] 15 ppm S = 15 mg/m^3 g S/scf = 15 mg S/m^3 * ((64 g/mol SO2)/(32 g/mol S)) * (0.001 g/1 mg) * (1 m^3/35.3147 ft^3)

DCP Midstream, LP - Zia II Gas Plant

Trim Reboiler Heater

Emission unit number(s):	H1
Source description:	Trim Reboiler Heater
Manufacturer:	Heatec

Fuel Consumption

Input heat rate:	26.0	MMBtu/hr	Design Specification[1]
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	26230	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	229.8	MMscf/yr	8760 hrs/yr operation

[1] Received in an e-mail from Jennifer Corser at DCP on 03/18/2013

Exhaust Parameters

Heat Rate:	26000	MBtu/hr	Design Specification
Exhaust temp (Tstk):	730	°F	Eng Estimate
Site Elevation:	3556	ft MSL	
Ambient pressure (Pstk):	26.25	in. Hg	Calculated based on elevation
F factor:	10610	wscf/MMBtu	40 CFR 60 Appx A Method 19
Exhaust flow	4597.7	scfm	Calculated from F factor and heat rate
Exhaust flow:	11994.6	acfm	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
Stack diameter:	3.0	ft	Eng Estimate
Stack height:	20	ft	Eng Estimate
Exhaust velocity:	28.3	ft/sec	Exhaust flow ÷ stack area

Emission Rates

Uncontrolled Heater Emissions

NO_x[6]	CO	VOC	SO_2[1]	PM[2]	H_2SO_4[7]		
50	84	5.5		7.6		lb/MMscf	AP-42 Table 1.4-1 & 2
							EF Conversion, per AP-42 = Fuel Heat Value / EF
48.6	81.6	5.3		7.4		lb/MMscf	Heat Value * EF
			5			gr Total Sulfur/100 scf	Pipeline specification
1.3	**2.1**	**0.14**	**0.37**	**0.19**	**0.017**	**lb/hr**	Hourly emission rate
5.6	**9.4**	**0.61**	**1.6**	**0.85**	**0.075**	**tpy**	Annual emission rate (8760 hrs/yr)

DCP Midstream, LP - Zia II Gas Plant

Trim Reboiler Heater

Emission unit number(s):	H1
Source description:	Trim Reboiler Heater
Manufacturer:	Heatec

Fuel Consumption

Input heat rate:	26.0	MMBtu/hr	Design Specification[1]
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	26230	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	229.8	MMscf/yr	8760 hrs/yr operation

HAP Emissions[4]

HCHO	Methanol	Benzene	Toluene	Ethylbenzene	Xylene	
0.022	**0.025**	**0.019**	**0.026**	**0.055**	**0.034**	**lb/hr**
0.096	**0.11**	**0.085**	**0.12**	**0.24**	**0.15**	**tpy**

Acetaldehyde	2,2,4-Trimethylpentane	n-Hexane	Styrene	Total HAPs	
0.02	**0.07**	**0.04**	**0.05**	**0.37**	**lb/hr**
0.0840	**0.3236**	**0.1602**	**0.2367**	**1.6416**	**tpy**

GHG Emissions

CO_2	CH_4	N_2O	CO_2e [3]		
53.06	0.001	0.0001		kg/MMbtu	40 CFR 98 Subpart C TIER 1
12,084.95	**2.28E-01**	**2.278E-02**	**12,097**	tonnes/yr	(1*10^-3)*EF*Fuel Heat Value*Annual Fuel Usage
13,321.37	**2.51E-01**	**2.511E-02**	**13,335**	tons/yr	

[1] *5 gr S/100scf. SO_2 calculation assumes 100% conversion of fuel elemental sulfur to SO_2.*

[2] *Assumes PM (Total) = TSP = PM-10 = PM-2.5*

[3] *Warming potential of CH4 is 25 times greater than CO2; warming potential of N2O is 298 times greater than CO2 (40 CFR 98 Subpart C)*

[4] *HAP Emissions from GRI HAPCalc 3.01*

[5] *HAP Emissions from GRI HAPCalc 3.01*

[6] *Low NOx Burner*

[7] *The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist*

$$H_2SO_4 \text{ Hourly Emissions (lb/hr)} = \frac{0.37 \text{ lb SO2}}{\text{hr}} \times 0.03 \times \frac{98.08 \text{ lb } H_2SO_4}{1 \text{ lb-mol } H_2SO_4} \times \frac{1 \text{ lb-mol } SO_2}{64.06 \text{ lb } SO_2} = 0.017 \text{ lb/hr}$$

DCP Midstream, LP - Zia II Gas Plant

Regen Gas Heater

Emission unit number(s):	H3
Source description:	Regen Gas Heater
Manufacturer:	Heatec

Fuel Consumption

Input heat rate:	10.00	MMBtu/hr	Design Specification[1]
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	10088	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	88.4	MMscf/yr	8760 hrs/yr operation

[1] *Received in an e-mail from Jennifer Corser at DCP on 03/18/2013*

Exhaust Parameters

Heat Rate:	10000	MBtu/hr	Design Specification
Exhaust temp (Tstk):	718	°F	Eng Estimate
Site Elevation:	3556	ft MSL	
Ambient pressure (Pstk):	26.25	in. Hg	Calculated based on elevation
F factor:	10610	wscf/MMBtu	40 CFR 60 Appx A Method 19
Exhaust flow	1768.3	scfm	Calculated from F factor and heat rate
Exhaust flow:	4566.8	acfm	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
Stack diameter:	2.5	ft	Eng Estimate
Stack height:	18	ft	Eng Estimate
Exhaust velocity:	15.5	ft/sec	Exhaust flow ÷ stack area

Emission Rates

Uncontrolled Heater Emissions

NOx	CO	VOC	SO_2[1]	PM[2]	H_2SO_4[5]		
50	84	5.5		7.6		lb/MMscf	AP-42 Table 1.4-1 & 2
48.6	81.6	5.3		7.4		lb/MMscf	EF Conversion, per AP-42 = Fuel Heat Value / EF Heat Value * EF
			5			gr Total Sulfur/100 scf	Pipeline specification
0.49	**0.82**	**0.054**	**0.14**	**0.075**	**0.0066**	**lb/hr**	Hourly emission rate
2.1	**3.6**	**0.24**	**0.63**	**0.33**	**0.029**	**tpy**	Annual emission rate (8760 hrs/yr)

DCP Midstream, LP - Zia II Gas Plant

Regen Gas Heater

Emission unit number(s):	H3
Source description:	Regen Gas Heater
Manufacturer:	Heatec

Fuel Consumption

Input heat rate:	10.00	MMBtu/hr	Design Specification[1]
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	10088	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	88.4	MMscf/yr	8760 hrs/yr operation

[1] *Received in an e-mail from Jennifer Corser at DCP on 03/18/2013*

HAP Emissions[4]

HCHO	Methanol	Benzene	Toluene	Ethylbenzene	Xylene	
0.0084	**0.0096**	**0.0075**	**0.0102**	**0.021**	**0.013**	**lb/hr**
0.037	**0.042**	**0.033**	**0.045**	**0.093**	**0.058**	**tpy**

Acetaldhyde	2,2,4-Trimethylpentane	n-Hexane	Styrene	Total HAPs	
0.0074	**0.028**	**0.014**	**0.021**	**0.14**	**lb/hr**
0.032	**0.12**	**0.062**	**0.091**	**0.63**	**tpy**

GHG Emissions

CO_2	CH_4	N_2O	CO_2e [3]		
53.06	0.001	0.0001		kg/MMbtu	40 CFR 98 Subpart C TIER 1
4,648.1	**8.76E-02**	**8.760E-03**	**4,652.9**	tonnes/yr	(1*10^-3)*EF*Fuel Heat Value*Annual Fuel Usage
5,123.6	**9.66E-02**	**9.656E-03**	**5,128.9**	tons/yr	

[1] *5 gr S/100scf. SO_2 calculation assumes 100% converstion of fuel elemental sulfur to SO_2.*
[2] *Assumes PM (Total) = TSP = PM-10 = PM-2.5*
[3] *Warming potential of CH4 is 25 times greater than CO2; warming potential of N2O is 298 times greater than CO2 (40 CFR 98 Subpart C)*
[4] *HAP Emissions from GRI HAPCalc 3.01*
[5] *The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).*

$$H_2SO_4 \text{ Hourly Emissions (lb/hr)} = \frac{0.14 \text{ lb } SO2}{\text{hr}} \times 0.03 \times \frac{98.08 \text{ lb } H_2SO_4}{1 \text{ lb-mol } H_2SO_4} \times \frac{1 \text{ lb-mol } SO_2}{64.06 \text{ lb } SO_2} = 0.007 \text{ lb/hr}$$

DCP Midstream, LP - Zia II Gas Plant

Hot Oil Heaters

Emission unit number(s):	H4 & H5
Source description:	Hot Oil Heater
Manufacturer:	OPF

Fuel Consumption

Input heat rate:	99.0	MMBtu/hr	Design Specification[1]
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	99876	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	874.9	MMscf/yr	8760 hrs/yr operation

[1] Received in an e-mail from Jennifer Corser at DCP on 03/18/2013

Exhaust Parameters

Heat Rate:	99000	MBtu/hr	Design Specification
Exhaust temp (Tstk):	512	°F	Eng Estimate
Site Elevation:	3556	ft MSL	
Ambient pressure (Pstk):	26.25	in. Hg	Calculated based on elevation
F factor:	10610	wscf/MMBtu	40 CFR 60 Appx A Method 19
Exhaust flow	17506.5	scfm	Calculated from F factor and heat rate
Exhaust flow:	37305.0	acfm	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
Stack diameter:	9.0	ft	Eng Estimate
Stack height:	129	ft	Eng Estimate
Exhaust velocity:	9.8	ft/sec	Exhaust flow ÷ stack area

Emission Rates

Uncontrolled Heater Emissions

NOx	CO	VOC	SO_2[1]	PM[2]	H_2SO_4[6]		
0.06	**0.041**					lb/MMBtu	Manufacturer data
50		5.5		7.6		lb/MMscf	AP-42 Table 1.4-1 & 2
48.6		5.3		7.4		lb/MMscf	EF Conversion, per AP-42 = Fuel Heat Value / EF Heat Value * EF
			5			gr Total Sulfur/100 scf	Pipeline specification
5.9	**4.1**	**0.53**	**1.4**	**0.74**	**0.066**	**lb/hr**	Hourly emission rate
26.0	**17.8**	**2.3**	**6.2**	**3.2**	**0.29**	**tpy**	Annual emission rate (8760 hrs/yr)

DCP Midstream, LP - Zia II Gas Plant

Hot Oil Heaters

Emission unit number(s):	H4 & H5
Source description:	Hot Oil Heater
Manufacturer:	OPF

Fuel Consumption

Input heat rate:	99.0	MMBtu/hr	Design Specification[1]
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	99876	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	874.9	MMscf/yr	8760 hrs/yr operation

[1] Received in an e-mail from Jennifer Corser at DCP on 03/18/2013

HAP Emissions[4]

HCHO	Methanol	Benzene	Toluene	Ethylbenzene	Xylene	
0.000844009	0.000963636	0.000748047	0.001016331	0.002112822	0.001320514	lb/MMBtu
0.08	**0.10**	**0.074**	**0.10**	**0.21**	**0.13**	**lb/hr**
0.37	**0.42**	**0.32**	**0.44**	**0.9**	**0.57**	**tpy**

Acetaldhyde	2,2,4-Trimethylpentane	n-Hexane	Styrene	1,3-Butadiene	Total HAPs	
0.000737592	0.002841758	0.001407066	0.002078896	0.000342335		lb/MMBtu
0.073	**0.28**	**0.14**	**0.21**	**0.034**	**1.4**	**lb/hr**
0.32	**1.2**	**0.61**	**0.9**	**0.15**	**6.3**	**tpy**

GHG Emissions

CO_2	CH_4	N_2O	CO_2e [3]		
53.06	0.001	0.0001		kg/MMbtu	40 CFR 98 Subpart C TIER 1
46,015.8	**8.67E-01**	**8.672E-02**	**46,063.28**	tonnes/yr	(1*10^-3)*EF*Fuel Heat Value*Annual Fuel Usage
50,723.7	**9.56E-01**	**9.560E-02**	**50,776.07**	tons/yr	

[1] 5 gr S/100scf. SO_2 calculation assumes 100% conversion of fuel elemental sulfur to SO_2.
[2] Assumes PM (Total) = TSP = PM-10 = PM-2.5
[3] Warming potential of CH4 is 25 times greater than CO2; warming potential of N2O is 298 times greater than CO2 (40 CFR 98 Subpart C)
[4] HAP Emission factors from GRI HAPCalc 3.01
[5] Low Nox burner emission factor provide by DCP.
[6] The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to form a sulfuric acid mist (AP-42 Section 1.3.3.2, May 2010).

$$H_2SO_4 \text{ Hourly Emissions (lb/hr)} = \frac{1.43 \text{ lb SO2}}{\text{hr}} \times 0.03 \times \frac{98.08 \text{ lb } H_2SO_4}{1 \text{ lb-mol } H_2SO_4} \times \frac{1 \text{ lb-mol } SO_2}{64.06 \text{ lb } SO_2} = 0.066 \text{ lb/hr}$$

DCP Midstream, LP - Zia II Gas Plant

TEG Regeneration Heater

Emission unit number(s):	H6
Source description:	TEG Regeneration Heater
Manufacturer:	Unknown

Fuel Consumption

Input heat rate:	3.5	MMBtu/hr	Design Specification
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	3531	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	30.9	MMscf/yr	8760 hrs/yr operation

Exhaust Parameters

Heat Rate:	3500	MBtu/hr	Design Specification
Exhaust temp (Tstk):	600	°F	Eng Estimate
Site Elevation:	3550	ft MSL	
Ambient pressure (Pstk):	26.25	in. Hg	Calculated based on elevation
F factor:	10610	wscf/MMBtu	40 CFR 60 Appx A Method 19
Exhaust flow	618.9	scfm	Calculated from F factor and heat rate
Exhaust flow:	1437.9	acfm	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
Stack diameter:	1.0	ft	Eng Estimate
Stack height:	25	ft	Eng Estimate
Exhaust velocity:	30.5	ft/sec	Exhaust flow ÷ stack area

Emission Rates

Uncontrolled Heater Emissions

NOx	CO	VOC	SO_2[1]	PM[2]	H_2SO_4[5]		
50	84	5.5		7.6		lb/MMscf	AP-42 Table 1.4-1 & 2
48.6	81.6	5.3		7.4		lb/MMscf	EF Conversion, per AP-42 = Fuel Heat Value /
			5			gr Total Sulfur/100 scf	Pipeline specification
0.17	**0.29**	**0.019**	**0.050**	**0.026**	**0.0023**	**lb/hr**	Hourly emission rate
0.75	**1.3**	**0.083**	**0.22**	**0.11**	**0.0101**	**tpy**	Annual emission rate (8760 hrs/yr)

DCP Midstream, LP - Zia II Gas Plant

TEG Regeneration Heater

Emission unit number(s):	H6
Source description:	TEG Regeneration Heater
Manufacturer:	Unknown

Fuel Consumption

Input heat rate:	3.5	MMBtu/hr	Design Specification
Fuel heat value:	991	Btu/scf	Residue Gas HHV
Fuel rate:	3531	scf/hr	Input heat rate / fuel heat value
Annual fuel usage:	30.9	MMscf/yr	8760 hrs/yr operation

Heater HAP Emissions [4]

HCHO	Methanol	Benzene	Toluene	Ethylbenzene	Xylene	
0.0029	**0.0034**	**0.0026**	**0.0036**	**0.0074**	**0.0046**	**lb/hr**
0.0129	**0.0148**	**0.0115**	**0.0156**	**0.0324**	**0.0202**	**tpy**

Acetaldehyde	2,2,4-Trimethylpentane	n-Hexane	Styrene	Total HAPs	
0.0026	**0.0100**	**0.0049**	**0.0073**	**0.050**	**lb/hr**
0.0113	**0.044**	**0.022**	**0.032**	**0.22**	**tpy**

GHG Emissions

CO_2	CH_4	N_2O	CO_2e [3]		
53.06	0.001	0.0001		kg/MMbtu	40 CFR 98 Subpart C TIER 1
1626.8	**3.07E-02**	**3.066E-03**	**1628.5**	tonnes/yr	(1*10^-3)*EF*Fuel Heat Value*Annual Fuel Usage
1793.26	**3.38E-02**	**3.380E-03**	**1795.1**	tons/yr	

[1] *5 gr S/100scf. SO_2 calculation assumes 100% conversion of fuel elemental sulfur to SO_2.*

[2] *Assumes PM (Total) = TSP = PM-10 = PM-2.5*

[3] *Warming potential of CH4 is 25 times greater than CO2; warming potential of N2O is 298 times greater than CO2*

[4] *HAP Emissions from GRI HAPCalc 3.01*

[5] *The sulfuric acid mist emission estimate is based on the assumption that 3% of total sulfur will be converted to SO_3 and that all of the SO_3 will react with water vapor to*

H_2SO_4 Hourly Emissions (lb/hr) = $\frac{0.05 \text{ lb } SO2}{hr} \times 0.03 \times \frac{98.08 \text{ lb } H_2SO_4}{1 \text{ lb-mol } H_2SO_4} \times \frac{1 \text{ lb-mol } SO_2}{64.06 \text{ lb } SO_2}$ = *0.0023 lb/hr*

DCP Midstream, LP - Zia II Gas Plant

Inlet Gas Flare

Emission Unit: FL1

Residue Gas Composition: Used for Pilot and Purge Fuel

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	0.000%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	0.000%	0.00	637.02	0.0	0.00	11.136	
Carbon Dioxide	44.01	0.000%	0.00	0.0	0.0	0.00	8.623	
Nitrogen	28.01	3.471%	0.97	0.0	0.0	0.06	13.547	
Oxygen	32.00	0.000%	0.00	0.0	0.0	0.00	13.5	
Methane	16.04	94.637%	15.18	1,010	955.8	0.91	23.65	
Ethane	30.07	1.674%	0.50	1,770	29.6	0.03	12.62	
Propane	44.10	0.180%	0.08	2,516	4.5	0.00	8.606	6.717
i-Butane	58.12	0.011%	0.01	3,252	0.4	0.00	6.529	0.404
n-Butane	58.12	0.028%	0.02	3,262	0.9	0.00	6.529	1.029
i-Pentane	72.15	0.000%	0.00	4007.7	0.0	0.00	4.26	0.000
Pentanes	72.15	0.000%	0.00	4008.7	0.0	0.00	5.26	0.000
Hexanes+	86.18	0.000%	0.00	4756.1	0.0	0.00	4.404	0.000
		100%	16.76		991.2	1.00		8.150
NMNEHC (VOC)		0.2%				0.6%		

[1] *Based on Residue Analysis from excel spreadsheet named, "SENM 200 mmcfd_v3.xlsx"*

[2] *Component HHVs based on DCP Gas Analysis; specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500.0	scf/hr	Design	
	0.00050	MMscf/hr		
	991.23	Btu/scf	Residue Gas, HHV	
	0.50	MMBtu/hr		
	4.38	MMscf/yr		
Purge Gas [1]	2000	scf/hr	Eng Estimate	
	0.0020	MMscf/hr	scf/hr / 10^6	
	991.23	Btu/scf	Residue Gas HHV	
	1.98	MMBtu/hr	MMscf/hr * Btu/scf	
	17.52	MMscf/yr		

Stack Parameters

	1000	˚C	Exhaust temperature	Per NMAQB guidelines
	20	m/sec	Exhaust velocity	Per NMAQB guidelines
	100	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot gas molecular weight	Mol. wt. of methane, the dominant species
	1.73E+05	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	1.40E+05		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	0.3743	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$
	0.64008	m	Actual Diameter	

DCP Midstream, LP - Zia II Gas Plant

Inlet Gas Flare

Emission Unit: FL1

Emission Rates

Pilot+ Purge Gas

	NOx	CO	VOC	H_2S	SO_2	Units	
	0.0680	0.3700				lb/MMBtu	Table 13.5-1; AP-42 Section 13
			0.22%	0.00%	0.00%	mol%	Flare Gas
			8.150	11.136	11.136	ft^3/lb	Specific volume
			0.67	0.00	0.00	lb/hr	vol. Gas * mole fraction / specific volume
	0.17	0.92	0.67	-	-	lb/hr	Uncontrolled Emissions Rate
	0.74	4.02	2.9	-	-	tpy	

	NOx	CO	VOC[2]	H_2S[2]	SO_2[3]	Units	
Pilot+ Purge Gas	**0.17**	**0.9**	**0.013**	**-**	**-**	**lb/hr**	Controlled Emissions Rate
	0.74	**4.0**	**0.059**	**-**	**-**	**tpy**	

[1] Includes tank purging from unit TK-7020.
[2] 98% combustion H_2S ,VOC; 100% conversion H_2S to SO_2
[3] (64/34)*uncontrolled H2S

Inlet Flare GHG Emissions

§98.233(n) Flare stack GHG emissions.

Pilot & Purge Gas

Step 1. Calculate contribution of un-combusted CH_4 emissions

$E_{a,CH4}$ (un-combusted) = V_a * (1- η)* X_{CH4} *(Equation W-39B)*

where:

$E_{a,CH4}$ = contribution of annual un-combusted CH_4 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

η = Fraction of gas combusted by a burning flare (or regenerator), default value from Subpart W = 0.98

For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare = 0.9464 (Client gas analysis)

Step 2. Calculate contribution of un-combusted CO_2 emissions

$E_{a,CO2}$ = V_a * X_{CO2} *(Equation W-20)*

where:

$E_{a,CO2}$ = contribution of annual un-combusted CO_2 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

X_{CO2} = Mole fraction of CO_2 in gas to the flare = 0.000

Step 3. Calculate contribution of combusted CO_2 emissions

$E_{a,CO2}$ (combusted) = ∑ (η * V_a * Y_j * R_j) *(Equation W-21)*

where:

η = Fraction of gas combusted by a burning flare (or regenerator) = 0.98

For gas sent to an unlit flare, η is zero.

V_a = volume of gas sent to combustion unit during the year (cf)

Y_j = mole fraction of gas hydrocarbon constituents j:

Constituent j, Methane =	0.9464	(Client gas analysis)
Constituent j, Ethane =	0.0167	
Constituent j, Propane =	0.0018	
Constituent j, Butane =	0.00038	
Constituent j, Pentanes Plus =	0.000	

R_j = number of carbon atoms in the gas hydrocarbon constituent j:

Constituent j, Methane =	1
Constituent j, Ethane =	2
Constituent j, Propane =	3
Constituent j, Butane =	4
Constituent j, Pentanes Plus =	5

Step 4. Calculate GHG volumetric emissions at standard conditions (scf).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$$ *(Equation W-33)*

where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) in cubic feet

$E_{a,n}$ = GHG i volumetric emissions at actual conditions (cf)

T_s = Temperature at standard conditions (F) = 60 F

T_a = Temperature at actual conditions (F) = 76 F (Based on Annual Avg Max Temperature for Hobbs, NM from Western Regional Climate Center)

P_s = Absolute pressure at standard conditions (psia) = 14.7 psia

P_a = Absolute pressure at actual conditions (psia) = 14.7 psia (Assumption)

Constant = 459.67 (temperature conversion from F to R)

Step 5. Calculate annual CH_4 and CO_2 mass emissions (ton).

$Mass_{s,i}$ = $E_{s,i}$ * ρ_i * 0.0011023 *(Equation W-36)*

where:

$Mass_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) mass emissions at standard conditions in tons (tpy)

$E_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) volumetric emissions at standard conditions (cf)

ρ_i = Density of GHG i. Use:

CH_4: 0.0192 kg/ft^3 (at 60F and 14.7 psia)

CO_2: 0.0526 kg/ft^3 (at 60F and 14.7 psia)

Step 6. Calculate annual N_2O emissions from portable or stationary fuel combustion sources under actual conditions (cf) using Equation W-40 .

$Mass_{N2O}$ = 0.0011023 * Fuel * HHV * EF *(Equation W-40)*

where:

$Mass_{N2O}$ = annual N_2O emissions from combustion of a particular type of fuel (tons).

Fuel = mass or volume of the fuel combusted

HHV = high heat value of the fuel

Pilot & Purge gas HHV = 9.912E-04 MMBtu/scf

EF = 1.00E-04 kg N_2O/MMBtu

10^{-3} = conversion factor from kg to metric tons.

Step 7. Calculate total annual emission from flare by summing Equations W-40, W-19, W-20, and W-21.

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
Pilot & Purge	21,900,000	414509	0	21,178,158	401,903	0	20,534,085	8.51	0.00	1,190.59	0.00239	1403.9

	CO_2	CH_4	N_2O
GWP	1	25	298

DCP Midstream, LP - Zia II Gas Plant

Acid Gas Flare

Emission Unit: FL2

Residue Gas Composition: Used for Pilot and Purge Fuel

Component	MW	Flared Gas[1] Mol%	MW * wet vol %	HHV Btu/scf[2]	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb
Water	18.02	0.000%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	0.000%	0.00	637.02	0.0	0.00	11.136	
Carbon Dioxide	44.01	0.000%	0.00	0.0	0.0	0.00	8.623	
Nitrogen	28.01	3.471%	0.97	0.0	0.0	0.06	13.547	
Oxygen	32.00	0.000%	0.00	0.0	0.0	0.00	13.5	
Methane	16.04	94.637%	15.18	1,010	955.8	0.91	23.65	
Ethane	30.07	1.674%	0.50	1,770	29.6	0.03	12.62	
Propane	44.10	0.180%	0.08	2,516	4.5	0.00	8.606	6.717
i-Butane	58.12	0.011%	0.01	3,252	0.4	0.00	6.529	0.404
n-Butane	58.12	0.028%	0.02	3,262	0.9	0.00	6.529	1.029
i-Pentane	72.15	0.000%	0.00	4007.7	0.0	0.00	4.26	0.000
Pentanes	72.15	0.000%	0.00	4008.7	0.0	0.00	5.26	0.000
Hexanes+	86.18	0.000%	0.00	4756.1	0.0	0.00	4.404	0.000
		100%	16.76		991.2	1.00		8.150
NMNEHC (VOC)		0.2%				0.6%		

[1] *Based on Residue Analysis from excel spreadsheet named, "SENM 200 mmcfd_v3.xlsx"*

[2] *Component HHVs based on DCP Gas Analysis; specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500.0	scf/hr	Design
	0.00050	MMscf/hr	
	991.23	Btu/scf	Residue Gas, HHV
	0.50	MMBtu/hr	
	4.38	MMscf/yr	
Purge Gas	1800.0	scf/hr	Eng Estimate
	0.0018	MMscf/hr	scf/hr / 10^6
	991.23	Btu/scf	Residue Gas HHV
	1.78	MMBtu/hr	MMscf/hr * Btu/scf
	15.77	MMscf/yr	

Stack Parameters

	1000	˚C	Exhaust temperature	Per NMAQB guidelines
	20	m/sec	Exhaust velocity	Per NMAQB guidelines
	150	ft	Flare height	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot gas molecular weight	Mol. wt. of methane, the dominant species
	159587.9	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	128908.8		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	0.3590	m	Effective stack diameter (D)	$D = (10^{-6} q_n)^{1/2}$
	0.64008	m	Actual Diameter	

DCP Midstream, LP - Zia II Gas Plant

Acid Gas Flare

Emission Unit: FL2

Emission Rates

Pilot+ Purge Gas

	NOx	CO	VOC	H_2S	SO_2	Units	
	0.0680	0.3700				lb/MMBtu	Table 13.5-1; AP-42 Section 13
			0.22%	0.00%	0.00%	mol%	Flare Gas
			8.150	11.136	11.136	ft^3/lb	Specific volume
			0.62	0.00	0.00	lb/hr	vol. Gas * mole fraction / specific volume
	0.16	0.84	0.62	-	-	lb/hr	Uncontrolled Emissions Rate
	0.68	3.69	2.7	-	-	tpy	

	NOx	CO	VOC[1]	H_2S[1]	SO_2[2]	Units	
Pilot+ Purge Gas	**0.16**	**0.8**	**0.012**	**-**	**-**	**lb/hr**	Controlled Emissions Rate
	0.7	**3.7**	**0.054**	**-**	**-**	**tpy**	

[1] 98% combustion H_2S ,VOC; 100% conversion H_2S to SO_2

[2] (64/34)*uncontrolled H2S

Acid Gas Flare GHG Emissions

§98.233(n) Flare stack GHG emissions.

Pilot & Purge Gas

Step 1. Calculate contribution of un-combusted CH_4 emissions

$E_{a,CH4}$ (un-combusted) = V_a * (1- η)* X_{CH4} *(Equation W-39B)*

where:

$E_{a,CH4}$ = contribution of annual un-combusted CH_4 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

η = Fraction of gas combusted by a burning flare (or regenerator), default value from Subpart W = 0.98

For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare = 0.9464 (Client gas analysis)

Step 2. Calculate contribution of un-combusted CO_2 emissions

$E_{a,CO2}$ = V_a * X_{CO2} *(Equation W-20)*

where:

$E_{a,CO2}$ = contribution of annual un-combusted CO_2 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

X_{CO2} = Mole fraction of CO_2 in gas to the flare = 0.000

Step 3. Calculate contribution of combusted CO_2 emissions

$E_{a,CO2}$ (combusted) = ∑ (η * V_a * Y_j * R_j) *(Equation W-21)*

where:

η = Fraction of gas combusted by a burning flare (or regenerator) = 0.98

For gas sent to an unlit flare, η is zero.

V_a = volume of gas sent to combustion unit during the year (cf)

Y_j = mole fraction of gas hydrocarbon constituents j:

Constituent j, Methane =	0.9464	(Client gas analysis)
Constituent j, Ethane =	0.0167	
Constituent j, Propane =	0.0018	
Constituent j, Butane =	0.00038	
Constituent j, Pentanes Plus =	0.000	

R_j = number of carbon atoms in the gas hydrocarbon constituent j:

Constituent j, Methane =	1
Constituent j, Ethane =	2
Constituent j, Propane =	3
Constituent j, Butane =	4
Constituent j, Pentanes Plus =	5

Step 4. Calculate GHG volumetric emissions at standard conditions (scf).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$$ *(Equation W-33)*

where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) in cubic feet

$E_{a,n}$ = GHG i volumetric emissions at actual conditions (cf)

T_s = Temperature at standard conditions (F) = 60 F

T_a = Temperature at actual conditions (F) = 76 F (Based on Annual Avg Max Temperature for Hobbs, NM from Western Regional Climate Center)

P_s = Absolute pressure at standard conditions (psia) = 14.7 psia

P_a = Absolute pressure at actual conditions (psia) = 14.7 psia (Assumption)

Constant = 459.67 (temperature conversion from F to R)

Step 5. Calculate annual CH_4 and CO_2 mass emissions (ton).

$Mass_{s,i}$ = $E_{s,i}$ * ρ_i * 0.0011023 *(Equation W-36)*

where:

$Mass_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) mass emissions at standard conditions in tons (tpy)

$E_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) volumetric emissions at standard conditions (cf)

ρ_i = Density of GHG i. Use:

CH_4: 0.0192 kg/ft^3 (at 60F and 14.7 psia)

CO_2: 0.0526 kg/ft^3 (at 60F and 14.7 psia)

Step 6. Calculate annual N_2O emissions from portable or stationary fuel combustion sources under actual conditions (cf) using Equation W-40 .

$Mass_{N2O}$ = 0.0011023 * Fuel * HHV * EF *(Equation W-40)*

where:

$Mass_{N2O}$ = annual N_2O emissions from combustion of a particular type of fuel (tons).

Fuel = mass or volume of the fuel combusted

HHV = high heat value of the fuel

Pilot & Purge gas HHV = 9.912E-04 MMBtu/scf

EF = 1.00E-04 kg N_2O/MMBtu

10^{-3} = conversion factor from kg to metric tons.

Step 7. Calculate total annual emission from flare by summing Equations W-40, W-19, W-20, and W-21.

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
Pilot & Purge	20,148,000	381349	0	19,483,906	369,751	0	18,891,358	7.83	0.00	1,095.34	0.00220	1291.6

	CO_2	CH_4	N_2O
GWP	1	25	298

DCP Midstream, LP - Zia II Gas Plant

Lusk Flare

Emission Unit: FL3

Residue Gas Composition: Used for Pilot and Purge Fuel

Component	**MW**	**Flared Gas[1] Mol%**	**MW * wet vol %**	**HHV Btu/scf[2]**	**Btu/scf * wet vol %**	**Mass Fraction (wet)**	**Spec. Volume[2] ft^3/lb**	**Spec. Volume VOC ft^3/lb**
Water	18.02	0.000%	0.00	0.0	0.0	0.00	21.06	
Hydrogen Sulfide	34.08	0.000%	0.00	637.02	0.0	0.00	11.136	
Carbon Dioxide	44.01	0.000%	0.00	0.0	0.0	0.00	8.623	
Nitrogen	28.01	3.471%	0.97	0.0	0.0	0.06	13.547	
Oxygen	32.00	0.000%	0.00	0.0	0.0	0.00	13.5	
Methane	16.04	94.637%	15.18	1,010	955.8	0.91	23.65	
Ethane	30.07	1.674%	0.50	1,770	29.6	0.03	12.62	
Propane	44.10	0.180%	0.08	2,516	4.5	0.00	8.606	6.717
i-Butane	58.12	0.011%	0.01	3,252	0.4	0.00	6.529	0.404
n-Butane	58.12	0.028%	0.02	3,262	0.9	0.00	6.529	1.029
i-Pentane	72.15	0.000%	0.00	4007.7	0.0	0.00	4.26	0.000
Pentanes	72.15	0.000%	0.00	4008.7	0.0	0.00	5.26	0.000
Hexanes+	86.18	0.000%	0.00	4756.1	0.0	0.00	4.404	0.000
		100%	16.76		991.2	1.00		8.150
NMNEHC (VOC)		0.22%	0.10			0.61%		

[1] *Based on Residue Analysis from excel spreadsheet named, "SENM 200 mmcfd_v3.xlsx"*

[2] *Component HHVs based on DCP Gas Analysis; specific volumes obtained from Physical Properties of Hydrocarbons, API Research Project 44, Fig. 16-1, Rev. 1981.*

Fuel Data

Flare Pilot	500.0	scf/hr	Design
	0.00050	MMscf/hr	
	991.23	Btu/scf	Residue Gas, HHV
	0.50	MMBtu/hr	
	4.38	MMscf/yr	
Purge Gas	1800.0	scf/hr	Eng Estimate
	0.0018	MMscf/hr	scf/hr / 10^6
	991.23	Btu/scf	Residue Gas HHV
	1.78	MMBtu/hr	MMscf/hr * Btu/scf
	15.77	MMscf/yr	

Stack Parameters

	1000	˚C	Exhaust temperature	Per NMAQB guidelines
	20	m/sec	Exhaust velocity	Per NMAQB guidelines
	50	ft	Per DCP Design	
	0.83	ft	Diameter	
Pilot+ Purge Gas only				
	16.04	g/mol	Pilot gas molecular weight	Mol. wt. of methane, the dominant species
	1.60E+05	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
	1.29E+05		q_n	$q_n = q(1-0.048(MW)^{1/2})$
	0.3590	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$

DCP Midstream, LP - Zia II Gas Plant

Lusk Flare

Emission Unit: FL3

1.18 ft Effective stack diameter (D)

Emission Rates

Pilot+ Purge Gas

NOx	CO	VOC	H_2S	SO_2	Units	
0.0680	0.3700				lb/MMBtu	Table 13.5-1; AP-42 Section 13
		0.22%	0.00%	0.00%	mol%	Flare Gas
		8.150	11.136	11.136	ft^3/lb	Specific volume
		0.62	0.00	0.00	lb/hr	vol. Gas * mole fraction / specific volume
0.16	0.84	0.62	-	-	lb/hr	Uncontrolled Emissions Rate
0.68	3.69	2.7	-	-	tpy	

	NOx	CO	VOC[1]	H_2S[1]	SO_2[2]	Units	
Pilot+ Purge Gas	**0.16**	**0.8**	**0.012**	**-**	**-**	**lb/hr**	Controlled Emissions Rate
	0.7	**3.7**	**0.054**	**-**	**-**	**tpy**	

[1] 98% combustion H_2S ,VOC; 100% conversion H_2S to SO_2

[2] (64/34)*uncontrolled H2S

Lusk Flare GHG Emissions

§98.233(n) Flare stack GHG emissions.

Pilot & Purge Gas

Step 1. Calculate contribution of un-combusted CH_4 emissions

$E_{a,CH4}$ (un-combusted) = V_a * (1- η)* X_{CH4} *(Equation W-39B)*

where:

$E_{a,CH4}$ = contribution of annual un-combusted CH_4 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

η = Fraction of gas combusted by a burning flare (or regenerator), default value from Subpart W = 0.98

For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare = 0.9464 (Client gas analysis)

Step 2. Calculate contribution of un-combusted CO_2 emissions

$E_{a,CO2}$ = V_a * X_{CO2} *(Equation W-20)*

where:

$E_{a,CO2}$ = contribution of annual un-combusted CO_2 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

X_{CO2} = Mole fraction of CO_2 in gas to the flare = 0.000

Step 3. Calculate contribution of combusted CO_2 emissions

$E_{a,CO2}$ (combusted) = ∑ (η * V_a * Y_j * R_j) *(Equation W-21)*

where:

η = Fraction of gas combusted by a burning flare (or regenerator) = 0.98

For gas sent to an unlit flare, η is zero.

V_a = volume of gas sent to combustion unit during the year (cf)

Y_j = mole fraction of gas hydrocarbon constituents j:

Constituent j, Methane =	0.9464	(Client gas analysis)
Constituent j, Ethane =	0.0167	
Constituent j, Propane =	0.0018	
Constituent j, Butane =	0.00038	
Constituent j, Pentanes Plus =	0.000	

R_j = number of carbon atoms in the gas hydrocarbon constituent j:

Constituent j, Methane =	1
Constituent j, Ethane =	2
Constituent j, Propane =	3
Constituent j, Butane =	4
Constituent j, Pentanes Plus =	5

Step 4. Calculate GHG volumetric emissions at standard conditions (scf).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$$ *(Equation W-33)*

where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) in cubic feet

$E_{a,n}$ = GHG i volumetric emissions at actual conditions (cf)

T_s = Temperature at standard conditions (F) = 60 F

T_a = Temperature at actual conditions (F) = 76 F (Based on Annual Avg Max Temperature for Hobbs, NM from Western Regional Climate Center)

P_s = Absolute pressure at standard conditions (psia) = 14.7 psia

P_a = Absolute pressure at actual conditions (psia) = 14.7 psia (Assumption)

Constant = 459.67 (temperature conversion from F to R)

Step 5. Calculate annual CH_4 and CO_2 mass emissions (ton).

$Mass_{s,i}$ = $E_{s,i}$ * ρ_i * 0.0011023 *(Equation W-36)*

where:

$Mass_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) mass emissions at standard conditions in tons (tpy)

$E_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) volumetric emissions at standard conditions (cf)

ρ_i = Density of GHG i. Use:

CH_4: 0.0192 kg/ft^3 (at 60F and 14.7 psia)

CO_2: 0.0526 kg/ft^3 (at 60F and 14.7 psia)

Step 6. Calculate annual N_2O emissions from portable or stationary fuel combustion sources under actual conditions (cf) using Equation W-40 .

$Mass_{N2O}$ = 0.0011023 * Fuel * HHV * EF *(Equation W-40)*

where:

$Mass_{N2O}$ = annual N_2O emissions from combustion of a particular type of fuel (tons).

Fuel = mass or volume of the fuel combusted

HHV = high heat value of the fuel

Field gas HHV = 1.235E-03 MMBtu/scf (Default provided in Subpart W Final Amendment;)

EF = 1.00E-04 kg N_2O/MMBtu

10^{-3} = conversion factor from kg to metric tons.

Step 7. Calculate total annual emission from flare by summing Equations W-40, W-19, W-20, and W-21.

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
Pilot & Purge	20,148,000	381349	0	19,483,906	369,751	0	18,891,358	7.83	0.00	1,095.34	0.00274	1291.8

	CO_2	CH_4	N_2O
GWP	1	25	298

DCP Midstream, LP - Zia II Gas Plant

Vapor Combustion Device

Emission Unit: VCD1
Source Description: Vapor Combustion Device

TEG Gas Analysis

Component	MW	Combusted Gas[1] Mol%	MW * wet vol %	HHV Btu/scf	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb	Heating Value (Btu/lb)
Water	18.02	0.000%	0.00	0.0	0.0	0.00	21.06		
Hydrogen Sulfide	34.08	0.000%	0.00	637.02	0.0	0.00	11.136		
Carbon Dioxide	44.01	0.011%	0.00	0.0	0.0	0.00	8.623		
Nitrogen	28.01	2.663%	0.75	0.0	0.0	0.03	13.547		
Oxygen	32.00	0.000%	0.00	0.0	0.0	0.00	13.5		
Methane	16.04	72.617%	11.65	1010.0	733.4	0.514	23.65		
Ethane	30.07	12.844%	3.86	1769.7	227.3	0.170	12.62		
Propane	44.10	6.898%	3.04	2516.2	173.6	0.13	8.606	4.091	10294.1
i-Butane	58.12	0.830%	0.48	3252.0	27.0	0.021	6.529	0.492	1600.8
n-Butane	58.12	2.113%	1.23	3262.0	68.9	0.05	6.529	1.253	4087.8
i-Pentane	72.15	0.524%	0.38	4001.0	21.0	0.017	5.26	0.311	1243.5
n-Pentane	72.15	0.554%	0.40	4009.0	22.2	0.018	5.26	0.329	1317.3
n-Hexane	86.18	0.617%	0.53	4756.0	29.3	0.023	4.404	0.366	1740.5
Heptanes (as n-Heptane)	100.20	0.217%	0.22	5502.5	11.9	0.010	3.787	0.129	708.1
Benzene	78.11	0.011%	0.01	3742.0	0.4	0.0004	4.858	0.007	24.4
Toluene	92.14	0.011%	0.01	4475.0	0.5	0.0004	4.119	0.007	29.2
Ethylbenzene	106.17	0.002%	0.00	5208.0	0.1	0.00009	3.574	0.001	6.2
Xylenes	106.17	0.011%	0.01	5208.0	0.6	0.0005	3.574	0.007	34.0
Octanes+	114.23	0.076%	0.09	6249.0	4.7	0.004	3.322	0.045	281.7
		100.0%	22.66		1321.0	1.00		7.036	21367.6
NMNEHC (VOC)		11.9%				28.2%			

[1] *Composition is based on TEG gas analysis received from J.Corser 3/7/13*
[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons*

Liquids Analysis

Component	MW	Combusted Gas[1] Mol%	MW * wet vol %	HHV Btu/scf	Btu/scf * wet vol %	Mass Fraction (wet)	Spec. Volume[2] ft^3/lb	Spec. Volume VOC ft^3/lb	Heating Value (Btu/lb)
Water	18.02	0.000%	0.00	0.0	0.0	0.00	21.06		
Hydrogen Sulfide	34.08	0.000%	0.00	637.0	0.0	0.00	11.136		
Carbon Dioxide	44.01	0.350%	0.15	0.0	0.0	0.00	8.623		
Nitrogen	28.01	0.000%	0.00	0.0	0.0	0.00	13.547		
Oxygen	32.00	0.000%	0.00	0.0	0.0	0.00	13.5		
Methane	16.04	15.700%	2.52	1010.0	158.6	0.04	23.65		
Ethane	30.07	4.190%	1.26	1769.7	74.2	0.02	12.62		
Propane	44.10	10.030%	4.42	2516.2	252.4	0.07	8.606	0.670	1686.4
i-Butane	58.12	6.360%	3.70	3252.0	206.8	0.06	6.529	0.425	1382.0
n-Butane	58.12	14.070%	8.18	3262.0	459.0	0.13	6.529	0.940	3066.7
i-Pentane	72.15	12.170%	8.78	4001.0	486.9	0.14	5.26	0.813	3253.7
n-Pentane	72.15	11.960%	8.63	4009.0	479.5	0.14	5.26	0.799	3204.0
n-Hexane	86.18	11.830%	10.19	4756.0	562.6	0.17	4.404	0.791	3759.8
Cyclohexane	84.16	1.200%	1.01	4481.6	53.8	0.02	4.509	0.080	359.3
Heptanes (as n-Heptane)	100.20	7.840%	7.86	5502.5	431.4	0.13	3.787	0.524	2882.4
Benzene	78.11	1.300%	1.02	3742.0	48.6	0.02	4.858	0.087	325.0
Toluene	92.14	1.790%	1.65	4475.0	80.1	0.03	4.119	0.120	535.3
Ethylbenzene	106.17	0.190%	0.20	5208.0	9.9	0.00	3.574	0.013	66.1
Xylenes	106.17	1.060%	1.13	5208.0	55.2	0.02	3.574	0.071	368.8
Octanes+	114.23	0.030%	0.03	6249.0	1.9	0.00	3.322	0.002	12.5
		100.1%	60.73		3360.8	1.00		5.334	20902.0
NMNEHC (VOC)		79.8%				0.9			

[1] *Composition is based on condensate analysis from DCP representative Gas Plant*
[2] *Component HHVs and specific volumes obtained from Physical Properties of Hydrocarbons*

DCP Midstream, LP - Zia II Gas Plant

Vapor Combustion Device

Emission Unit: VCD1
Source Description: Vapor Combustion Device

Weighted heat value of combusted VOC	21157.9	Btu/lb	Weighted average calculated from TEG and Liquids Analysis
Weighted heat value of combusted VOC	1513.3	MMBtu/MMscf	Weighted average calculated from TEG and Liquids Analysis

TEG Dehydrator Emissions

VOC Emissions from TEG Dehydrator Non-Condenables:

Total VOC Mass Flow Rate from TEG Dehydrator	48.4	lb/hr	GlyCalc v.4.0 Controlled Regenerator Emissions
Total VOC Mass Flow Rate from TEG Dehydrator	211.9	tpy	GlyCalc v.4.0 Controlled Regenerator Emissions
HAP Emissions from TEG Dehydrator	86.8	tpy	GlyCalc v.4.0 Controlled Regenerator Emissions

Tank Emissions

VOC Emissions for Each Tank - TK-2100 and TK-2200

2		Number of of Tanks	
58,472	lb/yr	TANKS 4.09 d	Working and Breathing per tank
29.24	tpy	tpy = lb/yr / (2000lb/ton)	Working and Breathing per tank
29.24	tpy	Working and breathing for each tank	

VOC Emissions for Each Tank - TK-6100, and TK-6150

0.29	tpy[1]	tpy = lb/yr / (2000lb/ton)	Working and Breathing per tank
0.29	tpy[1]	Working and breathing for each tank	

[1] *1.0% of the condensate tank emissions are assumend to be water tank emissions.*

Total VOC Mass Flow Rate from Tanks	**59.1**	**tpy**	TK-2100 and TK-2200 working and breathing from TANKS 4.09d; TK-6100, and TK-6150
Total HAP Mass Flow Rate from Tanks	**1.28**	**tpy**	TK-2100 and TK-2200 working and breathing from TANKS 4.09d; TK-6100, and TK-6150

Loading Emissions

VOC Emissions from Truck Loading	**114.5**	**tpy**	Based on Eq. 1, AP-42 Section 5.2, a requested condensate loadout of 38325000 gallons/year, and a loadout time of 7,560 gal/hr
HAP Emissions from Truck Loading	**1.3**	**tpy**	TK-2100 & TK-2200 HAP working & breathing *(Total loadout VOC/ TK-2100 & TK-2200 working & breathing losses)

Total VOC and HAP Mass Flow Rate Sent to Enclosed Combustion Device

VOC from TEG Dehy, Tanks & Loading	**385.5**	**tpy**
HAPS from TEG Dehy, Tanks & Loading	**89.36**	**tpy**

VOC Heat Input and Flow Rate Calculation

Total VOC Input Heat Rate	1.86	MMBtu/hr	Total VOC mass flow (ton/yr) * (1 ton/2000 lb) *(1 yr/8760 hr) * Weighted heat value (Btu/lb)* (MMBtu/10^6 Btu)
Safety Factor	100%	Eng. Estimate	Applied to emissions to account for variations in heat content.
VOC flow rate	551.78	scf/hr	(TEG Specific volume (ft^3/lb) * TEG VOC mass flow rate (211.9 ton/yr) * (2000 lb/1 ton) *(1 yr/8760 hr))+(Liquid Specific volume (ft^3/lb) * (Tank VOC mass flow rate (13.1 ton/yr)+ Load VOC mass flow rate (6.03 ton/yr * (2000 lb/1 ton) *(1 yr/8760 hr)
VOC flow rate with 100% safety factor	1103.6	scf/hr	
Heat Rate	3.72	MMBtu/hr	With safety factor applied.

Exhaust Parameters (F-factor method)

Heat Rate	3.72	MMBtu/hr	With safety factor applied.
Exhaust temp (Tstk)	1400	°F	
Site Elevation	3556	ft MSL	
Ambient pressure (Pstk)	26.25	in. Hg	Calculated based on elevation
F factor	10610	wscf/MMBtu	40 CFR 60 Appx A Method 19
Exhaust flow	658.5	scfm	Calculated from F factor and heat rate
Exhaust flow	2685.3	acfm	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
Stack diameter	4.5	ft	Eng. Estimate
Stack height	30	ft	Eng. Estimate
Exhaust velocity	2.81	ft/s	Exhaust flow ÷ stack area

DCP Midstream, LP - Zia II Gas Plant

Vapor Combustion Device

Emission Unit: VCD1
Source Description: Vapor Combustion Device

Emission Rates

NOx	CO	VOC[1]	SO_2	H_2S	HAPs	Units	
100	84					lb/MMscf	AP-42 Table 1.4-1
219.6	184.4					lb/MMscf	EF Conversion, per AP-42 = Fuel Heat Value / EF Heat Value * EF
				0.0		% H_2S	From combusted gas composition
			0.0			% SO_2	From combusted gas composition
		211.89			86.80	tpy	Mass flow rate from TEG Dehydrator
		59.1			1.28	tpy	Mass flow rate from tanks (working, breathing)
		114.5			1.28	tpy	Mass flow rate from loading
0.242	0.204					lb/hr	lb/MMBtu * MMBtu/hr
			-	-		lb/hr	From combusted gas composition
		4.24			1.7360	tpy	Controlled mass flow rate from TEG Dehydrator - 98% combustion of VOC, HAP
		1.18			0.0256	tpy	Controlled mass flow rate from tanks - 98% combustion of VOC, HAP
		2.29			0.026	tpy	Controlled mass flow rate from loading - 98% combustion of VOC, HAP
0.24	**0.2**	**1.76**	**-**	**-**	**0.4080**	**lb/hr**	
1.06	**0.891**	**7.71**	**-**	**-**	**1.787**	**tpy**	**8760 hrs/yr**

2,2,4-Trimethylpentane	Benzene	Toluene	Xylenes	Ethylbenzene	n-Hexane		
-	23.4	19.1	15.8	2.4	26.2	tpy	Mass flow rate from TEG Dehydrator
1.2704	0.37	0.42	0.121	0.029	0.33	tpy	Mass flow rate from tanks (working, breathing)
0.0099	0.35	0.40	0.12	0.028	0.32	tpy	Mass flow rate from loading
-	0.47	0.38	0.32	0.048	0.52	tpy	Controlled mass flow rate from TEG Dehydrator - 98% combustion of VOC, HAP
0.02541	0.0074	0.0084	0.0024	0.00058	0.0066	tpy	Controlled mass flow rate from tanks - 98% combustion of VOC, HAP
0.00020	0.007	0.008	0.0023	0.0006	0.006	tpy	Controlled mass flow rate from loading - 98% combustion of VOC, HAP
0.00585	**0.11**	**0.091**	**0.073**	**0.011**	**0.12**	**lb/hr**	
0.02561	**0.48**	**0.40**	**0.32**	**0.049**	**0.54**	**tpy**	**8760 hrs/yr**

GHG Emissions

CO_2	CH_4	N_2O	CO_2e [2]		
53.06	0.001	0.0001		kg/MMbtu	40 CFR 98 Subpart C TIER 1
1731	**3.3E-02**	**3.3E-03**	**1733**	tonnes/yr	(1*10^-3)*EF*Total heat input rate*8760* Safety Factor
1908	**3.6E-02**	**3.6E-03**	**1910**	tons/yr	
1908	**3.6E-02**	**3.6E-03**	**1910**	tons/yr	Combustion Emission from the VCD
0.24	**1.8E-01**	**-**	**5**	tons/yr	Dehydrator GHG Emission (98% Destruction Rate of CH4)
1908	**2.1E-01**	**3.6E-03**	**1915**	tons/yr	Total GHG Emission from the VCD

Notes

[1] *External combustion device is 98% efficient for combustion of VOC and HAPs*

[2] *Warming potential of CH_4 is 25 times greater than CO_2; warming potential of N_2O is 298 times greater than CO_2*

Combusted Gas

Combusted gas molecular weight	39.80	g/mol	Volume weighted mol. wt. of all components
Heat release (q)	2.61E+05	cal/sec	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
q_n	1.82E+05		$q_n = q(1-0.048(MW)^{1/2})$
Effective stack diameter (D)	0.4263	m	$D = (10^{-6} q_n)^{1/2}$

VOC Emissions TPY	Ratio	
211.9	0.55	TEG Dehydrator
59.1	0.15	Tanks Working and Breathing
114.51	0.30	Load
385.46	1.00	Total

DCP Midstream, LP - Zia II Gas Plant

TEG Dehydrator

Emission unit number(s):	Dehy
Source description:	TEG Dehydrator
Manufacturer:	Unknown
Capacity:	230 MMscfd

Emission Rates

Condensor Controlled Regenerator Emissions [1]

VOC	n-Hexane	Benzene	Toluene	Ethylbenzene	Xylene	Total HAPs	
48.4	**6.0**	**5.3**	**4.3**	**0.55**	**3.6**	**19.8**	**lb/hr**
211.9	**26.2**	**23.4**	**19.1**	**2.4**	**15.8**	**86.8**	**tpy**

CO_2	CH_4	CO_2e [3]	
0.055	**2.0**	**50.05**	lb/hr
0.24	**8.8**	**219.24**	tons/yr

Regenerator Emissions with Closed Loop System [4]

VOC	n-Hexane	Benzene	Toluene	Ethylbenzene	Xylene	
-	-	-	-	-	-	**lb/hr**
-	-	-	-	-	-	**tpy**

CO_2	CH_4	CO_2e	
-	-	-	**lb/hr**
-	-	-	**tons/yr**

[1] *Emissions are from GLYCalc 4.0*

[2] *GHG emissions are from the "Condenser Vent Stream" headings in GLY-Calc*

[3] *Warming potential of CH4 is 25 times greater than CO2*

[4] *The glycol dehydrator is a completely controlled system and will have a reboiler and condenser associated with the unit. The glycol dehydration system flash gases are re-routed to inlet compression for recycling. Non-condensibles/Regenerator emissions from still vent/condenser are sent to the VCD1 for combustion.*

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Condensate Tanks - Working and Breathing

Unit No:	TK-2100 and TK-2200
Source Description:	Condensate Tank
Manufacturer:	N/A
Description	Two 1,000 bbl Tanks

General Tank Information

TK-2100 and TK-2200

Volume	1,000	bbl	
	42,000	gal	
Height (shell)	20	ft	
Diameter	20	ft	
Throughput	1250	bbl/day	
	52,500	gal/day	bbl/day*42
	19,162,500	gal-tank/yr	gal/day * 365day/yr
	38,325,000	gal/yr	Total Facility Throughput

VOC Emissions

Uncontrolled Emissions

Unit No.	lb/yr[1]	tpy[2]	lb/hr[3]
TK-2100	58,472	29.24	6.67
TK-2200	58,472	29.24	6.67
Total	116,944	58.47	13.35

HAP Emissions for Each Tank [5]

HAP	lb/yr	tpy
Benzene	364.5	0.182
Toluene	417.3	0.209
Ethylbenzene	28.7	0.0143
Xylene (m)	119.8	0.060
Isopropyl Benzene	4.68	0.00234
1,2,4 -Trimethylbenzene	10.25	0.00513
n-Hexane	325.1	0.163
Cyclohexane	50.0	0.025
TOTAL HAPs	1320.4	**0.64**

[1] *TANKS 4.09 d*

[2] *tpy = lb/hr x [(8760hr/yr) / (2000lb/ton)])*

[3] *tpy * 2000 lb/ton / 8760 hrs/yr*

[4] *The maximum throughput of condensate for the entire facility will be 38,325,000 gal/yr. Emissions from working and breathing losses are calculated with the total throughput of 19,162,500 gal/yr going through each of the two tanks.*

[5] *HAP Emissions calculated using TANKS 4.09 d default speciation for petroleum distillate RVP 10*

[6] *Emissions from the tanks are routed to the vapor combustion device (Unit VCD1). The vapor combustion device is the control unit for Units TK-2100 and TK-2200.*
(Please see Unit VCD1 for controlled emisisons)

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Produced Water Tanks

Unit No:	TK-6100 and TK-6150
Source Description:	Produced Water Tanks
Manufacturer:	N/A
Description	Two 300 bbl Tanks

General Tank Information

TK-6100 and TK-6150

Volume	300	bbl	
	12,600	gal	
Height (shell)	15	ft	
Diameter	12	ft	
Throughput	50	bbl/day	
	2,100	gal/day	bbl/day*42
	766,500	gal/yr	Total Facility Throughput

Uncontrolled Emissions

Unit No.	tpy[1]
TK-6100	0.29
TK-6150	0.29
Total	0.58

HAP Emissions for Each Tank [1]

HAP	lb/yr	tpy
Benzene	2.5	0.0013
Toluene	2.8	0.0014
Ethylbenzene	0.19	0.000094
Xylene (m)	0.79	0.00039
Isopropyl Benzene	0.030	0.000015
1,2,4 -Trimethylbenzene	0.064	0.000032
n-Hexane	2.3	0.0012
Cyclohexane	0.35	0.00018
TOTAL HAPs	9.1	**0.0044**

[1] 1.0% of the condensate tank emissions are assumend to be water tank emissions.

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Truck Loading of Petroleum Liquids

Emission unit:	L1
Source Description:	Condensate Loadout

Loading of Petroleum Liquids

LL = 12.46 (SPM) / T — Eq. 1, AP-42 Section 5.2, *Transportation and Marketing of Petroleum Liquids*

S =	0.6	Dimensionless	Submerged Loading, Table 5.2-1
T =	70.78	F	Tanks 4.09d
P =	6.3647	psia	Tanks 4.09d (max vapor pressure)
M =	66	lb/lbmole	Tanks 4.09d

LL = 5.9 lb VOC/1000 gallons loaded — AP-42 Section 5.2

Short Term Hourly Loading Emission Rate - For Informational Purposes Only

7560	gal	truck capacity		Engineering Estimate
7.6	Mgal	gal / 1000 (gal/Mgal)		
1.0	hr	truck loading	Estimated, nominal	Engineering Estimate
7.6	Mgal/hr	Mgal loaded / hrs of loading time		
44.7	lb VOC/hr	lb VOC/Mgal loaded * Mgal/hr		
		(Short-term VOC emission rate, for informational purposes only)		

Requested Loadout =	38,325,000	gallons/yr	Loading Volume per Loadout
	2,500	bbl/day	

E (Condensate Loading) =	**113.4**	**tpy VOCs (requested)**	**Emission Rate per Loadout - TK1 and TK2**
E (Water Loading) =	**1.1**	**tpy VOCs (requested)**	**VOC content for water tanks is assumed to be 1% for produced water.**
L1 (VOC Totals)=	**114.5**	**tpy VOCs (requested)**	**Condensate Loading plus Water Loading**

<u>HAP Emissions</u>

Tank VOCs (Working & breathing):	59.06	tpy	Working and breathing emissions for TK1 and TK2
Loadout VOC:	113.38	tpy	
Truck Tank Volume:	7,560	gallons	
Loading Volume per Annual Loadout:	38,325,000	gallons/yr	Requested loadout
Loadout time:	1	hour/ loadout	
Turnovers[2]:	5,069	per year	

HAPs	TK1 & TK2 Working & Breathing lb/yr	Uncontrolled Loadout HAPs Condensate Tanks[1] tpy	Uncontrolled Loadout HAPs Water Tanks[3] tpy	Total Uncontrolled HAPs (From Condensate Loading and Water Loading) tpy
Benzene	364.5	0.35	0.0035	0.35
Toluene	417.3	0.40	0.0040	0.40
Ethylbenzene	28.7	0.028	0.00028	0.028
Xylene (m)	119.8	0.115	0.0012	0.12
Isopropyl Benzene	4.7	0.004	0.000045	0.0045
1,2,4 -Trimethylbenzene	10.3	0.010	0.00010	0.010
n-Hexane	325.1	0.312	0.0031	0.32
Cyclohexane	50.0	0.048	0.00048	0.049
TOTAL HAPs	1320.4	**1.3**	**0.013**	**1.3**

*[1] Loadout HAPs (tpy) = TK1 & TK2 HAP Working and Breathing *(total loadout VOC/ TK1 & TK2 working and breathing losses)*
[2] Turnovers = loading volume / truck tank volume
[3] VOC content for water tanks is assumed to be 1% for produced water.

<u>GHG Emissions</u>

The loading emissions are calculated by converting the TOC emissions to CH_4 and applying the annual loading rate, as shown below:

CH_4 Emissions

$$E_{CH4} = \frac{0.91 \text{ tonnes TOC}}{10^6 \text{ gal}} \times \frac{42 \text{ gal}}{\text{bbl}} \times \frac{912{,}500 \text{ bbl}}{\text{yr}} \times \frac{15.7 \text{ tonne } CH_4}{100 \text{ tonne TOC}}$$

E_{CH4} = 5.48 tonnes CH_4 / yr
4.97 ton CH_4 / yr

**Calculations from the Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry August 2009*

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Paved Haul Road

Emission unit number(s): HAUL
Source description: Paved Haul Road Emissions

Input Data

Empty vehicle weight[1]	16	tons	[1] Empty vehicle weight includes driver and occupants and full fuel load.
Load weight[2]	21.2	tons	[2] Cargo, transported materials, etc.
Loaded vehicle[3]	37.2	tons	[3] Loaded vehicle weight = Empty + Load Size
Mean vehicle weight[4]	26.6	tons	[4] Mean Vehicle weight = (Loaded Weight + Empty Weight) / 2
Round-trip distance	0.5	mile/trip	Obtained from Google earth - measuring roundtrip truck route from fenceline;
Trip frequency[5]	4.0	trips/hour	[5] Max trucks on road in one hour;
Trip frequency[6]	5,069	trips/yr	Annual trucks per year requested;
Surface silt content[7]	0.6	g/m^2	[7] AP-42 Table 13.2.1-2 - Paved Haul Roads < 500
Annual wet days[8]	60	days/yr	[8] AP-42 Figure 13.2.1-2
Vehicle miles traveled[9]	2.0	mile/hr	[9] VMT/hr = Vehicle Miles Traveled per hour= Trips per hour * Segment Length

Emission Factors and Constants

Parameter	PM_{30}	PM_{10}	$PM_{2.5}$	
k, lb/VMT[10]	0.011	0.0022	0.00054	[10] Table 13.2.1-1, Paved Roads
Hourly EF, lb/VMT[11]	0.20	0.039	0.010	[11] AP-42 13.2.1, Equation 1
Annual EF, lb/VMT[12]	0.19	0.038	0.0092	[12] AP-42 13.2.1, Equation 2

Haul Road Emission Calculations

	PM_{30}	PM_{10}	$PM_{2.5}$	
Hourly emissions	0.39	0.078	0.019	lb/hr = Hourly EF (lb/VMT) * VMT (mile/hr)
Annual Emissions	0.24	0.05	0.012	ton/yr =Annual EF (lb/VMT) * VMT (mile/Trip) * Trips per year (Trip/yr) / 2000 (lb/tpy)

Notes

[1] Empty vehicle weight includes driver and occupants and full fuel load.
[2] Cargo, transported materials, etc. (5.6 lb/gal RVP10 *7560 gal truck/ 2000lb/ton)
[3] Loaded vehicle weight = Empty + Load Size
[4] Mean Vehicle weight = (Loaded Weight + Empty Weight) / 2
[5] Trips per hour = Total loadout spots / Loading time
[6] Trips per year = Total throughput (gal/yr) / Truck size 7560 gal truck
[7] AP-42 Table 13.2.1-2 - Paved Haul Roads < 500
[8] AP-42 Figure 13.2.1-2
[9] VMT/hr = Vehicle Miles Traveled per hour= Trips per hour * Segment Length
[10] Table 13.2.1-1, Particle Size Multipliers for Paved Road Equation
[11] AP-42 13.2.1, Equation 1

$E = k\ (sL)^{0.91}\ x\ (W)^{1.02}$

where: E = particulate emission factor (having units matching the units of k),
k = particle size multiplier for particle size range and units of interest,
sL = road surface silt loading (grams per square meter) (g/m^2), and
W = average weight (tons) of the vehicles traveling the road.

[12] AP-42 13.2.1, Equation 2

$E_{ext} = [\ k\ (sL)^{0.91}\ x\ (W)^{1.02}\ ]\ (1 – P/4N)$

where k , sL , W, and S are as defined in Equation 1 and
E_{ext} = annual or other long-term average emission factor in the same units as k,
P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and
N = number of days in the averaging period (e.g., 365 for annual, 91 for seasonal, 30 for monthly).

[13] lb/hr = Hourly EF (lb/VMT) * VMT (mile/hr)
[14] ton/yr =Annual EF (lb/VMT) * VMT (mile/Trip) * Trips per year (Trip/yr) / 2000 (lb/tpy)

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Wet Surface Air Cooler

Emission unit number: CT-1
Source description: Wet Surface Air Cooler
Manufacturer: Niagara Blower
Model #: A4407SL

	Cooling Water Recirculation Rate (gpm)	Uncontrolled Liquid Drift %	Controlled Liquid Drift %	Total Uncontrolled Drift Mass lb/min	Total Controlled Drift Mass lb/min	Circulating Water Total Dissolved Solids (mg/l)	Circulating Water Total Dissolved Solids (ppm_w)
Note	1	2	3	4	4	5	
Wet Surface Air Cooler	240	0.02%	0.005%	0.4	0.1	3,500	3,500

Maximum Uncontrolled Emissions

	Hourly Uncontrolled Particulate Emissions (lb/hr)	Annual Uncontrolled Particulate Emissions (tpy)	Hourly Uncontrolled TSP Emissions (lb/hr)	Annual Uncontrolled TSP Emissions (tpy)	Hourly Uncontrolled PM_{10} Emissions (lb/hr)	Annual Uncontrolled PM_{10} Emissions (tpy)	Hourly Uncontrolled $PM_{2.5}$ Emissions (lb/hr)	Annual Uncontrolled $PM_{2.5}$ Emissions (tpy)
Note	6	6	7	7	7	7	7	7
Wet Surface Air Cooler	0.084	0.37	0.008	0.03	0.00020	0.00088	2.07E-06	9.07E-06

Maximum Controlled Emissions

	Hourly Controlled Particulate Emissions (lb/hr)	Annual Controlled Particulate Emissions (tpy)	Hourly Controlled TSP Emissions (lb/hr)	Annual Controlled TSP Emissions (tpy)	Hourly Controlled PM_{10} Emissions (lb/hr)	Annual Controlled PM_{10} Emissions (tpy)	Hourly Controlled $PM_{2.5}$ Emissions (lb/hr)	Annual Controlled $PM_{2.5}$ Emissions (tpy)
Note	6	6	7	7	7	7	7	7
Wet Surface Air Cooler	0.021	0.092	0.002	0.008	5.03E-05	2.20E-04	5.17E-07	2.27E-06

Notes

1 Cooling Tower Water Recirc rate based Niagara Blower Mfg data
2 Uncontrolled circulating water flow percent drift estimated based on AP-42 factors for induced draft cooling towers (Table 13.4-1)
3 Controlled circulating water flow percent drift established as BACT requirement for cooling towers.
4 Total Drift Mass = Recirculation rate * Drift Rate Fraction * Drift Density (8.34 lb/gal)
5 TDS estimated at 3,500 mg/l as a conservative measure.
6 Total particulate emission calculated using procedure described in Section 13.4 of AP-42 (01/95), Wet Cooling Towers.
PM = Water Circulation Rate * Drift Rate* Percent drift mass escape * TDS
Particulate Hourly Emissions:

Maximum Uncontrolled Emissions

$$\frac{240\ \text{gal}}{\text{min}} \times \frac{60\ \text{min}}{\text{hr}} \times \frac{0.0002\ \text{gal drift}}{\text{gal recirculation}} \times \frac{8.34\ \text{lb drift}}{\text{gal drift}} \times \frac{3500\ \text{lb PM}}{10^6\ \text{lb drift}} = \frac{0.08\ \text{lb}}{\text{hr}}$$

Maximum Controlled Emissions

$$\frac{240\ \text{gal}}{\text{min}} \times \frac{60\ \text{min}}{\text{hr}} \times \frac{0.00005\ \text{gal drift}}{\text{gal recirculation}} \times \frac{8.34\ \text{lb drift}}{\text{gal drift}} \times \frac{3500\ \text{lb PM}}{10^6\ \text{lb drift}} = \frac{0.02\ \text{lb}}{\text{hr}}$$

Particulate annual emissions = Hourly emissions (lb/hr) * 8760 (hrs/yr) / 2000 (lb/ton)
7 Particle size distribution based on the following distribution (from Frisbie data)

Particle Distribution

Particle	Mass % of Total Particulates	
TSP (PM 30)	9.0	Frisbie data
PM10	0.2	Frisbie data
PM2.5	2.46E-03	Frisbie data

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Wet Surface Air Cooler

Facility TDS	3,500	(mg/l)	ρ_{water} [6]	1.00E-06	µg/µm3
TDS Content	3,500	ppmw	ρ_{TDS} [6]	2.50E-06	µg/µm3

Droplet Diameter (µm)	Droplet Volume [1] (µm3)	Droplet Mass [2] (µg)	Particle Mass (Solids) [3] (µg)	Solid Particle Volume [4] (μm^3)	Solid Particle Diameter [5] (µm)	Particle % Mass Smaller
10	524	5.24E-04	1.83E-06	7.33E-01	1.12	0.00016
20	4189	4.19E-03	1.47E-05	5.86E+00	2.24	0.0014
30	14137	1.41E-02	4.95E-05	1.98E+01	3.36	0.01
40	33510	3.35E-02	1.17E-04	4.69E+01	4.47	0.02
50	65450	6.54E-02	2.29E-04	9.16E+01	5.59	0.04
60	113097	1.13E-01	3.96E-04	1.58E+02	6.71	0.07
70	179594	1.80E-01	6.29E-04	2.51E+02	7.83	0.13
90	381704	3.82E-01	1.34E-03	5.34E+02	10.07	0.24
110	696910	6.97E-01	2.44E-03	9.76E+02	12.31	0.46
130	1150347	1.15E+00	4.03E-03	1.61E+03	14.54	0.81
150	1767146	1.77E+00	6.19E-03	2.47E+03	16.78	1.35
180	3053628	3.05E+00	1.07E-02	4.28E+03	20.14	2.29
210	4849048	4.85E+00	1.70E-02	6.79E+03	23.49	3.77
240	7238229	7.24E+00	2.53E-02	1.01E+04	26.85	5.99
270	10305995	1.03E+01	3.61E-02	1.44E+04	30.20	9.15
300	14137167	1.41E+01	4.95E-02	1.98E+04	33.56	13.49
350	22449298	2.24E+01	7.86E-02	3.14E+04	39.15	20.37
400	33510322	3.35E+01	1.17E-01	4.69E+04	44.75	30.64
450	47712938	4.77E+01	1.67E-01	6.68E+04	50.34	45.27
500	65449847	6.54E+01	2.29E-01	9.16E+04	55.93	65.33
600	113097336	1.13E+02	3.96E-01	1.58E+05	67.12	100.00
		Sum	**1.14E+00**			
				PM2.5/Total	2.5	0.002
				PM10/Total	10	0.239
				TSP/Total	30	8.959

Notes

1 Droplet volume calculated with: $$Droplet\ Volume = \left(\frac{4}{3}\right)\pi\left(\frac{D_d}{2}\right)^3$$

2 Droplet mass calculated with: $$Droplet\ Mass = Droplet\ Volume \times \rho_{Water}$$

3 Particle mass calculated with: $$Particle\ Mass = TDS \times \rho_{water} \times \left(\frac{4}{3}\right)\pi\left(\frac{D_d}{2}\right)^3$$

4 Particle volume calculated with: $$Particle\ Volume = \frac{Particle\ Mass}{\rho_{TDS}}$$

5 Particle diameter calculated with: $$Particle\ Diameter = 2 \times \sqrt[3]{Particle\ Volume \times \left(\frac{1}{\pi}\right) \times \left(\frac{3}{4}\right)}$$

6 Based on "Calculating TSP, PM10 and PM2.5 from Cooling Towers - Technical Memorandum", Daren Zigich, September 9, 2013.

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Facility-wide VOC Fugitive Emissions

Component Source Counts for Gas Plant/Compressor Station Units

Equipment Type	Compressor*	Separator	Heaters	VOC Storage Tank	TEG Unit	DEA Unit	C3 Refrig Skid	Expan Demeth	Mole Sieve System	Flare
For this facility, Number of Units	15	5	5	2	1	2	1	1	1	3
Valves - Inlet Gas	40	6	10	4	75	15	40	40	25	8
Valves - Liquid	5	4	4	6	20	60	35	35	0	2
Relief Valves	2	2	1	2	4	4	6	6	4	2
Pump Seals - Liquid	0	0	0	2	4	4	0	0	0	0
Flanges/Connectors - Inlet Gas	150	150	60	20	250	250	250	250	100	75
Flanges/Connectors - Liquid	10	10	5	40	20	20	20	20	20	10
Compressor Seals	4	0	0	0	0	0	6	0	0	0

* The total compressor number is the eight 3616 RICE, two 3608 RICE, three electric compressors for refrigeration compression, and two electric compressors associated with the AGI wells at the facility.

Emissions from Gas Plant/Compressor Unit

Equipment Type	Emission Factor (kg/hr/source)	Emission Factor (lb/hr/ source)	Source Count *	**% VOC C3+**	**VOC Emission Rate (lb/hr)**	**VOC Emission Rate (tpy)**	**HAPs** Emission Rate (lb/hr)**	**HAPs** Emission Rate (tpy)**
Valves - Inlet Gas	4.5E-03	9.9E-03	922	29.123%	2.664	11.67	0.237	1.04
Valves - Liquid	2.5E-03	5.5E-03	343	100.000%	1.890	8.28	0.168	0.74
Relief Valves	8.8E-03	1.9E-02	83	29.123%	0.469	2.05	0.042	0.18
Pump Seals - Liquid	1.3E-02	2.9E-02	16	100.000%	0.459	2.01	0.041	0.18
Flanges/Connectors - Inlet Gas	3.9E-04	8.6E-04	4915	29.123%	1.231	5.39	0.109	0.48
Flanges/Connectors - Liquid	1.1E-04	2.4E-04	455	100.000%	0.110	0.48	0.010	0.043
Compressor Seals	8.8E-03	1.9E-02	66	29.123%	0.373	1.63	0.033	0.15
Total					**7.2**	**31.5**	**0.64**	**2.80**

* Source counts estimated from similar facilities. These counts are not actuals.

Source: EPA Protocol for Equipment Leak Emission Estimates, November, 1995, EPA-453/R-95-017, Table 2-4.

** HAP emissions were calculated using a weighted average of HAP in total VOCs. (Mole% Constituent x 1.2 for variability in the gas) /Total Mole % VOC x VOC Emission Rate

Gas Composition for Fugitive Emissions Estimate

* Inlet Gas Analysis Provided by DCP

	Molecular Wt (lb/lb-mole)	% Volume (%)	Wt. (lb/lb-mole)	Fraction (%)
Methane	16.0	67.0700%	10.731	44.521%
Ethane	30.0	11.8630%	3.559	14.765%
Total HC (non-VOC)				***59.286%***
Propane	44.0	6.3710%	2.803	11.630%
i-Butane	58.0	0.7670%	0.445	1.846%
n-Butane	58.0	1.9520%	1.132	4.697%
i-Pentane	72.0	0.4840%	0.348	1.446%
n-Pentane	72.0	0.5120%	0.369	1.529%
Hexane Plus	86.0	0.2700%	0.232	0.963%
n-Hexane	86.0	0.5700%	0.490	2.034%
Benzene	78.0	0.0100%	0.008	0.032%
Ethylbenzene	116.0	0.0020%	0.002	0.010%
Toluene	92.0	0.0100%	0.009	0.038%
Xylenes	106.0	0.0100%	0.011	0.044%
Total VOC				***24.269%***
Carbon Dioxide	44.0	6.7000%	2.948	12.230%
Hydrogen Sulfide	34.1	0.9600%	0.327	1.357%
Helium	4.0	0.0000%	0.000	0.000%
Nitrogen	28.0	2.4600%	0.689	2.858%
	Totals	100.0%	24.10	100.00%
	Total VOC Wt % plus 20% **			**29.123%**

** 20% added to Gas/Vapor Weight % VOC to account for variability in the gas.

DCP Midstream, LP - Zia II Gas Plant

Facility-wide H_2S Fugitive Emissions

	Gas*					Water / Oil*				
Unit	Valves	Pumps	Others	Connectors	Flanges	Valves	Pumps	Others	Connectors	Flanges
Acid Gas	447	8	55	215	1895	0	0	0	0	0
Sour Water	0	0	0	0	0	45	0	5	104	31
Totals	492	8	60	319	1926					

*Source counts estimated from similar facilities. These counts are not actuals.

SV (Screening Value): 35 ppmv[1]

Components in simultaneous service: 50%

Component	Number of Components	Correlation Factor (kg/hr)	Exponent	EPA Component Emission Factor[2] (kg/hr/source)	H_2S Fugitive Emissions (lb/hr)	H_2S Fugitive Emissions (tpy)
Valves/all	492	2.29E-06	0.746	3.25E-05	0.018	0.077
Pump seals/all	8	5.03E-05	0.610	4.40E-04	0.004	0.017
Others	60	1.36E-05	0.589	1.10E-04	0.007	0.032
Connectors/all	319	1.53E-06	0.735	2.09E-05	0.007	0.032
Flanges/all	1926	4.61E-06	0.703	5.61E-05	0.119	0.522
Open-ended lines/all	0	2.20E-06	0.704	2.69E-05	0.000	0.000
Totals					0.155	0.680

1 In-plant monitors are set at 10 ppm. Therefore, DCP is conservatively estimating emissions by assuming a screening value (correlated to leakage rate) for each component is 35 ppmv. Some components may leak at higher rates, but most will leak at lower rates.

2 EPA Protocol for Equipment Leak Emission Estimates (November, 1995, Publication No. EPA-453 /R-95-017), Table 2-10.

DCP Midstream, LP - Zia II Gas Plant

Facility-Wide Fugitive GHG Calculation

Facility-Level Average Emission Factors Approach

CH_4 Emissions

Click here to view Table 6-2 Facility Level Average Fugitive Emission Factors

$$E_{CH4} = \frac{5663370.0 \ m^3}{day} \times \frac{365 \ days}{year} \times \frac{1.032 \times 10^{0} \ tonne\ CH_4}{10^{6} \ m^3} \times \frac{0.671 \ \text{tonne mol CH4, actual}}{0.788 \ \text{tonne mol } CH_4\text{, default}}$$

E_{CH4} = 1815.723 tonnes CH_4/yr

E_{CH4} = 2001.5 ton CH_4/yr

CH4 Vapor emissions not available. Gas analysis used.

1 tonne = 1.102311 ton

CO_2 Emissions

$$E_{CO2} = \frac{1815.72 \ tonnes\ CH_4}{yr} \times \frac{tonne\ mol\ CH_4}{16 \ tonne\ CH_4} \times \frac{tonne\ mol\ gas}{0.671 \ tonne\ mol\ CH_4} \times \frac{0.067 \ tonne\ mol\ CO_2}{tonne\ mol\ gas} \times \frac{44 \ tonne\ CO_2}{tonne\ mol\ CO_2}$$

E_{CO2} = 498.8 tonnes CO_2/yr

E_{CO2} = 549.8 ton CO_2/yr

1 tonne = 1.102311 ton

*Calculations from the Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry August 2009

Equipment Leaks		
Unit	**Facility Input Capacity (scf/day)**	**Facility Input Capacity (M^3/day)**
Fugitives	200,000,000	5663370

1 bbl = 0.1589873 cubic meters = 42 gallons

DCP Midstream, LP - Zia II Gas Plant

Flare FL1 SSM Detail Sheet

Source ID Number	FL1		
Equipment ID			
Source Description	Inlet flare		
Equipment Usage			
Equipment Make	Zeeco	Potential operation	8.00 hr/yr
Serial Number	FL-5100/24093		
Date in Service	2015		
Equipment Configuration			
Stack ID	FL1		
Stack Height	100 ft, agl		
Stack Diameter	15.6 in		
Exit Velocity	4011.24 ft/s		
Exit Temperature	1830 deg F (estimated)		
Volume Flow Rate	319,453 ft^3/min		

Potential Emissions

Pollutant	Emission Factor	Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	0.0680	799.24	3.88	AP42
CO	0.3700	4348.79	21.09	AP42
VOC		2942.11	11.82	See Calcs Below
SO^2		14977.09	59.91	See Calcs Below
H_2S		162.86	0.65	See Calcs Below
n-Hexane		244.54	0.98	See Calcs Below
Benzene		3.89	0.016	See Calcs Below
Toluene		4.59	0.018	See Calcs Below
E-Benzene		1.06	0.0042	See Calcs Below
m-Xylene		5.29	0.021	See Calcs Below

DCP Midstream, LP - Zia II Gas Plant

Flare FL1 SSM Detail Sheet

Source ID Number	FL1
Equipment ID	
Source Description	Inlet flare

Maintenance/Startup/Shutdown Events

4.00	Events per Year	Plant rate	
19,166,667	scf/event	230	mmscf/day
76,667	mscf/year	9.6	mmscf/hr
2.00	duration per event (hr)	9,583,333	scf/hr
8.00	hours per year		

Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	Post control emission rate tons/yr
Nitrogen	0.02460	28.01	0.69	235750.0	17153.4	0	0.00	-	-
Carbon Dioxide	0.06700	44.01	2.95	642083.3	73397.1	0	0.00	73397.13	293.59
Methane	0.67070	16.04	10.76	6427541.7	267834.8	1010	677.41	-	-
Ethane	0.11863	30.07	3.57	1136870.8	88793.7	1770	209.94	-	-
Propane	0.06371	44.10	2.81	610554.2	69931.4	2516	160.31	1398.63	5.59
i-Butane	0.00767	58.12	0.45	73504.2	11097.0	3252	24.94	221.94	0.89
n-Butane	0.01952	58.12	1.13	187066.7	28241.7	3262	63.67	564.83	2.26
i-Pentane	0.00484	72.15	0.35	46383.3	8692.5	4001	19.36	173.85	0.70
n-Pentane	0.00512	72.15	0.37	49066.7	9195.3	4009	20.53	183.91	0.74
n-Hexane	0.00570	86.18	0.49	54625.0	12227.2	4756	27.11	244.54	0.98
n-Heptane	0.00200	100.21	0.20	19166.7	4988.6	5503	11.01	99.77	0.40
n-Octane	0.00070	114.23	0.08	6708.3	1990.4	6249	4.37	39.81	0.16
Benzene	0.00010	78.11	0.01	958.3	194.4	3742	0.37	3.89	0.02
Toluene	0.00010	92.14	0.01	958.3	229.4	4475	0.45	4.59	0.02
E-Benzene	0.00002	106.17	0.00	191.7	52.9	5208	0.10	1.06	0.00
m-Xylene	0.00010	106.17	0.01	958.3	264.3	5208	0.52	5.29	0.02
p-Xylene	0.00000	106.17	0.00	0.0	0.0	5208	0.00	0.00	0.00
o-Xylene	0.00000	106.17	0.00	0.0	0.0	5208	0.00	0.00	0.00
H2S	0.00960	34.08	0.33	92000.0	8142.8	637	6.12	162.86	0.65
Total	1.00011		24.20	9584387.50	602427.0		1226.21	76502.09	306.01
Total VOC	0.1096			1050141.67				2942.10	11.77

Heating Value	1226.21	Btu/scf
Heat Rate	11751.20	MMBtu/hr

Maintenance Event Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{11751.20 \text{ MMBtu}}{\text{hr}}$

= **799.08** **lb/hr NOx**

NOx (tpy): $\frac{799.08 \text{ lb}}{\text{hr}} \times \frac{8 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **3.20** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \times \frac{11751.20 \text{ MMBtu}}{\text{hr}}$

= **4347.94** **lb/hr CO**

CO (tpy): $\frac{4347.94 \text{ lb}}{\text{hr}} \times \frac{8 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **17.39** **tpy CO**

SO2 (lb/hr): $\frac{7979.98 \text{ lb H2S}}{\text{hr}} \times \frac{64.0 \text{ lb SO2}}{34.1 \text{ lb H2S}}$

= **14977.09** **lb/hr SO2**

SO2 (tpy): $\frac{14977.09 \text{ lb SO2}}{\text{hr}} \times \frac{8 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **59.91** **tpy SO2**

DCP Midstream, LP - Zia II Gas Plant

Flare FL1 SSM Detail Sheet

Source ID Number	FL1
Equipment ID	
Source Description	Inlet flare

Pilot Gas Emissions

500.00	scf/hr
0.00050	MMscf/hr
8760.00	hours per year

Residue Gas Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	Post control emission rate tons/yr
Nitrogen	0.03471	28.01	0.97	17.36	1.26	0	0.00		
Carbon Dioxide	0.00000	44.01	0.00	0.00	0.00	0	0.00		
Methane	0.94637	16.04	15.18	473.18	19.72	1010	955.83	0.39	1.73
Ethane	0.01674	30.07	0.50	8.37	0.65	1770	29.62	0.01	0.06
Propane	0.00180	44.10	0.08	0.90	0.10	2516	4.52	0.00	0.01
i-Butane	0.00011	58.12	0.01	0.05	0.01	3252	0.35	0.00	0.00
n-Butane	0.00028	58.12	0.02	0.14	0.02	3262	0.90	0.00	0.00
i-Pentane	0.00000	72.15	0.00	0.00	0.00	4008	0.00	0.00	0.00
n-Pentane	0.00000	72.15	0.00	0.00	0.00	4009	0.00	0.00	0.00
Hexane Plus	0.00000	86.18	0.00	0.00	0.00	4756	0.00	0.00	0.00
Total	1.00		16.76	500.00	21.8		991.23	0.41	1.80
Total VOC	0.0022			1.09				0.00	0.01

Heating Value	991.23	Btu/scf
Heat Rate	0.496	MMBtu/hr (pilot only)

Pilot Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{0.50 \text{ MMBtu}}{\text{hr}}$

= **0.03** **lb/hr NOx**

NOx (tpy): $\frac{0.03 \text{ lb}}{\text{hr}} \times \frac{8760.00 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.15** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \times \frac{0.50 \text{ MMBtu}}{\text{hr}}$

= **0.18** **lb/hr CO**

CO (tpy): $\frac{0.18 \text{ lb}}{\text{hr}} \times \frac{8760.00 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.80** **tpy CO**

DCP Midstream, LP - Zia II Gas Plant

Flare FL1 SSM Detail Sheet

Source ID Number	FL1
Equipment ID	
Source Description	Inlet flare

Purge Gas Emissions

1800.00	scf/hr	Eng Estimate
0.0018	MMscf/hr	
8760.00	hours per year	

Residue Gas Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	Post control emission rate tons/yr
Nitrogen	0.03471	28.01	0.97	62.48	4.55	0	0.00		
Carbon Dioxide	0.00000	44.01	0.00	0.00	0.00	0	0.00		
Methane	0.94637	16.04	15.18	1703.46	70.98	1010	955.83	1.42	6.22
Ethane	0.01674	30.07	0.50	30.13	2.35	1770	29.62	0.05	0.21
Propane	0.00180	44.10	0.08	3.24	0.37	2516	4.52	0.01	0.03
i-Butane	0.00011	58.12	0.01	0.19	0.03	3252	0.35	0.00	0.00
n-Butane	0.00028	58.12	0.02	0.50	0.07	3262	0.90	0.00	0.01
i-Pentane	0.00000	72.15	0.00	0.00	0.00	4008	0.00	0.00	0.00
n-Pentane	0.00000	72.15	0.00	0.00	0.00	4009	0.00	0.00	0.00
Hexane Plus	0.00000	86.18	0.00	0.00	0.00	4756	0.00	0.00	0.00
Total	1.00		16.76	1800.00	78.4		991.23	1.48	6.47
Total VOC	0.0022			3.93				0.01	0.04

Heating Value	991.23	Btu/scf
Heat Rate	1.784	MMBtu/hr (purge only)

Purge Gas Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \left| \frac{1.78 \text{ MMBtu}}{\text{hr}} \right.$

= **0.12** **lb/hr NOx**

NOx (tpy): $\frac{0.12 \text{ lb}}{\text{hr}} \left| \frac{8760.00 \text{ hr}}{\text{yr}} \right| \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.53** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \left| \frac{1.78 \text{ MMBtu}}{\text{hr}} \right.$

= **0.66** **lb/hr CO**

CO (tpy): $\frac{0.66 \text{ lb}}{\text{hr}} \left| \frac{8760.00 \text{ hr}}{\text{yr}} \right| \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **2.89** **tpy CO**

Maximum Velocity (During Events)

Maximum Tip Velocity calculation for non-assisted flares.

Volumetric Flow Rate	19,167,167	scf/hr (during event)
	5324.21	scf/sec
Flare Tip Area	1.33	square feet
Exit Velocity	4011.2	feet/sec

Inlet Flare SSM GHG Emissions

§98.233(n) Flare stack GHG emissions.

Step 1. Calculate contribution of un-combusted CH_4 emissions

$E_{a,CH4}$ (un-combusted) = $V_a * (1-\eta) * X_{CH4}$ *(Equation W-39B)*

where:

$E_{a,CH4}$ = contribution of annual un-combusted CH_4 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

η = Fraction of gas combusted by a burning flare (or regenerator), default value from Subpart W = 0.98

For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare = 0.6707 (Client gas analysis)

Step 2. Calculate contribution of un-combusted CO_2 emissions

$E_{a,CO2} = V_a * X_{CO2}$ *(Equation W-20)*

where:

$E_{a,CO2}$ = contribution of annual un-combusted CO_2 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

X_{CO2} = Mole fraction of CO_2 in gas to the flare = 0.067

Step 3. Calculate contribution of combusted CO_2 emissions

$E_{a,CO2}$ (combusted) = $\sum (\eta * V_a * Y_j * R_j)$ *(Equation W-21)*

where:

η = Fraction of gas combusted by a burning flare (or regenerator) = 0.98

For gas sent to an unlit flare, η is zero.

V_a = volume of gas sent to combustion unit during the year (cf)

Y_j = mole fraction of gas hydrocarbon constituents j:

Constituent j, Methane =	0.6707	(Client gas analysis)
Constituent j, Ethane =	0.1186	
Constituent j, Propane =	0.0637	
Constituent j, Butane =	0.02719	
Constituent j, Pentanes Plus =	0.028	

R_j = number of carbon atoms in the gas hydrocarbon constituent j:

Constituent j, Methane =	1
Constituent j, Ethane =	2
Constituent j, Propane =	3
Constituent j, Butane =	4
Constituent j, Pentanes Plus =	5

Step 4. Calculate GHG volumetric emissions at standard conditions (scf).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$$ *(Equation W-33)*

where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) in cubic feet

$E_{a,n}$ = GHG i volumetric emissions at actual conditions (cf)

T_s = Temperature at standard conditions (F) = 60 F

T_a = Temperature at actual conditions (F) = 76 F (Based on Annual Avg Max Temperature for Hobbs, NM from Western Regional Climate Center)

P_s = Absolute pressure at standard conditions (psia) = 14.7 psia

P_a = Absolute pressure at actual conditions (psia) = 14.7 psia (Assumption)

Constant = 459.67 (temperature conversion from F to R)

Step 5. Calculate annual CH_4 and CO_2 mass emissions (ton).

$Mass_{s,i} = E_{s,i} * \rho_i * 0.0011023$ *(Equation W-36)*

where:

$Mass_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) mass emissions at standard conditions in tons (tpy)

$E_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) volumetric emissions at standard conditions (cf)

ρ_i = Density of GHG i. Use:

CH_4: 0.0192 kg/ft^3 (at 60F and 14.7 psia)

CO_2: 0.0526 kg/ft^3 (at 60F and 14.7 psia)

Step 6. Calculate annual N_2O emissions from portable or stationary fuel combustion sources under actual conditions (cf) using Equation W-40 .

$Mass_{N2O} = 0.0011023 * Fuel * HHV * EF$ *(Equation W-40)*

where:

$Mass_{N2O}$ = annual N_2O emissions from combustion of a particular type of fuel (tons).

Fuel = mass or volume of the fuel combusted

HHV = high heat value of the fuel

SSM flaring gas HHV = 1.226E-03 MMBtu/scf

EF = 1.00E-04 kg N_2O/MMBtu

10^{-3} = conversion factor from kg to metric tons.

Step 7. Calculate total annual emission from flare by summing Equations W-40, W-19, W-20, and W-21.

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
SSM Flaring	76,666,667	1028407	5,136,667	101,373,650	997,131	4,980,450	98,290,659	21.10	288.77	5,698.99	0.01036	6518.4
Pilot & Purge Gas	21,900,000	414509	0	21,178,158	401,903	0	20,534,085	8.51	0.00	1,190.59	0.00239	1,403.9
Total	**98,566,667**	**1,442,916**	**5,136,666.7**	**122,551,808**	**1,399,034**	**4,980,449.6**	**118,824,744**	**29.6**	**288.8**	**6,889.6**	**0.01276**	**7,922.4**

	CO_2	CH_4	N_2O
GWP	1	25	298

DCP Midstream, LP - Zia II Gas Plant

Flare FL2 SSM Detail Sheet

Source ID Number	FL2		
Equipment ID			
Source Description	Acid gas flare		
Equipment Usage			
Equipment Make	Zeeco	Potential operation	10.00 hr/yr
Serial Number	FL-5200/24093		
Date in Service	2015		
Equipment Configuration			
Stack ID	FL2		
Stack Height	150 ft, agl		
Stack Diameter	15.6 in		
Exit Velocity	57.16 ft/s		
Exit Temperature	1830 deg F (estimated)		
Volume Flow Rate	4,552 ft³/min		

Potential Emissions

Pollutant	Emission Factor	Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(lb/hr)	(tpy)	
NO_x	0.0680	101.95	1.19	AP42
CO	0.3700	554.75	6.46	AP42
VOC		7.83	0.09	See Calcs Below
SO_2		4,409.79	22.05	See Calcs Below
H_2S		47.95	0.24	See Calcs Below

DCP Midstream, LP - Zia II Gas Plant

Flare FL2 SSM Detail Sheet

Source ID Number	FL2
Equipment ID	
Source Description	Acid gas flare

Maintenance/Startup/Shutdown Events

10.00	Events per Year	AGI Rate	
270,833	scf/event	6.5	mmscf/day
2,708	mscf/year	0.27	mmscf/hr
1.00	duration per event (hr)	270,833	scf/hr
10.00	hours per year		

Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	Post control emission rate tons/yr
Nitrogen	0.00	28.0134	0.00	0.00	0.00	0	0.00	-	-
Carbon Dioxide	0.90	44.01	39.61	243750.00	27863.47	0	0.00	27863.47	139.32
Methane	0.00	16.042	0.00	0.00	0.00	1010	0.00	-	-
Ethane	0.00	30.069	0.00	0.00	0.00	1769.7	0.00	-	-
Propane	0.00	44.096	0.00	0.00	0.00	2516.2	0.00	0.00	0.00
i-Butane	0.00	58.122	0.00	0.00	0.00	3252	0.00	0.00	0.00
n-Butane	0.00	58.122	0.00	0.00	0.00	3262	0.00	0.00	0.00
i-Pentane	0.00	72.15	0.00	0.00	0.00	4007.7	0.00	0.00	0.00
n-Pentane	0.00	72.149	0.00	0.00	0.00	4008.7	0.00	0.00	0.00
Hexane Plus	0.00	86.175	0.00	0.00	0.00	4756.1	0.00	0.00	0.00
Hydrogen Sulfide	0.10	34.082	3.41	27083.33	2397.54	637.02	63.70	47.95	0.24
Total	1.00		43.02	270833.33	30261.0		63.70	27911.42	139.56
Total VOC	0.0000			0.00				0.00	0.00

Heating Value	63.70	Btu/scf
Heat Rate	17.25	MMBtu/hr

Maintenance Event Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{17.25 \text{ MMBtu}}{\text{hr}}$

= **1.17** **lb/hr NOx**

NOx (tpy): $\frac{1.17 \text{ lb}}{\text{hr}} \times \frac{10 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.01** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \times \frac{17.25 \text{ MMBtu}}{\text{hr}}$

= **6.38** **lb/hr CO**

CO (tpy): $\frac{6.38 \text{ lb}}{\text{hr}} \times \frac{10 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.03** **tpy CO**

SO2 (lb/hr): $\frac{2349.59 \text{ lb H2S}}{\text{hr}} \times \frac{64.0 \text{ lb SO2}}{34.1 \text{ lb H2S}}$

= **4409.79** **lb/hr SO2**

SO2 (tpy): $\frac{4409.79 \text{ lb SO2}}{\text{hr}} \times \frac{10 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **22.05** **tpy SO2**

DCP Midstream, LP - Zia II Gas Plant

Flare FL2 SSM Detail Sheet

Source ID Number FL2
Equipment ID
Source Description Acid gas flare

Pilot Gas Emissions

500.00 scf/hr
0.00050 MMscf/hr
8760.00 hours per year

Residue Gas Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	Post control emission rate tons/yr
Nitrogen	0.03471	28.0134	0.97	17.36	1.26	0	0.00		
Carbon Dioxide	0.00000	44.01	0.00	0.00	0.00	0	0.00		
Methane	0.94637	16.042	15.18	473.18	19.72	1010	955.83	0.39	1.73
Ethane	0.01674	30.069	0.50	8.37	0.65	1769.7	29.62	0.01	0.06
Propane	0.00180	44.096	0.08	0.90	0.10	2516.2	4.52	0.00206	0.00902
i-Butane	0.00011	58.122	0.01	0.05	0.01	3252	0.35	0.00016	0.00072
n-Butane	0.00028	58.122	0.02	0.14	0.02	3262	0.90	0.00042	0.00182
i-Pentane	0.00000	72.15	0.00	0.00	0.00	4007.7	0.00	0.00000	0.00000
n-Pentane	0.00000	72.149	0.00	0.00	0.00	4008.7	0.00	0.00000	0.00000
Hexane Plus	0.00000	86.175	0.00	0.00	0.00	4756.1	0.00	0.00000	0.00000
Total	1.00		16.76	500.00	21.8		991.23	0.41	1.80
Total VOC	0.0022			1.09				0.003	0.01

Heating Value 991.23 Btu/scf
Heat Rate 0.496 MMBtu/hr (pilot only)

Pilot Emissions

NOx (lb/hr): 0.068 lb/MMBtu | 0.50 MMBtu/hr

= 0.03 lb/hr NOx

NOx (tpy): 0.03 lb/hr | 8760.00 hr/yr | 1 ton/2000 lb

= 0.15 tpy NOx

CO (lb/hr): 0.3700 lb/MMBtu | 0.50 MMBtu/hr

= 0.18 lb/hr CO

CO (tpy): 0.18 lb/hr | 8760.00 hr/yr | 1 ton/2000 lb

= 0.80 tpy CO

DCP Midstream, LP - Zia II Gas Plant

Flare FL2 SSM Detail Sheet

Source ID Number	FL2
Equipment ID	
Source Description	Acid gas flare

Purge Gas Emissions

1800.00	scf/hr	Eng Estimate
0.00180	MMscf/hr	
8760.00	hours per year	

Residue Gas Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	tons/yr
Nitrogen	0.03471	28.01	0.97	62.48	4.55	0	0.00		
Carbon Dioxide	0.00000	44.01	0.00	0.00	0.00	0	0.00		
Methane	0.94637	16.04	15.18	1703.46	70.98	1010	955.83	1.42	6.22
Ethane	0.01674	30.07	0.50	30.13	2.35	1770	29.62	0.05	0.21
Propane	0.00180	44.10	0.08	3.24	0.37	2516	4.52	0.01	0.03
i-Butane	0.00011	58.12	0.01	0.19	0.03	3252	0.35	0.0006	0.0026
n-Butane	0.00028	58.12	0.02	0.50	0.07	3262	0.90	0.0015	0.0066
i-Pentane	0.00000	72.15	0.00	0.00	0.00	4008	0.00	0.0000	0.0000
n-Pentane	0.00000	72.15	0.00	0.00	0.00	4009	0.00	0.00	0.00
Hexane Plus	0.00000	86.18	0.00	0.00	0.00	4756	0.00	0.00	0.00
Total	1.00	34.08	16.76	1800.00	78.4		991.23	1.48	6.47
Total VOC	0.0022			3.93				0.01	0.04

Heating Value	991.23	Btu/scf
Heat Rate	1.784	MMBtu/hr (purge only)

Purge Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \Big| \frac{1.78 \text{ MMBtu}}{\text{hr}}$

= **0.12** **lb/hr NOx**

NOx (tpy): $\frac{0.12 \text{ lb}}{\text{hr}} \Big| \frac{8760.00 \text{ hr}}{\text{yr}} \Big| \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.53** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \Big| \frac{1.78 \text{ MMBtu}}{\text{hr}}$

= **0.66** **lb/hr CO**

CO (tpy): $\frac{0.66 \text{ lb}}{\text{hr}} \Big| \frac{8760.00 \text{ hr}}{\text{yr}} \Big| \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **2.89** **tpy CO**

DCP Midstream, LP - Zia II Gas Plant

Flare FL2 SSM Detail Sheet

Source ID Number	FL2
Equipment ID	
Source Description	Acid gas flare

Assist Gas Emissions

	71.5	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	850	Btu/scf	target heat content
	991.2	Btu/scf	Assist gas-assumed sweet residue gas
	1.49	MMscf/hr	Assist gas volume
	1479.8	MMBtu/hr	Assist gas heat input
*Assist gas - Annual**	14.9	MMscf/yr	Estimated Maximum annual SSM flow rate. Not a requested limit; for calculation only.

Note: Flared gas annual/ ratio of assist gas: flared gas hourly usage) ex: 2.66 MMscf/yr / (1-.7931)

Residue Gas Components	Analysis mol frac	MW lb/lb mol	MW * Mol Frac	Stream scf/hr	Stream lb/hr	High Heating Value Btu/scf	Heat Frac Btu/scf	Post control emission rate lb/hr	Post control emission rate tons/yr
Nitrogen	0.03471	28.01	0.97	51,410.81	3,740.76	0	0.00		
Carbon Dioxide	0.00000	44.01	0.00	0.00	0.00	0	0.00		
Methane	0.94637	16.04	15.18	1,401,676.01	58,404.38	1010	955.83	1,168.09	5.84
Ethane	0.01674	30.07	0.50	24,792.13	1,936.30	1770	29.62	38.73	0.19
Propane	0.00180	44.10	0.08	2,662.91	305.00	2516	4.52	6.10	0.03
i-Butane	0.00011	58.12	0.01	160.29	24.20	3252	0.35	0.48	0.00
n-Butane	0.00028	58.12	0.02	407.94	61.59	3262	0.90	1.23	0.01
i-Pentane	0.00000	72.15	0.00	0.00	0.00	4008	0.00	0.00	0.00
n-Pentane	0.00000	72.15	0.00	0.00	0.00	4009	0.00	0.00	0.00
Hexane Plus	0.00000	86.18	0.00	0.00	0.00	4756	0.00	0.00	0.00
Total	1.00	34.08	16.76	1,481,110.10	64,472.22		991.23	1,214.63	6.07
Total VOC	0.0022			3,231.15				7.82	0.04

Heating Value	991.23	Btu/scf
Heat Rate	1479.800	MMBtu/hr (assist gas only)

Assist Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \cdot \frac{1479.80 \text{ MMBtu}}{\text{hr}}$

= **100.63** **lb/hr NOx**

NOx (tpy): $\frac{100.63 \text{ lb}}{\text{hr}} \cdot \frac{10.00 \text{ hr}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.503** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \cdot \frac{1479.80 \text{ MMBtu}}{\text{hr}}$

= **547.53** **lb/hr CO**

CO (tpy): $\frac{547.53 \text{ lb}}{\text{hr}} \cdot \frac{10.00 \text{ hr}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **2.74** **tpy CO**

DCP Midstream, LP - Zia II Gas Plant

Flare FL2 SSM Detail Sheet

Source ID Number	FL2
Equipment ID	
Source Description	Acid gas flare

Maximum Velocity (During Events)

Maximum Tip Velocity calculation for non-assisted flares.

Volumetric Flow Rate	273133.33	scf/hr (during event)
	75.87	scf/sec
Flare Tip Area	1.33	square feet
Exit Velocity	57.2	feet/sec

Note: SSM Calculations provided by J. Hanna of DCP on 4-5-13.

Pilot+ Purge Gas + Maintenance event+Assist Gas

20.79	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
1.05E+08	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
8.20E+07		q_n	$q_n = q(1-0.048(MW)^{1/2})$
9.1	m	Effective stack diameter (D)	$D = (10^{-6}q_n)^{1/2}$
0.64008	m	Actual Diameter	

Acid Gas Flare SSM GHG Emissions

§98.233(n) Flare stack GHG emissions.

Assist Gas Stream

Step 1. Calculate contribution of un-combusted CH_4 emissions

$E_{a,CH4}$ (un-combusted) = V_a * (1- η)* X_{CH4} *(Equation W-39B)*

where:

$E_{a,CH4}$ = contribution of annual un-combusted CH_4 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

η = Fraction of gas combusted by a burning flare (or regenerator), default value from Subpart W = 0.98

For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare = 0.9464 (Client gas analysis)

Step 2. Calculate contribution of un-combusted CO_2 emissions

$E_{a,CO2}$ = V_a * X_{CO2} *(Equation W-20)*

where:

$E_{a,CO2}$ = contribution of annual un-combusted CO_2 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

X_{CO2} = Mole fraction of CO_2 in gas to the flare = 0.000

Step 3. Calculate contribution of combusted CO_2 emissions

$E_{a,CO2}$ (combusted) = ∑ (η * V_a * Y_j * R_j) *(Equation W-21)*

where:

η = Fraction of gas combusted by a burning flare (or regenerator) = 0.98

For gas sent to an unlit flare, η is zero.

V_a = volume of gas sent to combustion unit during the year (cf)

Y_j = mole fraction of gas hydrocarbon constituents j:

Constituent j, Methane =	0.9464	(Client gas analysis)
Constituent j, Ethane =	0.0167	
Constituent j, Propane =	0.0018	
Constituent j, Butane =	0.00038	
Constituent j, Pentanes Plus =	0.000	

R_j = number of carbon atoms in the gas hydrocarbon constituent j:

Constituent j, Methane =	1
Constituent j, Ethane =	2
Constituent j, Propane =	3
Constituent j, Butane =	4
Constituent j, Pentanes Plus =	5

Step 4. Calculate GHG volumetric emissions at standard conditions (scf).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$$ *(Equation W-33)*

where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) in cubic feet

$E_{a,n}$ = GHG i volumetric emissions at actual conditions (cf)

T_s = Temperature at standard conditions (F) = 60 F

T_a = Temperature at actual conditions (F) = 76 F (Based on Annual Avg Max Temperature for Hobbs, NM from Western Regional Climate Center)

P_s = Absolute pressure at standard conditions (psia) = 14.7 psia

P_a = Absolute pressure at actual conditions (psia) = 14.7 psia (Assumption)

Constant = 459.67 (temperature conversion from F to R)

Step 5. Calculate annual CH_4 and CO_2 mass emissions (ton).

$Mass_{s,i}$ = $E_{s,i}$ * ρ_i * 0.0011023 *(Equation W-36)*

where:

$Mass_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) mass emissions at standard conditions in tons (tpy)

$E_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) volumetric emissions at standard conditions (cf)

ρ_i = Density of GHG i. Use:

CH_4: 0.0192 kg/ft^3 (at 60F and 14.7 psia)

CO_2: 0.0526 kg/ft^3 (at 60F and 14.7 psia)

Step 6. Calculate annual N_2O emissions from portable or stationary fuel combustion sources under actual conditions (cf) using Equation W-40 .

$Mass_{N2O}$ = 0.0011023 * Fuel * HHV * EF *(Equation W-40)*

where:

$Mass_{N2O}$ = annual N_2O emissions from combustion of a particular type of fuel (tons).

Fuel = mass or volume of the fuel combusted

HHV = high heat value of the fuel

Field gas HHV = 1.235E-03 MMBtu/scf (Default provided in Subpart W Final Amendment;)

EF = 1.00E-04 kg N_2O/MMBtu

10^{-3} = conversion factor from kg to metric tons.

Step 7. Calculate total annual emission from flare by summing Equations W-40, W-19, W-20, and W-21.

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
Assist Gas	14,928,933	282565	0.00	14,436,863	273,972	0.00	13,997,807	5.80	0.00	811.61	0.00203	957.2

Acid Gas Flare SSM GHG Emissions

§98.233(n) Flare stack GHG emissions.

Acid Gas Stream

Step 1. Calculate contribution of un-combusted CH_4 emissions

$E_{a,CH4}$ (un-combusted) = $V_a * (1- \eta) * X_{CH4}$ *(Equation W-39B)*

where:

$E_{a,CH4}$ = contribution of annual un-combusted CH_4 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

η = Fraction of gas combusted by a burning flare (or regenerator), default value from Subpart W = 0.98

For gas sent to an unlit flare, η is zero.

X_{CH4} = Mole fraction of CH_4 in gas to the flare = 0.0000 (Client gas analysis)

Step 2. Calculate contribution of un-combusted CO_2 emissions

$E_{a,CO2} = V_a * X_{CO2}$ *(Equation W-20)*

where:

$E_{a,CO2}$ = contribution of annual un-combusted CO_2 emissions from regenerator in cubic feet under actual conditions.

V_a = volume of gas sent to combustion unit during the year (cf)

X_{CO2} = Mole fraction of CO_2 in gas to the flare = 0.900

Step 3. Calculate contribution of combusted CO_2 emissions

$E_{a,CO2}$ (combusted) = $\sum (\eta * V_a * Y_j * R_j)$ *(Equation W-21)*

where:

η = Fraction of gas combusted by a burning flare (or regenerator) = 0.98

For gas sent to an unlit flare, η is zero.

V_a = volume of gas sent to combustion unit during the year (cf)

Y_j = mole fraction of gas hydrocarbon constituents j:

Constituent j, Methane =	0.0000	(Client gas analysis)
Constituent j, Ethane =	0.0000	
Constituent j, Propane =	0.0000	
Constituent j, Butane =	0.00000	
Constituent j, Pentanes Plus =	0.000	

R_j = number of carbon atoms in the gas hydrocarbon constituent j:

Constituent j, Methane =	1
Constituent j, Ethane =	2
Constituent j, Propane =	3
Constituent j, Butane =	4
Constituent j, Pentanes Plus =	5

Step 4. Calculate GHG volumetric emissions at standard conditions (scf).

$$E_{s,n} = \frac{E_{a,n} * (459.67 + T_s) * P_a}{(459.67 + T_a) * P_s}$$ *(Equation W-33)*

where:

$E_{s,n}$ = GHG i volumetric emissions at standard temperature and pressure (STP) in cubic feet

$E_{a,n}$ = GHG i volumetric emissions at actual conditions (cf)

T_s = Temperature at standard conditions (F) = 60 F

T_a = Temperature at actual conditions (F) = 76 F (Based on Annual Avg Max Temperature for Hobbs, NM from Western Regional Climate Center)

P_s = Absolute pressure at standard conditions (psia) = 14.7 psia

P_a = Absolute pressure at actual conditions (psia) = 14.7 psia (Assumption)

Constant = 459.67 (temperature conversion from F to R)

Step 5. Calculate annual CH_4 and CO_2 mass emissions (ton).

$Mass_{s,i} = E_{s,i} * \rho_i * 0.0011023$ *(Equation W-36)*

where:

$Mass_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) mass emissions at standard conditions in tons (tpy)

$E_{s,i}$ = GHG i (CO_2, CH_4, or N_2O) volumetric emissions at standard conditions (cf)

ρ_i = Density of GHG i. Use:

CH_4: 0.0192 kg/ft^3 (at 60F and 14.7 psia)

CO_2: 0.0526 kg/ft^3 (at 60F and 14.7 psia)

Step 6. Calculate annual N_2O emissions from portable or stationary fuel combustion sources under actual conditions (cf) using Equation W-40 .

$Mass_{N2O}$ = 0.0011023 * Fuel * HHV * EF *(Equation W-40)*

where:

$Mass_{N2O}$ = annual N_2O emissions from combustion of a particular type of fuel (tons).

Fuel = mass or volume of the fuel combusted

HHV = high heat value of the fuel

Target SSM flaring gas HHV = 8.500E-04 MMBtu/scf

EF = 1.00E-04 kg N_2O/MMBtu

10^{-3} = conversion factor from kg to metric tons.

Step 7. Calculate total annual emission from flare by summing Equations W-40, W-19, W-20, and W-21.

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
Acid Gas	2,708,333	0	2,437,500	0	0	2,363,370	0	0	137.0	0	2.538E-04	137.1

Total

Gas Sent to Flare	Gas Sent to Flare (cf/yr)	CH_4 Un-Combusted, $E_{a,CH4}$ (cf)	CO_2 Un-Combusted, $E_{a,CO2}$ (cf)	CO_2 Combusted, $E_{a,CO2}$ (cf)	CH_4 Un-Combusted, $E_{a,CH4}$ (scf)	CO_2 Un-Combusted, $E_{a,CO2}$ (scf)	CO_2 Combusted, $E_{a,CO2}$ (scf)	CH_4 Un-Combusted, $E_{a,CH4}$ (tpy)	CO_2 Un-Combusted, $E_{a,CO2}$ (tpy)	CO_2 Combusted, $E_{a,CO2}$ (tpy)	N_2O Mass Emissions (tpy)	CO2e (tpy)
Assist Gas	14,928,933	282,565	0.00	14,436,863	273,972	0.00	13,997,807	5.80	0.00	811.6	0.00203	957.2
Pilot & Purge Gas	20,148,000	381,349	0.00	19,483,906	369,751	0.00	18,891,358	7.83	0.00	1,095.3	0.0022	1,291.6
Acid Gas	2,708,333	0	2,437,500	0	0	2,363,370	0	0	137.0	0	0.00025	137.1
Total	**37,785,266**	**663,914.1**	**2,437,500.0**	**33,920,769.1**	**643,723.1**	**2,363,370.4**	**32,889,165.6**	**13.6**	**137.0**	**1,906.9**	**0.0045**	**2,385.9**

	CO_2	CH_4	N_2O
GWP	1	25	298

Startup, Shutdown, and Maintenance/Malfunction - Compressor Blowdowns

Unit SSM (CB)

Compressor Blowdowns				
Compressor Unit Number	**Total Volume (scf/event)**	**Number of MSS Blowdowns/ year (#/yr)**	**Yearly Release Including 15% Safety Factor (scf/yr)**	**Type of Gas Vented (Inlet, Residue, Acid Gas etc)**
C1	1000	4	4600	High Pressure Inlet
C2	1000	4	4600	High Pressure Inlet
C3	1000	4	4600	High Pressure Inlet
C4	1000	4	4600	High Pressure Inlet
C5	1000	4	4600	Residue
C6	1000	4	4600	Residue
C7	1000	4	4600	Residue
C8	1000	4	4600	Residue
C9	1000	4	4600	Low Pressure Inlet
C10	1000	4	4600	Low Pressure Inlet
C11	1000	4	4600	Propane
C12	1000	4	4600	Propane
C13	1000	4	4600	Propane
Totals	4000	16	18400	High Pressure Inlet
	4000	16	18400	Residue
	2000	8	9200	Low Pressure Inlet
	3000	12	13800	Propane

VOC Emissions	**Hourly Volume of Gas Sent to Atmosphere (ft^3)**	**Annual Volume of Gas Sent to Atmosphere (ft^3)**	**Mole Percent VOC**	**Molecular Wt * Mol % (lb/lb-mol)**	**VOC (lb/hr)**	**VOC (lb/yr)**	**VOC (ton/yr)**
High Pressure Inlet	4000	18400	11.0%	5.91	6.8	31.4	0.016
Residue	4000	18400	0.22%	0.10	0.0023	0.011	5.37E-06
Low Pressure Inlet	2000	9200	11.0%	5.91	3.4	15.7	0.0078
Propane	3000	13800	100.0%	44.10	348.6	1603.5	0.8018
				Total	**358.8**	**1650.6**	**0.83**

HAP Emissions	**Hourly Volume of Gas Sent to Atmosphere (ft^3)**	**Annual Volume of Gas Sent to Atmosphere (ft^3)**	**Mole Percent HAPs**	**Molecular Wt * Mol % (lb/lb-mol)**	**HAP (lb/hr)**	**HAP (lb/yr)**	**HAP (ton/yr)**
High Pressure Inlet	4000	18400	0.6%	0.52	0.033	0.15	7.60E-05
Residue	4000	18400	0.00%	0.00	0.0	0.0	0.0
Low Pressure Inlet	2000	9200	0.6%	0.52	0.017	0.076	3.802E-05
Propane	3000	13800	0.00%	0.00	0.0	0.0	0.0
				Total	**0.050**	**0.23**	**1.14E-04**

DCP Midstream, LP - Zia II Gas Plant

Startup, Shutdown, and Maintenance/Malfunction - Compressor Blowdowns

Unit SSM (CB)

H_2S Emissions	Hourly Volume of Gas Sent to Atmosphere (ft^3)	Annual Volume of Gas Sent to Atmosphere (ft^3)	Mole Percent H_2S	Molecular Wt * Mol % (lb/lb-mol)	H_2S (lb/hr)	H_2S (lb/yr)	H_2S (ton/yr)
High Pressure Inlet	4000	18400	0.96%	0.33	0.033	0.15	7.61E-05
Residue	4000	18400	0.00%	0.00	0.00	0.0	0.0
Low Pressure Inlet	2000	9200	0.96%	0.33	0.017	0.076	3.807E-05
Propane	3000	13800	0.00%	0.00	0.00	0.00	0.00
				Total	**0.050**	**0.23**	**1.14E-04**

CO_2 Emissions	Hourly Volume of Gas Sent to Atmosphere (ft^3)	Annual Volume of Gas Sent to Atmosphere (ft^3)	Mole Percent CO_2	Molecular Wt * Mol % (lb/lb-mol)	CO_2 (lb/hr)	CO_2 (lb/yr)	CO_2 (ton/yr)
High Pressure Inlet	4000	18400	6.7%	2.95	2.1	9.6	0.0048
Residue	4000	18400	0.00%	0.00	0.0	0.0	0.0
Low Pressure Inlet	2000	9200	6.7%	2.95	1.0	4.8	0.0023947
Propane	3000	13800	0.00%	0.00	0.0	0.0	0.0
				Total	**3.1**	**14.4**	**0.0072**

CH_4 Emissions	Hourly Volume of Gas Sent to Atmosphere (ft^3)	Annual Volume of Gas Sent to Atmosphere (ft^3)	Mole Percent CH_4	Molecular Wt * Mol % (lb/lb-mol)	CH_4 (lb/hr)	CH_4 (lb/yr)	CH_4 (ton/yr)
High Pressure Inlet	4000	18400	67.1%	10.76	76.1	349.9	0.17
Residue	4000	18400	94.6%	15.2	151.4	696.6	0.35
Low Pressure Inlet	2000	9200	67.1%	10.76	38.0	175.0	0.087
Propane	3000	13800	0.00%	0.00	0.0	0.0	0.00
				Total	**265.5**	**1221.5**	**0.61**

DCP Midstream, LP - Zia II Gas Plant

Startup, Shutdown, and Maintenance/Malfunction - Compressor Blowdowns

Unit SSM (CB)

Basis of Calculation:
Emissions from compressor maintenance activities are calculated based on a mass balance as follows:

Maximum Uncontrolled Annual Emissions (tpy) = [Volume of Gas Vented (scf/yr)] x [MW of constituent (lb/lb-mol)] x [mol % speciated constituent] / [379.5 (scf/lb-mol)] / [2,000 (lb/ton)]

Inlet Gas Analysis

Components	MW lb/lb mol	Analysis mol %	MW * Mol %	**HHV Btu/scf[2]**	**Btu/scf * wet vol %**	**Mass Fraction (wet)**
Nitrogen	28.01	2.46%	0.69	0	0.0	0.028
Carbon Dioxide	44.01	6.70%	2.95	0	0.0	0.122
Methane	16.04	67.07%	10.76	1010	677.4	0.445
Ethane	30.07	11.86%	3.57	1770	209.9	0.147
Propane	44.10	6.37%	2.81	2516	160.3	0.116
i-Butane	58.12	0.77%	0.45	3252	24.9	0.018
n-Butane	58.12	1.95%	1.13	3262	63.7	0.047
i-Pentane	72.15	0.48%	0.35	4001	19.4	0.014
n-Pentane	72.15	0.51%	0.37	4009	20.5	0.015
n-Hexane	86.18	0.57%	0.49	4756	27.1	0.020
n-Heptane	100.21	0.20%	0.20	5503	11.0	0.00828
n-Octane	114.23	0.07%	0.08	6249	4.4	0.00330
Benzene	78.11	0.01%	0.01	3742	0.37	0.000322744
Toluene	92.14	0.01%	0.01	4475	0.45	0.000380718
E-Benzene	106.17	0.00%	0.00	5208	0.10	8.77338E-05
m-Xylene	106.17	0.01%	0.01	5208	0.52	0.000438669
p-Xylene	106.17	0.00%	0.00	5208	0.0	0
o-Xylene	106.17	0.00%	0.00	5208	0.0	0
H2S	34.08	0.96%	0.33	637	6.1	0.014
Total		100.0%	24.20		1226.2	1.0
Total VOC		10.96%	5.91			24.4%
Total HAPs		0.6%	0.52			2.2%

DCP Midstream, LP - Zia II Gas Plant

Plant Venting SSM Emissions

Unit number(s): SSM (PV)

Source description: Plant Venting SSM Emissions

Volume of gas vented:	879000	ft^3	estimated max per hour
	1.41E+07	ft^3	estimated max per year

Constituent	From Inlet Gas Analysis mole %	MW * mol % (lb/lb-mol)	Emission Rates lb/hr	lb/yr	tpy
VOC	11.0%	5.91	1500.0	24060.8	12.0
H_2S	0.96%	0.33	7.3	116.7	0.058
HAP	0.60%	0.52	7.3	116.5	0.058
CO_2	6.7%	2.95	458	7340	4
CH_4	67.1%	10.76	16715	268131	134

Basis of Calculation:
Emissions from plant venting are calculated based on a mass balance as follows:

Maximum Uncontrolled Annual Emissions (tpy) = [Volume of Gas Vented (scf/yr)] x [MW of component (lb/lb-mol)] x [mol % speciated constituent] / [379.5 (scf/lb-mol)] / [2,000 (lb/ton)]

Section 6.a

Green House Gas Emissions

(Submitting under 20.2.70, 20.2.72 20.2.74 NMAC)

Title V (20.2.70 NMAC), Minor NSR (20.2.72 NMAC), and PSD (20.2.74 NMAC) applicants must estimate and report greenhouse gas (GHG) emissions to verify the emission rates reported in the public notice, determine applicability to 40 CFR 60 Subparts, and to evaluate Prevention of Significant Deterioration (PSD) applicability. GHG emissions that are subject to air permit regulations consist of the sum of an aggregate group of these six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Calculating GHG Emissions:

1. Calculate the ton per year (tpy) GHG mass emissions and GHG CO_2e emissions from your facility.
2. GHG mass emissions are the sum of the total annual tons of greenhouse gases without adjusting with the global warming potentials (GWPs). GHG CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its GWP found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. Emissions from routine or predictable start up, shut down, and maintenance must be included.
4. Report GHG mass and GHG CO_2e emissions in Table 2-P of this application. Emissions are reported in **short** tons per year and represent each emission unit's Potential to Emit (PTE).
5. All Title V major sources, PSD major sources, and all power plants, whether major or not, must calculate and report GHG mass and CO2e emissions for each unit in Table 2-P.
6. For minor source facilities that are not power plants, are not Title V, and are not PSD there are three options for reporting GHGs in Table 2-P: 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHGs as a second separate unit; 3) or check the following ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

Sources for Calculating GHG Emissions:

- Manufacturer's Data
- AP-42 Compilation of Air Pollutant Emission Factors at http://www.epa.gov/ttn/chief/ap42/index.html
- EPA's Internet emission factor database WebFIRE at http://cfpub.epa.gov/webfire/
- 40 CFR 98 Mandatory Green House Gas Reporting except that tons should be reported in short tons rather than in metric tons for the purpose of PSD applicability.
- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009 or most recent version.
- Sources listed on EPA's NSR Resources for Estimating GHG Emissions at http://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases:

Global Warming Potentials (GWP):
Applicants must use the Global Warming Potentials codified in Table A-1 of the most recent version of 40 CFR 98 Mandatory Greenhouse Gas Reporting. The GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specified time period.

"Greenhouse gas" for the purpose of air permit regulations is defined as the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. **(20.2.70.7 NMAC, 20.2.74.7 NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Metric to Short Ton Conversion:
Short tons for GHGs and other regulated pollutants are the standard unit of measure for PSD and title V permitting programs. 40 CFR 98 Mandatory Greenhouse Reporting requires metric tons.
1 metric ton = 1.10231 short tons (per Table A-2 to Subpart A of Part 98 – Units of Measure Conversions)

Greenhouse gas emissions were calculated and are included with the emissions calculations in Section 6.

Section 7

Information Used To Determine Emissions

Information Used to Determine Emissions shall include the following:

- ☑ If manufacturer data are used, include specifications for emissions units and control equipment, including control efficiencies specifications and sufficient engineering data for verification of control equipment operation, including design drawings, test reports, and design parameters that affect normal operation.
- ☐ If test data are used, include a copy of the complete test report. If the test data are for an emissions unit other than the one being permitted, the emission units must be identical. Test data may not be used if any difference in operating conditions of the unit being permitted and the unit represented in the test report significantly effect emission rates.
- ☑ If the most current copy of AP-42 is used, reference the section and date located at the bottom of the page. Include a copy of the page containing the emissions factors, and clearly mark the factors used in the calculations.
- ☐ If an older version of AP-42 is used, include a complete copy of the section.
- ☑ If an EPA document or other material is referenced, include a complete copy.
- ☐ Fuel specifications sheet.
- ☑ If computer models are used to estimate emissions, include an input summary (if available) and a detailed report, and a disk containing the input file(s) used to run the model. For tank-flashing emissions, include a discussion of the method used to estimate tank-flashing emissions, relative thresholds (i.e., permit or major source (NSPS, PSD or Title V)), accuracy of the model, the input and output from simulation models and software, all calculations, documentation of any assumptions used, descriptions of sampling methods and conditions, copies of any lab sample analysis.

The following information used to determine emissions is attached:

- **Section 7.1**
  Natural Gas-Fired Engines (Units C1 to C10)
  - Section 7.1-1 – Manufacturer Specification Sheet for Caterpillar RICE G3616 (Units C1 to C8)
  - Section 7.1-2 – Catalyst Specification Sheet for Caterpillar RICE G3616 (Units C1 to C8)
  - Section 7.1-3 – Manufacturer Specification Sheet for Caterpillar RICE G3608 (Units C9 to C10)
  - Section 7.1-4 – Catalyst Specification Sheet for Caterpillar RICE G3608 (Units C9 to C10)
  - Section 7.1-5 – EPA AP-42 Table 3.2-2 for Caterpillar RICE 3608 and 3616 (Units C1 to C10)
  - Section 7.1-6 – GRI-HAPCalc 3.01 For Caterpillar RICE 3608 and 3616 (Units C1 to C10)
  - Section 7.1-7 – 40 CFR 98 Subpart W Table C-1 and C-2 (Units C1 to C10)
  - Section 7.1-8 – EPA AP-42 Section 1.3.3.2 (Units C1 to C10)
- **Section 7.2**
  Heaters and Boilers (Units H1 to H6)
  - Section 7.2-1 – EPA AP-42 Tables 1.4-1 and 1.4-2 for heaters and boilers (Units H1 to H6)
  - Section 7.2-2 – Manufacturer Specification Sheet for 99 MMBtu/hr boilers (Units H4 and H5)
  - Section 7.2-3 – GRI-HAPCalc 3.01 for heaters and boilers (Units H1 to H3 and H6)
  - Section 7.2-4 – 40 CFR 98 Subpart W Table C-1 and C-2 (Units H1 to H6)
  - Section 7.2-5 – EPA AP-42 Section 1.3.3.2 (Units H1 to H6)
- **Section 7.3**
  Dehydrator (Unit Dehy)
  - Section 7.3-1 – GRI-GLYCalc 4.0 run for the Dehydrator (Unit Dehy)
  - Section 7.3-2 – TEG dehydrator Gas Analysis
- **Section 7.4**
  Flares (Units FL1, FL2, and FL3)
  - Section 7.4-1 – Inlet Gas Analysis
  - Section 7.4-2 – Acid Gas Analysis
  - Section 7.4-3 – EPA AP42 Table 13.5-1 for flares
- **Section 7.5**
  Condensate Tanks (TK-2100 and TK-2200)
  - Section 7.5-1 – TANKS 4.0.9d output (Units TK-2100 and TK-2200)

- **<u>Section 7.6</u>**
  Vapor Combustion Unit (Unit VCD1)
  - Section 7.6-1 – EPA AP-42 Tables 1.4-1 and 1.4-2 for Natural Gas Combustion (Unit VCD1)

  * Please note: Units TK-2100 and TK-2200 (condensate tanks), Unit Dehy (Dehydrator), and Unit L1 (condensate loading) emissions are controlled by the VCD1. Tanks 4.09d runs and GRI-GLYCalc runs can be found in Section 7.5 for the tanks and Section 7.3 for the dehydrator.
- **<u>Section 7.7</u>**
  Truck Loading (Unit L1)
  - Section 7.7-1 – EPA AP-42 Section 5.2 for Condensate Truck Loading (Unit L1)
- **<u>Section 7.8</u>**
  Haul Road Emissions (Unit HAUL)
  - Section 7.8-1 – AP-42 Section 13.2.1 for Paved Haul Roads (Unit HAUL)
- **<u>Section 7.9</u>**
  Fugitive Emissions (Unit FUG)
  - Section 7.9-1 – EPA Protocol for Equipment Leak Emission Estimates, November 1995, Tables 2-4 and 2-10
- **<u>Section 7.10</u>**
  Diesel Generator (Unit GEN-1)
  - Section 7.10-1 – Manufacturer's data
  - Section 7.10-2 – EPA AP-42 Tables 3.3-1 and 3.3-2
  - Section 7.1-3 - 40 CFR 98 Subpart W Table C-1 and C-2 (Refer to Section 7.1-7)
- **<u>Section 7.11</u>**
  Wet Surface Air Cooler (Unit CT-1)
  - Section 7.11-1 – EPA AP-42 Section 13.4
  - Section 7.11-2 – Manufacturer's data
- **<u>Section 7.12</u>**
  Compressor Blowdown SSM (Unit SSM(CB))
  - Section 7.12-1 - Inlet Gas Analysis (Refer to Section 7.4-1)
- **<u>Section 7.13</u>**
  Plant Venting SSM (Unit SSM(PV))
  - Section 7.13-1 - Inlet Gas Analysis (Refer to Section 7.4-1)
- **<u>Section 7.14</u>**
  Methanol Tanks – Not sources of regulated emissions (Units TK-7700, TK-7750, TK-7800, TK-L2)
  - Section 7.14-1 – TANKS 4.0.9d output

G3616

GAS ENGINE TECHNICAL DATA

CATERPILLAR®

ENGINE SPEED (rpm):	1000	FUEL:	Nat Gas
COMPRESSION RATIO:	9:1	FUEL SYSTEM:	GAV
AFTERCOOLER WATER INLET (°F):	130		WITH AIR FUEL RATIO CONTROL
JACKET WATER OUTLET (°F):	190	FUEL PRESSURE RANGE(psig):	42.8-47.0
ASPIRATION:	TA	FUEL METHANE NUMBER:	80
COOLING SYSTEM:	JW, OC+AC	FUEL LHV (Btu/scf):	905
IGNITION SYSTEM:	CIS/ADEM3	ALTITUDE CAPABILITY AT 77°F INLET AIR TEMP. (ft):	4419
EXHAUST MANIFOLD:	DRY	APPLICATION:	Gas Compression
COMBUSTION:	Low Emission		
NOx EMISSION LEVEL (g/bhp-hr NOx):	0.5		

RATING		NOTES	LOAD	100%	75%	50%
ENGINE POWER	(WITHOUT FAN)	(1)	bhp	4735	3551	2368
ENGINE EFFICIENCY	(ISO 3046/1)	(2)	%	38.5	36.9	33.7
ENGINE EFFICIENCY	(NOMINAL)	(2)	%	37.6	36.0	32.9

ENGINE DATA						
FUEL CONSUMPTION	(ISO 3046/1)	(3)	Btu/bhp-hr	6605	6893	7544
FUEL CONSUMPTION	(NOMINAL)	(3)	Btu/bhp-hr	6766	7061	7728
AIR FLOW (77°F, 14.7 psia)	(WET)	(4) (5)	scfm	12294	9507	6528
AIR FLOW	(WET)	(4) (5)	lb/hr	54511	42156	28947
COMPRESSOR OUT PRESSURE			in Hg(abs)	74.9	58.4	42.0
COMPRESSOR OUT TEMPERATURE			°F	291	226	160
AFTERCOOLER AIR OUT TEMPERATURE			°F	135	134	132
INLET MAN. PRESSURE		(6)	in Hg(abs)	73.7	56.7	40.5
INLET MAN. TEMPERATURE	(MEASURED IN PLENUM)	(7)	°F	145	145	143
TIMING			°BTDC	18	18	17
EXHAUST TEMPERATURE - ENGINE OUTLET		(8)	°F	856	897	974
EXHAUST GAS FLOW (@engine outlet temp, 14.5 psia)	(WET)	(9) (5)	ft3/min	32100	25615	18637
EXHAUST GAS MASS FLOW	(WET)	(9) (5)	lb/hr	56128	43422	29871

EMISSIONS DATA - ENGINE OUT					
NOx (as NO2)	(10)(11)	g/bhp-hr	0.50	0.50	0.50
CO	(10)(12)	g/bhp-hr	2.75	2.75	2.75
THC (mol. wt. of 15.84)	(10)(12)	g/bhp-hr	6.31	6.57	6.81
NMHC (mol. wt. of 15.84)	(10)(12)	g/bhp-hr	0.95	0.99	1.02
NMNEHC (VOCs) (mol. wt. of 15.84)	(10)(12)(13)	g/bhp-hr	0.63	0.66	0.68
HCHO (Formaldehyde)	(10)(12)	g/bhp-hr	0.26	0.28	0.31
CO2	(10)(12)	g/bhp-hr	439	458	502
EXHAUST OXYGEN	(10)(14)	% DRY	12.0	11.8	11.4
LAMBDA	(10)(14)		2.13	2.10	1.98

ENERGY BALANCE DATA					
LHV INPUT	(15)	Btu/min	533947	417935	304932
HEAT REJECTION TO JACKET WATER (JW)	(16)(22)	Btu/min	47935	41767	34205
HEAT REJECTION TO ATMOSPHERE	(17)	Btu/min	18688	17553	16771
HEAT REJECTION TO LUBE OIL (OC)	(18)(23)	Btu/min	24028	22986	22870
HEAT REJECTION TO EXHAUST (LHV TO 77°F)	(19)	Btu/min	205248	166501	124522
HEAT REJECTION TO EXHAUST (LHV TO 350°F)	(19)	Btu/min	125444	105246	83126
HEAT REJECTION TO AFTERCOOLER (AC)	(20)(23)	Btu/min	34290	15570	3206
PUMP POWER	(21)	Btu/min	2957	2957	2957

CONDITIONS AND DEFINITIONS

Engine rating obtained and presented in accordance with ISO 3046/1. (Standard reference conditions of 77°F, 29.60 in Hg barometric pressure, 500 ft. altitude.) No overload permitted at rating shown. Consult the altitude deration factor chart for applications that exceed the rated altitude or temperature.

Emission levels are at engine exhaust flange prior to any after treatment. Values are based on engine operating at steady state conditions, adjusted to the specified NOx level at 100% load. Tolerances specified are dependent upon fuel quality. Fuel methane number cannot vary more than ± 3.

For notes information consult page three.

FUEL USAGE GUIDE

CAT METHANE NUMBER	25	30	35	40	45	50	55	60	65	70	100
DERATION FACTOR	0	0	0	0	0.76	0.82	0.87	0.93	0.98	1	1

TOTAL DERATION FACTORS - ALTITUDE & COOLING AT RATED SPEED

INLET AIR TEMP °F	0	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
130	0.92	0.88	0.84	0.81	0.77	0.74	0.70	0.67	0.64	0.61	0.58	0.55	0.52
120	0.97	0.93	0.89	0.85	0.82	0.78	0.75	0.71	0.68	0.65	0.62	0.58	0.56
110	1	0.99	0.95	0.90	0.87	0.83	0.79	0.75	0.72	0.69	0.65	0.62	0.59
100	1	1	1	0.96	0.92	0.88	0.84	0.80	0.76	0.73	0.69	0.66	0.63
90	1	1	1	1	0.97	0.93	0.89	0.85	0.81	0.77	0.74	0.70	0.67
80	1	1	1	1	1	0.97	0.94	0.90	0.86	0.82	0.79	0.75	0.71
70	1	1	1	1	1	0.99	0.95	0.92	0.88	0.84	0.81	0.78	0.75
60	1	1	1	1	1	1	0.97	0.93	0.90	0.86	0.83	0.79	0.76
50	1	1	1	1	1	1	0.99	0.95	0.91	0.88	0.84	0.81	0.78

ALTITUDE (FEET ABOVE SEA LEVEL)

AFTERCOOLER HEAT REJECTION FACTORS (ACHRF)

INLET AIR TEMP °F	0	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
130	1.44	1.51	1.58	1.65	1.72	1.75	1.75	1.75	1.75	1.75	1.75	1.75	1.75
120	1.35	1.42	1.49	1.55	1.62	1.65	1.65	1.65	1.65	1.65	1.65	1.65	1.65
110	1.26	1.33	1.39	1.46	1.53	1.56	1.56	1.56	1.56	1.56	1.56	1.56	1.56
100	1.17	1.24	1.30	1.37	1.44	1.47	1.47	1.47	1.47	1.47	1.47	1.47	1.47
90	1.09	1.15	1.21	1.28	1.34	1.37	1.37	1.37	1.37	1.37	1.37	1.37	1.37
80	1	1.06	1.12	1.18	1.25	1.28	1.28	1.28	1.28	1.28	1.28	1.28	1.28
70	1	1	1.03	1.09	1.16	1.18	1.18	1.18	1.18	1.18	1.18	1.18	1.18
60	1	1	1	1	1.06	1.09	1.09	1.09	1.09	1.09	1.09	1.09	1.09
50	1	1	1	1	1	1	1	1	1	1	1	1	1

ALTITUDE (FEET ABOVE SEA LEVEL)

MINIMUM SPEED CAPABILITY AT THE RATED SPEED'S SITE TORQUE (RPM)

INLET AIR TEMP °F	0	1000	2000	3000	4000	5000	6000	7000	8000	9000	10000	11000	12000
130	750	750	750	750	750	750	750	750	750	750	750	760	780
120	750	750	750	750	750	750	750	750	750	750	750	760	770
110	750	750	750	750	750	750	750	750	750	750	750	750	770
100	750	750	770	770	770	760	760	750	750	750	750	750	760
90	750	750	760	790	790	790	790	780	780	770	770	760	760
80	750	750	750	770	800	800	800	800	800	800	800	790	790
70	750	750	750	760	790	800	800	800	800	800	800	800	800
60	750	750	750	750	770	800	800	800	800	800	800	800	800
50	750	750	750	750	760	790	800	800	800	800	800	800	800

ALTITUDE (FEET ABOVE SEA LEVEL)

FUEL USAGE GUIDE:
This table shows the derate factor required for a given fuel. Note that deration occurs as the methane number decreases. Methane number is a scale to measure detonation characteristics of various fuels. The methane number of a fuel is determined by using the Caterpillar Methane Number Calculation program.

ALTITUDE DERATION FACTORS:
This table shows the deration required for various air inlet temperatures and altitudes. Use this information along with the fuel usage guide chart to help determine actual engine power for your site.

ACTUAL ENGINE RATING:
To determine the actual rating of the engine at site conditions, one must consider separately, limitations due to fuel characteristics and air system limitations. The Fuel Usage Guide deration establishes fuel limitations. The Altitude/Temperature deration factors and RPC (reference the Caterpillar Methane Program) establish air system limitations. RPC comes into play when the Altitude/Temperature deration is less than 1.0 (100%). Under this condition, add the two factors together. When the site conditions do not require an Altitude/ Temperature derate (factor is 1.0), it is assumed the turbocharger has sufficient capability to overcome the low fuel relative power, and RPC is ignored. To determine the actual power available, take the lowest rating between 1) and 2).
1) Fuel Usage Guide Deration
2) 1-((1-Altitude/Temperature Deration) + (1-RPC))

AFTERCOOLER HEAT REJECTION FACTORS(ACHRF):
Aftercooler heat rejection is given for standard conditions of 77°F and 500 ft. altitude. To maintain a constant air inlet manifold temperature, as the inlet air temperature goes up, so must the heat rejection. As altitude increases, the turbocharger must work harder to overcome the lower atmospheric pressure. This increases the amount of heat that must be removed from the inlet air by the aftercooler. Use the aftercooler heat rejection factor (ACHRF) to adjust for inlet air temp and altitude conditions. See Notes 22 and 23 below for application of this factor in calculating the heat exchanger sizing criteria. Failure to properly account for these factors could result in detonation and cause the engine to shutdown or fail.

MINIMUM SPEED CAPABILITY AT THE RATED SPEED'S SITE TORQUE (RPM):
This table shows the minimum allowable engine turndown speed where the engine will maintain the Rated Speed’s Torque for the given ambient conditions.

NOTES:
1. Engine rating is with two engine driven water pumps. Tolerance is ± 3% of full load.
2. ISO 3046/1 engine efficiency tolerance is (+)0, (-)5% of full load % efficiency value. Nominal engine efficiency tolerance is ± 2.5% of full load % efficiency value.
3. ISO 3046/1 fuel consumption tolerance is (+)5, (-)0% of full load data. Nominal fuel consumption tolerance is ± 2.5% of full load data.
4. Air flow value is on a 'wet' basis. Flow is a nominal value with a tolerance of ± 5 %.
5. Inlet and Exhaust Restrictions must not exceed A&I limits based on full load flow rates from the standard technical data sheet.
6. Inlet manifold pressure is a nominal value with a tolerance of ± 5 %.
7. Inlet manifold temperature is a nominal value with a tolerance of ± 9°F.
8. Exhaust temperature is a nominal value with a tolerance of (+)63°F, (-)54°F.
9. Exhaust flow value is on a 'wet' basis. Flow is a nominal value for total flow rate with a tolerance of ±6%. Exhaust gas vented through the wastegate flows only to the right exhaust outlet. The total flow through the wastegate may be as great as 15% of the total value for conditions under which the wastegate is open. For installations that use dual exhaust runs this difference must be taken into account when specifying any items to be connected to the exhaust outlets. The flow in the right exhaust outlet must be sized for at least 65% of the total flow to allow for the wastegate full open condition, while the left outlet must be sized for 50% of the total flow for the wastegate closed condition. Both runs must meet the allowable backpressure requirement as described in the Exhaust Systems A&I Guide.
10. Emissions data is at engine exhaust flange prior to any after treatment.
11. NOx values are "Not to Exceed".
12. CO, CO2, THC, NMHC, NMNEHC, and HCHO values are "Not to Exceed" levels. THC, NMHC, and NMNEHC do not include aldehydes. An oxidation catalyst may be required to meet Federal, State or local CO or HC requirements.
13. VOCs - Volatile organic compounds as defined in US EPA 40 CFR 60, subpart JJJJ
14. Exhaust Oxygen tolerance is ± 0.5; Lambda tolerance is ± 0.05. Lambda and Exhaust Oxygen level are the result of adjusting the engine to operate at the specified NOx level.
15. LHV rate tolerance is ± 2.5%.
16. Heat rejection to jacket water value displayed includes heat to jacket water alone. Value is based on treated water. Tolerance is ± 10% of full load data.
17. Heat rejection to atmosphere based on treated water. Tolerance is ± 50% of full load data.
18. Lube oil heat rate based on treated water. Tolerance is ± 20% of full load data.
19. Exhaust heat rate based on treated water. Tolerance is ± 10% of full load data.
20. Heat rejection to aftercooler based on treated water. Tolerance is ±5% of full load data.
21. Pump power includes engine driven jacket water and aftercooler water pumps. Engine brake power includes effects of pump power.
22. Total Jacket Water Circuit heat rejection is calculated as: JW x 1.1. Heat exchanger sizing criterion is maximum circuit heat rejection at site conditions, with applied tolerances. A cooling system safety factor may be multiplied by the total circuit heat rejection to provide additional margin.
23. Total Aftercooler Circuit heat rejection is calculated as: (OC x 1.2) + (AC x ACHRF x 1.05). Heat exchanger sizing criterion is maximum circuit heat rejection at site conditions, with applied tolerances. A cooling system safety factor may be multiplied by the total circuit heat rejection to provide additional margin.

ENGINE POWER (bhp):	4735	COOLING SYSTEM:	JW, OC+AC
ENGINE SPEED (rpm):	1000	AFTERCOOLER WATER INLET (°F):	130
EXHAUST MANIFOLD:	DRY	JACKET WATER OUTLET (°F):	190

Free Field Mechanical and Exhaust Noise

SOUND PRESSURE LEVEL (dB)												
			Octave Band Center Frequency (OBCF)									
100% Load Data			dB(A)	32 Hz	63 Hz	125 Hz	250 Hz	500 Hz	1 kHz	2 kHz	4 kHz	8 kHz
Mechanical Sound	Distance from the Engine (ft)	3.3	107	90	97	103.8	100.3	98.3	98.1	100.4	102.2	97
		23.0	99.7	82.7	89.7	96.5	93	91	90.8	93.1	94.9	89.7
		49.2	94.9	77.9	84.9	91.7	88.2	86.2	86	88.3	90.1	84.9
Exhaust (Right) Sound	Distance from the Engine (ft)	4.9	133.1	105.8	110.7	117.1	112.9	113.8	117.5	123.2	128.3	127.5
		23.0	119.7	92.4	97.3	103.7	99.5	100.4	104.1	109.8	114.9	114.1
		49.2	113.1	85.8	90.7	97.1	92.9	93.8	97.5	103.2	108.3	107.5
Exhaust (Left) Sound	Distance from the Engine (ft)	4.9	117.5	106	115.5	114.8	109.6	109.6	111.8	112	109.4	108.4
		23.0	104.1	92.6	102.1	101.4	96.2	96.2	98.4	98.6	96	95
		49.2	97.5	86	95.5	94.8	89.6	89.6	91.8	92	89.4	88.4
Air Inlet (Left) Sound	Distance from the Engine (ft)	3.3	121.3	<92	<92	91.9	94.9	94.9	100	106.8	118.2	117.5
		23.0	104.4	<75.1	<75.1	75	78	78	83.1	89.9	101.3	100.6
		49.2	97.8	<68.5	<68.5	68.4	71.4	71.4	76.5	83.3	94.7	94

SOUND POWER LEVEL (dB)										
	Octave Band Center Frequency (OBCF)									
100% Load Data	dB(A)	32 Hz	63 Hz	125 Hz	250 Hz	500 Hz	1 kHz	2 kHz	4 kHz	8 kHz
Mechanical Sound	128.1	111.1	118.1	124.9	121.4	119.4	119.2	121.5	123.3	118.1
Exhaust (Right) Sound	144.6	117.3	122.2	128.6	124.4	125.3	129	134.7	139.8	139
Exhaust (Left) Sound	129	117.5	127	126.3	121.1	121.1	123.3	123.5	120.9	119.9
Air Inlet (Left) Sound	129.3	<100	<100	99.9	102.9	102.9	108	114.8	126.2	125.5

Sound Data

Data Variability Statement:

Sound data presented by Caterpillar has been measured in accordance with ISO 6798 in a Grade 3 test environment. Measurements made in accordance with ISO 6798 will result in some amount of uncertainty. The uncertainties depend not only on the accuracies with which sound pressure levels and measurement surface areas are determined, but also on the 'near-field error' which increases for smaller measurement distances and lower frequencies. The uncertainty for a Grade 3 test environment, that has a source that produces sounds that are uniformly distributed in frequency over the frequency range of interest, is equal to 4 dB (A-weighted). This uncertainty is expressed as the largest value of the standard deviation.

Section 7.1-2–Catalyst Specification for RICE G3616 (Units C1 to C8)

EMIT TECHNOLOGIES

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Prepared For:
Wes Shoen
UE COMPRESSION LLC

QUOTE: QUO-12287-N1F5
Expires: May 21, 2014

INFORMATION PROVIDED BY CATERPILLAR

Engine:	G3616
Horsepower:	4735
RPM:	1000
Compression Ratio:	9.2
Exhaust Flow Rate:	32100 CFM
Exhaust Temperature:	856 °F
Reference:	DM8608-04-001
Fuel:	Natural Gas
Annual Operating Hours:	8760

Uncontrolled Emissions

	g/bhp-hr
NOx:	0.50
CO:	2.75
THC:	6.31
NMHC	0.95
NMNEHC:	0.63
HCHO:	0.26
O2:	12.00 %

POST CATALYST EMISSIONS

	g/bhp-hr
NOx:	Unaffected by Oxidation Catalyst
CO:	<0.05
VOC:	<0.20
HCHO:	<0.01

CONTROL EQUIPMENT

Catalyst Housing

Model:	EBH-9000-3036F-8C4E-48
Manufacturer:	EMIT Technologies, Inc
Element Size:	Rectangle 48" x 15" x 3.5"
Housing Type:	8 Element Capacity
Catalyst Installation:	Ground Level Accessible Housing
Construction:	3/16" Carbon Steel
Sample Ports:	9 (0.5" NPT)
Inlet Connections:	30" Flat Face Flange
Outlet Connections:	36" Flat Face Flange
Configuration:	Side In / End Out
Silencer:	Integrated
Silencer Grade:	Hospital
Insertion Loss:	35-40 dBA
Estimated Lead Time:	2 Weeks to Ship

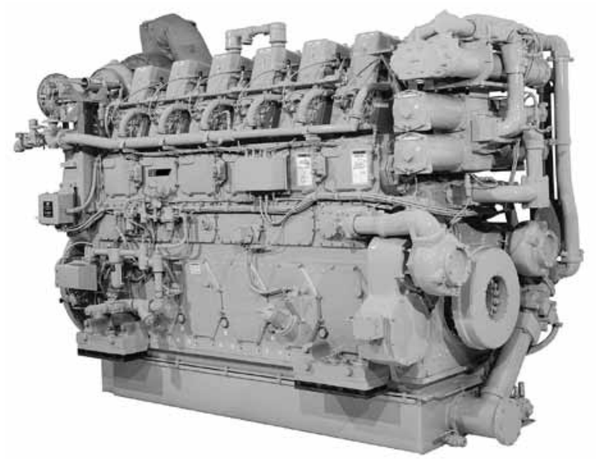
Catalyst Element

Model:	RT-4815-H
Catalyst Type:	Oxidation, Premium Precious Group Metals
Substrate Type:	BRAZED
Manufacturer:	EMIT Technologies, Inc
Element Quantity:	6
Element Size:	Rectangle 48" x 15" x 3.5"
Estimated Lead Time:	In Stock

G3608 LE Gas Petroleum Engine

1767-1823 bkW (2370-2445 bhp) 1000 rpm

0.5 g/bhp-hr NOx or 0.7 g/bhp-hr NOx (NTE)



Shown with Optional Equipment

CAT® ENGINE SPECIFICATIONS

In-Line 8, 4-Stroke-Cycle

Bore	300 mm (11.8 in.)
Stroke	300 mm (11.8 in.)
Displacement	169.6 L (10,350 cu. in.)
Aspiration	Turbocharged-Aftercooled
Digital Engine Management Governor and Protection	Electronic (ADEM™ A3)
Combustion	Low Emission (Lean Burn)
Engine Weight net dry (approx)	19,000 kg (41,888 lb)
Power Density	10.4 kg/kW (17.1 lb/hp)
Power per Displacement	14.5 bhp/L
Total Cooling System Capacity	530 L (140 gal)
Jacket Water	470 L (124 gal)
Aftercooler Circuit	60.6 L (16 gal)
Lube Oil System (refill)	912.3 L (241 gal)
Oil Change Interval	5000 hours
Rotation (from flywheel end)	Counterclockwise
Flywheel Teeth	255

FEATURES

Engine Design
- Proven reliability and durability
- Ability to burn a wide spectrum of gaseous fuels
- Robust diesel strength design prolongs life and lowers owning and operating costs
- Broad operating speed range

Emissions
Meets U.S. EPA Spark Ignited Stationary NSPS Emissions for 2010/11 with the use of an oxidation catalyst

Lean Burn Engine Technology
Lean-burn engines operate with large amounts of excess air. The excess air absorbs heat during combustion reducing the combustion temperature and pressure, greatly reducing levels of NOx. Lean-burn design also provides longer component life and excellent fuel consumption.

Ease of Operation
- High-strength pan and rails for excellent mounting and stability
- Side covers on block allow for inspection of internal components

Advanced Digital Engine Management
ADEM A3 engine management system integrates speed control, air/fuel ratio control, and ignition/detonation controls into a complete engine management system. ADEM A3 has improved: user interface, display system, shutdown controls, and system diagnostics.

Full Range of Attachments
Large variety of factory-installed engine attachments reduces packaging time.

Testing
Every engine is full-load tested to ensure proper engine performance.

Gas Engine Rating Pro
GERP is a PC-based program designed to provide site performance capabilities for Cat® natural gas engines for the gas compression industry. GERP provides engine data for your site's altitude, ambient temperature, fuel, engine coolant heat rejection, performance data, installation drawings, spec sheets, and pump curves.

Product Support Offered Through Global Cat Dealer Network
More than 2,200 dealer outlets

Cat factory-trained dealer technicians service every aspect of your petroleum engine

Cat parts and labor warranty

Preventive maintenance agreements available for repair-before-failure options

S•O•S℠ program matches your oil and coolant samples against Caterpillar set standards to determine:
- Internal engine component condition
- Presence of unwanted fluids
- Presence of combustion by-products
- Site-specific oil change interval

Over 80 Years of Engine Manufacturing Experience
Over 60 years of natural gas engine production

Ownership of these manufacturing processes enables Caterpillar to produce high quality, dependable products
- Cast engine blocks, heads, cylinder liners, and flywheel housings
- Machine critical components
- Assemble complete engine

Web Site
For all your petroleum power requirements, visit www.catoilandgas.cat.com.

STANDARD EQUIPMENT

Air Inlet System
Air cleaner — standard-duty
Inlet air adapter

Control System
ADEM A3 control system provides electronic governing integrated with air/fuel ratio control and individual cylinder ignition timing control

Cooling System
Jacket water pump
Jacket water thermostats and housing
Aftercooler pump
Aftercooler water thermostats and housing
Single-stage aftercooler

Exhaust System
Dry wrapped exhaust manifolds
Vertical outlet adapter

Flywheels & Flywheel Housings
SAE standard rotation

Fuel System
Gas admission valves with electronically controlled fuel supply pressure

Ignition System
A3 control system senses individual cylinder detonation and controls individual cylinder timing

Instrumentation
LCD display panel monitors engine parameters and displays diagnostic codes

Lube System
Crankcase breather — top mounted
Oil cooler
Oil filter
Oil pan drain valve

Mounting System
Engine mounting feet (six total)

Protection System
Electronic shutoff system with purge cycle
Crankcase explosion relief valves
Gas shutoff valve

Starting System
Air starting system

General
Paint — Cat yellow
Vibration dampers

OPTIONAL EQUIPMENT

Air Inlet System
Heavy-duty air cleaner — with precleaners
Heavy-duty air cleaner — with rain protection

Charging System
Charging alternators

Control System
Custom control system software is available for non-standard ratings. Software is field programmable using flash memory.

Cooling System
Expansion tank
Flexible connections
Jacket water heater

Exhaust System
Flexible bellows adapters
Exhaust expander
Weld flanges

Fuel System
Fuel filter
Gas pressure regulator
Flexible connection
Low energy fuel system
Corrosive gas fuel system

Ignition System
CSA certification

Instrumentation
Remote data monitoring and speed control
Compatible with Cat Electronic Technician (ET) and Data View
Communication Device — PL1000T/E
Display panel deletion is optional

Lube System
Air or electric motor-driven prelube
Duplex oil filter
LH or RH service
Lube oil makeup system

Mounting System
Mounting plates (set of six)

Power Take-Offs
Front stub shafts

Starting System
Air pressure reducing valve
Natural gas starting system

General
Engine barring device
Damper guard

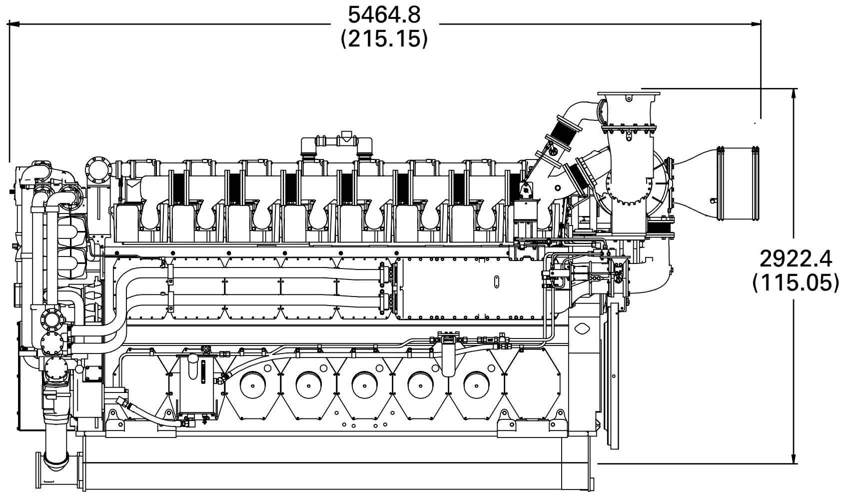
TECHNICAL DATA

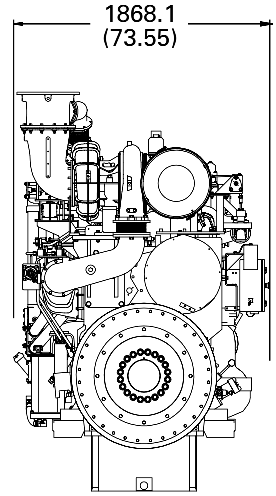
G3608 LE Gas Petroleum Engine — 1000 rpm

		DM5561-03	DM5562-03	DM5136-03	DM8606-02
Engine Power					
@ 100% Load	bkW (bhp)	1767 (2370)	1879 (2520)	1823 (2445)	1767 (2370)
@ 75% Load	bkW (bhp)	1326 (1778)	1409 (1890)	1367 (1834)	1326 (1778)
Engine Speed	rpm	**1000**	**1000**	**1000**	**1000**
Max Altitude @ Rated Torque and 38°C (100°F)	m (ft)	1219.2 (4000)	1219.2 (4000)	1219.2 (4000)	914.4 (3000)
Speed Turndown @ Max Altitude, Rated Torque, and 38°C (100°F)	%	20	20	20	20
SCAC Temperature	°C (°F)	54 (130)	32 (90)	43 (110)	54 (130)
Emissions*					
NOx	g/bkW-hr (g/bhp-hr)	.94 (0.7)	.94 (0.7)	.94 (0.7)	.67 (0.5)
CO	g/bkW-hr (g/bhp-hr)	3.35 (2.5)	3.4 (2.5)	3.4 (2.5)	3.7 (2.75)
CO_2	g/bkW-hr (g/bhp-hr)	589 (439)	584 (436)	587 (438)	591 (441)
VOC**	g/bkW-hr (g/bhp-hr)	0.81 (0.6)	0.76 (0.57)	0.79 (0.59)	0.85 (0.63)
Fuel Consumption***					
@ 100% Load	MJ/bkW-hr (Btu/bhp-hr)	9.34 (6600)	9.28 (6561)	9.31 (6580)	9.38 (6629)
@ 75% Load	MJ/bkW-hr (Btu/bhp-hr)	9.74 (6883)	9.66 (6829)	9.7 (6856)	9.78 (6914)
Heat Balance					
Heat Rejection to Jacket Water					
@ 100% Load	bkW (Btu/min)	420 (23,918)	449 (25,555)	435 (24,751)	420 (23,911)
@ 75% Load	bkW (Btu/min)	364 (20,697)	388 (22,055)	376 (21,389)	366 (20,824)
Heat Rejection to Aftercooler					
@ 100% Load	bkW (Btu/min)	297 (16,916)	394 (22,403)	344 (19,601)	310 (17,633)
@ 75% Load	bkW (Btu/min)	139 (7898)	207 (11,778)	172 (9794)	145 (8279)
Heat Rejection to Exhaust					
@ 100% Load	bkW (Btu/min)	1783 (101,403)	1792 (101,922)	1789 (101,728)	1790 (101,780)
@ 75% Load	bkW (Btu/min)	1437 (81,695)	1443 (82,061)	1441 (81,932)	1442 (82,023)
Exhaust System					
Exhaust Gas Flow Rate					
@ 100% Load	m^3/min (cfm)	451.80 (15,955)	463.55 (16,370)	457.83 (16,168)	457.15 (16,144)
@ 75% Load	m^3/min (cfm)	359.68 (12,702)	368.23 (13,004)	364.10 (12,858)	363.93 (12,852)
Exhaust Stack Temperature					
@ 100% Load	°C (°F)	470 (878)	450 (841)	460 (859)	459 (857)
@ 75% Load	°C (°F)	492 (918)	469 (877)	480 (897)	480 (897)
Intake System					
Air Inlet Flow Rate					
@ 100% Load	m^3/min (scfm)	170.07 (6006)	179.36 (6334)	174.71 (6170)	174.91 (6177)
@ 75% Load	m^3/min (scfm)	131.36 (4639)	138.58 (4894)	134.99 (4767)	135.13 (4772)
Gas Pressure	kPag (psig)	295-324 (42.8-47)	295-324 (42.8-47)	295-324 (42.8-47)	295-324 (42.8-47)

*at 100% load and speed, all values are listed as not to exceed
**Volatile organic compounds as defined in U.S. EPA 40 CFR 60, subpart JJJJ
***ISO 3046/1

GAS PETROLEUM ENGINE





DIMENSIONS		
Length	mm (in)	5464.8 (215.15)
Width	mm (in)	1868.1 (73.55)
Height	mm (in)	2922.4 (115.05)
Shipping Weight	kg (lb)	19,000 (41,888)

Note: General configuration not to be used for installation. See general dimension drawing number 246-1516 for detail.

RATING DEFINITIONS AND CONDITIONS

Engine performance is obtained in accordance with SAE J1995, ISO3046/1, BS5514/1, and DIN6271/1 standards.

Transient response data is acquired from an engine/ generator combination at normal operating temperature and in accordance with ISO3046/1 standard ambient conditions. Also in accordance with SAE J1995, BS5514/1, and DIN6271/1 standard reference conditions.

Conditions: Power for gas engines is based on fuel having an LHV of 33.74 kJ/L (905 Btu/cu ft) at 101 kPa (29.91 in. Hg) and 15° C (59° F). Fuel rate is based on a cubic meter at 100 kPa (29.61 in. Hg) and 15.6° C (60.1° F). Air flow is based on a cubic foot at 100 kPa (29.61 in. Hg) and 25° C (77° F). Exhaust flow is based on a cubic foot at 100 kPa (29.61 in. Hg) and stack temperature.

Section 7.1-4 – Catalyst Specification Sheet RICE G3608 (Units C9 to C10)

EMIT TECHNOLOGIES

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Prepared For:
Gary Prill
UE COMPRESSION LLC

QUOTE: QUO-11305-Q6H8
Expires: February 06, 2014

INFORMATION PROVIDED BY CATERPILLAR

Engine:	G3608
Horsepower:	2370
RPM:	1000
Compression Ratio:	9.2
Exhaust Flow Rate:	16141 CFM
Exhaust Temperature:	857 °F
Reference:	DM8606-04-001
Fuel:	Natural Gas
Annual Operating Hours:	8760

Uncontrolled Emissions

	g/bhp-hr
NOx:	0.50
CO:	2.75
THC:	6.31
NMHC	0.95
NMNEHC:	0.63
HCHO:	0.26
O2:	12.00 %

POST CATALYST EMISSIONS

	g/bhp-hr
NOx:	Unaffected by Oxidation Catalyst
CO:	<0.20
VOC:	<0.30
HCHO:	<0.19

CONTROL EQUIPMENT

Catalyst Housing

Model:	EBH-7000-2022F-6C4E-36
Manufacturer:	EMIT Technologies, Inc
Element Size:	Rectangle 36" x 15" x 3.5"
Housing Type:	6 Element Capacity
Catalyst Installation:	Ground Level Accessible Housing
Construction:	3/16" Carbon Steel
Sample Ports:	9 (0.5" NPT)
Inlet Connections:	20" Flat Face Flange
Outlet Connections:	22" Flat Face Flange
Configuration:	Side In / End Out
Silencer:	Integrated
Silencer Grade:	Hospital
Insertion Loss:	35-40 dBA
Estimated Lead Time:	2 - 4 Weeks to Ship

Catalyst Element

Model:	RT-3615-Z
Catalyst Type:	Oxidation, Standard Precious Group Metals
Substrate Type:	BRAZED
Manufacturer:	EMIT Technologies, Inc
Element Quantity:	2
Element Size:	Rectangle 36" x 15" x 3.5"
Estimated Lead Time:	In Stock

Section 7.1-5 – EPA AP-42 Table 3.2-2 RICE 3608 and 3616 (Units C1 to C10)

PM=PM10=PM2.5;
Emission Factor =
Filterable + Condensable=
7.71E-05 + 9.91E-03 =
9.99E-03

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Criteria Pollutants and Greenhouse Gases		
NO_x[c] 90 - 105% Load	4.08 E+00	B
NO_x[c] <90% Load	8.47 E-01	B
CO[c] 90 - 105% Load	3.17 E-01	C
CO[c] <90% Load	5.57 E-01	B
CO_2[d]	1.10 E+02	A
SO_2[e]	5.88 E-04	A
TOC[f]	1.47 E+00	A
Methane[g]	1.25 E+00	C
VOC[h]	1.18 E-01	C
PM10 (filterable)[i]	7.71 E-05	D
PM2.5 (filterable)[i]	7.71 E-05	D
PM Condensable[j]	9.91 E-03	D
Trace Organic Compounds		
1,1,2,2-Tetrachloroethane[k]	<4.00 E-05	E
1,1,2-Trichloroethane[k]	<3.18 E-05	E
1,1-Dichloroethane	<2.36 E-05	E
1,2,3-Trimethylbenzene	2.30 E-05	D
1,2,4-Trimethylbenzene	1.43 E-05	C
1,2-Dichloroethane	<2.36 E-05	E
1,2-Dichloropropane	<2.69 E-05	E
1,3,5-Trimethylbenzene	3.38 E-05	D
1,3-Butadiene[k]	2.67E-04	D
1,3-Dichloropropene[k]	<2.64 E-05	E
2-Methylnaphthalene[k]	3.32 E-05	C
2,2,4-Trimethylpentane[k]	2.50 E-04	C
Acenaphthene[k]	1.25 E-06	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES (Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
Acenaphthylene[k]	5.53 E-06	C
Acetaldehyde[k,l]	8.36 E-03	A
Acrolein[k,l]	5.14 E-03	A
Benzene[k]	4.40 E-04	A
Benzo(b)fluoranthene[k]	1.66 E-07	D
Benzo(e)pyrene[k]	4.15 E-07	D
Benzo(g,h,i)perylene[k]	4.14 E-07	D
Biphenyl[k]	2.12 E-04	D
Butane	5.41 E-04	D
Butyr/Isobutyraldehyde	1.01 E-04	C
Carbon Tetrachloride[k]	<3.67 E-05	E
Chlorobenzene[k]	<3.04 E-05	E
Chloroethane	1.87 E-06	D
Chloroform[k]	<2.85 E-05	E
Chrysene[k]	6.93 E-07	C
Cyclopentane	2.27 E-04	C
Ethane	1.05 E-01	C
Ethylbenzene[k]	3.97 E-05	B
Ethylene Dibromide[k]	<4.43 E-05	E
Fluoranthene[k]	1.11 E-06	C
Fluorene[k]	5.67 E-06	C
Formaldehyde[k,l]	5.28 E-02	A
Methanol[k]	2.50 E-03	B
Methylcyclohexane	1.23 E-03	C
Methylene Chloride[k]	2.00 E-05	C
n-Hexane[k]	1.11 E-03	C
n-Nonane	1.10 E-04	C

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES
(Continued)

Pollutant	Emission Factor (lb/MMBtu)[b] (fuel input)	Emission Factor Rating
n-Octane	3.51 E-04	C
n-Pentane	2.60 E-03	C
Naphthalene[k]	7.44 E-05	C
PAH[k]	2.69 E-05	D
Phenanthrene[k]	1.04 E-05	D
Phenol[k]	2.40 E-05	D
Propane	4.19 E-02	C
Pyrene[k]	1.36 E-06	C
Styrene[k]	<2.36 E-05	E
Tetrachloroethane[k]	2.48 E-06	D
Toluene[k]	4.08 E-04	B
Vinyl Chloride[k]	1.49 E-05	C
Xylene[k]	1.84 E-04	B

[a] Reference 7. Factors represent uncontrolled levels. For NO_x, CO, and PM10, "uncontrolled" means no combustion or add-on controls; however, the factor may include turbocharged units. For all other pollutants, "uncontrolled" means no oxidation control; the data set may include units with control techniques used for NOx control, such as PCC and SCR for lean burn engines, and PSC for rich burn engines. Factors are based on large population of engines. Factors are for engines at all loads, except as indicated. SCC = Source Classification Code. TOC = Total Organic Compounds. PM-10 = Particulate Matter ≤ 10 microns (μm) aerodynamic diameter. A "<" sign in front of a factor means that the corresponding emission factor is based on one-half of the method detection limit.

[b] Emission factors were calculated in units of (lb/MMBtu) based on procedures in EPA Method 19. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by the heat content of the fuel. If the heat content is not available, use 1020 Btu/scf. To convert from (lb/MMBtu) to (lb/hp-hr) use the following equation:

$$\text{lb/hp-hr} = (\text{lb/MMBtu})\,(\text{heat input, MMBtu/hr})\,(\text{1/operating HP, 1/hp})$$

[c] Emission tests with unreported load conditions were not included in the data set.

[d] Based on 99.5% conversion of the fuel carbon to CO_2. CO_2 [lb/MMBtu] = (3.67)(%CON)(C)(D)(1/h), where %CON = percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.75), D = density of fuel, 4.1 E+04 lb/10^6 scf, and

GRI-HAPCalc ® 3.01
Engines Report

Facility ID:	**DCP - ZIA II GP**	**Notes:**
Operation Type:	**GAS PLANT**	
Facility Name:	**ZIA II GAS PLANT**	
User Name:		
Units of Measure:	**U.S. STANDARD**	

***Note:** Emissions less than 5.00E-09 tons (or tonnes) per year are considered insignificant and are treated as zero.*
These emissions are indicated on the report with a "0".
Emissions between 5.00E-09 and 5.00E-05 tons (or tonnes) per year are represented on the report with "0.0000".

Engine Unit

Unit Name: G3608 LE

Hours of Operation:	8,760	Yearly
Rate Power:	2,370	hp
Fuel Type:	NATURAL GAS	
Engine Type:	4-Stroke, Lean Burn	
Emission Factor Set:	EPA > FIELD > LITERATURE	
Additional EF Set:	-NONE-	

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor		Emission Factor Set
HAPs				
Tetrachloroethane	0.0002	0.00000820	g/bhp-hr	EPA
Formaldehyde	3.9844	0.17425810	g/bhp-hr	EPA
Methanol	0.1887	0.00825090	g/bhp-hr	EPA
Acetaldehyde	0.6309	0.02759090	g/bhp-hr	EPA
1,3-Butadiene	0.0201	0.00088120	g/bhp-hr	EPA
Acrolein	0.3879	0.01696380	g/bhp-hr	EPA
Benzene	0.0332	0.00145220	g/bhp-hr	EPA
Toluene	0.0308	0.00134650	g/bhp-hr	EPA
Ethylbenzene	0.0030	0.00013100	g/bhp-hr	EPA
Xylenes(m,p,o)	0.0139	0.00060730	g/bhp-hr	EPA
2,2,4-Trimethylpentane	0.0189	0.00082510	g/bhp-hr	EPA
n-Hexane	0.0838	0.00366340	g/bhp-hr	EPA
Phenol	0.0018	0.00007920	g/bhp-hr	EPA
Styrene	0.0018	0.00007790	g/bhp-hr	EPA
Naphthalene	0.0056	0.00024550	g/bhp-hr	EPA
2-Methylnaphthalene	0.0025	0.00010960	g/bhp-hr	EPA
Acenaphthylene	0.0004	0.00001830	g/bhp-hr	EPA
Biphenyl	0.0160	0.00069970	g/bhp-hr	EPA
Acenaphthene	0.0001	0.00000410	g/bhp-hr	EPA
Fluorene	0.0004	0.00001870	g/bhp-hr	EPA
Phenanthrene	0.0008	0.00003430	g/bhp-hr	EPA
Ethylene Dibromide	0.0033	0.00014620	g/bhp-hr	EPA
Fluoranthene	0.0001	0.00000370	g/bhp-hr	EPA
Pyrene	0.0001	0.00000450	g/bhp-hr	EPA
Chrysene	0.0001	0.00000230	g/bhp-hr	EPA

Benzo(b)fluoranthene	0.0000	0.00000050	g/bhp-hr	EPA
Benzo(e)pyrene	0.0000	0.00000140	g/bhp-hr	EPA
Benzo(g,h,i)perylene	0.0000	0.00000140	g/bhp-hr	EPA
Vinyl Chloride	0.0011	0.00004920	g/bhp-hr	EPA
Methylene Chloride	0.0015	0.00006600	g/bhp-hr	EPA
1,1-Dichloroethane	0.0018	0.00007790	g/bhp-hr	EPA
1,3-Dichloropropene	0.0020	0.00008710	g/bhp-hr	EPA
Chlorobenzene	0.0023	0.00010030	g/bhp-hr	EPA
Chloroform	0.0022	0.00009410	g/bhp-hr	EPA
1,1,2-Trichloroethane	0.0024	0.00010500	g/bhp-hr	EPA
1,1,2,2-Tetrachloroethane	0.0030	0.00013200	g/bhp-hr	EPA
Carbon Tetrachloride	0.0028	0.00012110	g/bhp-hr	EPA
Total	5.4479			

Total HAPs = Total HAPs from GRI HAPCalc - GRI HAPCalc HCHO + Manufacturer HCHO = 5.8 tpy

Criteria Pollutants

PM	0.7536	0.03296090	g/bhp-hr	EPA
CO	23.9213	1.04620860	g/bhp-hr	EPA
NMEHC	8.9045	0.38944040	g/bhp-hr	EPA
NOx	307.8831	13.46539810	g/bhp-hr	EPA
SO2	0.0444	0.00194060	g/bhp-hr	EPA

Other Pollutants

Butryaldehyde	0.0076	0.00033330	g/bhp-hr	EPA
Chloroethane	0.0001	0.00000620	g/bhp-hr	EPA
Methane	94.3269	4.12542830	g/bhp-hr	EPA
Ethane	7.9235	0.34653600	g/bhp-hr	EPA
Propane	3.1618	0.13828440	g/bhp-hr	EPA
Butane	0.0408	0.00178550	g/bhp-hr	EPA
Cyclopentane	0.0171	0.00074920	g/bhp-hr	EPA
n-Pentane	0.1962	0.00858090	g/bhp-hr	EPA
Methylcyclohexane	0.0928	0.00405940	g/bhp-hr	EPA
1,2-Dichloroethane	0.0018	0.00007790	g/bhp-hr	EPA
1,2-Dichloropropane	0.0020	0.00008880	g/bhp-hr	EPA
n-Octane	0.0265	0.00115840	g/bhp-hr	EPA
1,2,3-Trimethylbenzene	0.0017	0.00007590	g/bhp-hr	EPA
1,2,4-Trimethylbenzene	0.0011	0.00004720	g/bhp-hr	EPA
1,3,5-Trimethylbenzene	0.0026	0.00011160	g/bhp-hr	EPA
n-Nonane	0.0083	0.00036300	g/bhp-hr	EPA
CO2	8,300.7689	363.03769350	g/bhp-hr	EPA

Unit Name: G3616 LE

Hours of Operation: 8,760 Yearly

Rate Power: 4,735 hp

Fuel Type: NATURAL GAS

Engine Type: 4-Stroke, Lean Burn

Emission Factor Set: EPA > FIELD > LITERATURE

Additional EF Set: -NONE-

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor		Emission Factor Set
HAPs				
Tetrachloroethane	0.0004	0.00000820	g/bhp-hr	EPA
Formaldehyde	7.9603	0.17425810	g/bhp-hr	EPA

Methanol	0.3769	0.00825090	g/bhp-hr	EPA
Acetaldehyde	1.2604	0.02759090	g/bhp-hr	EPA
1,3-Butadiene	0.0403	0.00088120	g/bhp-hr	EPA
Acrolein	0.7749	0.01696380	g/bhp-hr	EPA
Benzene	0.0663	0.00145220	g/bhp-hr	EPA
Toluene	0.0615	0.00134650	g/bhp-hr	EPA
Ethylbenzene	0.0060	0.00013100	g/bhp-hr	EPA
Xylenes(m,p,o)	0.0277	0.00060730	g/bhp-hr	EPA
2,2,4-Trimethylpentane	0.0377	0.00082510	g/bhp-hr	EPA
n-Hexane	0.1673	0.00366340	g/bhp-hr	EPA
Phenol	0.0036	0.00007920	g/bhp-hr	EPA
Styrene	0.0036	0.00007790	g/bhp-hr	EPA
Naphthalene	0.0112	0.00024550	g/bhp-hr	EPA
2-Methylnaphthalene	0.0050	0.00010960	g/bhp-hr	EPA
Acenaphthylene	0.0008	0.00001830	g/bhp-hr	EPA
Biphenyl	0.0320	0.00069970	g/bhp-hr	EPA
Acenaphthene	0.0002	0.00000410	g/bhp-hr	EPA
Fluorene	0.0009	0.00001870	g/bhp-hr	EPA
Phenanthrene	0.0016	0.00003430	g/bhp-hr	EPA
Ethylene Dibromide	0.0067	0.00014620	g/bhp-hr	EPA
Fluoranthene	0.0002	0.00000370	g/bhp-hr	EPA
Pyrene	0.0002	0.00000450	g/bhp-hr	EPA
Chrysene	0.0001	0.00000230	g/bhp-hr	EPA
Benzo(b)fluoranthene	0.0000	0.00000050	g/bhp-hr	EPA
Benzo(e)pyrene	0.0001	0.00000140	g/bhp-hr	EPA
Benzo(g,h,i)perylene	0.0001	0.00000140	g/bhp-hr	EPA
Vinyl Chloride	0.0022	0.00004920	g/bhp-hr	EPA
Methylene Chloride	0.0030	0.00006600	g/bhp-hr	EPA
1,1-Dichloroethane	0.0036	0.00007790	g/bhp-hr	EPA
1,3-Dichloropropene	0.0040	0.00008710	g/bhp-hr	EPA
Chlorobenzene	0.0046	0.00010030	g/bhp-hr	EPA
Chloroform	0.0043	0.00009410	g/bhp-hr	EPA
1,1,2-Trichloroethane	0.0048	0.00010500	g/bhp-hr	EPA
1,1,2,2-Tetrachloroethane	0.0060	0.00013200	g/bhp-hr	EPA
Carbon Tetrachloride	0.0055	0.00012110	g/bhp-hr	EPA
Total	10.8840			

Total HAPs = Total HAPs from GRI HAPCalc - GRI HAPCalc HCHO + Manufacturer HCHO = 3.3 tpy

Criteria Pollutants

PM	1.5057	0.03296090	g/bhp-hr	EPA
CO	47.7921	1.04620860	g/bhp-hr	EPA
NMEHC	17.7901	0.38944040	g/bhp-hr	EPA
NOx	615.1166	13.46539810	g/bhp-hr	EPA
SO2	0.0886	0.00194060	g/bhp-hr	EPA

Other Pollutants

Butryaldehyde	0.0152	0.00033330	g/bhp-hr	EPA
Chloroethane	0.0003	0.00000620	g/bhp-hr	EPA
Methane	188.4548	4.12542830	g/bhp-hr	EPA
Ethane	15.8302	0.34653600	g/bhp-hr	EPA
Propane	6.3170	0.13828440	g/bhp-hr	EPA
Butane	0.0816	0.00178550	g/bhp-hr	EPA
Cyclopentane	0.0342	0.00074920	g/bhp-hr	EPA
n-Pentane	0.3920	0.00858090	g/bhp-hr	EPA
Methylcyclohexane	0.1854	0.00405940	g/bhp-hr	EPA
1,2-Dichloroethane	0.0036	0.00007790	g/bhp-hr	EPA

1,2-Dichloropropane	0.0041	0.00008880	g/bhp-hr	EPA
n-Octane	0.0529	0.00115840	g/bhp-hr	EPA
1,2,3-Trimethylbenzene	0.0035	0.00007590	g/bhp-hr	EPA
1,2,4-Trimethylbenzene	0.0022	0.00004720	g/bhp-hr	EPA
1,3,5-Trimethylbenzene	0.0051	0.00011160	g/bhp-hr	EPA
n-Nonane	0.0166	0.00036300	g/bhp-hr	EPA
CO_2	16,584.0256	363.03769350	g/bhp-hr	EPA

40 CFR Appendix Table C-1 to Subpart C of Part 98 - Default CO2 Emission Factors and High Heat Values for Various Types of Fuel

CFR

Table C-1 to Subpart C of Part 98 - Default CO^2 Emission Factors and High Heat Values for Various Types of Fuel

Default CO^2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel type	Default high heat value	Default CO^2 emission factor
Coal and coke	mmBtu/short ton	kg CO^2/mmBtu
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural gas	mmBtu/scf	kg CO^2/mmBtu
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products - liquid	mmBtu/gallon	kg CO^2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG) [1]	0.092	61.71
Propane [1]	0.091	62.87
Propylene [2]	0.091	67.77
Ethane [1]	0.068	59.60
Ethanol	0.084	68.44
Ethylene [2]	0.058	65.96
Isobutane [1]	0.099	64.94
Isobutylene [1]	0.103	68.86
Butane [1]	0.103	64.77
Butylene [1]	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Special Naphtha	0.125	72.34

Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Petroleum products - solid	mmBtu/short ton	kg CO2/mmBtu.
Petroleum Coke	30.00	102.41.
Petroleum products - gaseous	mmBtu/scf	kg CO2/mmBtu.
Propane Gas	2.516×10^{-3}	61.46.
Other fuels - solid	mmBtu/short ton	kg CO^2/mmBtu
Municipal Solid Waste	9.95 [3]	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Other fuels - gaseous	mmBtu/scf	kg CO^2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Fuel Gas [4]	1.388×10^{-3}	59.00
Biomass fuels - solid	mmBtu/short ton	kg CO^2/mmBtu
Wood and Wood Residuals (dry basis) [5]	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass fuels - gaseous	mmBtu/scf	kg CO^2/mmBtu
Landfill Gas	0.485×10^{-3}	52.07
Other Biomass Gases	0.655×10^{-3}	52.07
Biomass Fuels - Liquid	mmBtu/gallon	kg CO^2/mmBtu
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2] Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3] Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4] Reporters subject to subpart X of this part that are complying with § 98.243(d) or subpart Y of this part may only use the default HHV and the default CO^2 emission factor for fuel gas combustion under the conditions prescribed in § 98.243(d)(2)(i) and (d)(2)(ii) and § 98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C-5) or Tier 4.

[5] Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV^w = ((100 - M)/100)*HHV^d$ where HHV^w = wet basis HHV, M = moisture content (percent) and HHV^d = dry basis HHV from Table C-1.

[78 FR 71950, Nov. 29, 2013, as amended at 81 FR 89252, Dec. 9, 2016]

1.3.3 Emissions[5]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

1.3.3.1 Particulate Matter Emissions[6-15] -

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particules that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling van. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

Filterable particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM than does the firing of heavier No. 6 oil.

In general, filterable PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers primarily comprises carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning are related to the oil sulfur content. This is because low-sulfur No. 6 oil, either from naturally low-sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect filterable particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emission reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions (approximately 30 percent of maximum rating), proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

1.3.3.2 Sulfur Oxides Emissions[1-2,6-9,16] -

Sulfur oxides (SO_x) emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist.

Section 7.2 – Heaters and Boilers (Units H1 to H6)

- Section 7.2-1 – EPA AP-42 Tables 1.4-1 and 1.4-2 for heater and boilers (Units H1 to H6)
- Section 7.2-2 – Manufacturer Specification Sheet for 99 MMBtu/hr boilers (Units H4 and H5)
- Section 7.2-3 – GRI-HAPCalc 3.01 for heaters and boilers (Units H1to H3 and H6)
- Section 7.2-4 – 40 CFR 98 Subpart W Table C-1 and C-2 (Units H1 to H6)
- Section 7.2-5 – EPA AP-42 Section 1.3.3.2 (Units H1 to H6)

Section 7.2-1 – EPA AP-42 Tables 1.4-1 and 1.4-1 for heater and boilers (Units H1 to H6)

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b]		CO	
	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

Units 4 and 5 are small Boilers (<100) with emission factor manufacturer guarantee of 0.06 lb/MMBtu for NOx and 0.041 lb/MMBtu for CO.

Units 3 and 6 are small boilers (< 100) and do not contain low NOx burners.

Unit 1 is a small boiler (<100) and contains a low NOx burner

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6\ m^3$, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

PM and VOC emission factors are used for all heaters and boilers at the facility (Units H1 to H6)

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to 1b/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. $CO_2[lb/10^6 \text{ scf}] = (3.67)(CON)(C)(D)$, where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2.
Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

Section 7.2-2 – Manufacturer Specification Sheet (Units H4 and H5)

BURNER PERFORMANCE DATA

TABLE OF CONTENTS

TECHNICAL & SCOPE OF SUPPLY

NOTES & CLARIFICATIONS

1. This technical proposal is based upon the information that has been provided to us at this time. Please note, as additional information is provided to us, we may need to revise our burner performance predictions, scope of supply and/or commercial details.

2. NOx and CO emissions as stated in this proposal are made at maximum and normal heat releases only, due to the "limited ability" to control the excess air in a process heater, while firing at minimum turndown conditions.

3. The NOx and CO emission levels included in this proposal are based on all of the combustion air entering the secondary combustion zone through the throat of the burner. Due to the detrimental effect on emissions and performance, "tramp" air entering the furnace must be minimized.

4. Zeeco does not guarantee SOx emissions since these are stoichiometrically related to sulfur compounds in the fuels and the equilibrium conditions in the furnace.

5. Zeeco takes exception to providing NOx emission guarantees for any fuel gas compositions containing ammonia (NH_3).

6. Warranty period shall be twelve (12) months from start-up or eighteen (18) months from ship date, whichever comes first. The value of the warranty / maximum liability shall be limited to the amount of the purchase order.

7. Zeeco limits the sum of all liability, either expressed or implied, to the value of the purchase order.

8. This proposal is based upon all fuels being supplied to each burner in a single phase. That is, all gas fuels shall be provided to the burner in 100% gas state and all liquid fuels shall be provided in 100% liquid state.

9. This proposal is based on the use of Zeeco standard sub-suppliers for cast components, some of whom are located in mainland China.

10. Should any fuel gas, off gas, vent gas, etc. have oxygen as a component, there is a chance of the mixture being a flammable mixture. There is no mechanism included in the burner to prevent burn back in the line in the event that the oxygen content becomes high enough to create a flammable mixture. In the event that the gas mixture should become flammable and burn back in the line should occur, Zeeco assumes no liability for any damage caused.

11. In the case that the fuel contains harmful components, such as H_2S, CO, etc, the customer should use the industry accepted/recommended practices relating to the fuel delivery system to protect personnel from exposure to potentially hazardous chemicals.

12. Zeeco shall not be liable for any consequential, indirect, special or incidental damages arising out or resulting from this purchase order.

13. Non-destructive materials testing, such as PMI, PT testing, X-ray, refractory testing, etc is not included in this proposal unless explicitly quoted in the pricing section.

14. Destructive materials testing, such as refractory testing, etc is not included in this proposal unless explicitly quoted in the pricing section.

TECHNICAL & SCOPE OF SUPPLY

NOTES & CLARIFICATIONS (Page 2)

15. This proposal is based on any customer specifications on piping ending at the burner fuel flange connection. The burner is not a pressure vessel or pressure retaining vessel, because the burner fuel manifold/risers/tips are open to the atmosphere. All materials for piping downstream of the burner fuel flange connections are listed explicitly in the burner data sheets of this proposal.

ZEECO BURNER DATA SHEETS

Burner Design Criteria

Customer:	**Optimized Process Furnaces, Inc.**
End User:	
Jobsite:	
Heater Tag Number:	**2010-011**
Type of Heater:	**Process Heater**
Burner Designation:	**GLSF**
Burner Description:	**Round Flame, Min-Emissions**
Patent Info:	***US Patent # 6,394,792***

Revision Table

Rev #	Issue	Description of Revision	Rev Date	Name
D	4	Revised Emissions Guarantee.	20-Apr-11	SAM
C	3	Revised ambient air temperature.	2-Mar-10	DTV
B	2	Revised to include Alternate Option.	19-Feb-20	DTV
A	1	Original Issue.	18-Feb-10	Seth A. Marty

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ZEECO BURNER DATA SHEETS

Rev. Rev.

GENERAL INFORMATION

Customer Name	Optimized Process Furnaces, Inc.
End User Name	
Jobsite	

FURNACE DATA / SITE CONDITIONS

Furnace Tag Number	2010-011	Plant Site Elevation Above Sea Level, ft	1000
Type of Furnace	Process Heater	Ambient Air Temperature (°F)	70
Refractory Thickness, in	10.5	Minimum Relative Humidity	0%
Heater Steel Thickness, in	0.25	Normal Relative Humidity	50%
Type of Draft	Natural	Maximum Relative Humidity	100%
Direction of Firing	Vertical, Up	Heater Height (to convective sec.), ft	52.0
Mounting Direction	Vertical, Up	Tube Circle Diameter (ft)	18.7

PROCESS DATA

	Gas		
Maximum Heat Release (MM BTU/hr)	19.000	Available Combustion Air dP (in H2O)	0.620
Normal Heat Release (MM BTU/hr)	18.100	Combustion Air Temperature (°F)	105
Minimum Heat Release (MM BTU/hr)	3.800	Furnace Temperature (°F)	1535
Turndown	5.00	Combustion Test	Not Required
Available Fuel Pressure (psig)	25		
Design Excess Air	15%		

GENERAL BURNER DESCRIPTION

Burner Model / Size	GLSF 15	Flame Shape	Round Flame
Burner Description	Round Flame, Min-Emissions	Maximum Predicted Flame Length (ft)	23.1
Number Required	6	Maximum Predicted Flame Width (ft)	2.94
Oil Gun Model / Size	N/A	Pilot Model	JM-1S-E
Atomizing Media	N/A	Pilot Ignition Method	Electric Ignition
Atomizing Type	N/A	Pilot Heat release (Btu/hr)	90,000
Available Atomizing Pressure (psig)	N/A	Pilot Operating Pressure (psig)	10
Atomizing Media Rate (# / # fuel)	N/A	Pilot Fuel	Natural Gas
		Flame / Ionization Rod Provided	None

NOISE DATA (SINGLE BURNER BASIS)

Predicted @ 63 Hz (dB)	85	Predicted @ 2000 Hz (dB)	72
Predicted @ 125 Hz (dB)	89	Predicted @ 4000 Hz (dB)	74
Predicted @ 250 Hz (dB)	82	Predicted @ 8000 Hz (dB)	72
Predicted @ 500 Hz (dB)	86	Guar. Noise Level @ 3 ft from burner, dBA	85
Predicted @ 1000 Hz (dB)	76		

GENERAL BURNER COMMENTS

2-1. The above noise emissions are "Sound Pressure Level".
2-2. The above heat releases are based on the lower heating value 'LHV' of the fuel(s).
2-3. The burners are sized based on the maximum relative humidity case, as listed above.

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ZEECO BURNER DATA SHEETS

FUEL GAS CHARACTERISTICS / **OFF GAS CHARACTERISTICS**

Composition	Fuel Gas % vol						Waste Gas % vol		
CH4 (methane)	94.29%						79.85%		
C2H6 (ethane)	1.40%						1.14%		
C3H8 (propane)	0.14%						0.10%		
C4H10 (butane)	0.04%								
C5H12 (pentane)									
C6H14 (hexane)									
C5H10 (cyclopen)									
C6H12 (cyclohex)									
C2H4 (ethene)									
C3H6 (propene)									
C4H8 (butene)									
C5H10 (pentene)									
C6H6 (benzene)									
C5H8 (isoprene)									
CO2	3.80%						15.33%		
H2O	0.07%						3.33%		
O2									
N2	0.20%						0.09%		
SO2									
H2S	0.05%						0.16%		
CO									
NH3									
H2									
AR									
Total (vol%)	100%						100%		
Excess O2 (vol%)	2.99%						2.95%		
LHV (Btu/scf)	884						748		
S.G.	0.61						0.72		
TEMP (°F)	70.00						70.00		
M.W.	17.56						20.76		

FUEL OIL CHARACTERISTICS

LHV (BTU/lb)
S.G. @ 60°F
TEMP (°F)
API GRAVITY @ 60°F
NITROGEN (wt%)
VANADIUM (PPM)
SULFUR (wt%)
CATALYST PRESENT
GENERAL OIL TYPE

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ZEECO BURNER DATA SHEETS

BASIS OF EMISSIONS INFORMATION

Rev.

Furnace Temperature (°F)	1,535.00		
Excess Combustion Air (%)	15% Gas		
Combustion Air Temperature (°F)	105		
Relative Humidity (%)	50%		
Heat Release for Guarantee (MM Btu/hr)	19.000	to	18.100 LHV

EMISSIONS INFORMATION

	PREDICTED		GUARANTEED	
	(ppmv)	(#/MMBtu)	(ppmv)	(#/MMBtu)
NOx Fuel Gas	26	0.034	45	0.060
CO - Gas	0	0.000	50	0.041
UHC - Gas	1	0.001	15	0.007
Particulate - Gas	2	0.002	15	0.013
VOC - Gas	0	0.000	15	0.019

EMISSIONS COMMENTS

4-1 The above listed UHC emissions are based upon UHC being defined as free "methane" as the result of incomplete combustion due to the supplied combustion equipment as stated in these data sheets.

4-2 The above listed VOC emissions are based upon VOC being defined as free "propane" as the result of incomplete combustion due to the supplied combustion equipment as stated in these data sheets.

4-3 The above listed Particulate emissions are based upon Particulate being defined as free "ethane" as the result of incomplete combustion due to the supplied combustion equipment as stated in these data sheets. This excludes ash, sand and heavy metals in the fuel oil.

4-4 NOx guarantees are based on the furnace temperature, combustion air temperature, excess combustion air and the fuel gas compositions as specified the Zeeco Burner Data Sheets.

4-5 The emissions guarantees above are for operation between maximum and normal heat release.

4-6 The emissions guarantees as stated above are based upon operation with the % excess air, temperature, furnace temperature, and fuel temperatures as stated in these data sheets.

4-7 See Notes & Clarifications section for more information concerning noise emissions.

4-8 See Notes & Clarifications section for more information concerning the above emissions guarantees.

4-9 Zeeco takes exception to any SOx guarantees since SOx production is based upon the amount of Sulfur in the fuel stream and the equilibrium conditions in the furnace.

4-10 The above listed predictions & guarantees are based on the lower heating value 'LHV' of the fuel(s).

4-11 All ppmv and/or mg/Nm3 guarantees are corrected to 3% O2 dry basis.

4-12 All CO, UHC, Particulate and VOC emissions guarantees are based on the furnace local temperature at the burner being above 1100°F (593°C).

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Section 7.2-3 – GRI-HAPCalc 3.01 heaters (Units H1,H3 H4, H5 and H6)

GRI-HAPCalc ® 3.01

External Combustion Devices Report

Facility ID:	**ZIA II GAS PLANT**	**Notes:**
Operation Type:	**GAS PLANT**	
Facility Name:	**DCP ZIA II GAS PLANT**	**Please note emission factors from this report are used to calculate emissions for boilers greater than 100 MMBtu/hr (Units H4 and H5) because GRI-HAPCalc 3.01 does not accept units larger than 100 MMBtu/hr.**
User Name:		
Units of Measure:	**U.S. STANDARD**	

***Note:** Emissions less than 5.00E-09 tons (or tonnes) per year are considered insignificant and are treated as zero.*
These emissions are indicated on the report with a "0".
Emissions between 5.00E-09 and 5.00E-05 tons (or tonnes) per year are represented on the report with "0.0000".

External Combustion Devices

Unit Name: H1

Hours of Operation:	8,760	Yearly
Heat Input:	26.00	MMBtu/hr
Fuel Type:	NATURAL GAS	
Device Type:	HEATER	
Emission Factor Set:	FIELD > EPA > LITERATURE	
Additional EF Set:	-NONE-	

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor	Emission Factor Set
HAPs			
3-Methylcholanthrene	0.0000	0.0000000018 lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157 lb/MMBtu	EPA
Formaldehyde	0.0961	0.0008440090 lb/MMBtu	GRI Field
Methanol	0.1097	0.0009636360 lb/MMBtu	GRI Field
Acetaldehyde	0.0840	0.0007375920 lb/MMBtu	GRI Field
1,3-Butadiene	0.0390	0.0003423350 lb/MMBtu	GRI Field
Benzene	0.0852	0.0007480470 lb/MMBtu	GRI Field
Toluene	0.1157	0.0010163310 lb/MMBtu	GRI Field
Ethylbenzene	0.2406	0.0021128220 lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.1504	0.0013205140 lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	0.3236	0.0028417580 lb/MMBtu	GRI Field
n-Hexane	0.1602	0.0014070660 lb/MMBtu	GRI Field
Phenol	0.0000	0.0000001070 lb/MMBtu	GRI Field
Styrene	0.2367	0.0020788960 lb/MMBtu	GRI Field
Naphthalene	0.0001	0.0000005100 lb/MMBtu	GRI Field
2-Methylnaphthalene	0.0000	0.0000001470 lb/MMBtu	GRI Field
Acenaphthylene	0.0000	0.0000000670 lb/MMBtu	GRI Field
Biphenyl	0.0001	0.0000004730 lb/MMBtu	GRI Field
Acenaphthene	0.0000	0.0000000900 lb/MMBtu	GRI Field
Fluorene	0.0000	0.0000000800 lb/MMBtu	GRI Field
Anthracene	0.0000	0.0000000870 lb/MMBtu	GRI Field
Phenanthrene	0.0000	0.0000000600 lb/MMBtu	GRI Field
Fluoranthene	0.0000	0.0000000900 lb/MMBtu	GRI Field
Pyrene	0.0000	0.0000000830 lb/MMBtu	GRI Field
Benz(a)anthracene	0.0000	0.0000000870 lb/MMBtu	GRI Field

Chrysene	0.0000	0.0000001170	lb/MMBtu	GRI Field
Benzo(a)pyrene	0.0000	0.0000000700	lb/MMBtu	GRI Field
Benzo(b)fluoranthene	0.0000	0.0000001500	lb/MMBtu	GRI Field
Benzo(k)fluoranthene	0.0001	0.0000007600	lb/MMBtu	GRI Field
Benzo(g,h,i)perylene	0.0000	0.0000002600	lb/MMBtu	GRI Field
Indeno(1,2,3-c,d)pyrene	0.0000	0.0000001200	lb/MMBtu	GRI Field
Dibenz(a,h)anthracene	0.0000	0.0000001030	lb/MMBtu	GRI Field
Lead	0.0001	0.0000004902	lb/MMBtu	EPA
Total	1.6416			

Criteria Pollutants

VOC	0.6141	0.0053921569	lb/MMBtu	EPA
PM	0.8485	0.0074509804	lb/MMBtu	EPA
PM, Condensible	0.6364	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.2121	0.0018627451	lb/MMBtu	EPA
CO	3.6856	0.0323636360	lb/MMBtu	GRI Field
NMHC	0.9713	0.0085294118	lb/MMBtu	EPA
NOx	11.0483	0.0970167730	lb/MMBtu	GRI Field
SO2	0.0670	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0001	0.0000011765	lb/MMBtu	EPA
Methane	1.1982	0.0105212610	lb/MMBtu	GRI Field
Acetylene	1.5943	0.0140000000	lb/MMBtu	GRI Field
Ethylene	0.1079	0.0009476310	lb/MMBtu	GRI Field
Ethane	0.2996	0.0026312210	lb/MMBtu	GRI Field
Propylene	0.2671	0.0023454550	lb/MMBtu	GRI Field
Propane	0.1217	0.0010686280	lb/MMBtu	GRI Field
Isobutane	0.1667	0.0014640770	lb/MMBtu	GRI Field
Butane	0.1568	0.0013766990	lb/MMBtu	GRI Field
Cyclopentane	0.1287	0.0011304940	lb/MMBtu	GRI Field
Pentane	0.3948	0.0034671850	lb/MMBtu	GRI Field
n-Pentane	0.1620	0.0014221310	lb/MMBtu	GRI Field
Cyclohexane	0.1046	0.0009183830	lb/MMBtu	GRI Field
Methylcyclohexane	0.2507	0.0022011420	lb/MMBtu	GRI Field
n-Octane	0.3250	0.0028538830	lb/MMBtu	GRI Field
1,2,3-Trimethylbenzene	0.3897	0.0034224540	lb/MMBtu	GRI Field
1,2,4-Trimethylbenzene	0.3897	0.0034224540	lb/MMBtu	GRI Field
1,3,5-Trimethylbenzene	0.3897	0.0034224540	lb/MMBtu	GRI Field
n-Nonane	0.4168	0.0036604170	lb/MMBtu	GRI Field
CO2	13,397.6471	117.6470588235	lb/MMBtu	EPA

Unit Name: H3

Hours of Operation:	8,760	Yearly
Heat Input:	10.00	MMBtu/hr
Fuel Type:	NATURAL GAS	
Device Type:	HEATER	
Emission Factor Set:	FIELD > EPA > LITERATURE	
Additional EF Set:	-NONE-	

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor		Emission Factor Set
HAPs				
3-Methylcholanthrene	0.0000	0.0000000018	lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157	lb/MMBtu	EPA
Formaldehyde	0.0370	0.0008440090	lb/MMBtu	GRI Field
Methanol	0.0422	0.0009636360	lb/MMBtu	GRI Field
Acetaldehyde	0.0323	0.0007375920	lb/MMBtu	GRI Field
1,3-Butadiene	0.0150	0.0003423350	lb/MMBtu	GRI Field
Benzene	0.0328	0.0007480470	lb/MMBtu	GRI Field
Toluene	0.0445	0.0010163310	lb/MMBtu	GRI Field
Ethylbenzene	0.0925	0.0021128220	lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.0578	0.0013205140	lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	0.1245	0.0028417580	lb/MMBtu	GRI Field
n-Hexane	0.0616	0.0014070660	lb/MMBtu	GRI Field
Phenol	0.0000	0.0000001070	lb/MMBtu	GRI Field
Styrene	0.0911	0.0020788960	lb/MMBtu	GRI Field
Naphthalene	0.0000	0.0000005100	lb/MMBtu	GRI Field
2-Methylnaphthalene	0.0000	0.0000001470	lb/MMBtu	GRI Field
Acenaphthylene	0.0000	0.0000000670	lb/MMBtu	GRI Field
Biphenyl	0.0000	0.0000004730	lb/MMBtu	GRI Field
Acenaphthene	0.0000	0.0000000900	lb/MMBtu	GRI Field
Fluorene	0.0000	0.0000000800	lb/MMBtu	GRI Field
Anthracene	0.0000	0.0000000870	lb/MMBtu	GRI Field
Phenanthrene	0.0000	0.0000000600	lb/MMBtu	GRI Field
Fluoranthene	0.0000	0.0000000900	lb/MMBtu	GRI Field
Pyrene	0.0000	0.0000000830	lb/MMBtu	GRI Field
Benz(a)anthracene	0.0000	0.0000000870	lb/MMBtu	GRI Field
Chrysene	0.0000	0.0000001170	lb/MMBtu	GRI Field
Benzo(a)pyrene	0.0000	0.0000000700	lb/MMBtu	GRI Field
Benzo(b)fluoranthene	0.0000	0.0000001500	lb/MMBtu	GRI Field
Benzo(k)fluoranthene	0.0000	0.0000007600	lb/MMBtu	GRI Field
Benzo(g,h,i)perylene	0.0000	0.0000002600	lb/MMBtu	GRI Field
Indeno(1,2,3-c,d)pyrene	0.0000	0.0000001200	lb/MMBtu	GRI Field
Dibenz(a,h)anthracene	0.0000	0.0000001030	lb/MMBtu	GRI Field
Lead	0.0000	0.0000004902	lb/MMBtu	EPA
Total	0.6313			
Criteria Pollutants				
VOC	0.2362	0.0053921569	lb/MMBtu	EPA
PM	0.3264	0.0074509804	lb/MMBtu	EPA
PM, Condensible	0.2448	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.0816	0.0018627451	lb/MMBtu	EPA
CO	1.4175	0.0323636360	lb/MMBtu	GRI Field

NMHC	0.3736	0.0085294118	lb/MMBtu	EPA
NOx	4.2493	0.0970167730	lb/MMBtu	GRI Field
SO2	0.0258	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0001	0.0000011765	lb/MMBtu	EPA
Methane	0.4608	0.0105212610	lb/MMBtu	GRI Field
Acetylene	0.6132	0.0140000000	lb/MMBtu	GRI Field
Ethylene	0.0415	0.0009476310	lb/MMBtu	GRI Field
Ethane	0.1152	0.0026312210	lb/MMBtu	GRI Field
Propylene	0.1027	0.0023454550	lb/MMBtu	GRI Field
Propane	0.0468	0.0010686280	lb/MMBtu	GRI Field
Isobutane	0.0641	0.0014640770	lb/MMBtu	GRI Field
Butane	0.0603	0.0013766990	lb/MMBtu	GRI Field
Cyclopentane	0.0495	0.0011304940	lb/MMBtu	GRI Field
Pentane	0.1519	0.0034671850	lb/MMBtu	GRI Field
n-Pentane	0.0623	0.0014221310	lb/MMBtu	GRI Field
Cyclohexane	0.0402	0.0009183830	lb/MMBtu	GRI Field
Methylcyclohexane	0.0964	0.0022011420	lb/MMBtu	GRI Field
n-Octane	0.1250	0.0028538830	lb/MMBtu	GRI Field
1,2,3-Trimethylbenzene	0.1499	0.0034224540	lb/MMBtu	GRI Field
1,2,4-Trimethylbenzene	0.1499	0.0034224540	lb/MMBtu	GRI Field
1,3,5-Trimethylbenzene	0.1499	0.0034224540	lb/MMBtu	GRI Field
n-Nonane	0.1603	0.0036604170	lb/MMBtu	GRI Field
CO2	5,152.9412	117.6470588235	lb/MMBtu	EPA

Unit Name: H4 & H5

Hours of Operation: 8,760 Yearly

Heat Input: 99.00 MMBtu/hr

Fuel Type: NATURAL GAS

Device Type: HEATER

Emission Factor Set: FIELD > EPA > LITERATURE

Additional EF Set: -NONE-

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor		Emission Factor Set
HAPs				
3-Methylcholanthrene	0.0000	0.0000000018	lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157	lb/MMBtu	EPA
Formaldehyde	0.3660	0.0008440090	lb/MMBtu	GRI Field
Methanol	0.4179	0.0009636360	lb/MMBtu	GRI Field
Acetaldehyde	0.3198	0.0007375920	lb/MMBtu	GRI Field
1,3-Butadiene	0.1484	0.0003423350	lb/MMBtu	GRI Field
Benzene	0.3244	0.0007480470	lb/MMBtu	GRI Field
Toluene	0.4407	0.0010163310	lb/MMBtu	GRI Field
Ethylbenzene	0.9162	0.0021128220	lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.5726	0.0013205140	lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	1.2322	0.0028417580	lb/MMBtu	GRI Field
n-Hexane	0.6101	0.0014070660	lb/MMBtu	GRI Field
Phenol	0.0000	0.0000001070	lb/MMBtu	GRI Field
Styrene	0.9015	0.0020788960	lb/MMBtu	GRI Field

Naphthalene	0.0002	0.0000005100	lb/MMBtu	GRI Field
2-Methylnaphthalene	0.0001	0.0000001470	lb/MMBtu	GRI Field
Acenaphthylene	0.0000	0.0000000670	lb/MMBtu	GRI Field
Biphenyl	0.0002	0.0000004730	lb/MMBtu	GRI Field
Acenaphthene	0.0000	0.0000000900	lb/MMBtu	GRI Field
Fluorene	0.0000	0.0000000800	lb/MMBtu	GRI Field
Anthracene	0.0000	0.0000000870	lb/MMBtu	GRI Field
Phenanthrene	0.0000	0.0000000600	lb/MMBtu	GRI Field
Fluoranthene	0.0000	0.0000000900	lb/MMBtu	GRI Field
Pyrene	0.0000	0.0000000830	lb/MMBtu	GRI Field
Benz(a)anthracene	0.0000	0.0000000870	lb/MMBtu	GRI Field
Chrysene	0.0001	0.0000001170	lb/MMBtu	GRI Field
Benzo(a)pyrene	0.0000	0.0000000700	lb/MMBtu	GRI Field
Benzo(b)fluoranthene	0.0001	0.0000001500	lb/MMBtu	GRI Field
Benzo(k)fluoranthene	0.0003	0.0000007600	lb/MMBtu	GRI Field
Benzo(g,h,i)perylene	0.0001	0.0000002600	lb/MMBtu	GRI Field
Indeno(1,2,3-c,d)pyrene	0.0001	0.0000001200	lb/MMBtu	GRI Field
Dibenz(a,h)anthracene	0.0000	0.0000001030	lb/MMBtu	GRI Field
Lead	0.0002	0.0000004902	lb/MMBtu	EPA
Total	6.2512			

Criteria Pollutants

VOC	2.3381	0.0053921569	lb/MMBtu	EPA
PM	3.2309	0.0074509804	lb/MMBtu	EPA
PM, Condensible	2.4232	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.8077	0.0018627451	lb/MMBtu	EPA
CO	14.0335	0.0323636360	lb/MMBtu	GRI Field
NMHC	3.6985	0.0085294118	lb/MMBtu	EPA
NOx	42.0684	0.0970167730	lb/MMBtu	GRI Field
SO2	0.2550	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0005	0.0000011765	lb/MMBtu	EPA
Methane	4.5622	0.0105212610	lb/MMBtu	GRI Field
Acetylene	6.0707	0.0140000000	lb/MMBtu	GRI Field
Ethylene	0.4109	0.0009476310	lb/MMBtu	GRI Field
Ethane	1.1410	0.0026312210	lb/MMBtu	GRI Field
Propylene	1.0170	0.0023454550	lb/MMBtu	GRI Field
Propane	0.4634	0.0010686280	lb/MMBtu	GRI Field
Isobutane	0.6349	0.0014640770	lb/MMBtu	GRI Field
Butane	0.5970	0.0013766990	lb/MMBtu	GRI Field
Cyclopentane	0.4902	0.0011304940	lb/MMBtu	GRI Field
Pentane	1.5034	0.0034671850	lb/MMBtu	GRI Field
n-Pentane	0.6167	0.0014221310	lb/MMBtu	GRI Field
Cyclohexane	0.3982	0.0009183830	lb/MMBtu	GRI Field
Methylcyclohexane	0.9545	0.0022011420	lb/MMBtu	GRI Field
n-Octane	1.2375	0.0028538830	lb/MMBtu	GRI Field
1,2,3-Trimethylbenzene	1.4840	0.0034224540	lb/MMBtu	GRI Field
1,2,4-Trimethylbenzene	1.4840	0.0034224540	lb/MMBtu	GRI Field
1,3,5-Trimethylbenzene	1.4840	0.0034224540	lb/MMBtu	GRI Field
n-Nonane	1.5872	0.0036604170	lb/MMBtu	GRI Field
CO2	51,014.1176	117.6470588235	lb/MMBtu	EPA

Unit Name: H6

Hours of Operation:	8,760	Yearly
Heat Input:	3.5	MMBtu/hr
Fuel Type:	NATURAL GAS	
Device Type:	HEATER	
Emission Factor Set:	FIELD > EPA > LITERATURE	
Additional EF Set:	-NONE-	

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor		Emission Factor Set
HAPs				
3-Methylcholanthrene	0.0000	0.0000000018	lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157	lb/MMBtu	EPA
Formaldehyde	0.0129	0.0008440090	lb/MMBtu	GRI Field
Methanol	0.0148	0.0009636360	lb/MMBtu	GRI Field
Acetaldehyde	0.0113	0.0007375920	lb/MMBtu	GRI Field
1,3-Butadiene	0.0052	0.0003423350	lb/MMBtu	GRI Field
Benzene	0.0115	0.0007480470	lb/MMBtu	GRI Field
Toluene	0.0156	0.0010163310	lb/MMBtu	GRI Field
Ethylbenzene	0.0324	0.0021128220	lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.0202	0.0013205140	lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	0.0436	0.0028417580	lb/MMBtu	GRI Field
n-Hexane	0.0216	0.0014070660	lb/MMBtu	GRI Field
Phenol	0.0000	0.0000001070	lb/MMBtu	GRI Field
Styrene	0.0319	0.0020788960	lb/MMBtu	GRI Field
Naphthalene	0.0000	0.0000005100	lb/MMBtu	GRI Field
2-Methylnaphthalene	0.0000	0.0000001470	lb/MMBtu	GRI Field
Acenaphthylene	0.0000	0.0000000670	lb/MMBtu	GRI Field
Biphenyl	0.0000	0.0000004730	lb/MMBtu	GRI Field
Acenaphthene	0.0000	0.0000000900	lb/MMBtu	GRI Field
Fluorene	0.0000	0.0000000800	lb/MMBtu	GRI Field
Anthracene	0.0000	0.0000000870	lb/MMBtu	GRI Field
Phenanthrene	0.0000	0.0000000600	lb/MMBtu	GRI Field
Fluoranthene	0.0000	0.0000000900	lb/MMBtu	GRI Field
Pyrene	0.0000	0.0000000830	lb/MMBtu	GRI Field
Benz(a)anthracene	0.0000	0.0000000870	lb/MMBtu	GRI Field
Chrysene	0.0000	0.0000001170	lb/MMBtu	GRI Field
Benzo(a)pyrene	0.0000	0.0000000700	lb/MMBtu	GRI Field
Benzo(b)fluoranthene	0.0000	0.0000001500	lb/MMBtu	GRI Field
Benzo(k)fluoranthene	0.0000	0.0000007600	lb/MMBtu	GRI Field
Benzo(g,h,i)perylene	0.0000	0.0000002600	lb/MMBtu	GRI Field
Indeno(1,2,3-c,d)pyrene	0.0000	0.0000001200	lb/MMBtu	GRI Field
Dibenz(a,h)anthracene	0.0000	0.0000001030	lb/MMBtu	GRI Field
Lead	0.0000	0.0000004902	lb/MMBtu	EPA
Total	0.2210			
Criteria Pollutants				
VOC	0.0827	0.0053921569	lb/MMBtu	EPA
PM	0.1142	0.0074509804	lb/MMBtu	EPA
PM, Condensible	0.0857	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.0286	0.0018627451	lb/MMBtu	EPA
CO	0.4961	0.0323636360	lb/MMBtu	GRI Field

NMHC	0.1308	0.0085294118	lb/MMBtu	EPA
NOx	1.4873	0.0970167730	lb/MMBtu	GRI Field
SO2	0.0090	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0000	0.0000011765	lb/MMBtu	EPA
Methane	0.1613	0.0105212610	lb/MMBtu	GRI Field
Acetylene	0.2146	0.0140000000	lb/MMBtu	GRI Field
Ethylene	0.0145	0.0009476310	lb/MMBtu	GRI Field
Ethane	0.0403	0.0026312210	lb/MMBtu	GRI Field
Propylene	0.0360	0.0023454550	lb/MMBtu	GRI Field
Propane	0.0164	0.0010686280	lb/MMBtu	GRI Field
Isobutane	0.0224	0.0014640770	lb/MMBtu	GRI Field
Butane	0.0211	0.0013766990	lb/MMBtu	GRI Field
Cyclopentane	0.0173	0.0011304940	lb/MMBtu	GRI Field
Pentane	0.0532	0.0034671850	lb/MMBtu	GRI Field
n-Pentane	0.0218	0.0014221310	lb/MMBtu	GRI Field
Cyclohexane	0.0141	0.0009183830	lb/MMBtu	GRI Field
Methylcyclohexane	0.0337	0.0022011420	lb/MMBtu	GRI Field
n-Octane	0.0438	0.0028538830	lb/MMBtu	GRI Field
1,2,3-Trimethylbenzene	0.0525	0.0034224540	lb/MMBtu	GRI Field
1,2,4-Trimethylbenzene	0.0525	0.0034224540	lb/MMBtu	GRI Field
1,3,5-Trimethylbenzene	0.0525	0.0034224540	lb/MMBtu	GRI Field
n-Nonane	0.0561	0.0036604170	lb/MMBtu	GRI Field
CO2	1,803.5294	117.6470588235	lb/MMBtu	EPA

40 CFR Appendix Table C-1 to Subpart C of Part 98 - Default CO2 Emission Factors and High Heat Values for Various Types of Fuel

CFR

Table C-1 to Subpart C of Part 98 - Default CO^2 Emission Factors and High Heat Values for Various Types of Fuel

Default CO^2 Emission Factors and High Heat Values for Various Types of Fuel

Fuel type	Default high heat value	Default CO^2 emission factor
Coal and coke	mmBtu/short ton	kg CO^2/mmBtu
Anthracite	25.09	103.69
Bituminous	24.93	93.28
Subbituminous	17.25	97.17
Lignite	14.21	97.72
Coal Coke	24.80	113.67
Mixed (Commercial sector)	21.39	94.27
Mixed (Industrial coking)	26.28	93.90
Mixed (Industrial sector)	22.35	94.67
Mixed (Electric Power sector)	19.73	95.52
Natural gas	mmBtu/scf	kg CO^2/mmBtu
(Weighted U.S. Average)	1.026×10^{-3}	53.06
Petroleum products - liquid	mmBtu/gallon	kg CO^2/mmBtu
Distillate Fuel Oil No. 1	0.139	73.25
Distillate Fuel Oil No. 2	0.138	73.96
Distillate Fuel Oil No. 4	0.146	75.04
Residual Fuel Oil No. 5	0.140	72.93
Residual Fuel Oil No. 6	0.150	75.10
Used Oil	0.138	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG) [1]	0.092	61.71
Propane [1]	0.091	62.87
Propylene [2]	0.091	67.77
Ethane [1]	0.068	59.60
Ethanol	0.084	68.44
Ethylene [2]	0.058	65.96
Isobutane [1]	0.099	64.94
Isobutylene [1]	0.103	68.86
Butane [1]	0.103	64.77
Butylene [1]	0.105	68.72
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.88
Other Oil (>401 deg F)	0.139	76.22
Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.125	71.02
Special Naphtha	0.125	72.34

Lubricants	0.144	74.27
Motor Gasoline	0.125	70.22
Aviation Gasoline	0.120	69.25
Kerosene-Type Jet Fuel	0.135	72.22
Asphalt and Road Oil	0.158	75.36
Crude Oil	0.138	74.54
Petroleum products - solid	mmBtu/short ton	kg CO2/mmBtu.
Petroleum Coke	30.00	102.41.
Petroleum products - gaseous	mmBtu/scf	kg CO2/mmBtu.
Propane Gas	2.516×10^{-3}	61.46.
Other fuels - solid	mmBtu/short ton	kg CO^2/mmBtu
Municipal Solid Waste	9.95 [3]	90.7
Tires	28.00	85.97
Plastics	38.00	75.00
Other fuels - gaseous	mmBtu/scf	kg CO^2/mmBtu
Blast Furnace Gas	0.092×10^{-3}	274.32
Coke Oven Gas	0.599×10^{-3}	46.85
Fuel Gas [4]	1.388×10^{-3}	59.00
Biomass fuels - solid	mmBtu/short ton	kg CO^2/mmBtu
Wood and Wood Residuals (dry basis) [5]	17.48	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	10.39	105.51
Biomass fuels - gaseous	mmBtu/scf	kg CO^2/mmBtu
Landfill Gas	0.485×10^{-3}	52.07
Other Biomass Gases	0.655×10^{-3}	52.07
Biomass Fuels - Liquid	mmBtu/gallon	kg CO^2/mmBtu
Ethanol	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] The HHV for components of LPG determined at 60 °F and saturation pressure with the exception of ethylene.

[2] Ethylene HHV determined at 41 °F (5 °C) and saturation pressure.

[3] Use of this default HHV is allowed only for: (a) Units that combust MSW, do not generate steam, and are allowed to use Tier 1; (b) units that derive no more than 10 percent of their annual heat input from MSW and/or tires; and (c) small batch incinerators that combust no more than 1,000 tons of MSW per year.

[4] Reporters subject to subpart X of this part that are complying with § 98.243(d) or subpart Y of this part may only use the default HHV and the default CO^2 emission factor for fuel gas combustion under the conditions prescribed in § 98.243(d)(2)(i) and (d)(2)(ii) and § 98.252(a)(1) and (a)(2), respectively. Otherwise, reporters subject to subpart X or subpart Y shall use either Tier 3 (Equation C-5) or Tier 4.

[5] Use the following formula to calculate a wet basis HHV for use in Equation C-1: $HHV^w = ((100 - M)/100)*HHV^d$ where HHV^w = wet basis HHV, M = moisture content (percent) and HHV^d = dry basis HHV from Table C-1.

[78 FR 71950, Nov. 29, 2013, as amended at 81 FR 89252, Dec. 9, 2016]

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1.3.3 Emissions[5]

Emissions from fuel oil combustion depend on the grade and composition of the fuel, the type and size of the boiler, the firing and loading practices used, and the level of equipment maintenance. Because the combustion characteristics of distillate and residual oils are different, their combustion can produce significantly different emissions. In general, the baseline emissions of criteria and noncriteria pollutants are those from uncontrolled combustion sources. Uncontrolled sources are those without add-on air pollution control (APC) equipment or other combustion modifications designed for emission control. Baseline emissions for sulfur dioxide (SO_2) and particulate matter (PM) can also be obtained from measurements taken upstream of APC equipment.

1.3.3.1 Particulate Matter Emissions[6-15] -

Particulate emissions may be categorized as either filterable or condensable. Filterable emissions are generally considered to be the particules that are trapped by the glass fiber filter in the front half of a Reference Method 5 or Method 17 sampling van. Vapors and particles less than 0.3 microns pass through the filter. Condensable particulate matter is material that is emitted in the vapor state which later condenses to form homogeneous and/or heterogeneous aerosol particles. The condensable particulate emitted from boilers fueled on coal or oil is primarily inorganic in nature.

Filterable particulate matter emissions depend predominantly on the grade of fuel fired. Combustion of lighter distillate oils results in significantly lower PM formation than does combustion of heavier residual oils. Among residual oils, firing of No. 4 or No. 5 oil usually produces less PM than does the firing of heavier No. 6 oil.

In general, filterable PM emissions depend on the completeness of combustion as well as on the oil ash content. The PM emitted by distillate oil-fired boilers primarily comprises carbonaceous particles resulting from incomplete combustion of oil and is not correlated to the ash or sulfur content of the oil. However, PM emissions from residual oil burning are related to the oil sulfur content. This is because low-sulfur No. 6 oil, either from naturally low-sulfur crude oil or desulfurized by one of several processes, exhibits substantially lower viscosity and reduced asphaltene, ash, and sulfur contents, which results in better atomization and more complete combustion.

Boiler load can also affect filterable particulate emissions in units firing No. 6 oil. At low load (50 percent of maximum rating) conditions, particulate emissions from utility boilers may be lowered by 30 to 40 percent and by as much as 60 percent from small industrial and commercial units. However, no significant particulate emission reductions have been noted at low loads from boilers firing any of the lighter grades. At very low load conditions (approximately 30 percent of maximum rating), proper combustion conditions may be difficult to maintain and particulate emissions may increase significantly.

1.3.3.2 Sulfur Oxides Emissions[1-2,6-9,16] -

Sulfur oxides (SO_x) emissions are generated during oil combustion from the oxidation of sulfur contained in the fuel. The emissions of SO_x from conventional combustion systems are predominantly in the form of SO_2. Uncontrolled SO_x emissions are almost entirely dependent on the sulfur content of the fuel and are not affected by boiler size, burner design, or grade of fuel being fired. On average, more than 95 percent of the fuel sulfur is converted to SO_2, about 1 to 5 percent is further oxidized to sulfur trioxide (SO_3), and 1 to 3 percent is emitted as sulfate particulate. SO_3 readily reacts with water vapor (both in the atmosphere and in flue gases) to form a sulfuric acid mist.

Section 7.3 – Dehydrator (Unit Dehy)

- Section 7.3-1 – GRI-GLYCalc 4.0 run for the Dehydrator (Unit Dehy)
- Section 7.3-2 – TEG dehydrator Gas Analysis

Section 7.3-1 – GRI-GLYCalc 4.0 run for the Dehydrator (Unit Dehy)

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: Zia II Gas Plant
File Name: P:\1. CLIENTS\DCP Midstream\00 Greenfield Gas Plant (Zia II)\04 CALCULATIONS\Glycol Dehy\GlyCalc\Zia II Glycol Dehy.ddf
Date: March 28, 2013

DESCRIPTION:

Description: the Glycol Dehydrator gas stream is inlet gas, after being treated by amine, at a volume of 230 MMscfd.

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 120.00 deg. F
Pressure: 900.00 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	0.0110
Nitrogen	2.6630
Methane	72.6170
Ethane	12.8440
Propane	6.8980
Isobutane	0.8300
n-Butane	2.1130
Isopentane	0.5240
n-Pentane	0.5540
n-Hexane	0.6170
Heptanes	0.2170
Benzene	0.0110
Toluene	0.0110
Ethylbenzene	0.0020
Xylenes	0.0110
C8+ Heavies	0.0760

DRY GAS:

Flow Rate: 230.0 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.0 wt% H2O
Flow Rate: 30.0 gpm

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Recycle/recompression
Temperature: 190.0 deg. F
Pressure: 60.0 psig

REGENERATOR OVERHEADS CONTROL DEVICE:

Control Device: Condenser
Temperature: 140.0 deg. F
Pressure: 13.0 psia

GRI-GLYCalc VERSION 4.0 - EMISSIONS SUMMARY

Case Name: Zia II Gas Plant
File Name: P:\1. CLIENTS\DCP Midstream\00 Greenfield Gas Plant (Zia II)\04 CALCULATIONS\Glycol Dehy\GlyCalc\Zia II Glycol Dehy.ddf
Date: March 28, 2013

CONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	2.0047	48.113	8.7807
Ethane	4.5008	108.018	19.7133
Propane	9.7230	233.351	42.5865
Isobutane	2.2321	53.571	9.7768
n-Butane	8.1941	196.658	35.8901
Isopentane	2.1545	51.709	9.4368
n-Pentane	2.9620	71.089	12.9737
n-Hexane	5.9849	143.637	26.2137
Heptanes	3.2606	78.254	14.2813
Benzene	5.3355	128.052	23.3694
Toluene	4.3499	104.399	19.0528
Ethylbenzene	0.5461	13.107	2.3920
Xylenes	3.6011	86.427	15.7729
C8+ Heavies	0.0333	0.800	0.1459
Total Emissions	54.8827	1317.184	240.3861
Total Hydrocarbon Emissions	54.8827	1317.184	240.3861
Total VOC Emissions	48.3772	1161.052	211.8921
Total HAP Emissions	19.8175	475.621	86.8009
Total BTEX Emissions	13.8327	331.984	60.5871

These are the emissions used in the dehydrator calculations.

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	2.0083	48.199	8.7964
Ethane	4.5301	108.722	19.8418
Propane	10.0078	240.188	43.8343
Isobutane	2.3540	56.496	10.3106
n-Butane	8.7867	210.881	38.4857
Isopentane	2.5195	60.468	11.0355
n-Pentane	3.6979	88.750	16.1968
n-Hexane	8.8344	212.026	38.6947
Heptanes	7.3614	176.675	32.2431
Benzene	10.1984	244.761	44.6690
Toluene	15.3278	367.866	67.1356
Ethylbenzene	3.9665	95.196	17.3732
Xylenes	30.6941	736.658	134.4401
C8+ Heavies	10.1574	243.778	44.4895
Total Emissions	120.4444	2890.665	527.5463
Total Hydrocarbon Emissions	120.4444	2890.665	527.5463
Total VOC Emissions	113.9060	2733.743	498.9081
Total HAP Emissions	69.0211	1656.508	302.3126
Total BTEX Emissions	60.1867	1444.481	263.6179

FLASH GAS EMISSIONS

Note: Flash Gas Emissions are zero with the
Recycle/recompression control option.

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	36.2761	870.625	158.8891
Ethane	29.9055	717.733	130.9863
Propane	30.5148	732.355	133.6548
Isobutane	5.5795	133.909	24.4384
n-Butane	16.9234	406.163	74.1247
Isopentane	4.7716	114.518	20.8995
n-Pentane	5.8992	141.581	25.8386
n-Hexane	9.2852	222.846	40.6693
Heptanes	4.5817	109.961	20.0678
Benzene	0.4991	11.979	2.1862
Toluene	0.5738	13.772	2.5133
Ethylbenzene	0.1002	2.405	0.4389
Xylenes	0.5487	13.168	2.4032
C8+ Heavies	11.3321	271.970	49.6345
Total Emissions	156.7910	3762.984	686.7446
Total Hydrocarbon Emissions	156.7910	3762.984	686.7446
Total VOC Emissions	90.6094	2174.626	396.8692
Total HAP Emissions	11.0071	264.170	48.2109
Total BTEX Emissions	1.7218	41.324	7.5416

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: Zia II Gas Plant
File Name: P:\1. CLIENTS\DCP Midstream\00 Greenfield Gas Plant (Zia II)\04 CALCULATIONS\Glycol Dehy\GlyCalc\Zia II Glycol Dehy.ddf
Date: March 28, 2013

DESCRIPTION:

Description: the Glycol Dehydrator gas stream is inlet gas, after being treated by amine, at a volume of 230 MMscfd.

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

CONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	2.0047	48.113	8.7807
Ethane	4.5008	108.018	19.7133
Propane	9.7230	233.351	42.5865
Isobutane	2.2321	53.571	9.7768
n-Butane	8.1941	196.658	35.8901
Isopentane	2.1545	51.709	9.4368
n-Pentane	2.9620	71.089	12.9737
n-Hexane	5.9849	143.637	26.2137
Heptanes	3.2606	78.254	14.2813
Benzene	5.3355	128.052	23.3694
Toluene	4.3499	104.399	19.0528
Ethylbenzene	0.5461	13.107	2.3920
Xylenes	3.6011	86.427	15.7729
C8+ Heavies	0.0333	0.800	0.1459
Total Emissions	54.8827	1317.184	240.3861
Total Hydrocarbon Emissions	54.8827	1317.184	240.3861
Total VOC Emissions	48.3772	1161.052	211.8921
Total HAP Emissions	19.8175	475.621	86.8009
Total BTEX Emissions	13.8327	331.984	60.5871

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	2.0083	48.199	8.7964
Ethane	4.5301	108.722	19.8418
Propane	10.0078	240.188	43.8343
Isobutane	2.3540	56.496	10.3106
n-Butane	8.7867	210.881	38.4857
Isopentane	2.5195	60.468	11.0355
n-Pentane	3.6979	88.750	16.1968
n-Hexane	8.8344	212.026	38.6947
Heptanes	7.3614	176.675	32.2431
Benzene	10.1984	244.761	44.6690
Toluene	15.3278	367.866	67.1356
Ethylbenzene	3.9665	95.196	17.3732

Xylenes	30.6941	736.658	134.4401
C8+ Heavies	10.1574	243.778	44.4895
Total Emissions	120.4444	2890.665	527.5463
Total Hydrocarbon Emissions	120.4444	2890.665	527.5463
Total VOC Emissions	113.9060	2733.743	498.9081
Total HAP Emissions	69.0211	1656.508	302.3126
Total BTEX Emissions	60.1867	1444.481	263.6179

FLASH GAS EMISSIONS

Note: Flash Gas Emissions are zero with the Recycle/recompression control option.

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	36.2761	870.625	158.8891
Ethane	29.9055	717.733	130.9863
Propane	30.5148	732.355	133.6548
Isobutane	5.5795	133.909	24.4384
n-Butane	16.9234	406.163	74.1247
Isopentane	4.7716	114.518	20.8995
n-Pentane	5.8992	141.581	25.8386
n-Hexane	9.2852	222.846	40.6693
Heptanes	4.5817	109.961	20.0678
Benzene	0.4991	11.979	2.1862
Toluene	0.5738	13.772	2.5133
Ethylbenzene	0.1002	2.405	0.4389
Xylenes	0.5487	13.168	2.4032
C8+ Heavies	11.3321	271.970	49.6345
Total Emissions	156.7910	3762.984	686.7446
Total Hydrocarbon Emissions	156.7910	3762.984	686.7446
Total VOC Emissions	90.6094	2174.626	396.8692
Total HAP Emissions	11.0071	264.170	48.2109
Total BTEX Emissions	1.7218	41.324	7.5416

EQUIPMENT REPORTS:

CONDENSER

Condenser Outlet Temperature:	140.00 deg. F
Condenser Pressure:	13.00 psia
Condenser Duty:	7.35e-001 MM BTU/hr
Hydrocarbon Recovery:	5.24 bbls/day
Produced Water:	67.73 bbls/day
VOC Control Efficiency:	57.53 %
HAP Control Efficiency:	71.29 %
BTEX Control Efficiency:	77.02 %
Dissolved Hydrocarbons in Water:	533.18 mg/L

Component	Emitted	Condensed

Water	0.52%	99.48%
Carbon Dioxide	98.56%	1.44%
Nitrogen	99.81%	0.19%
Methane	99.82%	0.18%
Ethane	99.35%	0.65%
Propane	97.15%	2.85%
Isobutane	94.82%	5.18%
n-Butane	93.26%	6.74%
Isopentane	85.51%	14.49%
n-Pentane	80.10%	19.90%
n-Hexane	67.74%	32.26%
Heptanes	44.29%	55.71%
Benzene	52.32%	47.68%
Toluene	28.38%	71.62%
Ethylbenzene	13.77%	86.23%
Xylenes	11.73%	88.27%
C8+ Heavies	0.33%	99.67%

ABSORBER

Calculated Absorber Stages:	1.56
Specified Dry Gas Dew Point:	7.00 lbs. H2O/MMSCF
Temperature:	120.0 deg. F
Pressure:	900.0 psig
Dry Gas Flow Rate:	230.0000 MMSCF/day
Glycol Losses with Dry Gas:	12.3147 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	110.55 lbs. H2O/MMSCF
Calculated Lean Glycol Recirc. Ratio:	1.81 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	6.32%	93.68%
Carbon Dioxide	99.85%	0.15%
Nitrogen	99.99%	0.01%
Methane	99.99%	0.01%
Ethane	99.96%	0.04%
Propane	99.95%	0.05%
Isobutane	99.93%	0.07%
n-Butane	99.92%	0.08%
Isopentane	99.92%	0.08%
n-Pentane	99.90%	0.10%
n-Hexane	99.87%	0.13%
Heptanes	99.78%	0.22%
Benzene	95.07%	4.93%
Toluene	93.79%	6.21%
Ethylbenzene	92.42%	7.58%
Xylenes	89.40%	10.60%
C8+ Heavies	99.34%	0.66%

FLASH TANK

Flash Control:	Recycle/recompression
Flash Temperature:	190.0 deg. F
Flash Pressure:	60.0 psig

Left in Removed in

Component	Glycol	Flash Gas
Water	99.84%	0.16%
Carbon Dioxide	30.96%	69.04%
Nitrogen	4.99%	95.01%
Methane	5.25%	94.75%
Ethane	13.15%	86.85%
Propane	24.70%	75.30%
Isobutane	29.67%	70.33%
n-Butane	34.17%	65.83%
Isopentane	34.88%	65.12%
n-Pentane	38.84%	61.16%
n-Hexane	49.01%	50.99%
Heptanes	61.83%	38.17%
Benzene	95.57%	4.43%
Toluene	96.68%	3.32%
Ethylbenzene	97.79%	2.21%
Xylenes	98.47%	1.53%
C8+ Heavies	53.63%	46.37%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	14.53%	85.47%
Carbon Dioxide	0.00%	100.00%
Nitrogen	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
Isobutane	0.00%	100.00%
n-Butane	0.00%	100.00%
Isopentane	1.43%	98.57%
n-Pentane	1.29%	98.71%
n-Hexane	1.02%	98.98%
Heptanes	0.81%	99.19%
Benzene	5.23%	94.77%
Toluene	8.18%	91.82%
Ethylbenzene	10.66%	89.34%
Xylenes	13.17%	86.83%
C8+ Heavies	22.49%	77.51%

STREAM REPORTS:

WET GAS STREAM

Temperature: 120.00 deg. F
Pressure: 914.70 psia
Flow Rate: 9.61e+006 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Component	Conc.	Loading
Water	2.33e-001	1.06e+003
Carbon Dioxide	1.10e-002	1.22e+002
Nitrogen	2.66e+000	1.88e+004
Methane	7.24e+001	2.94e+005
Ethane	1.28e+001	9.76e+004
Propane	6.88e+000	7.69e+004
Isobutane	8.28e-001	1.22e+004
n-Butane	2.11e+000	3.10e+004
Isopentane	5.23e-001	9.55e+003
n-Pentane	5.53e-001	1.01e+004
n-Hexane	6.16e-001	1.34e+004
Heptanes	2.16e-001	5.49e+003
Benzene	1.10e-002	2.17e+002
Toluene	1.10e-002	2.56e+002
Ethylbenzene	2.00e-003	5.36e+001
Xylenes	1.10e-002	2.95e+002
C8+ Heavies	7.58e-002	3.27e+003
Total Components	100.00	5.75e+005

DRY GAS STREAM

Temperature: 120.00 deg. F
Pressure: 914.70 psia
Flow Rate: 9.58e+006 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.47e-002	6.71e+001
Carbon Dioxide	1.10e-002	1.22e+002
Nitrogen	2.66e+000	1.88e+004
Methane	7.26e+001	2.94e+005
Ethane	1.28e+001	9.75e+004
Propane	6.90e+000	7.68e+004
Isobutane	8.30e-001	1.22e+004
n-Butane	2.11e+000	3.10e+004
Isopentane	5.24e-001	9.54e+003
n-Pentane	5.54e-001	1.01e+004
n-Hexane	6.16e-001	1.34e+004
Heptanes	2.17e-001	5.48e+003
Benzene	1.05e-002	2.06e+002
Toluene	1.03e-002	2.40e+002
Ethylbenzene	1.85e-003	4.96e+001
Xylenes	9.84e-003	2.64e+002
C8+ Heavies	7.55e-002	3.25e+003
Total Components	100.00	5.73e+005

LEAN GLYCOL STREAM

Temperature: 120.00 deg. F
Flow Rate: 3.00e+001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.89e+001	1.67e+004
Water	1.00e+000	1.69e+002

Carbon Dioxide	1.07e-013	1.80e-011
Nitrogen	1.66e-012	2.81e-010
Methane	7.62e-018	1.29e-015
Ethane	9.63e-008	1.63e-005
Propane	9.77e-009	1.65e-006
Isobutane	1.41e-009	2.38e-007
n-Butane	3.78e-009	6.38e-007
Isopentane	2.17e-004	3.67e-002
n-Pentane	2.86e-004	4.82e-002
n-Hexane	5.39e-004	9.11e-002
Heptanes	3.56e-004	6.00e-002
Benzene	3.34e-003	5.63e-001
Toluene	8.09e-003	1.37e+000
Ethylbenzene	2.80e-003	4.73e-001
Xylenes	2.76e-002	4.66e+000
C8+ Heavies	1.75e-002	2.95e+000
Total Components	100.00	1.69e+004

RICH GLYCOL STREAM

Temperature: 120.00 deg. F
Pressure: 914.70 psia
Flow Rate: 3.25e+001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.20e+001	1.67e+004
Water	6.42e+000	1.16e+003
Carbon Dioxide	9.92e-004	1.80e-001
Nitrogen	1.54e-002	2.79e+000
Methane	2.11e-001	3.83e+001
Ethane	1.90e-001	3.44e+001
Propane	2.23e-001	4.05e+001
Isobutane	4.37e-002	7.93e+000
n-Butane	1.42e-001	2.57e+001
Isopentane	4.04e-002	7.33e+000
n-Pentane	5.32e-002	9.65e+000
n-Hexane	1.00e-001	1.82e+001
Heptanes	6.62e-002	1.20e+001
Benzene	6.21e-002	1.13e+001
Toluene	9.52e-002	1.73e+001
Ethylbenzene	2.50e-002	4.54e+000
Xylenes	1.98e-001	3.59e+001
C8+ Heavies	1.35e-001	2.44e+001
Total Components	100.00	1.81e+004

FLASH TANK OFF GAS STREAM

Temperature: 190.00 deg. F
Pressure: 74.70 psia
Flow Rate: 1.87e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	2.15e+000	1.91e+000

Carbon Dioxide	5.73e-002	1.24e-001
Nitrogen	1.92e+000	2.65e+000
Methane	4.59e+001	3.63e+001
Ethane	2.02e+001	2.99e+001
Propane	1.40e+001	3.05e+001
Isobutane	1.95e+000	5.58e+000
n-Butane	5.91e+000	1.69e+001
Isopentane	1.34e+000	4.77e+000
n-Pentane	1.66e+000	5.90e+000
n-Hexane	2.19e+000	9.29e+000
Heptanes	9.28e-001	4.58e+000
Benzene	1.30e-001	4.99e-001
Toluene	1.26e-001	5.74e-001
Ethylbenzene	1.92e-002	1.00e-001
Xylenes	1.05e-001	5.49e-001
C8+ Heavies	1.35e+000	1.13e+001
Total Components	100.00	1.61e+002

FLASH TANK GLYCOL STREAM

Temperature: 190.00 deg. F
Flow Rate: 3.22e+001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.28e+001	1.67e+004
Water	6.46e+000	1.16e+003
Carbon Dioxide	3.10e-004	5.57e-002
Nitrogen	7.74e-004	1.39e-001
Methane	1.12e-002	2.01e+000
Ethane	2.52e-002	4.53e+000
Propane	5.57e-002	1.00e+001
Isobutane	1.31e-002	2.35e+000
n-Butane	4.89e-002	8.79e+000
Isopentane	1.42e-002	2.56e+000
n-Pentane	2.08e-002	3.75e+000
n-Hexane	4.96e-002	8.93e+000
Heptanes	4.13e-002	7.42e+000
Benzene	5.99e-002	1.08e+001
Toluene	9.29e-002	1.67e+001
Ethylbenzene	2.47e-002	4.44e+000
Xylenes	1.97e-001	3.54e+001
C8+ Heavies	7.29e-002	1.31e+001
Total Components	100.00	1.80e+004

FLASH GAS EMISSIONS

Control Method: Recycle/recompression
Control Efficiency: 100.00

Note: Flash Gas Emissions are zero with the Recycle/recompression control option.

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 2.15e+004 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.71e+001	9.93e+002
Carbon Dioxide	2.23e-003	5.57e-002
Nitrogen	8.75e-003	1.39e-001
Methane	2.20e-001	2.01e+000
Ethane	2.65e-001	4.53e+000
Propane	4.00e-001	1.00e+001
Isobutane	7.13e-002	2.35e+000
n-Butane	2.66e-001	8.79e+000
Isopentane	6.15e-002	2.52e+000
n-Pentane	9.02e-002	3.70e+000
n-Hexane	1.80e-001	8.83e+000
Heptanes	1.29e-001	7.36e+000
Benzene	2.30e-001	1.02e+001
Toluene	2.93e-001	1.53e+001
Ethylbenzene	6.58e-002	3.97e+000
Xylenes	5.09e-001	3.07e+001
C8+ Heavies	1.05e-001	1.02e+001
Total Components	100.00	1.11e+003

CONDENSER VENT GAS STREAM

Temperature: 140.00 deg. F
Pressure: 13.00 psia
Flow Rate: 4.92e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	2.23e+001	5.21e+000
Carbon Dioxide	9.62e-002	5.49e-002
Nitrogen	3.82e-001	1.39e-001
Methane	9.63e+000	2.00e+000
Ethane	1.15e+001	4.50e+000
Propane	1.70e+001	9.72e+000
Isobutane	2.96e+000	2.23e+000
n-Butane	1.09e+001	8.19e+000
Isopentane	2.30e+000	2.15e+000
n-Pentane	3.16e+000	2.96e+000
n-Hexane	5.35e+000	5.98e+000
Heptanes	2.51e+000	3.26e+000
Benzene	5.26e+000	5.34e+000
Toluene	3.64e+000	4.35e+000
Ethylbenzene	3.96e-001	5.46e-001
Xylenes	2.61e+000	3.60e+000
C8+ Heavies	1.51e-002	3.33e-002
Total Components	100.00	6.03e+001

These are the GHG emissions used in the condenser controlled regenerator emissions in the calculations.

CONDENSER PRODUCED WATER STREAM

Temperature: 140.00 deg. F
Flow Rate: 1.98e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)	(ppm)
Water	9.99e+001	9.88e+002	999466.
Carbon Dioxide	6.22e-005	6.15e-004	1.
Nitrogen	4.70e-006	4.64e-005	0.
Methane	1.25e-004	1.23e-003	1.
Ethane	3.06e-004	3.02e-003	3.
Propane	7.67e-004	7.58e-003	8.
Isobutane	9.38e-005	9.28e-004	1.
n-Butane	4.47e-004	4.42e-003	4.
Isopentane	8.05e-005	7.96e-004	1.
n-Pentane	1.17e-004	1.16e-003	1.
n-Hexane	1.89e-004	1.87e-003	2.
Heptanes	5.57e-005	5.50e-004	1.
Benzene	2.28e-002	2.26e-001	228.
Toluene	1.48e-002	1.46e-001	148.
Ethylbenzene	1.36e-003	1.34e-002	14.
Xylenes	1.22e-002	1.20e-001	122.
C8+ Heavies	2.89e-007	2.86e-006	0.
Total Components	100.00	9.88e+002	1000000.

CONDENSER RECOVERED OIL STREAM

Temperature: 140.00 deg. F
Flow Rate: 1.53e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
Water	5.19e-002	3.38e-002
Carbon Dioxide	2.86e-004	1.86e-004
Nitrogen	3.45e-004	2.25e-004
Methane	3.60e-003	2.35e-003
Ethane	4.05e-002	2.63e-002
Propane	4.26e-001	2.77e-001
Isobutane	1.86e-001	1.21e-001
n-Butane	9.04e-001	5.88e-001
Isopentane	5.60e-001	3.64e-001
n-Pentane	1.13e+000	7.35e-001
n-Hexane	4.38e+000	2.85e+000
Heptanes	6.30e+000	4.10e+000
Benzene	7.13e+000	4.64e+000
Toluene	1.66e+001	1.08e+001
Ethylbenzene	5.24e+000	3.41e+000
Xylenes	4.15e+001	2.70e+001
C8+ Heavies	1.56e+001	1.01e+001
Total Components	100.00	6.51e+001

Section 7.3-2 – TEG dehydrator Gas Analysis

From: Corser, Jennifer
To: Adam Erenstein (aerenstein@trinityconsultants.com)
Subject: FW: Gas composition to TEG, Zia 2
Date: 03/07/2013 03:43 PM
For Follow Up: Normal Priority.

Jennifer Corser
432-249-2702

From: Ross, Jeffrey D
Sent: Thursday, March 07, 2013 4:40 PM
To: Corser, Jennifer
Subject: Gas composition to TEG, Zia 2

	Inlet Gas mol%	Normalized To TEG mol%
Nitrogen	2.460	2.663
CO2	6.700	0.011
Methane	67.070	72.617
Ethane	11.863	12.844
Propane	6.371	6.898
i-Butane	0.767	0.830
n-Butane	1.952	2.113
i-Pentane	0.484	0.524
n-Pentane	0.512	0.554
n-Hexane	0.570	0.617
n-Heptane	0.200	0.217
n-Octane	0.070	0.076
Benzene	0.010	0.011
Toluene	0.010	0.011
E-Benzene	0.002	0.002
m-Xylene	0.010	0.011
p-Xylene	0.000	0.000
o-Xylene	0.000	0.000
H2S	0.960	0.000
H2O	0.000	0.000
	100.01	100.000

Jeff Ross
Director, Project Development
Engineering/Chief Corporate Office
DCP Midstream
303-605-1609 Office
303-249-3137 Mobile

Section 7.4 – Flares (Units FL1, FL2, FL3)

- Section 7.4-1 – Inlet Gas Analysis
- Section 7.4-2 – Acid Gas Analysis
- Section 7.4-3 – EPA AP42 Table 13.5-1 for flares

Section 7.4-1 – Inlet Gas Analysis

DCP Midstream, LP - Zia II Gas Plant

Inlet Gas Analysis

Components	Analysis Mole%	MW lb/lb mol
Nitrogen	2.46%	28.01
Carbon Dioxide	6.70%	44.01
Methane	67.07%	16.04
Ethane	11.86%	30.07
Propane	6.37%	44.10
i-Butane	0.77%	58.12
n-Butane	1.95%	58.12
i-Pentane	0.48%	72.15
n-Pentane	0.51%	72.15
n-Hexane	0.57%	86.18
n-Heptane	0.20%	100.21
n-Octane	0.07%	114.23
Benzene	0.01%	78.11
Toluene	0.01%	92.14
E-Benzene	0.00%	106.17
m-Xylene	0.01%	106.17
p-Xylene	0.00%	106.17
o-Xylene	0.00%	106.17
H2S	0.96%	34.08
Total	100.0%	
Total VOC	10.96%	
Heating Value	1226.2	Btu/scf

Section 7.4-2 – Acid Gas Analysis

DCP Midstream, LP - Zia II Gas Plant

Acid Gas Analysis

Components	Analysis Mole%	MW lb/lb mol
Nitrogen	0.00%	28.01
Carbon Dioxide	90.00%	44.01
Methane	0.00%	16.04
Ethane	0.00%	30.07
Propane	0.00%	44.10
i-Butane	0.00%	58.12
n-Butane	0.00%	58.12
i-Pentane	0.00%	72.15
n-Pentane	0.00%	72.15
n-Hexane	0.00%	86.18
n-Heptane	0.00%	100.21
n-Octane	0.00%	114.23
Benzene	0.00%	78.11
Toluene	0.00%	92.14
E-Benzene	0.00%	106.17
m-Xylene	0.00%	106.17
p-Xylene	0.00%	106.17
o-Xylene	0.00%	106.17
H2S	10.00%	34.08
Total	100.0%	
Total VOC	0.00%	
Heating Value	63.7	Btu/scf

Section 7.4-3 – EPA AP42 Table 13.5-1 for Flares

Since flares do not lend themselves to conventional emission testing techniques, only a few attempts have been made to characterize flare emissions. Recent EPA tests using propylene as flare gas indicated that efficiencies of 98 percent can be achieved when burning an offgas with at least 11,200 kJ/m^3 (300 Btu/ft^3). The tests conducted on steam-assisted flares at velocities as low as 39.6 meters per minute (m/min) (130 ft/min) to 1140 m/min (3750 ft/min), and on air-assisted flares at velocities of 180 m/min (617 ft/min) to 3960 m/min (13,087 ft/min) indicated that variations in incoming gas flow rates have no effect on the combustion efficiency. Flare gases with less than 16,770 kJ/m^3 (450 Btu/ft^3) do not smoke.

Table 13.5-1 presents flare emission factors, and Table 13.5-2 presents emission composition data obtained from the EPA tests.[1] Crude propylene was used as flare gas during the tests. Methane was a major fraction of hydrocarbons in the flare emissions, and acetylene was the dominant intermediate hydrocarbon species. Many other reports on flares indicate that acetylene is always formed as a stable intermediate product. The acetylene formed in the combustion reactions may react further with hydrocarbon radicals to form polyacetylenes followed by polycyclic hydrocarbons.[2]

In flaring waste gases containing no nitrogen compounds, NO is formed either by the fixation of atmospheric nitrogen (N) with oxygen (O) or by the reaction between the hydrocarbon radicals present in the combustion products and atmospheric nitrogen, by way of the intermediate stages, HCN, CN, and OCN.[2] Sulfur compounds contained in a flare gas stream are converted to SO_2 when burned. The amount of SO_2 emitted depends directly on the quantity of sulfur in the flared gases.

Table 13.5-1 (English Units). EMISSION FACTORS FOR FLARE OPERATIONS[a]

EMISSION FACTOR RATING: B

Component	Emission Factor ($lb/10^6$ Btu)
Total hydrocarbons[b]	0.14
Carbon monoxide	0.37
Nitrogen oxides	0.068
Soot[c]	0 - 274

[a] Reference 1. Based on tests using crude propylene containing 80% propylene and 20% propane.
[b] Measured as methane equivalent.
[c] Soot in concentration values: nonsmoking flares, 0 micrograms per liter (µg/L); lightly smoking flares, 40 µg/L; average smoking flares, 177 µg/L; and heavily smoking flares, 274 µg/L.

Section 7.5 – Condensate Tanks (Units TK-2100 and TK-2200)

- Section 7.5-1 - TANKS 4.09d output (Units TK-2100 and TK-2200)

Section 7.5-1 - TANKS 4.09d output (Units TK-2100 and TK-2200)

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Zia II stabilized 1000bbl tank
City:	
State:	New Mexico
Company:	DCP Midstream LP
Type of Tank:	Vertical Fixed Roof Tank
Description:	Stabilized Condensate, 1250 bbl/day, thru one tank

Tank Dimensions

Shell Height (ft):	20.00
Diameter (ft):	20.00
Liquid Height (ft) :	18.00
Avg. Liquid Height (ft):	10.00
Volume (gallons):	42,301.48
Turnovers:	453.00
Net Throughput(gal/yr):	19,162,500.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	White/White
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Roswell, New Mexico (Avg Atmospheric Pressure = 12.73 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Zia II stabilized 1000bbl tank - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Gasoline (RVP 10)	All	63.26	55.73	70.78	60.84	5.5219	4.7708	6.3647	66.0000			92.00	Option 4: RVP=10, ASTM Slope=3
1,2,4-Trimethylbenzene						0.0233	0.0172	0.0311	120.1900	0.0250	0.0001	120.19	Option 2: A=7.04383, B=1573.267, C=208.56
Benzene						1.2774	1.0363	1.5633	78.1100	0.0180	0.0058	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Cyclohexane						1.3223	1.0780	1.6108	84.1600	0.0024	0.0008	84.16	Option 2: A=6.841, B=1201.53, C=222.65
Ethylbenzene						0.1215	0.0934	0.1565	106.1700	0.0140	0.0004	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Hexane (-n)						2.0814	1.7106	2.5158	86.1700	0.0100	0.0053	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Isooctane									114.2200	0.0400	0.0000	114.22	
Isopropyl benzene						0.0543	0.0409	0.0713	120.2000	0.0050	0.0001	120.20	Option 2: A=6.93666, B=1460.793, C=207.78
Toluene						0.3651	0.2887	0.4580	92.1300	0.0700	0.0065	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Unidentified Components						7.0806	7.0504	7.0541	65.6601	0.7456	0.9793	89.36	
Xylene (-m)						0.1013	0.0777	0.1308	106.1700	0.0700	0.0018	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Zia II stabilized 1000bbl tank - Vertical Fixed Roof Tank

Annual Emission Calcaulations	
Standing Losses (lb):	5,153.8052
Vapor Space Volume (cu ft):	3,207.0425
Vapor Density (lb/cu ft):	0.0649

Vapor Space Expansion Factor:	0.2703
Vented Vapor Saturation Factor:	0.2508
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	3,207.0425
Tank Diameter (ft):	20.0000
Vapor Space Outage (ft):	10.2083
Tank Shell Height (ft):	20.0000
Average Liquid Height (ft):	10.0000
Roof Outage (ft):	0.2083
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.2083
Roof Height (ft):	0.0000
Roof Slope (ft/ft):	0.0625
Shell Radius (ft):	10.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0649
Vapor Molecular Weight (lb/lb-mole):	66.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	5.5219
Daily Avg. Liquid Surface Temp. (deg. R):	522.9287
Daily Average Ambient Temp. (deg. F):	60.8167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	520.5067
Tank Paint Solar Absorptance (Shell):	0.1700
Tank Paint Solar Absorptance (Roof):	0.1700
Daily Total Solar Insulation Factor (Btu/sqft day):	1,810.0000
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2703
Daily Vapor Temperature Range (deg. R):	30.0956
Daily Vapor Pressure Range (psia):	1.5939
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	5.5219
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	4.7708
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	6.3647
Daily Avg. Liquid Surface Temp. (deg R):	522.9287
Daily Min. Liquid Surface Temp. (deg R):	515.4048
Daily Max. Liquid Surface Temp. (deg R):	530.4526
Daily Ambient Temp. Range (deg. R):	29.8333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.2508
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	5.5219
Vapor Space Outage (ft):	10.2083
Working Losses (lb):	38,724.5386
Vapor Molecular Weight (lb/lb-mole):	66.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	5.5219
Annual Net Throughput (gal/yr.):	19,162,500.0000
Annual Turnovers:	452.9983
Turnover Factor:	0.2329
Maximum Liquid Volume (gal):	42,301.4811
Maximum Liquid Height (ft):	18.0000
Tank Diameter (ft):	20.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	43,878.3438

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Zia II stabilized 1000bbl tank - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Gasoline (RVP 10)	38,724.54	5,153.81	43,878.34
Hexane (-n)	203.47	27.08	230.55
Benzene	224.78	29.92	254.70
Isooctane	0.00	0.00	0.00
Toluene	249.85	33.25	283.10
Ethylbenzene	16.62	2.21	18.84
Xylene (-m)	69.29	9.22	78.51
Isopropyl benzene	2.65	0.35	3.01
1,2,4-Trimethylbenzene	5.68	0.76	6.44
Cyclohexane	31.02	4.13	35.15
Unidentified Components	37,921.16	5,046.88	42,968.05

Section 7.6 – Vapor Combustion Unit (Unit VCD1)

- Section 7.6-1 – EPA AP-42 Table 1.4-1 for Natural Gas Combustion (Unit VCD1)

* Please note: Units TK-2100 and TK-2200 (condensate tanks), Unit Dehy (Dehydrator), and Unit L1 (condensate loading) emissions are controlled by Unit VCD1. Tanks 4.09d runs and GRI-GLYCalc runs can be found in Section 7.5 for the tanks and Section 7.3 for the dehydrator.

Section 7.6-1 – EPA AP-42 Tables 1.4-1 and 1.4-2 for Natural Gas Combustion (Unit VCD1)

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b] Emission Factor ($lb/10^6$ scf)	NO_x[b] Emission Factor Rating	CO Emission Factor ($lb/10^6$ scf)	CO Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from $1b/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO_2. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO_X emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO_X emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

Section 7.7 – Condensate Loading (Unit L1)

- Section 7.7-1 – EPA AP-42 Section 5.2 for Condensate Truck Loading (Unit L1)

Section 7.7-1 – EPA AP-42 Section 5.2 for Truck Loading (Unit L1)

5.2 Transportation And Marketing Of Petroleum Liquids[1-3]

5.2.1 General

The transportation and marketing of petroleum liquids involve many distinct operations, each of which represents a potential source of evaporation loss. Crude oil is transported from production operations to a refinery by tankers, barges, rail tank cars, tank trucks, and pipelines. Refined petroleum products are conveyed to fuel marketing terminals and petrochemical industries by these same modes. From the fuel marketing terminals, the fuels are delivered by tank trucks to service stations, commercial accounts, and local bulk storage plants. The final destination for gasoline is usually a motor vehicle gasoline tank. Similar distribution paths exist for fuel oils and other petroleum products. A general depiction of these activities is shown in Figure 5.2-1.

5.2.2 Emissions And Controls

Evaporative emissions from the transportation and marketing of petroleum liquids may be considered, by storage equipment and mode of transportation used, in four categories:

1. Rail tank cars, tank trucks, and marine vessels: loading, transit, and ballasting losses.
2. Service stations: bulk fuel drop losses and underground tank breathing losses.
3. Motor vehicle tanks: refueling losses.
4. Large storage tanks: breathing, working, and standing storage losses. (See Chapter 7, "Liquid Storage Tanks".)

Evaporative and exhaust emissions are also associated with motor vehicle operation, and these topics are discussed in AP-42 *Volume II: Mobile Sources*.

5.2.2.1 Rail Tank Cars, Tank Trucks, And Marine Vessels -
Emissions from these sources are from loading losses, ballasting losses, and transit losses.

5.2.2.1.1 Loading Losses -
Loading losses are the primary source of evaporative emissions from rail tank car, tank truck, and marine vessel operations. Loading losses occur as organic vapors in "empty" cargo tanks are displaced to the atmosphere by the liquid being loaded into the tanks. These vapors are a composite of (1) vapors formed in the empty tank by evaporation of residual product from previous loads, (2) vapors transferred to the tank in vapor balance systems as product is being unloaded, and (3) vapors generated in the tank as the new product is being loaded. The quantity of evaporative losses from loading operations is, therefore, a function of the following parameters:

- Physical and chemical characteristics of the previous cargo;
- Method of unloading the previous cargo;
- Operations to transport the empty carrier to a loading terminal;
- Method of loading the new cargo; and
- Physical and chemical characteristics of the new cargo.

The principal methods of cargo carrier loading are illustrated in Figure 5.2-2, Figure 5.2-3, and Figure 5.2-4. In the splash loading method, the fill pipe dispensing the cargo is lowered only part way into the cargo tank. Significant turbulence and vapor/liquid contact occur during the splash loading operation, resulting in high levels of vapor generation and loss. If the turbulence is great enough, liquid droplets will be entrained in the vented vapors.

A second method of loading is submerged loading. Two types are the submerged fill pipe method and the bottom loading method. In the submerged fill pipe method, the fill pipe extends almost to the bottom of the cargo tank. In the bottom loading method, a permanent fill pipe is attached to the cargo tank bottom. During most of submerged loading by both methods, the fill pipe opening is below the liquid surface level. Liquid turbulence is controlled significantly during submerged loading, resulting in much lower vapor generation than encountered during splash loading.

The recent loading history of a cargo carrier is just as important a factor in loading losses as the method of loading. If the carrier has carried a nonvolatile liquid such as fuel oil, or has just been cleaned, it will contain vapor-free air. If it has just carried gasoline and has not been vented, the air in the carrier tank will contain volatile organic vapors, which will be expelled during the loading operation along with newly generated vapors.

Cargo carriers are sometimes designated to transport only one product, and in such cases are practicing "dedicated service". Dedicated gasoline cargo tanks return to a loading terminal containing air fully or partially saturated with vapor from the previous load. Cargo tanks may also be "switch loaded" with various products, so that a nonvolatile product being loaded may expel the vapors remaining from a previous load of a volatile product such as gasoline. These circumstances vary with the type of cargo tank and with the ownership of the carrier, the petroleum liquids being transported, geographic location, and season of the year.

One control measure for vapors displaced during liquid loading is called "vapor balance service", in which the cargo tank retrieves the vapors displaced during product unloading at bulk plants or service stations and transports the vapors back to the loading terminal. Figure 5.2-5 shows a tank truck in vapor balance service filling a service station underground tank and taking on displaced gasoline vapors for return to the terminal. A cargo tank returning to a bulk terminal in vapor balance service normally is saturated with organic vapors, and the presence of these vapors at the start of submerged loading of the tanker truck results in greater loading losses than encountered during nonvapor balance, or "normal", service. Vapor balance service is usually not practiced with marine vessels, although some vessels practice emission control by means of vapor transfer within their own cargo tanks during ballasting operations, discussed below.

Emissions from loading petroleum liquid can be estimated (with a probable error of ±30 percent)[4] using the following expression:

$$L_L = 12.46 \frac{SPM}{T} \tag{1}$$

where:

L_L = loading loss, pounds per 1000 gallons (lb/10^3 gal) of liquid loaded

S = a saturation factor (see Table 5.2-1)
P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia) (see Figure 7.1-5, Figure 7.1-6, and Table 7.1-2)
M = molecular weight of vapors, pounds per pound-mole (lb/lb-mole) (see Table 7.1-2)
T = temperature of bulk liquid loaded, °R (°F + 460)

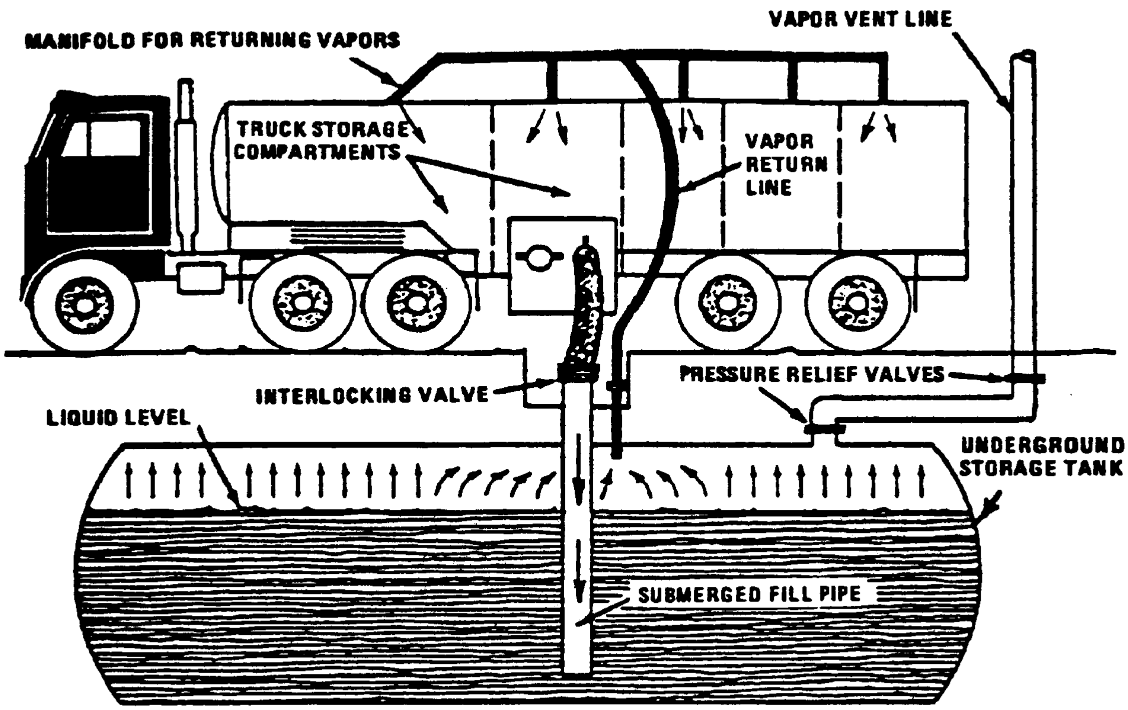

Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

Table 5.2-1. SATURATION (S) FACTORS FOR CALCULATING PETROLEUM LIQUID LOADING LOSSES

Cargo Carrier	Mode Of Operation	S Factor
Tank trucks and rail tank cars	Submerged loading of a clean cargo tank	0.50
	Submerged loading: dedicated normal service	0.60
	Submerged loading: dedicated vapor balance service	1.00
	Splash loading of a clean cargo tank	1.45
	Splash loading: dedicated normal service	1.45
	Splash loading: dedicated vapor balance service	1.00
Marine vessels[a]	Submerged loading: ships	0.2
	Submerged loading: barges	0.5

[a] For products other than gasoline and crude oil. For marine loading of gasoline, use factors from Table 5.2-2. For marine loading of crude oil, use Equations 2 and 3 and Table 5.2-3.

Section 7.8 – Haul Roads (Unit HAUL)

- Section 7.8-1 – AP-42 Section 13.2.1 for Paved Haul Roads (Unit HAUL)

Section 7.8-1 – AP-42 Section 13.2.1 for Paved Haul Roads (Unit HAUL)

13.2.1 Paved Roads

13.2.1.1 General

Particulate emissions occur whenever vehicles travel over a paved surface such as a road or parking lot. Particulate emissions from paved roads are due to direct emissions from vehicles in the form of exhaust, brake wear and tire wear emissions and resuspension of loose material on the road surface. In general terms, resuspended particulate emissions from paved roads originate from, and result in the depletion of, the loose material present on the surface (i.e., the surface loading). In turn, that surface loading is continuously replenished by other sources. At industrial sites, surface loading is replenished by spillage of material and trackout from unpaved roads and staging areas. Figure 13.2.1-1 illustrates several transfer processes occurring on public streets.

Various field studies have found that public streets and highways, as well as roadways at industrial facilities, can be major sources of the atmospheric particulate matter within an area.[1-9] Of particular interest in many parts of the United States are the increased levels of emissions from public paved roads when the equilibrium between deposition and removal processes is upset. This situation can occur for various reasons, including application of granular materials for snow and ice control, mud/dirt carryout from construction activities in the area, and deposition from wind and/or water erosion of surrounding unstabilized areas. In the absence of continuous addition of fresh material (through localized track out or application of antiskid material), paved road surface loading should reach an equilibrium value in which the amount of material resuspended matches the amount replenished. The equilibrium surface loading value depends upon numerous factors. It is believed that the most important factors are: mean speed of vehicles traveling the road; the average daily traffic (ADT); the number of lanes and ADT per lane; the fraction of heavy vehicles (buses and trucks); and the presence/absence of curbs, storm sewers and parking lanes.[10]

The particulate emission factors presented in a previous version of this section of AP-42, dated October 2002, implicitly included the emissions from vehicles in the form of exhaust, brake wear, and tire wear as well as resuspended road surface material. EPA included these sources in the emission factor equation for paved roads since the field testing data used to develop the equation included both the direct emissions from vehicles and emissions from resuspension of road dust.

This version of the paved road emission factor equation only estimates particulate emissions from resuspended road surface material[28]. The particulate emissions from vehicle exhaust, brake wear, and tire wear are now estimated separately using EPA's MOVES [29] model. This approach eliminates the possibility of double counting emissions. Double counting results when employing the previous version of the emission factor equation in this section and MOVES to estimate particulate emissions from vehicle traffic on paved roads. It also incorporates the decrease in exhaust emissions that has occurred since the paved road emission factor equation was developed. Earlier versions of the paved road emission factor equation includes estimates of emissions from exhaust, brake wear, and tire wear based on emission rates for vehicles in the 1980 calendar year fleet. The amount of PM released from vehicle exhaust has decreased since 1980 due to lower new vehicle emission standards and changes in fuel characteristics.

13.2.1.2 Emissions And Correction Parameters

Dust emissions from paved roads have been found to vary with what is termed the "silt loading" present on the road surface. In addition, the average weight and speed of vehicles traveling the road influence road dust emissions. The term silt loading (sL) refers to the mass of silt-size material (equal to or less than 75 micrometers [µm] in physical diameter) per unit area of the travel surface. The total road surface dust loading consists of loose material that can be collected by broom sweeping and vacuuming of the traveled portion of the paved road. The silt fraction is determined by measuring the proportion of the loose dry surface dust that passes through a 200-mesh screen, using the ASTM-C-136 method. Silt loading is the product of the silt fraction and the total loading, and is abbreviated "sL". Additional details on the sampling and analysis of such material are provided in AP-42 Appendices C.1 and C.2.

The surface sL provides a reasonable means of characterizing seasonal variability in a paved road emission inventory. In many areas of the country, road surface loadings [11-21] are heaviest during the late winter and early spring months when the residual loading from snow/ice controls is greatest. As noted earlier, once replenishment of fresh material is eliminated, the road surface loading can be expected to reach an equilibrium value, which is substantially lower than the late winter/early spring values.

13.2.1.3 Predictive Emission Factor Equations[10,29]

The quantity of particulate emissions from resuspension of loose material on the road surface due to vehicle travel on a dry paved road may be estimated using the following empirical expression:

$$E = k\,(sL)^{0.91} \times (W)^{1.02} \qquad (1)$$

where:
- E = particulate emission factor (having units matching the units of k),
- k = particle size multiplier for particle size range and units of interest (see below),
- sL = road surface silt loading (grams per square meter) (g/m^2), and
- W = average weight (tons) of the vehicles traveling the road.

It is important to note that Equation 1 calls for the average weight of all vehicles traveling the road. For example, if 99 percent of traffic on the road are 2 ton cars/trucks while the remaining 1 percent consists of 20 ton trucks, then the mean weight "W" is 2.2 tons. More specifically, Equation 1 is *not* intended to be used to calculate a separate emission factor for each vehicle weight class. Instead, only one emission factor should be calculated to represent the "fleet" average weight of all vehicles traveling the road.

The particle size multiplier (k) above varies with aerodynamic size range as shown in Table 13.2.1-1. To determine particulate emissions for a specific particle size range, use the appropriate value of k shown in Table 13.2.1-1.

To obtain the total emissions factor, the emission factors for the exhaust, brake wear and tire wear obtained from either EPA's MOBILE6.2 [27] or MOVES2010 [29] model should be added to the emissions factor calculated from the empirical equation.

Table 13.2.1-1. PARTICLE SIZE MULTIPLIERS FOR PAVED ROAD EQUATION

Size range[a]	Particle Size Multiplier k[b]		
	g/VKT	g/VMT	lb/VMT
PM-2.5[c]	0.15	0.25	0.00054
PM-10	0.62	1.00	0.0022
PM-15	0.77	1.23	0.0027
PM-30[d]	3.23	5.24	0.011

[a] Refers to airborne particulate matter (PM-x) with an aerodynamic diameter equal to or less than x micrometers.

[b] Units shown are grams per vehicle kilometer traveled (g/VKT), grams per vehicle mile traveled (g/VMT), and pounds per vehicle mile traveled (lb/VMT). The multiplier k includes unit conversions to produce emission factors in the units shown for the indicated size range from the mixed units required in Equation 1.

[c] The k-factors for $PM_{2.5}$ were based on the average $PM_{2.5}$:PM_{10} ratio of test runs in Reference 30.

[d] PM-30 is sometimes termed "suspendable particulate" (SP) and is often used as a surrogate for TSP.

Equation 1 is based on a regression analysis of 83 tests for PM-10.[3, 5-6, 8, 27-29, 31-36] Sources tested include public paved roads, as well as controlled and uncontrolled industrial paved roads. The majority of tests involved freely flowing vehicles traveling at constant speed on relatively level roads. However, 22 tests of slow moving or "stop-and-go" traffic or vehicles under load were available for inclusion in the data base.[32-36] Engine exhaust, tire wear and break wear were subtracted from the emissions measured in the test programs prior to stepwise regression to determine Equation 1.[37, 39] The equations retain the quality rating of A (D for PM-2.5), if applied within the range of source conditions that were tested in developing the equation as follows:

Silt loading:	0.03 - 400 g/m^2 0.04 - 570 grains/square foot (ft^2)
Mean vehicle weight:	1.8 - 38 megagrams (Mg) 2.0 - 42 tons
Mean vehicle speed:	1 - 88 kilometers per hour (kph) 1 - 55 miles per hour (mph)

The upper and lower 95% confidence levels of equation 1 for PM_{10} is best described with equations using an exponents of 1.14 and 0.677 for silt loading and an exponents of 1.19 and 0.85 for weight. Users are cautioned that application of equation 1 outside of the range of variables and operating conditions specified above, e.g., application to roadways or road networks with speeds above 55 mph and average vehicle weights of 42 tons, will result in emission estimates with a higher level of uncertainty. In these situations, users are encouraged to consider an assessment of the impacts of the influence of extrapolation to the overall emissions and alternative methods that are equally or more plausible in light of local emissions data and/or ambient concentration or compositional data.

To retain the quality rating for the emission factor equation when it is applied to a specific paved road, it is necessary that reliable correction parameter values for the specific road in question be determined. With the exception of limited access roadways, which are difficult to sample, the collection and use of site-specific silt loading (sL) data for public paved road emission inventories are strongly recommended. The field and laboratory procedures for determining surface material silt content and surface dust loading are summarized in Appendices C.1 and C.2. In the event that site-specific values cannot be obtained, an appropriate value for a paved public road may be selected from the values in Table 13.2.1-2, but the quality rating of the equation should be reduced by 2 levels.

Equation 1 may be extrapolated to average uncontrolled conditions (but including natural mitigation) under the simplifying assumption that annual (or other long-term) average emissions are inversely proportional to the frequency of measurable (> 0.254 mm [0.01 inch]) precipitation by application of a precipitation correction term. The precipitation correction term can be applied on a daily or an hourly basis [26, 38].

For the daily basis, Equation 1 becomes:

$$E_{ext} = [\, k\, (sL)^{0.91} \times (W)^{1.02}\,]\, (1 - P/4N) \qquad (2)$$

where k, sL, W, and S are as defined in Equation 1 and

E_{ext} = annual or other long-term average emission factor in the same units as k,

P = number of "wet" days with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and

N = number of days in the averaging period (e.g., 365 for annual, 91 for seasonal, 30 for monthly).

Note that the assumption leading to Equation 2 is based on analogy with the approach used to develop long-term average unpaved road emission factors in Section 13.2.2. However, Equation 2 above incorporates an additional factor of "4" in the denominator to account for the fact that paved roads dry more quickly than unpaved roads and that the precipitation may not occur over the complete 24-hour day.

For the hourly basis, equation 1 becomes:

$$E_{ext} = [\ k\ (sL)^{0.91} \times (W)^{1.02}\ ]\ (1 - 1.2P/N) \qquad (3)$$

where k, sL, W, and S are as defined in Equation 1 and

E_{ext} = annual or other long-term average emission factor in the same units as k,

P = number of hours with at least 0.254 mm (0.01 in) of precipitation during the averaging period, and

N = number of hours in the averaging period (e.g., 8760 for annual, 2124 for season 720 for monthly)

Note: In the hourly moisture correction term (1-1.2P/N) for equation 3, the 1.2 multiplier is applied to account for the residual mitigative effect of moisture. For most applications, this equation will produce satisfactory results. Users should select a time interval to include sufficient "dry" hours such that a reasonable emissions averaging period is evaluated. For the special case where this equation is used to calculate emissions on an hour by hour basis, such as would be done in some emissions modeling situations, the moisture correction term should be modified so that the moisture correction "credit" is applied to the first hours following cessation of precipitation. In this special case, it is suggested that this 20% "credit" be applied on a basis of one hour credit for each hour of precipitation up to a maximum of 12 hours.

Note that the assumption leading to Equation 3 is based on analogy with the approach used to develop long-term average unpaved road emission factors in Section 13.2.2.

Figure 13.2.1-2 presents the geographical distribution of "wet" days on an annual basis for the United States. Maps showing this information on a monthly basis are available in the *Climatic Atlas of the United States*[23]. Alternative sources include other Department of Commerce publications (such as local climatological data summaries). The National Climatic Data Center (NCDC) offers several products that provide hourly precipitation data. In particular, NCDC offers *Solar and Meteorological Surface Observation Network 1961-1990* (SAMSON) CD-ROM, which contains 30 years worth of hourly meteorological data for first-order National Weather Service locations. Whatever meteorological data are used, the source of that data and the averaging period should be clearly specified.

It is emphasized that the simple assumption underlying Equations 2 and 3 has not been verified in any rigorous manner. For that reason, the quality ratings for Equations 2 and 3 should be downgraded one letter from the rating that would be applied to Equation 1.

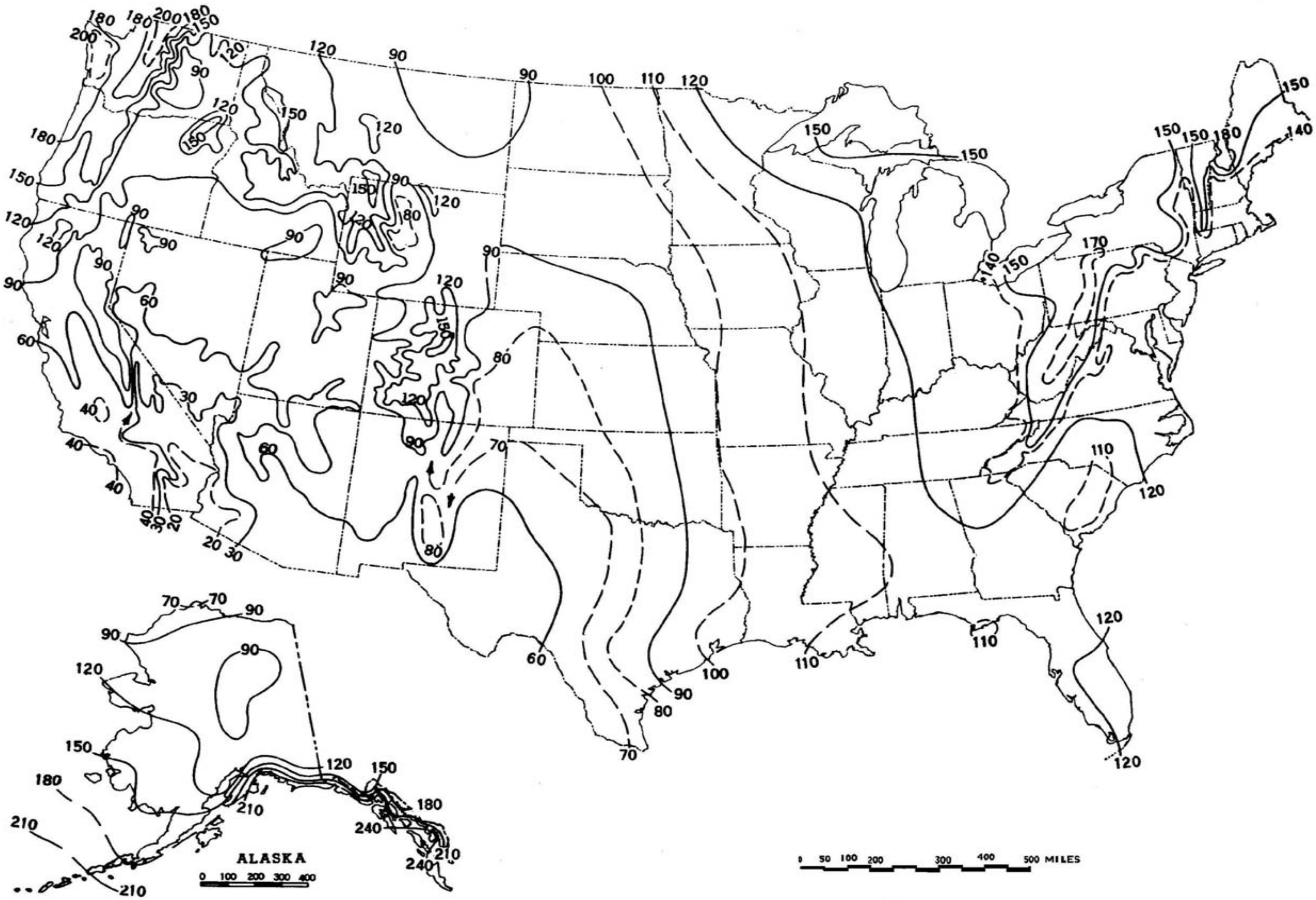

Figure 13.2.1-2. Mean number of days with 0.01 inch or more of precipitation in the United States.

Table 13.2.1-2 presents recommended default silt loadings for normal baseline conditions and for wintertime baseline conditions in areas that experience frozen precipitation with periodic application of antiskid material[24]. The winter baseline is represented as a multiple of the non-winter baseline, depending on the ADT value for the road in question. As shown, a multiplier of 4 is applied for low volume roads (< 500 ADT) to obtain a wintertime baseline silt loading of 4 X 0.6 = 2.4 g/m^2.

Table 13.2.1-2. Ubiquitous Silt Loading Default Values with Hot Spot Contributions from Anti-Skid Abrasives (g/m^2)

ADT Category	< 500	500-5,000	5,000-10,000	> 10,000
Ubiquitous Baseline g/m^2	0.6	0.2	0.06	0.03 0.015 limited access
Ubiquitous Winter Baseline Multiplier during months with frozen precipitation	X4	X3	X2	X1
Initial peak additive contribution from application of antiskid abrasive (g/m^2)	2	2	2	2
Days to return to baseline conditions (assume linear decay)	7	3	1	0.5

It is suggested that an additional (but temporary) silt loading contribution of 2 g/m^2 occurs with each application of antiskid abrasive for snow/ice control. This was determined based on a typical application rate of 500 lb per lane mile and an initial silt content of 1 % silt content. Ordinary rock salt and other chemical deicers add little to the silt loading, because most of the chemical dissolves during the snow/ice melting process.

To adjust the baseline silt loadings for mud/dirt trackout, the number of trackout points is required. It is recommended that in calculating PM_{10} emissions, six additional miles of road be added for each active trackout point from an active construction site, to the paved road mileage of the specified category within the county. In calculating $PM_{2.5}$ emissions, it is recommended that three additional miles of road be added for each trackout point from an active construction site.

It is suggested the number of trackout points for activities other than road and building construction areas be related to land use. For example, in rural farming areas, each mile of paved road would have a specified number of trackout points at intersections with unpaved roads. This value could be estimated from the unpaved road density (mi/sq. mi.).

The use of a default value from Table 13.2.1-2 should be expected to yield only an order-of-magnitude estimate of the emission factor. Public paved road silt loadings are dependent

Section 7.9 – Fugitives (Unit FUG)

- Section 7.9-1 – EPA Protocol for Equipment Leak Emission Estimates, November 1995, Tables 2-4 and 2-10

Section 7.9-1 – EPA Protocol for Equipment Leak Emission Estimates (Unit FUG)

United States
Environmental Protection
Agency

Office of Air Quality
Planning and Standards
Research Triangle Park NC 27711

EPA-453/R-95-017
November 1995

Air

EPA

Protocol for Equipment Leak Emission Estimates

EPA-453/R-95-017

1995 Protocol for Equipment Leak Emission Estimates

Emission Standards Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

November 1995

TABLE 2-4. OIL AND GAS PRODUCTION OPERATIONS AVERAGE EMISSION FACTORS (kg/hr/source)

Equipment Type	Service[a]	Emission Factor (kg/hr/source)[b]
Valves	Gas	4.5E-03
	Heavy Oil	8.4E-06
	Light Oil	2.5E-03
	Water/Oil	9.8E-05
Pump seals	Gas	2.4E-03
	Heavy Oil	NA
	Light Oil	1.3E-02
	Water/Oil	2.4E-05
Others[c]	Gas	8.8E-03
	Heavy Oil	3.2E-05
	Light Oil	7.5E-03
	Water/Oil	1.4E-02
Connectors	Gas	2.0E-04
	Heavy Oil	7.5E-06
	Light Oil	2.1E-04
	Water/Oil	1.1E-04
Flanges	Gas	3.9E-04
	Heavy Oil	3.9E-07
	Light Oil	1.1E-04
	Water/Oil	2.9E-06
Open-ended lines	Gas	2.0E-03
	Heavy Oil	1.4E-04
	Light Oil	1.4E-03
	Water/Oil	2.5E-04

[a]Water/Oil emission factors apply to water streams in oil service with a water content greater than 50%, from the point of origin to the point where the water content reaches 99%. For water streams with a water content greater than 99%, the emission rate is considered negligible.

[b]These factors are for total organic compound emission rates (including non-VOC's such as methane and ethane) and apply to light crude, heavy crude, gas plant, gas production, and off shore facilities. "NA" indicates that not enough data were available to develop the indicated emission factor.

[c]The "other" equipment type was derived from compressors, diaphrams, drains, dump arms, hatches, instruments, meters, pressure relief valves, polished rods, relief valves, and vents. This "other" equipment type should be applied for any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

TABLE 2-10. PETROLEUM INDUSTRY LEAK RATE/SCREENING VALUE CORRELATIONS[a]

Equipment type/service	Correlation[b,c]
Valves/all	Leak rate (kg/hr) = 2.29E-06 × $(SV)^{0.746}$
Pump seals/all	Leak rate (kg/hr) = 5.03E-05 × $(SV)^{0.610}$
Others[d]	Leak rate (kg/hr) = 1.36E-05 × $(SV)^{0.589}$
Connectors/all	Leak rate (kg/hr) = 1.53E-06 × $(SV)^{0.735}$
Flanges/all	Leak rate (kg/hr) = 4.61E-06 × $(SV)^{0.703}$
Open-ended lines/all	Leak rate (kg/hr) = 2.20E-06 × $(SV)^{0.704}$

[a]The correlations presented in this table are revised petroleum industry correlations.

[b]SV = Screening value in ppmv.

[c]These correlations predict total organic compound emission rates (including non-VOC’s such as methane and ethane).

[d]The "other" equipment type was derived from instruments, loading arms, pressure relief valves, stuffing boxes, and vents. This "other" equipment type should be applied to any equipment type other than connectors, flanges, open-ended lines, pumps, or valves.

Section 7.10 – Diesel Generator (Unit GEN-1)

- Section 7.10-1 – Manufacturer's data
- Section 7.10-2 – EPA AP-42 Tables 3.3-1 and 3.3-2

Section 7.10-1 – Manufacturer's Data (Unit GEN-1)

Model: DSFAC
Frequency: 60
Fuel type: Diesel
Emissions level: EPA Nonroad Tier 3

Generator set data sheet
50 kW standby

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Exhaust emission data sheet:	**EDS-1090**
EPA Tier 3 exhaust emission compliance sheet:	**EPA-1124**
Sound performance data sheet:	**MSP-1070**
Cooling performance data sheet:	**MCP-177**
Prototype test summary data sheet:	**PTS-275**
Standard set-mounted radiator cooling outline:	**500-4552**
Optional set-mounted radiator cooling outline:	
Optional heat exchanger cooling outline:	
Optional remote radiator cooling outline:	

Fuel consumption

	Standby				Prime				Continuous
	kW (kVA)				kW (kVA)				kW (kVA)
Ratings	50 (63)				45 (56)				
Load	**1/4**	**1/2**	**3/4**	**Full**	**1/4**	**1/2**	**3/4**	**Full**	**Full**
US gph	1.6	2.6	3.8	5.1	1.5	2.4	3.4	4.7	
L/hr	6.2	9.9	14.4	19.4	5.8	9.0	13.0	17.9	

Engine

	Standby rating	Prime rating	Continuous rating
Engine manufacturer	Cummins Inc.		
Engine model	QSB5-G3 NR3		
Configuration	Cast iron, in-line, 4 cylinder		
Aspiration	Turbocharged and CAC		
Gross engine power output, kWm (bhp)	108 (145)	94 (126)	
BMEP at set rated load, kPa (psi)	972 (141)	889 (129)	
Bore, mm (in)	107 (4.21)		
Stroke, mm (in)	124 (4.88)		
Rated speed, rpm	1800		
Piston speed, m/s (ft/min)	7.4 (1464)		
Compression ratio	17.3:1		
Lube oil capacity, L (qt)	12.1 (12.8)		
Overspeed limit, rpm	2100		
Regenerative power, kW	13.0		

Fuel flow

Maximum fuel flow, L/hr (US gph)	106 (28)	
Maximum fuel flow with C174, L/hr (US gph)		
Maximum fuel inlet restriction w/ clean filter, mm Hg (in Hg)	127 (5)	
Maximum return restriction, mm Hg (in Hg)	152 (6)	

Air	Standby rating	Prime rating	Continuous rating
Combustion air, m^3/min (scfm)	7.5 (266)	7.2 (256)	
Maximum air cleaner restriction w/clean filter, kPa (in H_2O)	3.7 (15)		
Alternator cooling air, m^3/min (cfm)	37.0 (1308)		

Exhaust			
Exhaust gas flow at set rated load, m^3/min (cfm)	17.9 (632)	17.2 (607)	
Exhaust gas temperature, ° C (° F)	401 (754)	391 (736)	
Maximum exhaust back pressure, kPa (in H_2O)	10 (40)		

Standard set-mounted radiator cooling			
Ambient design, ° C (° F)	55 (131)		
Fan load, kWm (HP)	9.3 (12.5)		
Coolant capacity (with radiator), L (US Gal)	17 (4.5)		
Cooling system air flow, m^3/min (scfm)	189 (6675)		
Total heat rejection, MJ/min (BTU/min)	2.90 (2750)	2.71 (2571)	
Maximum cooling air flow static restriction, kPa (in H_2O)	0.12 (0.5)		

Optional set-mounted radiator cooling			
Ambient design, °C (°F)			
Fan load, kWm (HP)			
Coolant capacity (with radiator), L (US Gal.)			
Cooling system air flow, m^3/min (scfm)			
Total heat rejection, MJ/min (BTU/min)			
Maximum cooling air flow static restriction, kPa (in. H_2O)			

Optional heat exchanger cooling			
Set coolant capacity, L (US Gal.)			
Heat rejected, jacket water circuit, MJ/min (BTU/min)			
Heat rejected, after-cooler circuit, MJ/min (BTU/min)			
Heat rejected, fuel circuit, MJ/min (BTU/min)			
Total heat radiated to room, MJ/min (BTU/min)			
Maximum raw water pressure, jacket water circuit, kPa (psi)			
Maximum raw water pressure, sftercooler circuit, kPa (psi)			
Maximum raw water pressure, fuel circuit, kPa (psi)			
Maximum raw water flow, jacket water circuit, L/min (US Gal/min)			
Maximum raw water flow, aftercooler circuit, L/min (US Gal/min)			
Maximum raw water flow, fuel circuit, L/min (US Gal/min)			
Minimum raw water flow @ 27 °C (80 °F) Inlet temp, jacket water circuit, L/min (US Gal/min)			
Minimum raw water flow @ 27 °C (80 °F) Inlet remp, after-cooler circuit, L/min (US Gal/min)			
Minimum raw water flow @ 27 °C (80 °F) Inlet temp, fuel circuit, L/min (US Gal/min)			
Raw water delta P @ min flow, jacket water circuit, kPa (psi)			
Raw water delta P @ min flow, after-cooler circuit, kPa (psi)			
Raw water delta P @ min flow, fuel circuit, kPa (psi)			
Maximum jacket water outlet temp, °C (°F)			
Maximum after-cooler inlet temp, °C (°F)			
Maximum after-cooler inlet temp @ 25 °C (77 °F) ambient, °C (°F)			

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Optional remote radiator cooling[1]

	Standby rating	Prime rating	Continuous rating
Set coolant capacity, L (US Gal.)			
Max flow rate @ max friction head, jacket water circuit, L/min (US Gal/min)			
Heat rejected, jacket water circuit, MJ/min (BTU/min)			
Total heat radiated to room, MJ/min (BTU/min)			
Maximum friction head, jacket water circuit, kPa (psi)			
Maximum static head, jacket water circuit , m (ft)			
Maximum jacket water outlet temp, °C (°F)			

Weights[2]

Unit dry weight kgs (lbs.)	1100 (2425)
Unit wet weight kgs (lbs.)	1120 (2470)

Notes:

[1] For non-standard remote installations contact your local Cummins Power Generation representative.

[2] Weights represent a set with standard features. See outline drawing for weights of other configurations.

Derating factors

Standby	Engine power available up to 3050 m (10,006 ft) at ambient temperature up to 55° C (131° F). Consult your Cummins Power Generation distributor for temperature and ambient requirements above these parameters.
Prime	Engine power available up to 3050 m (10,006 ft) at ambient temperature up to 55° C (131° F). Consult your Cummins Power Generation distributor for temperature and ambient requirements above these parameters.
Continuous	

Ratings definitions

Emergency standby power (ESP):	Limited-time running power (LTP):	Prime power (PRP):	Base load (continuous) power (COP):
Applicable for supplying power to varying electrical load for the duration of power interruption of a reliable utility source. Emergency Standby Power (ESP) is in accordance with ISO 8528. Fuel Stop power in accordance with ISO 3046, AS 2789, DIN 6271 and BS 5514.	Applicable for supplying power to a constant electrical load for limited hours. Limited Time Running Power (LTP) is in accordance with ISO 8528.	Applicable for supplying power to varying electrical load for unlimited hours. Prime Power (PRP) is in accordance with ISO 8528. Ten percent overload capability is available in accordance with ISO 3046, AS 2789, DIN 6271 and BS 5514.	Applicable for supplying power continuously to a constant electrical load for unlimited hours. Continuous Power (COP) is in accordance with ISO 8528, ISO 3046, AS 2789, DIN 6271 and BS 5514.

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Power Generation

Alternator data

Three Phase Table[1]		105 °C	105 °C	105 °C	105 °C	125 °C	125 °C	125 °C	125 °C	150 °C	150 °C	150 °C
Feature Code		B418	B415	B268	B304	B417	B414	B267	B303	B416	B413	B419
Alternator Data Sheet Number		203	203	204	203	202	203	204	202	202	202	202
Voltage Ranges		110/190 Thru 120/208 220/380 Thru 240/416	120/208 Thru 139/240 240/416 Thru 277/480	120/208 Thru 139/240 240/416 Thru 277/480	347/600	110/190 Thru 120/208 220/380 Thru 240/416	120/208 Thru 139/240 240/416 Thru 277/480	120/208 Thru 139/240 240/416 Thru 277/480	347/600	110/190 Thru 120/208 220/380 Thru 240/416	120/208 Thru 139/240 240/416 Thru 277/480	347/600
Surge kW		65	65	66	66	64	65	66	65	64	64	65
Motor Starting kVA (at 90% sustained voltage)	Shunt	188	188	231	188	163	188	231	163	163	163	163
	PMG	221	221	272	221	191	221	272	191	191	191	191

Full Load Current - Amps at Standby Rating	120/208	127/220	139/240	220/380	240/416	277/480	347/600
	173	164	150	95	87	75	60

Single Phase Table		105 °C	105 °C	105 °C	105 °C	125 °C	125 °C	125 °C	125 °C
Feature Code		B418	B415	B274	B268	B417	B414	B273	B267
Alternator Data Sheet Number		203	203	204	204	202	203	203	204
Voltage Ranges		120/240[2]	120/240[2]	120/240[3]	120/240[3]	120/240[2]	120/240[2]	120/240[3]	120/240[3]
Surge kW		61	63	65	64	60	62	64	64
Motor Starting kVA (at 90% sustained voltage)	Shunt	113	113	130	130	95	113	113	130
	PMG	133	133	153	153	112	133	133	153

Full Load Current - Amps at Standby Rating	120/240[2]	120/240[3]
	139	208

Notes:

[1] Single phase power can be taken from a three phase generator set at up to 2/3 set rated 3-phase kW at 1.0 power factor. Also see Note 3 below.

[2] The broad range alternators can supply single phase output up to 2/3 set rated 3-phase kW at 1.0 power factor.

[3] The extended stack (full single phase output) and 4 lead alternators can supply single phase output up to full set rated 3-phase kW at 1.0 power factor.

Formulas for calculating full load currents:

Three phase output	Single phase output
$\frac{\text{kW} \times 1000}{\text{Voltage} \times 1.73 \times 0.8}$	$\frac{\text{kW} \times \text{Single Phase Factor} \times 1000}{\text{Voltage}}$

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3.3 Gasoline And Diesel Industrial Engines

3.3.1 General

The engine category addressed by this section covers a wide variety of industrial applications of both gasoline and diesel internal combustion (IC) engines such as aerial lifts, fork lifts, mobile refrigeration units, generators, pumps, industrial sweepers/scrubbers, material handling equipment (such as conveyors), and portable well-drilling equipment. The three primary fuels for reciprocating IC engines are gasoline, diesel fuel oil (No.2), and natural gas. Gasoline is used primarily for mobile and portable engines. Diesel fuel oil is the most versatile fuel and is used in IC engines of all sizes. The rated power of these engines covers a rather substantial range, up to 250 horsepower (hp) for gasoline engines and up to 600 hp for diesel engines. (Diesel engines greater than 600 hp are covered in Section 3.4, "Large Stationary Diesel And All Stationary Dual-fuel Engines".) Understandably, substantial differences in engine duty cycles exist. It was necessary, therefore, to make reasonable assumptions concerning usage in order to formulate some of the emission factors.

3.3.2 Process Description

All reciprocating IC engines operate by the same basic process. A combustible mixture is first compressed in a small volume between the head of a piston and its surrounding cylinder. The mixture is then ignited, and the resulting high-pressure products of combustion push the piston through the cylinder. This movement is converted from linear to rotary motion by a crankshaft. The piston returns, pushing out exhaust gases, and the cycle is repeated.

There are 2 methods used for stationary reciprocating IC engines: compression ignition (CI) and spark ignition (SI). This section deals with both types of reciprocating IC engines. All diesel-fueled engines are compression ignited, and all gasoline-fueled engines are spark ignited.

In CI engines, combustion air is first compression heated in the cylinder, and diesel fuel oil is then injected into the hot air. Ignition is spontaneous because the air temperature is above the autoignition temperature of the fuel. SI engines initiate combustion by the spark of an electrical discharge. Usually the fuel is mixed with the air in a carburetor (for gasoline) or at the intake valve (for natural gas), but occasionally the fuel is injected into the compressed air in the cylinder.

CI engines usually operate at a higher compression ratio (ratio of cylinder volume when the piston is at the bottom of its stroke to the volume when it is at the top) than SI engines because fuel is not present during compression; hence there is no danger of premature autoignition. Since engine thermal efficiency rises with increasing pressure ratio (and pressure ratio varies directly with compression ratio), CI engines are more efficient than SI engines. This increased efficiency is gained at the expense of poorer response to load changes and a heavier structure to withstand the higher pressures.[1]

3.3.3 Emissions

Most of the pollutants from IC engines are emitted through the exhaust. However, some total organic compounds (TOC) escape from the crankcase as a result of blowby (gases that are vented from the oil pan after they have escaped from the cylinder past the piston rings) and from the fuel tank and carburetor because of evaporation. Nearly all of the TOCs from diesel CI engines enter the

Table 3.3-1. EMISSION FACTORS FOR UNCONTROLLED GASOLINE AND DIESEL INDUSTRIAL ENGINES[a]

Pollutant	Gasoline Fuel (SCC 2-02-003-01, 2-03-003-01)		Diesel Fuel (SCC 2-02-001-02, 2-03-001-01)		EMISSION FACTOR RATING
	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	Emission Factor (lb/hp-hr) (power output)	Emission Factor (lb/MMBtu) (fuel input)	
NO_x	0.011	1.63	0.031	4.41	D
CO	6.96 E-03[d]	0.99[d]	6.68 E-03	0.95	D
SO_x	5.91 E-04	0.084	2.05 E-03	0.29	D
PM-10[b]	7.21 E-04	0.10	2.20 E-03	0.31	D
CO_2[c]	1.08	154	1.15	164	B
Aldehydes	4.85 E-04	0.07	4.63 E-04	0.07	D
TOC					
Exhaust	0.015	2.10	2.47 E-03	0.35	D
Evaporative	6.61 E-04	0.09	0.00	0.00	E
Crankcase	4.85 E-03	0.69	4.41 E-05	0.01	E
Refueling	1.08 E-03	0.15	0.00	0.00	E

[a] References 2,5-6,9-14. When necessary, an average brake-specific fuel consumption (BSFC) of 7,000 Btu/hp-hr was used to convert from lb/MMBtu to lb/hp-hr. To convert from lb/hp-hr to kg/kw-hr, multiply by 0.608. To convert from lb/MMBtu to ng/J, multiply by 430. SCC = Source Classification Code. TOC = total organic compounds.

[b] PM-10 = particulate matter less than or equal to 10 µm aerodynamic diameter. All particulate is assumed to be $\leq$ 1 µm in size.

[c] Assumes 99% conversion of carbon in fuel to CO_2 with 87 weight % carbon in diesel, 86 weight % carbon in gasoline, average BSFC of 7,000 Btu/hp-hr, diesel heating value of 19,300 Btu/lb, and gasoline heating value of 20,300 Btu/lb.

[d] Instead of 0.439 lb/hp-hr (power output) and 62.7 lb/mmBtu (fuel input), the correct emissions factors values are 6.96 E-03 lb/hp-hr (power output) and 0.99 lb/mmBtu (fuel input), respectively. This is an editorial correction. March 24, 2009

Table 3.3-2. SPECIATED ORGANIC COMPOUND EMISSION FACTORS FOR UNCONTROLLED DIESEL ENGINES[a]

EMISSION FACTOR RATING: E

Pollutant	Emission Factor (Fuel Input) (lb/MMBtu)
Benzene[b]	9.33 E-04
Toluene[b]	4.09 E-04
Xylenes[b]	2.85 E-04
Propylene	2.58 E-03
1,3-Butadiene[b,c]	<3.91 E-05
Formaldehyde[b]	1.18 E-03
Acetaldehyde[b]	7.67 E-04
Acrolein[b]	<9.25 E-05
Polycyclic aromatic hydrocarbons (PAH)	
Naphthalene[b]	8.48 E-05
Acenaphthylene	<5.06 E-06
Acenaphthene	<1.42 E-06
Fluorene	2.92 E-05
Phenanthrene	2.94 E-05
Anthracene	1.87 E-06
Fluoranthene	7.61 E-06
Pyrene	4.78 E-06
Benzo(a)anthracene	1.68 E-06
Chrysene	3.53 E-07
Benzo(b)fluoranthene	<9.91 E-08
Benzo(k)fluoranthene	<1.55 E-07
Benzo(a)pyrene	<1.88 E-07
Indeno(1,2,3-cd)pyrene	<3.75 E-07
Dibenz(a,h)anthracene	<5.83 E-07
Benzo(g,h,l)perylene	<4.89 E-07
TOTAL PAH	1.68 E-04

[a] Based on the uncontrolled levels of 2 diesel engines from References 6-7. Source Classification Codes 2-02-001-02, 2-03-001-01. To convert from lb/MMBtu to ng/J, multiply by 430.
[b] Hazardous air pollutant listed in the *Clean Air Act*.
[c] Based on data from 1 engine.

Section 7.11 – Wet Surface Air Cooler (Unit CT-1)

- Section 7.11-1 – EPA AP-42 Table 13.4-1
- Section 7.11-2 – Manufacturer's data

13.4 Wet Cooling Towers

13.4.1 General[1]

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. They are used as an important component in many industrial and commercial processes needing to dissipate heat. Cooling towers may range in size from less than $5.3(10)^6$ kilojoules (kJ) ($5[10]^6$ British thermal units per hour [Btu/hr]) for small air conditioning cooling towers to over $5275(10)^6$ kJ/hr ($5000[10^6]$ Btu/hr) for large power plant cooling towers.

When water is used as the heat transfer medium, wet, or evaporative, cooling towers may be used. Wet cooling towers rely on the latent heat of water evaporation to exchange heat between the process and the air passing through the cooling tower. The cooling water may be an integral part of the process or may provide cooling via heat exchangers.

Although cooling towers can be classified several ways, the primary classification is into dry towers or wet towers, and some hybrid wet-dry combinations exist. Subclassifications can include the draft type and/or the location of the draft relative to the heat transfer medium, the type of heat transfer medium, the relative direction of air movement, and the type of water distribution system.

In wet cooling towers, heat transfer is measured by the decrease in the process temperature and a corresponding increase in both the moisture content and the wet bulb temperature of the air passing through the cooling tower. (There also may be a change in the sensible, or dry bulb, temperature, but its contribution to the heat transfer process is very small and is typically ignored when designing wet cooling towers.) Wet cooling towers typically contain a wetted medium called "fill" to promote evaporation by providing a large surface area and/or by creating many water drops with a large cumulative surface area.

Cooling towers can be categorized by the type of heat transfer; the type of draft and location of the draft, relative to the heat transfer medium; the type of heat transfer medium; the relative direction of air and water contact; and the type of water distribution system. Since wet, or evaporative, cooling towers are the dominant type, and they also generate air pollutants, this section will address only that type of tower. Diagrams of the various tower configurations are shown in Figure 13.4-1 and Figure 13.4-2.

13.4.2 Emissions And Controls[1]

Because wet cooling towers provide direct contact between the cooling water and the air passing through the tower, some of the liquid water may be entrained in the air stream and be carried out of the tower as "drift" droplets. Therefore, the particulate matter constituent of the drift droplets may be classified as an emission.

The magnitude of drift loss is influenced by the number and size of droplets produced within the cooling tower, which in turn are determined by the fill design, the air and water patterns, and other interrelated factors. Tower maintenance and operation levels also can influence the formation of drift droplets. For example, excessive water flow, excessive airflow, and water bypassing the tower drift eliminators can promote and/or increase drift emissions.

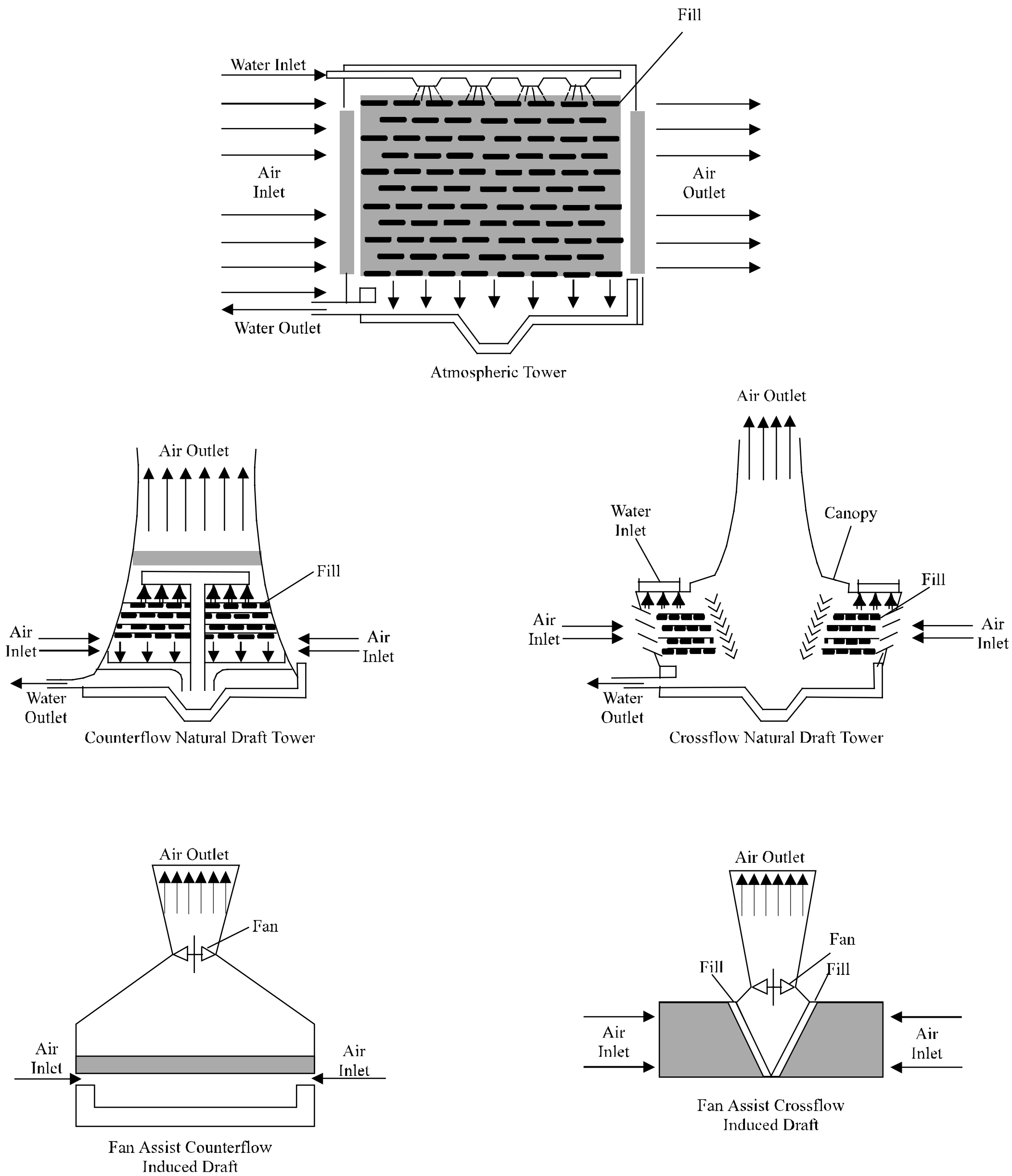

Figure 13.4-1 Atmospheric and natural draft cooling towers.

Because the drift droplets generally contain the same chemical impurities as the water circulating through the tower, these impurities can be converted to airborne emissions. Large drift droplets settle out of the tower exhaust air stream and deposit near the tower. This process can lead to wetting, icing, salt deposition, and related problems such as damage to equipment or to vegetation. Other drift droplets may evaporate before being deposited in the area surrounding the tower, and they also can produce PM-10 emissions. PM-10 is generated when the drift droplets evaporate and leave fine particulate matter formed by crystallization of dissolved solids. Dissolved solids found in cooling tower drift can consist of mineral matter, chemicals for corrosion inhibition, etc.

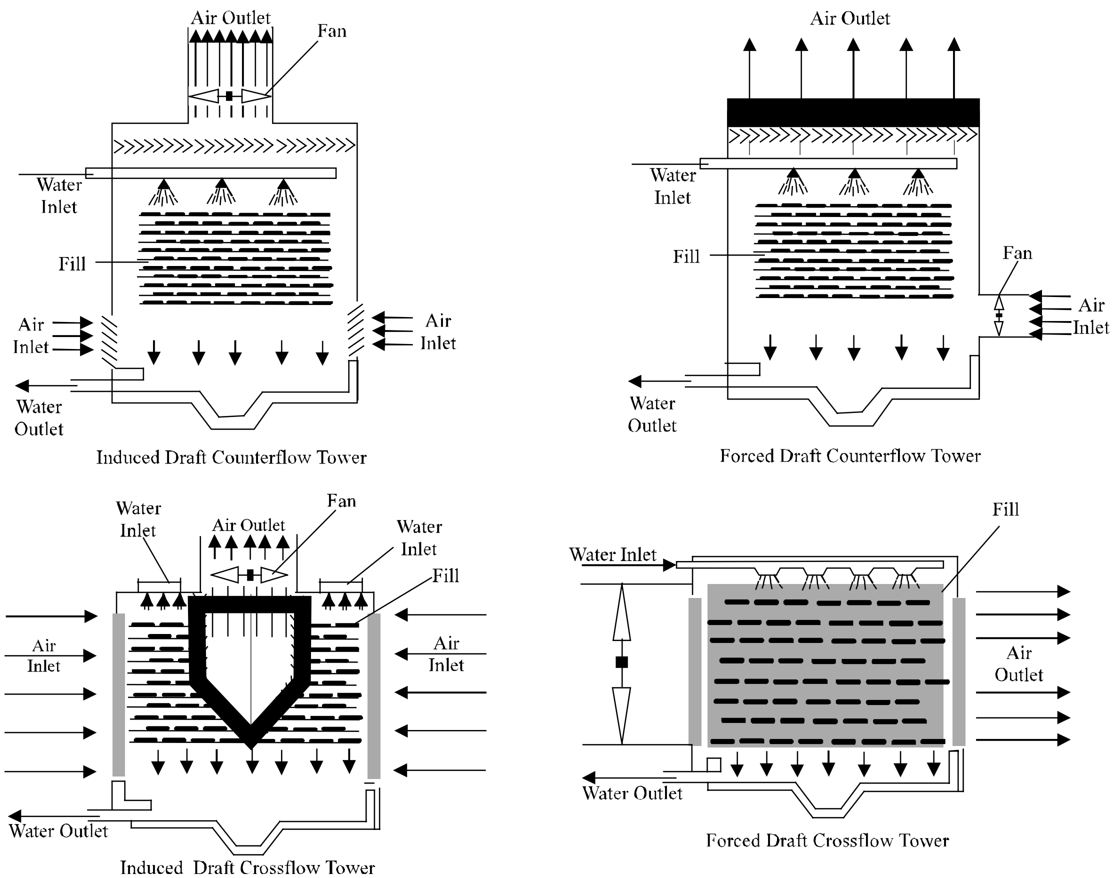

Figure 13.4-2. Mechanical draft cooling towers.

To reduce the drift from cooling towers, drift eliminators are usually incorporated into the tower design to remove as many droplets as practical from the air stream before exiting the tower. The drift eliminators used in cooling towers rely on inertial separation caused by direction changes while passing through the eliminators. Types of drift eliminator configurations include herringbone (blade-type), wave form, and cellular (or honeycomb) designs. The cellular units generally are the most efficient. Drift eliminators may include various materials, such as ceramics, fiber reinforced cement, fiberglass, metal, plastic, and wood installed or formed into closely spaced slats, sheets, honeycomb assemblies, or tiles. The materials may include other features, such as corrugations and water removal channels, to enhance the drift removal further.

Table 13.4-1 provides available particulate emission factors for wet cooling towers. Separate emission factors are given for induced draft and natural draft cooling towers. Several features in Table 13.4-1 should be noted. First, a *conservatively high* PM-10 emission factor can be obtained by (a) multiplying the total liquid drift factor by the total dissolved solids (TDS) fraction in the circulating water and (b) assuming that, once the water evaporates, all remaining solid particles are within the PM-10 size range.

Second, if TDS data for the cooling tower are not available, a source-specific TDS content can be estimated by obtaining the TDS data for the make-up water and multiplying them by the cooling tower cycles of concentration. The cycles of concentration ratio is the ratio of a measured

Table 13.4-1 (Metric And English Units). PARTICULATE EMISSIONS FACTORS FOR WET COOLING TOWERS[a]

	Total Liquid Drift[b]				PM-10[c]		
Tower Type[d]	Circulating Water Flow[b]	g/daL	lb/10^3 gal	EMISSION FACTOR RATING	g/daL[e]	lb/10^3 gal	EMISSION FACTOR RATING
Induced Draft (SCC 3-85-001-01, 3-85-001-20, 3-85-002-01)	0.020	2.0	1.7	D	0.023	0.019	E
Natural Draft (SCC 3-85-001-02, 3-85-002-02)	0.00088	0.088	0.073	E	ND	ND	—

[a] References 1-17. Numbers are given to 2 significant digits. ND = no data. SCC = Source Classification Code.

[b] References 2,5-7,9-10,12-13,15-16. Total liquid drift is water droplets entrained in the cooling tower exit air stream. Factors are for % of circulating water flow (10^{-2} L drift/L [10^{-2} gal drift/gal] water flow) and g drift/daL (lb drift/10^3 gal) circulating water flow. 0.12 g/daL = 0.1 lb/10^3 gal; 1 daL = 10^1 L.

[c] See discussion in text on how to use the table to obtain PM-10 emission estimates. Values shown above are the arithmetic average of test results from References 2,4,8, and 11-14, and they imply an effective TDS content of approximately 12,000 parts per million (ppm) in the circulating water.

[d] See Figure 13.4-1 and Figure 13.4-2. Additional SCCs for wet cooling towers of unspecified draft type are 3-85-001-10 and 3-85-002-10.

[e] Expressed as g PM-10/daL (lb PM-10/10^3 gal) circulating water flow.

parameter for the cooling tower water (such as conductivity, calcium, chlorides, or phosphate) to that parameter for the make-up water. This estimated cooling tower TDS can be used to calculate the PM-10 emission factor as above. If neither of these methods can be used, the arithmetic average PM-10 factor given in Table 13.4-1 can be used. Table 13.4-1 presents the arithmetic average PM-10 factor calculated from the test data in References 2, 4, 8, and 11 - 14. Note that this average corresponds to an effective cooling tower recirculating water TDS content of approximately 11,500 ppm for induced draft towers. (This can be found by dividing the total liquid drift factor into the PM-10 factor.)

As an alternative approach, if TDS data are unavailable for an induced draft tower, a value may be selected from Table 13.4-2 and then be combined with the total liquid drift factor in Table 13.4-1 to determine an apparent PM-10 factor.

As shown in Table 13.4-2, available data do not suggest that there is any significant difference between TDS levels in counter and cross flow towers. Data for natural draft towers are not available.

Table 13.4-2. SUMMARY STATISTICS FOR TOTAL DISSOLVED SOLIDS (TDS) CONTENT IN CIRCULATING WATER[a]

Type Of Draft	No. Of Cases	Range Of TDS Values (ppm)	Geometric Mean TDS Value (ppm)
Counter Flow	10	3700 - 55,000	18,500
Cross Flow	7	380 - 91,000	24,000
Overall[b]	17	380 - 91,000	20,600

[a] References 2,4,8,11-14.
[b] Data unavailable for natural draft towers.

References For Section 13.4

1. *Development Of Particulate Emission Factors For Wet Cooling Towers*, EPA Contract No. 68-D0-0137, Midwest Research Institute, Kansas City, MO, September 1991.

2. *Cooling Tower Test Report, Drift And PM-10 Tests T89-50, T89-51, And T89-52*, Midwest Research Institute, Kansas City, MO, February 1990.

3. *Cooling Tower Test Report, Typical Drift Test*, Midwest Research Institute, Kansas City, MO, January 1990.

4. *Mass Emission Measurements Performed On Kerr-McGee Chemical Corporation's Westend Facility*, Kerr-McGee Chemical Corporation, Trona, CA, And Environmental Systems Corporation, Knoxville, TN, December 1989.

5. Confidential Cooling Tower Drift Test Report For Member Of The Cooling Tower Institute, Houston, TX, Midwest Research Institute, Kansas City, MO, January 1989.

6. Confidential Cooling Tower Drift Test Report For Member Of The Cooling Tower Institute, Houston, TX, Midwest Research Institute, Kansas City, MO, October 1988.

7. Confidential Cooling Tower Drift Test Report For Member Of The Cooling Tower Institute, Houston, TX, Midwest Research Institute, Kansas City, MO, August 1988.

8. *Report Of Cooling Tower Drift Emission Sampling At Argus And Sulfate #2 Cooling Towers*, Kerr-McGee Chemical Corporation, Trona, CA, and Environmental Systems Corporation, Knoxville, TN, February 1987.

9. Confidential Cooling Tower Drift Test Report For Member Of The Cooling Tower Institute, Houston, TX, Midwest Research Institute, Kansas City, MO, February 1987.

10. Confidential Cooling Tower Drift Test Report For Member Of The Cooling Tower Institute, Houston, TX, Midwest Research Institute, Kansas City, MO, January 1987.

NIAGARA
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673 Ontario St., Buffalo, NY 14207
Phone: (716) 875-2000 ~ Fax: (716) 875-1077
sales@niagarablower.com / www.niagarablower.com

Customer:	**DCP**	**Proposal #:**	**WS14-072**
Engineering Firm	**Saulsbury Engineering & Construction**	**Rev:**	**Original**
Domestic Project:	**Zia II**	**Engineer:**	**Chris Imiola**
Sales Office:	**Thermal & Mechanical**	**Date:**	**April 17, 2014**

WSAC Design Summary

Specification	Requirement	Niagara Blower Company
Unit		
Model Number		A4407SL
Flow Type		Parallel
Number of Units		1 Unit
Unit Type		Wet Surface Air Cooler
Shipping / Operating Weight (LBS)		13,500 / 17,650
Length (in.) / Width (in.) / Height (in.)		208.0 / 76.375 / 83.0
Performance		
Service		Water Cooler
Mass Flow Rate (lb/hr)		131,500 lb/hr
Temp In		130.0 ˚F
Temp Out		100.0 ˚F
Inlet Air Wet Bulb Temp		70.0 ˚F
Design Heat Load		2,481,000 BTU/hr
Over Design		10 %
Fouling		0.001 hr-^{o}F-ft^{2}/Btu
Coils		
Cooling Surface Construction Type		Serpentine - Welded Domes
Operating Pressure		1,200.0 PSIG
Design / Test Pressure (psig)		1,440.0 / 1,872.0
Number of Bundles (Total)		1 Bundle(s)
Cooling Tube Material		SA-214 Carbon Steel, H.D.G.A.F.*
Tube Diameter and Thickness		1 in. x 0.109 in.
Pressure Drop (Total)		4 psi
Header Material		Carbon Steel, H.D.G.A.F.*
Fan System		
No of Fans (Total)		3
Fan Diameter		30"
Fan Control		On/ Off
Fan Type		Propeller, Direct Drive
Fan Horsepower (Operating)		7.5 Bhp
CFM (Total)		35,400 CFM
Spray System		
Quantity / Type		1 / recirculating
Spray Water Recirculation Rate (Total)		240 GPM
Spray Pipe Material		Carbon Steel, H.D.G.A.F.*
Spray Pump Horsepower (Operating)		2.1 Bhp
Estimated Make-Up Water Requirements (based on 6 cycles of concentration)		5.3 GPM
Structure		
Basin / Plenum Material		Carbon Steel, H.D.G.A.F.*

*H.D.G.A.F. IS HOT DIPPED GALVANIZED AFTER FABRICATION

NIAGARA

Niagara Blower Heat Transfer Solutions

673 Ontario St., Buffalo, NY 14207

Phone: (716) 875-2000 ~ Fax: (716) 875-1077

sales@niagarablower.com / www.niagarablower.com

Customer:	**DCP**	**Proposal #:**	**WS14-072**
Engineering Firm	**Saulsbury Engineering & Construction**	**Rev:**	**Original**
Domestic Project:	**Zia II**	**Engineer:**	**Chris Imiola**
Sales Office:	**Thermal & Mechanical**	**Date:**	**April 17, 2014**

Included Special Requirements		
Code Stamped		ASME Cert. w/ U-Stamp
Special Welding Procedure		Per Code
Testing Requirements		Per Code
Non-Destructive Examination		Per Code
Nitrogen Charge		Included
Positive Material Identification		None
Drift Eliminators		Not Included
Electrical Supply	Volts / Hertz / Phase	480 / 60 / 3
Electrical Area Classification		Class 1 Div. II
Niagara Field Service Technician (0 day(s) on site for installation supervision, 0 day(s) on site for startup assistance)		Available Upon Request
Chemical Injection Package - Chemicals not included		Included
3 Basin Heaters - 4kW ea.		Included
Prewire to Junction Box		Included
NEMA 4x Standalone controls cabinet. Includes Motor Starters.		Included

Equipment Pricing (U.S. Funds; Excludes Taxes, Duties, Fees)

Unit Base Price	$179,310

Exceptions to Specification
DCP Midstream General Construction Specification Oct 2011 Section N
Para. 4 Seperpentine coils will have butt welded (fusion) joints.
Para. 7 Fans will be direct mounted on the motors.
Para. 10 Units is induced draft design
Para. 14 Not Applicable as a WSAC is not an Aircooler
VDR Has a few changes on Documents that we will not supply

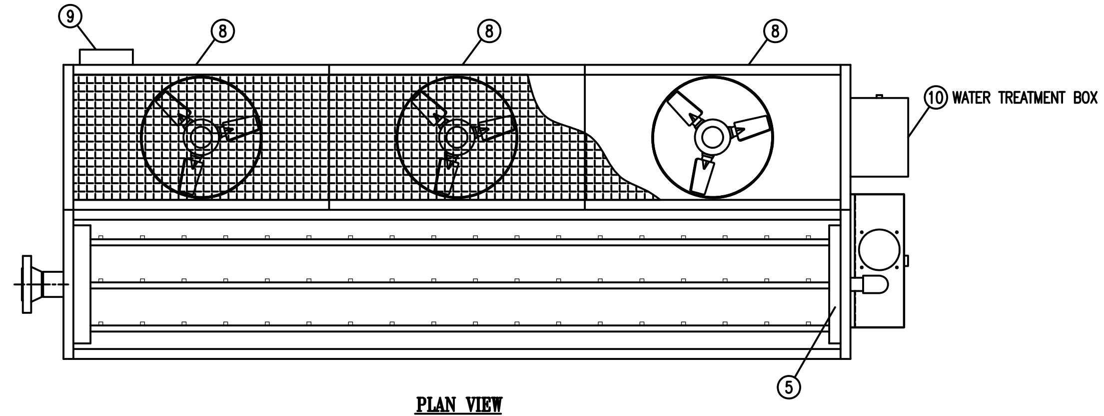
Terms and Conditions		
Progress Payments (Net 30 Days)	Warranty (From Startup/ Delivery)	12 / 18 months
10% with receipt of order	Approval Drawings	3 weeks + 2 weeks for customer approval
20% submission of approval drawings	Equipment Shipment Date	18 weeks from approved drawing(s)
25% receipt tube material	Proposal validity	14 Days
25% receipt tubesheet & header material	Freight	Not Included / pre-paid & added
20% Upon shipment	ExWorks	Factory in Buffalo, NY

*H.D.G.A.F. IS HOT DIPPED GALVANIZED AFTER FABRICATION

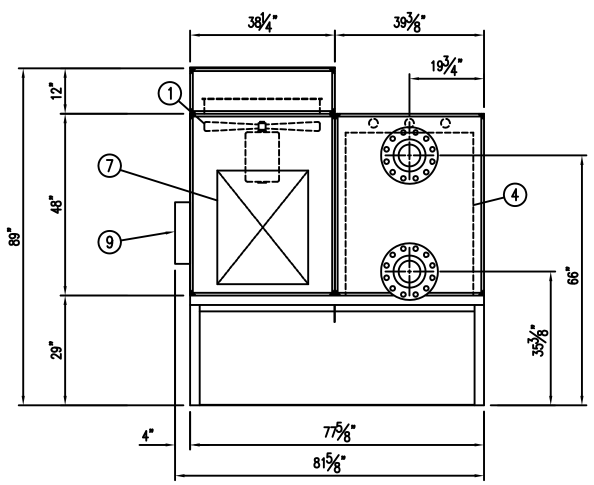
REVISION	LOCATION	MADE BY	CHECKED BY	DATE	REVISION OR ADDITION

SCHEDULE OF CONNECTIONS

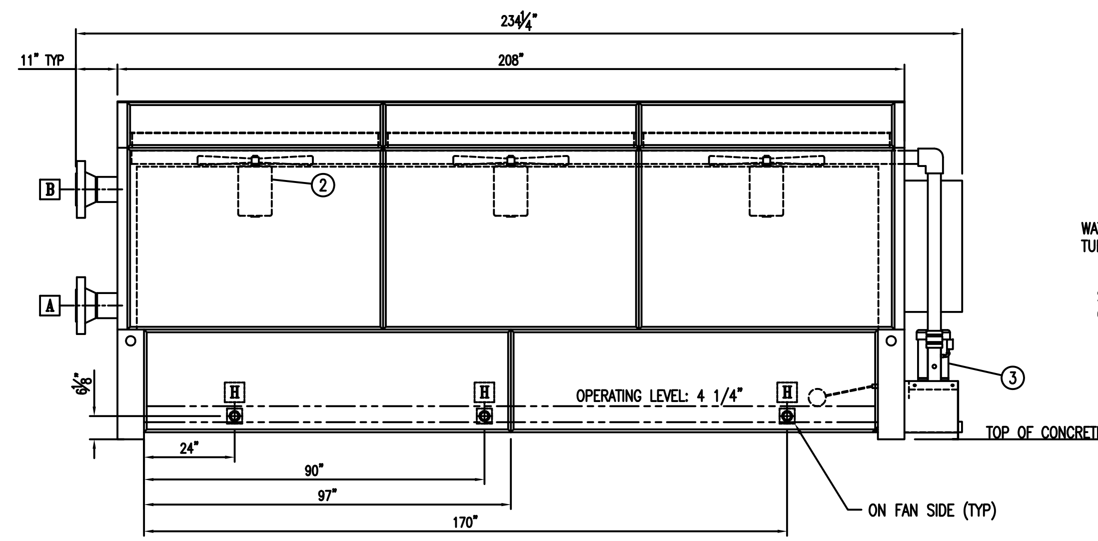
MARK	SIZE	RATING	TYPE	SERVICE
A	6"	900#	RFWN	PROCESS INLET
B	6"	900#	RFWN	PROCESS OUTLET
C	3/4"	150#	NPT	WATER MAKE-UP
D	2"	150#	NPT	DRAIN
E	2"	150#	NPT	OVERFLOW
F	3/4"	150#	NPT	BLOWDOWN
G	1/2"	150#	NPT	AIR INLET (WATER TREATMENT)
H	2"	150#	NPT	BASIN HEATER
J	3/4"	150#	NPT	WATER TEMPERATURE SENSOR



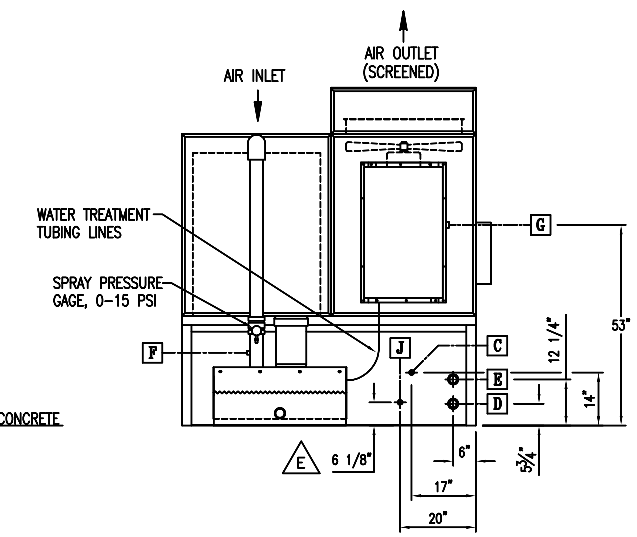
PLAN VIEW



LEFT SIDE VIEW



ELEVATION VIEW



RIGHT SIDE VIEW

NOTES:
1. ONE (1) ASSEMBLY REQUIRED
2. ALL PROCESS AND WATER CONNECTION LOCATIONS ARE APPROXIMATE DO NOT USE FOR PREFABRICATION OF PIPING.
3. WEIGHTS: SHIPPING – 13,500 LBS
OPERATING – 17,650 LBS
4. MOTORS AND OTHER ELECTRICAL COMPONENTS TO BE CLASS I DIV II COMPLIANT.

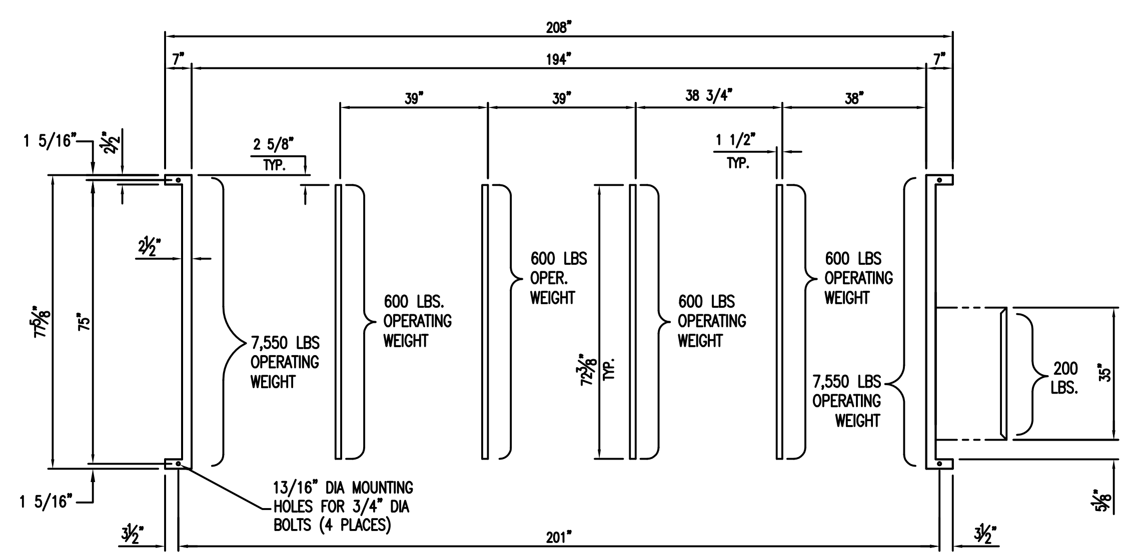
MATERIALS	
TUBES	CARBON STEEL, HDGAF
TUBESHEETS	CARBON STEEL, HDGAF
HEADERS	CARBON STEEL, HDGAF
UNIT CASING	CARBON STEEL, HDGAF
ACCESS PACKAGE	CARBON STEEL, HDGAF
SPRAY PIPING	P.V.C. (UV PROTECTED)
RISER PIPING	CARBON STEEL, PAINTED

OPERATING DATA (PER UNIT)	
TOTAL AIRFLOW	35,400 CFM
FAN BHP (TOTAL)	7.5 BHP
RECIRCULATION SPRAY RATE	240 GPM
PUMP BHP (TOTAL)	2.1
EST. MAKE-UP WATER	5.3 GPM
MAKE-UP BASED ON	6 COC

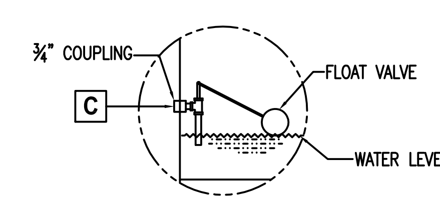
PERFORMANCE DATA (SYSTEM)	
SERVICE	NGL PRODUCT COOLER
FLOW	131,500 LBS/HR
OPERATING TEMP. IN	130'F
OPERATING TEMP. OUT	100'F
DESIGN WET BULB	70'F
HEAT LOAD	2,532,684 BTU/HR
PRESSURE DROP	5 PSI
DESIGN PRESSURE	1440 PSIG
DESIGN TEMPERATURE	200/-20'F
BARE TUBE SURFACE AREA	991 SQ. FT.

COMPONENT LIST

ITEM	QTY	DESCRIPTION
1	3	FAN, 30" DIA., LOW NOISE, FRP BLADES
2	3	FAN MOTOR, 5 HP, 1800 RPM, TEFC, 3PH/60/460V
3	1	SPRAY PUMP, END SUCTION, 3 HP, 1800 RPM, TEFC, 3PH/60/230/460V
4	1	COIL, CARBON STEEL – HDGAF, 1" DIAMETER, X .109" WALL TUBES
5	1	NIAGARA SPRAY SYSTEM W/ NYLON NOZZLES
6	1	STAINLESS STEEL PUMP SCREEN
7	1	24" X 30" ACCESS DOOR
8	3	BASIN HEATERS, 4KW 3PH/60/460V
9	1	JUNCTION BOX
10	1	WATER TREATMENT BOX



FOUNDATION LOAD DISTRIBUTION



FLOAT VALVE DETAIL

WSAC NAMEPLATE

WET SURFACE AIR COOLER ®

DCP MIDSTREAM
NGL PRODUCT COOLER

MODEL A4407SL
PURCHASE ORDER
SERIAL
TAG

NIAGARA BLOWER COMPANY 54230-G19

APPROVAL SIGNATURES	DATE	CUST. P.O. NO.
DRAWN BY:		SERIAL NO.
CHECKED BY:		SHOP ORDER NO.
ENGINEER:		DIMENSIONS IN: MILLIMETERS INCHES ☒
RELEASED BY:		TOLERANCES UNLESS OTHERWISE SPECIFIED DECIMALS: .XX ± .015 .XXX ± .010 ANGLES: ± 1/2 DEG. FRACTIONS: ± 1/4"
APPLICABLE SPECIFICATIONS		SCALE: 1" = 2'-0"

Niagara Blower Company
ENGINEERED HEAT TRANSFER SYSTEMS
BUFFALO, NEW YORK

UNAUTHORIZED USE, MANUFACTURE, OR REPRODUCTION EITHER IN WHOLE OR PART IS PROHIBITED. DRAWING DESIGN AND OTHER DISCLOSURES PROPERTY OF NIAGARA BLOWER COMPANY.

TITLE: GENERAL ARRANGEMENT
WSAC A4407SL WET SURFACE NGL PRODUCT COOLER

CUSTOMER: SAULSBURY INDUSTRIES
BERCLAIR, TEXAS

DWG. SIZE D | DRAWING NO. | SHEET NO. 1 OF 1 | SHEET | REVISION | SEE SHEET 1 REV. RECORD FOR LATEST DRAWING REV.

FIRST USED ON S/O – 12-22686

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Customer:	DCP	Proposal #:	WS14-072
Engineering Firm	Saulsbury Engineering & Construction	Rev:	Original
Domestic Project:	Zia II	Engineer:	Chris Imiola
Sales Office:	Thermal & Mechanical	Date:	April 17, 2014

STANDARD TERMS AND CONDITIONS OF SALE

1. PERFORMANCE GUARANTEE – Seller guarantees the thermal and mechanical performance of each heat exchanger when operated at the design conditions.
2. MATERIAL SELECTION – Niagara does not warrant the selection of material against corrosion, erosion or degradation from process or spray water related chemistry. Material selection shall be the sole responsibility of the purchaser.
3. WARRANTY – Each sold article or part manufactured by the Seller is warranted, at the time of original shipment thereof, from defects of material or workmanship, which warranty shall be in force for one (1) year following equipment start-up and not to exceed eighteen (18) months following delivery to jobsite, provided such article or part is properly installed and is used and operated solely in a normal manner and under normal conditions subject to the following provisions: - Written notice of any claimed defect must be given to the company at its Buffalo, N.Y. office by registered mail within thirty (30) days after the first discovery of such claimed defect the Purchaser or user; and the Seller's written authorization prepaid, to the company's factory. The Seller's sole obligation (which shall represent the Purchaser's sole remedy) hereunder shall be, at its option, (a) to repair or replace such article or part which is found by the Seller to have been, at the time of the original shipment thereof by the Seller, defective solely as the result of poor materials or unsound workmanship, or (b) to refund to the Purchaser the purchase price of such article or part so found by the Seller to have been defective when originally shipped. Seller makes no warranties covering deterioration or failures from corrosion, erosion, improper water treatment or normal wear and tear.
4. **IF ANY. In no event whatsoever shall the Company be liable for any special, indirect, consequential or other damages of like general nature, including, without limitation, loss or profits or of production, or costs, incurred by the Buyer or any third party, of labor or material or in connection with the replacement, adjustment, repair, installation, operation or maintenance of any article or part after original shipment thereof by the company. No warranty whatsoever shall apply to any article or part if the Company shall reasonably determine that the same, in any respect prejudicial to the Company, has been repaired or altered by anyone other than the Company or elsewhere than at the Company's factory or has been improperly installed or subjected to accident, damage, misuse or abnormal or unusual operating conditions or conditions not made known to or contemplated by the Company**
5. TAXES – Any local, state or federal sales or use taxes imposed on the sale shall be paid by the Purchaser.
6. CHANGES – Any changes requested are subject to corresponding price change (scope, materials, delivery).
7. LIABILITY – Seller will not be liable for incidental, consequential, indirect or special damages. Under no circumstances will the Seller's total liability under this purchase order exceed the value of the order.
8. SHIPPING – In the absence of specific written shipping or routing instructions from the Purchaser, the Seller may select method of shipment and routing. Verification of prepaid shipments will be substantiated by non-receipt copies of the freight bill.
9. DELIVERY – All shipment or delivery dates are subject to non-penalty delays caused or contributed to by any contingency or condition beyond the Seller's control, including, without limitation, labor troubles, war, continuance of war, fires, floods, weather or action of public authorities.
10. PURCHASE OF MATERIAL – Unless specified to the contrary, Seller will proceed with purchase of materials upon receipt of confirmed verbal or written PO.

BASIC COMMERCIAL TERMS

1. The prices quoted are ex-works, Buffalo, New York, freight prepay and add (unless otherwise agreed to), and are firm for acceptance within fourteen (14) calendar days from the date of this proposal. Due to market conditions, materials are price-in-effect for all major components (defined as tubes, header components and tubesheet material).
2. If Purchaser requests delay in shipment, the entire purchase price of the items or components ready for shipment shall forthwith become due and payable and Purchaser shall also pay to the Seller all expenses and charges for storage and of any other nature which result from such delay in shipment. Seller assumes no liability of items/components while in storage. Warranty period will NOT be extended for those items stored by Seller for Purchaser.
3. Until full payment, all articles sold shall remain the property and title thereto shall remain in the Seller notwithstanding any method of annexation to any real property. All risks of loss of or damage to such articles shall nevertheless be for Purchaser's account.
4. Equipment will be ready for shipment within the above stated weeks after receipt of approved drawings based on currently available shop space and quoted material lead times.
5. Drawing lead time is subject to engineering workload at time of purchase order acceptance by Seller.
6. All orders are subject to credit approval.
7. All past due accounts are subject to a late charge of 1% per month or any part thereof.
8. 8. CANCELLATION – In the event of cancellation, Purchaser shall pay Seller for all engineering, purchasing, material and fabrication costs incurred prior to cancellation. These charges will be a minimum of the following after receipt of order:
   0-3 weeks – 10%
   4-9 weeks – 25%
   10-15 weeks – 50%
   16-21 weeks – 75%
   22+ weeks – 100%

*H.D.G.A.F. IS HOT DIPPED GALVANIZED AFTER FABRICATION

Section 7.12 – Compressor Blowdown SSM (Unit SSM(CB))

- Section 7.12-1 – Inlet Gas Analysis (Refer to Section 7.4-1)

Section 7.13 – Plant Venting SSM (Unit SSM(PV))

- Section 7.13-1 – Inlet Gas Analysis (Refer to Section 7.4-1)

Section 7.14 – Methanol Tanks – *Not a regulated source of emissions.*
(Units TK-7700, TK-7750, TK-7800, TK-L2)

- Section 7.14-1 - TANKS 4.09d output (Units TK-7700, TK-7750, TK-7800, TK-L2)

Section 7.14-1 – TANKS 4.0.9d Output (Units TK-7700, TK-7750)

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	Zia II MEOH Tank
City:	Roswell
State:	New Mexico
Company:	DCP Midstream
Type of Tank:	Vertical Fixed Roof Tank
Description:	35bbl tank, 142bbl thruput
Tank Dimensions	
Shell Height (ft):	9.00
Diameter (ft):	5.30
Liquid Height (ft) :	8.00
Avg. Liquid Height (ft):	7.00
Volume (gallons):	1,320.28
Turnovers:	4.52
Net Throughput(gal/yr):	5,964.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Red/Primer
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good
Roof Characteristics	
Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Roswell, New Mexico (Avg Atmospheric Pressure = 12.73 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Zia II MEOH Tank - Vertical Fixed Roof Tank
Roswell, New Mexico

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	69.62	57.53	81.70	63.00	1.9396	1.3336	2.7663	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Zia II MEOH Tank - Vertical Fixed Roof Tank
Roswell, New Mexico

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	8.82	32.67	41.49

Section 7.14-1 – TANKS 4.0.9d Output (Unit TK-7800)

TANKS 4.0.9d
Emissions Report - Summary Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Zia II MEOH Tank 1036
City:	Roswell
State:	New Mexico
Company:	DCP Midstream
Type of Tank:	Vertical Fixed Roof Tank
Description:	25bbl tank, 100bbl thruput

Tank Dimensions

Shell Height (ft):	12.00
Diameter (ft):	4.00
Liquid Height (ft) :	11.00
Avg. Liquid Height (ft):	8.00
Volume (gallons):	1,034.04
Turnovers:	4.06
Net Throughput(gal/yr):	4,200.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Red/Primer
Shell Condition	Good
Roof Color/Shade:	White/White
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Roswell, New Mexico (Avg Atmospheric Pressure = 12.73 psia)

TANKS 4.0.9d
Emissions Report - Summary Format
Liquid Contents of Storage Tank

Zia II MEOH Tank 1036 - Vertical Fixed Roof Tank
Roswell, New Mexico

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	69.62	57.53	81.70	63.00	1.9396	1.3336	2.7663	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Summary Format
Individual Tank Emission Totals

Emissions Report for: Annual

Zia II MEOH Tank 1036 - Vertical Fixed Roof Tank
Roswell, New Mexico

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	6.21	31.31	37.53

Section 7.14-1 – TANKS 4.0.9d Output (Unit TK-L2)

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	Zia II Methanol Tank TK-L2
City:	
State:	
Company:	
Type of Tank:	Horizontal Tank
Description:	443 bbl
Tank Dimensions	
Shell Length (ft):	13.50
Diameter (ft):	15.30
Volume (gallons):	18,606.00
Turnovers:	2.69
Net Throughput(gal/yr):	50,000.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Light
Shell Condition	Poor
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Roswell, New Mexico (Avg Atmospheric Pressure = 12.73 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Zia II Methanol Tank TK-L2 - Horizontal Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	71.38	58.03	84.73	63.60	2.0453	1.3550	3.0153	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Zia II Methanol Tank TK-L2 - Horizontal Tank

Annual Emission Calcaulations	
Standing Losses (lb):	908.0687
Vapor Space Volume (cu ft):	1,580.9090
Vapor Density (lb/cu ft):	0.0115
Vapor Space Expansion Factor:	0.2503
Vented Vapor Saturation Factor:	0.5467
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	1,580.9090
Tank Diameter (ft):	15.3000
Effective Diameter (ft):	16.2210
Vapor Space Outage (ft):	7.6500
Tank Shell Length (ft):	13.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0115
Vapor Molecular Weight (lb/lb-mole):	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.0453
Daily Avg. Liquid Surface Temp. (deg. R):	531.0518
Daily Average Ambient Temp. (deg. F):	60.8167
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	523.2667
Tank Paint Solar Absorptance (Shell):	0.6300
Daily Total Solar Insulation Factor (Btu/sqft day):	1,810.0000
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2503
Daily Vapor Temperature Range (deg. R):	53.4084
Daily Vapor Pressure Range (psia):	1.6603
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.0453
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.3550
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	3.0153
Daily Avg. Liquid Surface Temp. (deg R):	531.0518
Daily Min. Liquid Surface Temp. (deg R):	517.6997
Daily Max. Liquid Surface Temp. (deg R):	544.4039
Daily Ambient Temp. Range (deg. R):	29.8333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.5467
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.0453
Vapor Space Outage (ft):	7.6500
Working Losses (lb):	78.0146
Vapor Molecular Weight (lb/lb-mole):	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.0453
Annual Net Throughput (gal/yr.):	50,000.0000
Annual Turnovers:	2.6873
Turnover Factor:	1.0000
Tank Diameter (ft):	15.3000
Working Loss Product Factor:	1.0000
Total Losses (lb):	986.0833

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

Zia II Methanol Tank TK-L2 - Horizontal Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	78.01	908.07	986.08

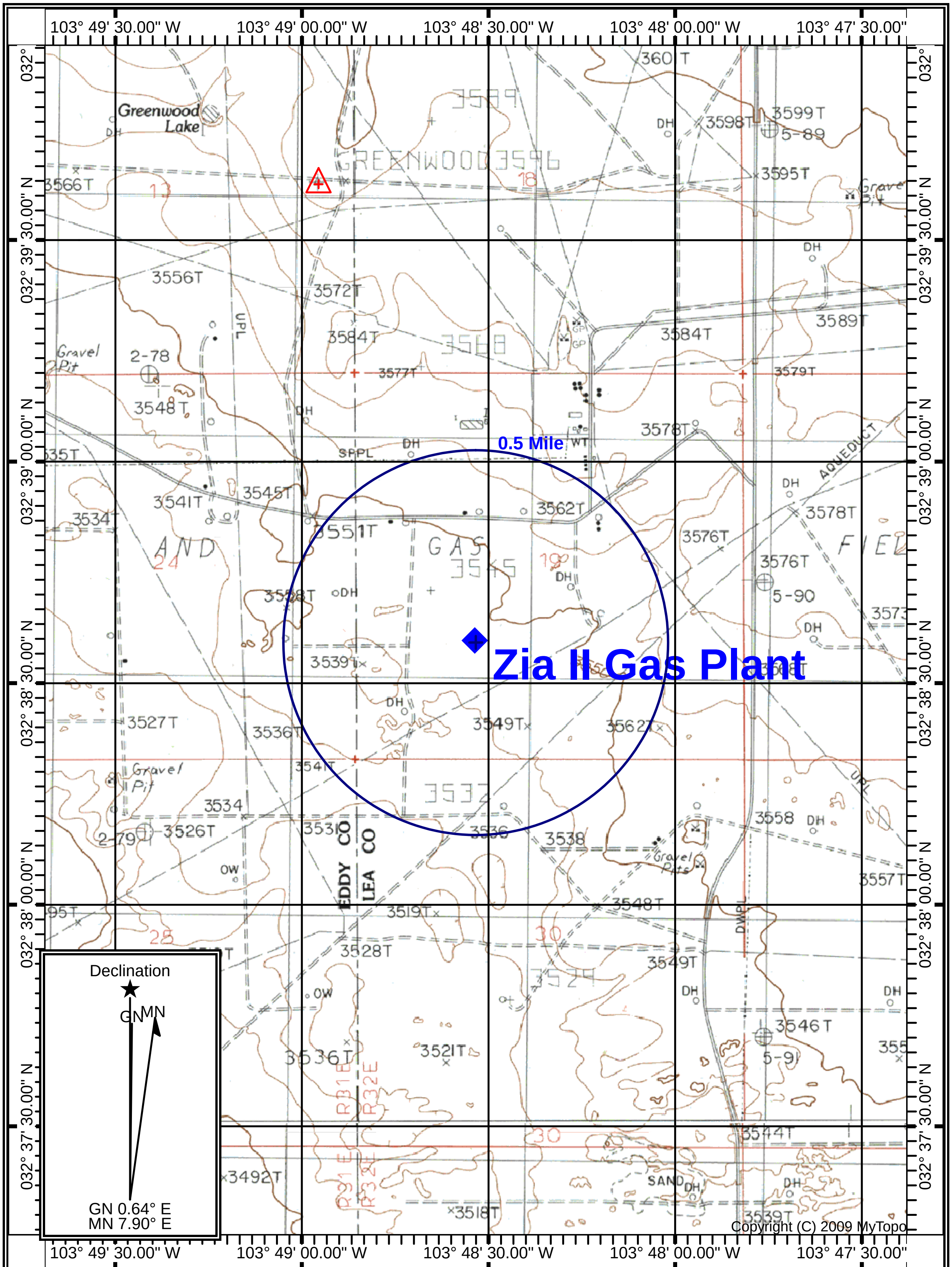
Section 8

Map(s)

A map such as a 7.5 minute topographic quadrangle showing the exact location of the source. The map shall also include the following:

The UTM or Longitudinal coordinate system on both axes	An indicator showing which direction is north
A minimum radius around the plant of 0.8km (0.5 miles)	Access and haul roads
Topographic features of the area	Facility property boundaries
The name of the map	The area which will be restricted to public access
A graphical scale	

A topographic map is attached.



Map Name: GREENWOOD LAKE Scale: 1 inch = 2,000 ft. Horizontal Datum: WGS84

Print Date: 04/17/15 Map Center: 032° 38' 35.87" N 1

Section 9

Proof of Public Notice

(for NSR applications submitting under 20.2.72 or 20.2.74 NMAC)
(This proof is required by: 20.2.72.203.A.14 NMAC "Documentary Proof of applicant's public notice")

☐ **I have read the AQB "Guidelines for Public Notification for Air Quality Permit Applications"**
This document provides detailed instructions about public notice requirements for various permitting actions. It also provides public notice examples and certification forms. Material mistakes in the public notice will require a re-notice before issuance of the permit.

Unless otherwise allowed elsewhere in this document, the following items document proof of the applicant's Public Notification. Please include this page in your proof of public notice submittal with checkmarks indicating which documents are being submitted with the application.

New Permit and **Significant Permit Revision** public notices must include all items in this list.

Technical Revision public notices require only items 1, 5, 9, and 10.

Per the Guidelines for Public Notification document mentioned above, include:

1. ☐ A copy of the certified letter receipts with post marks (20.2.72.203.B NMAC)
2. ☐ A list of the places where the public notice has been posted in at least four publicly accessible and conspicuous places, including the proposed or existing facility entrance. (e.g: post office, library, grocery, etc.)
3. ☐ A copy of the property tax record (20.2.72.203.B NMAC).
4. ☐ A sample of the letters sent to the owners of record.
5. ☐ A sample of the letters sent to counties, municipalities, and Indian tribes.
6. ☐ A sample of the public notice posted and a verification of the local postings.
7. ☐ A table of the noticed citizens, counties, municipalities and tribes and to whom the notices were sent in each group.
8. ☐ A copy of the public service announcement (PSA) sent to a local radio station and documentary proof of submittal.
9. ☐ A copy of the classified or legal ad including the page header (date and newspaper title) or its affidavit of publication stating the ad date, and a copy of the ad. When appropriate, this ad shall be printed in both English and Spanish.
10. ☐ A copy of the display ad including the page header (date and newspaper title) or its affidavit of publication stating the ad date, and a copy of the ad. When appropriate, this ad shall be printed in both English and Spanish.
11. ☐ A map with a graphic scale showing the facility boundary and the surrounding area in which owners of record were notified by mail. This is necessary for verification that the correct facility boundary was used in determining distance for notifying land owners of record.

Not applicable as this application is pursuant to 20.2.70.300.B.(2) NMAC for a Title V Renewal.

Section 10

Written Description of the Routine Operations of the Facility

<u>A written description of the routine operations of the facility</u>. Include a description of how each piece of equipment will be operated, how controls will be used, and the fate of both the products and waste generated. For modifications and/or revisions, explain how the changes will affect the existing process. In a separate paragraph describe the major process bottlenecks that limit production. The purpose of this description is to provide sufficient information about plant operations for the permit writer to determine appropriate emission sources.

The Zia II Gas Plant is a 230 MMscf/d cryogenic gas processing plant designed to treat and process produced natural gas for DCP gathering systems located throughout central and southern New Mexico.

Field natural gas entering the Zia II Gas Plant is sent through an inlet separation designed to remove entrained solids and dissolved liquids from the field-gas stream. The water produced from the separation is sent to tanks (Units TK-6100 and TK-6150). Condensate from the inlet will be separated, stabilized using heat medium oil, and stored (Units TK-2100 and TK-2200) prior to loadout via truck (Unit L1). Working and breathing losses from the tanks and loading emissions are sent to the vapor combustion device (VCD1). Working and breathing losses from the tanks and loading emissions are sent to the vapor combustion device (VCD1). The flash gas vapors [e.g. from the condensate stabilizer] will be sent back to the inlet stream of the plant via compression (Unit C9-E and C10-E).

Once the field gas passes through the inlet separation, it will be routed to the inlet compression (Units C1-E to C4-E and C9-E and C10-E) to increase the pressure of the gas. The stream will then be sent to an amine treater (Unit Amine) for the purpose of removing carbon dioxide and hydrogen sulfide entrained in the field gas stream. The amine system will consist of an amine contactor, flash tank, amine tanks, amine pumping system and an amine still. Emissions originating from the flash tank will be recovered and sent to the inlet stream of the plant to be re-compressed by Units C9-E and C10-E. Two hot oil heaters (Units H4 and H5) will be used as the heat source to regenerate the rich amine. Emissions from the amine still overheads will be routed to the AGI wells (Units AGI1 and AGI2) via the AGI electric compressors (units C14-C and C15-C) or the emergency acid gas flare (Unit FL2). Only one of the AGI wells will be taken offline at a time for routine and predictable maintenance. The gas for the well that is out of service will be routed to the acid gas flare (Unit FL2). The plant flare (Unit FL1) will be used for SSM associated with catalyst compressor changes, specialized blowdowns for associated maintenance, and PSD maintenance of process safety valves. The Lusk flare (Unit FL3) will be used as an emergency flare.

After the amine treating, the field gas will then be sent to a TEG dehydration system (Unit Dehy) for the purpose of removing water from the gas stream. The dehydrator system will consist of a TEG contactor, flash tank, and BTEX condenser. Emissions originating from the flash tank will be recovered and sent to the low-pressure inlet stream of the plant. A TEG regeneration heater (Unit H6) will be used to regenerate the rich TEG. TEG regenerator emissions will be re-routed to the inlet. Non-condensables will be sent to the vapor combustion device (Unit VCD1). The TEG dehydrator system is a completely closed system. The gas is then sent to multiple mole sieve adsorption towers for additional water removal. One or more towers will be in dehydration mode while one or more are in regeneration mode. The towers will contain a solid desiccant material that will remove the moisture contained within the field gas stream prior to entrance into the "cold plant." The solid desiccant material will be regenerated by heating gas (Unit H3) through the tower that is in regeneration mode. The wet gas from the regeneration of the mole sieve beds will be routed to the gas stream entering the amine treating system.

NGL recovery is achieved through a cryogenic process where the liquid-rich field gas temperature is dropped to approximately minus 122° Fahrenheit. This temperature drop will be accomplished using a propane refrigerant and a turbo expander. The combination of the propane refrigerant and the expansion of the field gas via turbo expander results in a rapid temperature drop condensing out the ethane and heavier NGL's while at the same time maintaining methane in gas form (residue gas). The resulting condensed liquid consists of a marketable NGL Y-Grade product that will be sent to market via pipeline. The electric-driven screw compressor engines correspond with refrigerant compressors Units C11-C to C13-C.

The dry, pipeline quality, residue gas (consisting of primarily methane) from the top of the de-methanizer tower will be sent to the suction header of the residue gas compressors (Units C5-E to C8-E). A trim reboiler (Unit H1) will also be associated with de-methanizer tower to regulate the temperature when needed. The residue gas will then be compressed up to a pressure high enough for delivery into a high-pressure natural gas (sales) pipeline.

Section 11

Source Determination

Source submitting under 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC

Sources applying for a construction permit, PSD permit, or operating permit shall evaluate surrounding and/or associated sources (including those sources directly connected to this source for business reasons) and complete this section. Responses to the following questions shall be consistent with the Air Quality Bureau's permitting guidance, Single Source Determination Guidance, which may be found on the Applications Page in the Permitting Section of the Air Quality Bureau website.

Typically, buildings, structures, installations, or facilities that have the same SIC code, that are under common ownership or control, and that are contiguous or adjacent constitute a single stationary source for 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC applicability purposes. Submission of your analysis of these factors in support of the responses below is optional, unless requested by NMED.

A. Identify the emission sources evaluated in this section (list and describe)**: See Table 2-A in Section 2 of this application.**

B. Apply the 3 criteria for determining a single source:

SIC Code: Surrounding or associated sources belong to the same 2-digit industrial grouping (2-digit SIC code) as this facility, OR surrounding or associated sources that belong to different 2-digit SIC codes are support facilities for this source.

☑ **Yes** ☐ **No**

Common Ownership or Control: Surrounding or associated sources are under common ownership or control as this source.

☑ **Yes** ☐ **No**

Contiguous or Adjacent: Surrounding or associated sources are contiguous or adjacent with this source.

☑ **Yes** ☐ **No**

C. Make a determination:

☑ The source, as described in this application, constitutes the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes. If in "A" above you evaluated only the source that is the subject of this application, all "**YES**" boxes should be checked. If in "A" above you evaluated other sources as well, you must check **AT LEAST ONE** of the boxes "**NO**" to conclude that the source, as described in the application, is the entire source for 20.2.70, 20.2.72, 20.2.73, and 20.2.74 NMAC applicability purposes.

☐ The source, as described in this application, **does not** constitute the entire source for 20.2.70, 20.2.72, 20.2.73, or 20.2.74 NMAC applicability purposes (A permit may be issued for a portion of a source). The entire source consists of the following facilities or emissions sources (list and describe):

Section 12

Section 12.A
PSD Applicability Determination for All Sources

(Submitting under 20.2.72, 20.2.74 NMAC)

A PSD applicability determination for all sources. For sources applying for a significant permit revision, apply the applicable requirements of 20.2.74.AG and 20.2.74.200 NMAC and to determine whether this facility is a major or minor PSD source, and whether this modification is a major or a minor PSD modification. It may be helpful to refer to the procedures for Determining the Net Emissions Change at a Source as specified by Table A-5 (Page A.45) of the EPA New Source Review Workshop Manual to determine if the revision is subject to PSD review.

A. This facility is:

- ☐ **a minor PSD source before and after this modification (if so, delete C and D below).**
- ☐ **a major PSD source before this modification. This modification will make this a PSD minor source.**
- ☐ **an existing PSD Major Source that has never had a major modification requiring a BACT analysis.**
- ☐ **an existing PSD Major Source that has had a major modification requiring a BACT analysis**
- ☐ **a new PSD Major Source after this modification.**

B. **This facility is not one of the listed 20.2.74.501 Table I – PSD Source Categories. There are no "project" emissions associated with this Title V permit renewal application as there are no proposed changes.**

C. **Netting is not required as there is no project.**

D. **BACT is not required as there is no project.**

E. If this is an existing PSD major source, or any facility with emissions greater than 250 TPY (or 100 TPY for 20.2.74.501 Table 1 – PSD Source Categories), determine whether any permit modifications are related, or could be considered a single project with this action, and provide an explanation for your determination whether a PSD modification is triggered.

DCP Midstream, LP (DCP) is submitting an application pursuant to 20.2.70.300.B.(1) NMAC for an Title V permit renewal. A PSD applicability determination was submitted with the application for modification of permit PSD-5217. A PSD applicability determination is not required for this application.

Section 13

Determination of State & Federal Air Quality Regulations

<u>This section lists each state and federal air quality regulation that may apply to your facility and/or equipment that are stationary sources of regulated air pollutants.</u>

Not all state and federal air quality regulations are included in this list. Go to the Code of Federal Regulations (CFR) or to the Air Quality Bureau's regulation page to see the full set of air quality regulations.

Required Information for Specific Equipment:
For regulations that apply to specific source types, in the 'Justification' column **provide any information needed to determine if the regulation does or does not apply**. **For example**, to determine if emissions standards at 40 CFR 60, Subpart IIII apply to your three identical stationary engines, we need to know the construction date as defined in that regulation; the manufacturer date; the date of reconstruction or modification, if any; if they are or are not fire pump engines; if they are or are not emergency engines as defined in that regulation; their site ratings; and the cylinder displacement.

Required Information for Regulations that Apply to the Entire Facility:
See instructions in the 'Justification' column for the information that is needed to determine if an 'Entire Facility' type of regulation applies (e.g. 20.2.70 or 20.2.73 NMAC).

Regulatory Citations for Regulations That Do Not, but Could Apply:
If there is a state or federal air quality regulation that does not apply, but you have a piece of equipment in a source category for which a regulation has been promulgated, you must **provide the low level regulatory citation showing why your piece of equipment is not subject to or exempt from the regulation. For example** if you have a stationary internal combustion engine that is not subject to 40 CFR 63, Subpart ZZZZ because it is an existing 2 stroke lean burn stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, your citation would be 40 CFR 63.6590(b)(3)(i). **We don't want a discussion of every non-applicable regulation, but if it is possible a regulation could apply, explain why it does not. For example,** if your facility is a power plant, you do not need to include a citation to show that 40 CFR 60, Subpart OOO does not apply to your non-existent rock crusher.

Regulatory Citations for Emission Standards:
For each unit that is subject to an emission standard in a source specific regulation, such as 40 CFR 60, Subpart OOO or 40 CFR 63, Subpart HH, include the low level regulatory citation of that emission standard. Emission standards can be numerical emission limits, work practice standards, or other requirements such as maintenance. **Here are examples:** a glycol dehydrator is subject to the general standards at 63.764C(1)(i) through (iii); an engine is subject to 63.6601, Tables 2a and 2b; a crusher is subject to 60.672(b), Table 3 and all transfer points are subject to 60.672(e)(1)

Federally Enforceable Conditions:
All federal regulations are federally enforceable. All Air Quality Bureau State regulations are federally enforceable except for the following: affirmative defense portions at 20.2.7.6.B, 20.2.7.110(B)(15), 20.2.7.11 through 20.2.7.113, 20.2.7.115, and 20.2.7.116; 20.2.37; 20.2.42; 20.2.43; 20.2.62; 20.2.63; 20.2.86; 20.2.89; and 20.2.90 NMAC. Federally enforceable means that EPA can enforce the regulation as well as the Air Quality Bureau and federally enforceable regulations can count toward determining a facility's potential to emit (PTE) for the Title V, PSD, and nonattainment permit regulations.

INCLUDE ANY OTHER INFORMATION NEEDED TO COMPLETE AN APPLICABILITY DETERMINATION OR THAT IS RELEVENT TO YOUR FACILITY'S NOTICE OF INTENT OR PERMIT.

EPA Applicability Determination Index for 40 CFR 60, 61, 63, etc: http://cfpub.epa.gov/adi/

Table for STATE REGULATIONS:

STATE REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION: Identify the applicability criteria, numbering each (i.e. 1. Post 7/23/84, 2. 75 m³, 3. VOL)
20.2.3 NMAC	Ambient Air Quality Standards NMAAQS	X	N/A	X	N/A	20.2.3 NMAC is a SIP approved regulation that limits the maximum allowable concentration of Total Suspended Particulates, Sulfur Compounds, Carbon Monoxide and Nitrogen Dioxide. The facility will meet maximum allowable concentrations under this regulation.
20.2.7 NMAC	Excess Emissions	X	N/A	X	N/A	This regulation establishes requirements for the facility if operations at the facility result in any excess emissions. The owner or operator will operate the source at the facility having an excess emission, to the extent practicable, including associated air pollution control equipment, in a manner consistent with good air pollution control practices for minimizing emissions. The facility will also notify the NMED of any excess emission per 20.2.7.110 NMAC.
20.2.33 NMAC	Gas Burning Equipment - Nitrogen Dioxide	N/A	N/A	N/A	X	This regulation applies to all gas burning equipment (external combustion emission sources, such as gas fired boilers and heaters) having a heat input greater than 1,000,000 million British Thermal Units per year per unit. The heaters at the facility are less than the 1,000,000 million British Thermal Units per year per unit applicability limit of this regulation. This regulation does not apply.
20.2.34 NMAC	Oil Burning Equipment: NO_2	N/A	N/A	N/A	X	This facility does not have oil burning equipment having a heat input of greater than 1,000,000 million British Thermal Units per year per unit. The facility is not subject to this regulation and does not have emission sources that meet the applicability requirements under 20.2.34.108 NMAC.
20.2.35 NMAC	Natural Gas Processing Plant – Sulfur	X	N/A	N/A	N/A	This regulation establishes sulfur emission standards for natural gas processing plants. The facility meets the definition of a new natural gas processing plant under this regulation and is subject to the requirements of this regulation [20.2.35.7 (B) NMAC]. The facility will meet all applicable requirements under 20.2.35 NMAC as applicable.
20.2.37 NMAC	Petroleum Processing Facilities	X	N/A	N/A	N/A	This purpose of this regulation is to minimize emissions from petroleum or natural gas processing facilities. The facility is considered a new petroleum processing facility under this regulation [20.2.37.7(C) NMAC]. The facility will meet all applicable requirements under this regulation.
20.2.38 NMAC	Hydrocarbon Storage Facility	N/A	N/A	N/A	X	The facility is not a tank battery or petroleum production facility as defined in this regulation [20.2.38.7 (D) and (E) NMAC]. The facility does not receive crude oil or condensate from a well. All gas and liquids enter the facility through a pipeline.
20.2.39 NMAC	Sulfur Recovery Plant - Sulfur	N/A	N/A	N/A	X	This regulation establishes sulfur emission standards for sulfur recovery plants which are not part of petroleum or natural gas processing facilities. This regulation does not apply to the facility because it is superseded by 20.2.35 NMAC.
20.2.61.109 NMAC	Smoke & Visible Emissions	N/A	N/A	X	X	This regulation establishes controls on smoke and visible emissions from certain sources. The facility is not subject to this regulation because 20.2.61.109 NMAC is superseded by 20.2.37 NMAC. [20.2.61.109 NMAC]
20.2.70 NMAC	Operating Permits	X	N/A	X	N/A	This regulation establishes requirements for obtaining an operating permit. The facility is a major source for criteria pollutants, HAPs, and GHG. DCP is submitting this application for initial Title V permit per 20.2.70.300.B(1) NMAC.
20.2.71 NMAC	Operating Permit Fees	X	N/A	X	N/A	This regulation establishes a schedule of operating permit emission fees. The facility is subject to 20.2.70 NMAC and is therefore subject to requirements of this regulation. The facility will meet all fee requirements under 20.2.71.110 NMAC.

STATE REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION: Identify the applicability criteria, numbering each (i.e. 1. Post 7/23/84, 2. 75 m^3, 3. VOL)
20.2.72 NMAC	Construction Permits	X	N/A	X	N/A	This regulation establishes the requirements for obtaining a construction permit. The facility is a stationary source that has potential emission rates greater than 10 pounds per hour and 25 tons per year of any regulated air contaminant for which there is a National or New Mexico Air Quality Standard. This regulation applies.
20.2.73 NMAC	NOI & Emissions Inventory Requirements	X	N/A	X	N/A	This regulation establishes emission inventory requirements. The facility meets the applicability requirements of 20.2.73.300 NMAC. The facility will meet all applicable reporting requirements under 20.2.73.300.B.1 NMAC.
20.2.74 NMAC	Permits – PSD	X	N/A	X	N/A	This regulation establishes requirements for obtaining a prevention of significant deterioration permit. The facility will be PSD major for NO_X, Ozone and CO_2e. Also, the facility will trigger the significant emission rates (SER) for CO, VOC, SO_X, $PM_{2.5}$, and PM_{10}. The facility complies with PSD Permit PSD-5217-M2R1.
20.2.75 NMAC	Construction Permit Fees	X	ALL	X	N/A	This facility is subject to 20.2.72 NMAC and is in turn subject to 20.2.75 NMAC for NSR permit application fees only. This facility is exempt from annual fees under this part (20.2.75.11.E NMAC) as it is subject to fees pursuant to 20.2.71 NMAC.
20.2.77 NMAC	New Source Performance	X	C1-E to C10-E, C1-C to C10-C, C14-C, C15-C, H1, H3, H4, H5, Amine, Leaks, TK-2100, TK-2200, TK-6100, TK-6150, FL1, FL2, VCD1, GEN-1	X	N/A	This is a stationary source subject to the requirements of 40 CFR Part 60, as amended through January 31, 2009. The facility is subject to this regulation because of applicability under 40 CFR Part 60 Subpart JJJJ (applies to all RICE Units C1-E to C10-E), Subpart Dc (applies to Units H1, H3, H4, and H5), and Subpart OOOO (applies to the Amine unit, leaks, tanks, pneumatic devices, and non-screw compressors). Also, the inlet gas flare (FL1), acid gas flare (Unit FL2) and vapor combustion device (VCD1) must meet control requirements under NSPS 60.18. Unit GEN-1 is subject to 40 CFR 60 Subpart IIII.
20.2.78 NMAC	Emission Standards for HAPS	N/A	N/A	N/A	X	This regulation establishes state authority to implement emission standards for hazardous air pollutants subject to 40 CFR Part 61. This facility does not emit hazardous air pollutants which are subject to the requirements of 40 CFR Part 61 and is therefore not subject to this regulation.
20.2.79 NMAC	Permits – Nonattainment Areas	N/A	N/A	N/A	X	This regulation establishes the requirements for obtaining a non-attainment area permit. The facility is not located in a non-attainment area and therefore is not subject to this regulation.
20.2.80 NMAC	Stack Heights	N/A	N/A	N/A	X	This regulation establishes requirements for the evaluation of stack heights and other dispersion techniques. This regulation does not apply as all stacks at the facility will follow good engineering practice.
20.2.82 NMAC	MACT Standards for source categories of HAPS	N/A	C1-E to C10-E, Dehy, and H1 to H6	X	N/A	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63, as amended through January 31, 2009.

Table for Applicable FEDERAL REGULATIONS (Note: This in not an exhaustive list):

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
40 CFR 50	NAAQS	X	All	X	N/A	This regulation defines national ambient air quality standards. The facility meets all applicable national ambient air quality standards for NOx, CO, SO_2, PM_{10}, and $PM_{2.5}$ under this regulation.
NSPS 40 CFR 60, Subpart A	General Provisions	X	C1-E to C10-E, C1-C to C10-C, C14-C, C15-C, H1, H3, H4, H5, Amine, Leaks, TK-2100, TK-2200, TK-6100, TK-6150, FL1, FL2, VCD1, GEN-1	X	N/A	This regulation defines general provisions for relevant standards that have been set under this part. The facility is subject to this regulation because of applicability under 40 CFR Part 60 Subpart JJJJ (applies to all RICE Units C1-E to C10-E), Subpart Dc (applies to Units H1, H4, and H5), and Subpart OOOO (applies to the Amine unit, leaks, tanks, pneumatic devices, and non-screw compressors). Also, the inlet gas flare (FL1), acid gas flare (Unit FL2) and vapor combustion device (VCD1) must meet control requirements under NSPS 60.18. Unit GEN-1 is subject to 40 CFR 60 Subpart IIII.
NSPS 40 CFR60.40 a, Subpart Da	Subpart Da, Performance Standards for **Electric Utility Steam Generating Units**	N/A	N/A	N/A	X	This regulation establishes standards of performance for electric utility steam generating units. This regulation does not apply because the facility does not operate any electric utility steam generating units.
NSPS 40 CFR60.40b Subpart Db	**Electric Utility Steam Generating Units**	N/A	N/A	X	X	This regulation establishes standards of performance for industrial-commercial-institutional steam generating units. This facility does not have steam generating units with heat input capacity greater than 100 MMBtu/hr. This regulation does not apply.
NSPS 40 CFR 60.40c Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	N/A	H1, H3, H4, H5	X	N/A	This regulation establishes standards of performance for small industrial-commercial-institutional steam generating units. Units H1, H3, H4, and H5 will be installed or modified after June 9, 1989, with a heat input capacity greater than or equal to 10 MMBtu/hr but less than 100 MMBtu/hr. The units will only burn natural gas and therefore will not be subject to performance tests, reporting requirements, or emission limits under this regulation. The facility will follow all record keeping requirements for this unit. Unit H6 is less than 10 MMBtu/hr and are therefore not subject to this regulation.
NSPS 40 CFR 60, Subpart Ka	Standards of Performance for **Storage Vessels for Petroleum Liquids** for which Construction, Reconstruction, or Modification Commenced After May 18, 1978, and **Prior** to July 23, 1984	N/A	N/A	N/A	X	Each petroleum liquid storage vessel at the facility has a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer. The tanks at the facility are therefore exempt from the requirements of this subpart.

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
NSPS 40 CFR 60, Subpart Kb	Standards of Performance for **Volatile Organic Liquid Storage Vessels** (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced **After** July 23, 1984	N/A	N/A	N/A	X	Each petroleum liquid storage vessel at the facility has a capacity of less than 1,589,873 liters (420,000 gallons) used for petroleum or condensate stored, processed, or treated prior to custody transfer. The tanks at the facility are therefore exempt from the requirements of this subpart.
NSPS 40 CFR 60.330 Subpart GG	**Stationary Gas Turbines**	N/A	N/A	N/A	X	This regulation establishes standards of performance for certain stationary gas turbines. There are no stationary gas turbines at Zia II Gas Plant.
NSPS 40 CFR 60, Subpart KKK	Leaks of VOC from **Onshore Gas Plants**	N/A	N/A	N/A	X	This regulation defines standards of performance for equipment leaks of VOC emissions from onshore natural gas processing plants for which construction, reconstruction, or modification commenced after January 20, 1984, and on or before August 23, 2011. The facility will be constructed after August 23, 2011 and is therefore not subject to this regulation.
NSPS 40 CFR Part 60 Subpart LLL	Standards of Performance for **Onshore Natural Gas Processing**: SO_2 Emissions	N/A	N/A	N/A	X	This regulation establishes standards of performance for SO_2 emissions from onshore natural gas processing for which construction, reconstruction, or modification of the amine sweetening unit commenced after January 20, 1984 and on or before August 23, 2011. The facility will be constructed after August 23, 2011 and is therefore not subject to this regulation.
NSPS 40 CFR Part 60 Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution	N/A	C1-C to C10-C, C14-C, C15-C, TK-2100, TK-2200, TK-6100, TK-6150, Amine, and Equip-ment leaks	X	X	This regulation establishes emission standards and compliance schedule for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011. Since the facility will be constructed after August 23, 2011, all non-screw compressors, tanks, and equipment leaks are subject to this regulation. The acid gas from the amine unit (sweetening unit) at the facility is completely injected into oil or gas-bearing geological strata (AGI wells) and is not subject to 60.5405 through 60.5407, 60.5410(g), and 60.5423 of this subpart [per NSPS OOOO 60.5365(g)(4)]. When the acid gas flare is used during planned SSM and the acid gas is not sent to the AGI wells, the facility is subject to SO_2 standards for the amine unit. Since the flare will be used as a control device during planned SSM, the flare is subject to NSPS 60.18. The inlet Gas Flare (FL1) during times of SSM is used as a control and can be subject to NSPS 60.18. The vapor combustion device is also subject to NSPS 60.18 since the device controls tanks emissions. 40 CFR part 60.5365(f) in NSPS OOOO identifies that a group of all equipment (except compressors) within a process unit is an affected facility under this subpart and is covered by 60.5400 (equipment leak standards), 60.5401 (exceptions to equipment leak standards), 60.5402 (alternative emission limitations), 60.5421(notification, recordkeeping and reporting requirements) and 60.5422 (additional reporting requirements).Pursuant to 60.5365(f)(3), this equipment

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
						includes equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system or LNG unit (a cold plant and refrigeration unit would be part of the LNG unit) The facility will comply with this regulation upon startup. The pneumatic devices located at the facility will not be continuous bleed and therefore will not have applicable requirements under this regulation. Compressor Units C11-C through C13-C are screw compressors and therefore are not subject to NSPS OOOO.
NSPS 40 CFR 60 Subpart IIII	Standards of performance for Stationary Compression Ignition Internal Combustion Engines	N/A	GEN-1	X	N/A	This regulation establishes standards of performance for stationary compression ignition combustion engines. The emergency diesel generator, Unit GEN-1, commenced construction after July 11, 2005, was manufactured after April 1, 2006, and is not a fire pump engine. The engine is subject to this regulation [§60.4205(b)].
NSPS 40 CFR Part 60 Subpart JJJJ	Standards for Performance for Stationary Spark Ignition Internal Combustion Engines	N/A	C1-E to C10-E	X	N/A	This regulation establishes standards of performance for stationary spark ignition combustion engines. All non-emergency engines at the facility will be new 4 stroke lean burn engines with horsepower greater than 500 located at a major source of HAPs. All engines are subject to NO_x and VOC standards per Table 1 of NSPS JJJJ. Engines will meet NSPS JJJJ CO standards by meeting MACT ZZZZ CO standards per Table 1 of NSPS JJJJ.
NSPS 40 CFR 60 Subpart TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	N/A	N/A	N/A	X	This subpart establishes emission standards and compliance schedules for the control of greenhouse gas (GHG) emissions from a steam generating unit, IGCC, or a stationary combustion turbine that commences construction after January 8, 2014 or commences modification or reconstruction after June 18, 2014. This facility does not contain the affected source therefore this regulation does not apply.
NSPS 40 CFR 60 Subpart UUUU	Emissions Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units	N/A	N/A	N/A	X	This subpart establishes emission guidelines and approval criteria for State or multi-State plans that establish emission standards limiting greenhouse gas (GHG) emissions from an affected steam generating unit, integrated gasification combined cycle (IGCC), or stationary combustion turbine. This facility does not contain the affected source therefore this regulation does not apply.
NESHAP 40 CFR 61 Subpart A	General Provisions	N/A	N/A	N/A	X	NSPS 40 CFR 61 does not apply to the facility because the facility does not emit or have the triggering substances on site and/or the facility is not involved in the triggering activity. The facility is not subject to this regulation. None of the subparts of Part 61 apply to the facility.
NESHAP 40 CFR 61 Subpart E	National Emission Standards for **Mercury**	N/A	N/A	N/A	X	This regulation establishes a national emission standard for mercury. The facility does not have stationary sources which process mercury ore to recover mercury, use mercury chlor-alkali cells to produce chlorine gas and alkali metal hydroxide, and incinerate or dry wastewater treatment plant sludge [40 CFR Part 61.50]. The facility is not subject to this regulation.
NESHAP 40 CFR 61 Subpart V	National Emission Standards for **Equipment Leaks** (Fugitive Emission Sources)	N/A	N/A	N/A	X	This regulation establishes national emission standards for equipment leaks (fugitive emission sources). The facility does not have equipment that operates in volatile hazardous air pollutant (VHAP) service [40 CFR Part 61.240]. The regulated activities subject to this regulation do not take place at this facility. The facility is not subject to this regulation.

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
MACT 40 CFR 63, Subpart A	General Provisions	N/A	C1-E to C10-E, Dehy, Heaters	X	N/A	This regulation defines general provisions for relevant standards that have been set under this part. The facility is subject to this regulation because 40 CFR Part 63 Subpart ZZZZ applies to Units C1-E to C10-E, 40 CFR Part 63 Subpart HH applies to the dehydrator, 40 CFR Part 63 Subpart DDDDD applies to the heaters at the facility.
MACT 40 CFR 63.760 Subpart HH	**Oil and Natural Gas Production Facilities**	N/A	Dehy	X	N/A	This regulation establishes national emission standards for hazardous air pollutants from oil and natural gas production facilities. The facility is a major source of HAPs and meets the definition of a natural gas processing plant. The dehydrator will have a natural gas flow rate equal to or greater than 85 thousand standard cubic feet. The dehydrator vents less than 0.90 megagrams of benzene per year to the atmosphere and is therefore exempt from the emissions control requirements of MACT HH per 63.764(e)(1)(ii). Because the dehydrator complies with the 1 tpy control option under 63.765(b)(1)(ii) it is considered to be a large dehydrator under MACT HH and must comply with monitoring, recordkeeping, and reporting requirements of 63.773, 63.774, and 63.775. The facility is not subject to the equipment leak standards under this regulations since the equipment at the facility has a total VHAP concentration less than 10 percent by weight [63.764(e)(2)(i)] and the facility is subject to equipment leak standards under NSPS OOOO which exempts them from the equipment leak standards under MACT HH. The tanks at the facility are not storage vessels with the potential for flash emissions. The condensate is sent to a stabilizer before transferred to the condensate tanks. There are no flash emissions associated with the condensate tanks therefore the tanks are not subject to this regulation.
MACT 40 CFR 63 Subpart HHH	National Emissions Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage facilities	N/A	N/A	N/A	X	This regulation establishes national emission standards for hazardous air pollutants from natural gas transmission and storage facilities. This regulation does not apply because this facility is not a natural gas transmission or storage facility as defined in this regulation [40 CFR Part 63.1270(a)].
MACT 40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Industrial, Commercial, and Institutional Boilers & Process Heaters	N/A	H1, H3, H4, H5, H6	X	N/A	The facility is a major source of HAPS. Units H1, H3, H4 and H5 will be subject to MACT 40 CFR 63 Subpart DDDDD as they will be constructed after the June 4, 2010 applicability date. The boilers will be combusting natural gas and will have the following compliance requirement in MACT DDDDD: • Per 63.7540 (a)(10) - Tune up every year (except for boilers and process heaters with continuous oxygen trim system which conduct a tune-up every 5 years). Units H1, H3, H4, and H5 do not have emission limits under this regulation. Units H3 and H6 are subject to MACT 40 CFR 63 Subpart DDDDD as they will be constructed after the June 4, 2010 applicability date. The heaters are less than 10 MMBtu/hr and will be combusting natural gas. The units have the following requirements in regards to MACT DDDDD: • Per 63.7500 (e) - Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity of less than or equal to 5 million Btu per hour must complete a tune-up every 5 years as specified

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
						in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory with a heat input capacity greater than 5 million Btu per hour and less than 10 million Btu per hour must complete a tune-up every 2 years as specified in § 63.7540. Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to this subpart, or the operating limits in Table 4 to this subpart DCP will comply with all applicable MACT DDDDD requirements.
MACT 40 CFR 63 Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants Coal & Oil Fire Electric Utility Steam Generating Unit	N/A	N/A	N/A	X	This subpart establishes national emission limitations and work practice standards for hazardous air pollutants (HAP) emitted from coal- and oil-fired electric utility steam generating units (EGUs) as defined in §63.10042 of this subpart. This subpart also establishes requirements to demonstrate initial and continuous compliance with the emission limitations. This facility does not contain the affected units and is therefore not subject to this regulation.
MACT 40 CFR 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (**RICE MACT**)	N/A	C1-E to C10-E	N/A	N/A	This regulation defines national emissions standards for HAPs for stationary Reciprocating Internal Combustion Engines. All engines at the facility will be new 4 stroke lean burn engines with a capacity greater than 500 hp located at a major source of HAPs. The facility will reduce CO emissions by 93% per 63.6600(b).
MACT 40 CFR 63 Subpart JJJJJJ	National Emissions Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers Area Source	N/A	N/A	N/A	X	This regulation establishes emission standards for hazardous air pollutants for industrial, commercial, and industrial boilers area sources. This regulation does not apply to the facility, as the facility is a major source of HAPs.
40 CFR 64	**Compliance Assurance Monitoring**	N/A	L-1, Amine	N/A	N/A	This regulation defines compliance assurance monitoring. Emission from the amine unit and loading (Unit L1) at the facility are subject to a CAM plan. The units have potential pre-control emission levels of an applicable major source threshold [40 CFR 64.2(a)(3)]. The control devices for the amine unit at the facility are the two AGI wells (Units AGI1 and AGI2) and the acid gas flare (Unit FL2). The control device for the loading is the vapor combustion device (Unit VCD1). Engines (Units C1 to C8) are subject to MACT Subpart ZZZZ and are therefore not subject to 40 CFR 64. The dehydrator (Unit Dehy) is subject to NSPS Subpart HH and is therefore not subject to 40 CFR 64.
40 CFR 68	**Chemical Accident Prevention**	X	N/A	X	N/A	The facility is an affected facility, as it will use flammable process chemicals such as propane at quantities greater than the thresholds. The facility will develop and maintain an RMP for these chemicals.
Title IV –	**Acid Rain**	N/A	N/A	N/A	X	This part establishes the acid rain program. This part does

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
Acid Rain 40 CFR 72						not apply because the facility is not covered by this regulation [40 CFR Part 72.6].
Title IV – Acid Rain 40 CFR 73	**Sulfur Dioxide** Allowance Emissions	N/A	N/A	N/A	X	This regulation establishes sulfur dioxide allowance emissions for certain types of facilities. This part does not apply because the facility is not the type covered by this regulation [40 CFR Part 73.2].
Title IV – Acid Rain 40 CFR 76	**Acid Rain** Nitrogen Oxides **Emission Reduction Program**	N/A	N/A	N/A	X	This regulation establishes an acid rain nitrogen oxides emission reduction program. This regulation applies to each coal-fired utility unit that is subject to an acid rain emissions limitation or reduction requirement for SO_2. This part does not apply because the facility does not operate any coal-fired units [40 CFR Part 76.1].
Title VI – 40 CFR 82	Protection of **Stratospheric Ozone**	N/A	N/A	N/A	X	This regulation establishes requirements for protection of the stratospheric ozone. The regulation is not applicable because the facility does not "service", "maintain" or "repair" class I or class II appliances nor "disposes" of the appliances [40 CFR Part 82.1(a)].
CAA Section 112(r)	Accidental Release Prevention/ Risk Management Plan	X	N/A	X	N/A	The facility is an affected facility as it will use quantities of flammable process chemicals such as propane which has threshold quantity of 10,000 lb per Table 3 to 40 CFR Part 68.130. The facility will have quantities of propane and other chemicals which are above the threshold and must maintain a current RMP. The facility will maintain a current RMP for these chemicals.

Section 14

Operational Plan to Mitigate Emissions

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

☑ **Title V Sources** (20.2.70 NMAC)**:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Emissions During Startups, Shutdowns, and Emergencies** defining the measures to be taken to mitigate source emissions during startups, shutdowns, and emergencies as required by 20.2.70.300.D.5(f) and (g) NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☐ **NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has developed an **Operational Plan to Mitigate Source Emissions During Malfunction, Startup, or Shutdown** defining the measures to be taken to mitigate source emissions during malfunction, startup, or shutdown as required by 20.2.72.203.A.5 NMAC. This plan shall be kept on site to be made available to the Department upon request. This plan should not be submitted with this application.

☑ **Title V** (20.2.70 NMAC)**, NSR** (20.2.72 NMAC)**, PSD** (20.2.74 NMAC) **& Nonattainment** (20.2.79 NMAC) **Sources:** By checking this box and certifying this application the permittee certifies that it has established and implemented a Plan to Minimize Emissions During Routine or Predictable Startup, Shutdown, and Scheduled Maintenance through work practice standards and good air pollution control practices as required by 20.2.7.14.A and B NMAC. This plan shall be kept on site or at the nearest field office to be made available to the Department upon request. This plan should not be submitted with this application.

Startup and shutdown procedures are either based on manufacturer's recommendations or based on DCP's experience with specific equipment. These procedures are designed to proactively address the potential for malfunction to the greatest extent possible. These procedures dictate a sequence of operations that are designed to minimize emissions from the facility during events that result in shutdown and subsequent startup.

Equipment located at this facility is equipped with various safety devices and features that aid in the prevention of excess emissions in the event of an operational emergency. If an operational emergency does occur and excess emissions occur DCP will submit the required Excess Emissions Report per 20.2.7 NMAC if any emissions occur beyond the requested total SSM emission limit. Corrective action to eliminate the excess emissions and prevent recurrence in the future will be undertaken as quickly as safety allows.

Section 15

Alternative Operating Scenarios

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

Alternative Operating Scenarios: Provide all information required by the department to define alternative operating scenarios. This includes process, material and product changes; facility emissions information; air pollution control equipment requirements; any applicable requirements; monitoring, recordkeeping, and reporting requirements; and compliance certification requirements. Please ensure applicable Tables in this application are clearly marked to show alternative operating scenario.

Construction Scenarios: When a permit is modified authorizing new construction to an existing facility, NMED includes a condition to clearly address which permit condition(s) (from the previous permit and the new permit) govern during the interval between the date of issuance of the modification permit and the completion of construction of the modification(s). There are many possible variables that need to be addressed such as: Is simultaneous operation of the old and new units permitted and, if so for example, for how long and under what restraints? In general, these types of requirements will be addressed in Section A100 of the permit, but additional requirements may be added elsewhere. Look in A100 of our NSR and/or TV permit template for sample language dealing with these requirements. Find these permit templates at: https://www.env.nm.gov/aqb/permit/aqb_pol.html. Compliance with standards must be maintained during construction, which should not usually be a problem unless simultaneous operation of old and new equipment is requested.

In this section, under the bolded title "Construction Scenarios", specify any information necessary to write these conditions, such as: conservative-realistic estimated time for completion of construction of the various units, whether simultaneous operation of old and new units is being requested (and, if so, modeled), whether the old units will be removed or decommissioned, any PSD ramifications, any temporary limits requested during phased construction, whether any increase in emissions is being requested as SSM emissions or will instead be handled as a separate Construction Scenario (with corresponding emission limits and conditions, etc.

This facility operates on a continuous basis with no alternative operating scenarios.

Section 16

Air Dispersion Modeling

1) Minor Source Construction (20.2.72 NMAC) and Prevention of Significant Deterioration (PSD) (20.2.74 NMAC) ambient impact analysis (modeling): Provide an ambient impact analysis as required at 20.2.72.203.A(4) and/or 20.2.74.303 NMAC and as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines found on the Planning Section's modeling website. If air dispersion modeling has been waived for one or more pollutants, attach the AQB Modeling Section modeling waiver approval documentation.
2) SSM Modeling: Applicants must conduct dispersion modeling for the total short term emissions during routine or predictable startup, shutdown, or maintenance (SSM) using realistic worst case scenarios following guidance from the Air Quality Bureau's dispersion modeling section. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions modeling requirements.
3) Title V (20.2.70 NMAC) ambient impact analysis: Title V applications must specify the construction permit and/or Title V Permit number(s) for which air quality dispersion modeling was last approved. Facilities that have only a Title V permit, such as landfills and air curtain incinerators, are subject to the same modeling required for preconstruction permits required by 20.2.72 and 20.2.74 NMAC.

What is the purpose of this application?	Enter an X for each purpose that applies
New PSD major source or PSD major modification (20.2.74 NMAC). See #1 above.	
New Minor Source or significant permit revision under 20.2.72 NMAC (20.2.72.219.D NMAC). See #1 above. **Note:** Neither modeling nor a modeling waiver is required for VOC emissions.	
Reporting existing pollutants that were not previously reported.	
Reporting existing pollutants where the ambient impact is being addressed for the first time.	
Title V application (new, renewal, significant, or minor modification. 20.2.70 NMAC). See #3 above.	X
Relocation (20.2.72.202.B.4 or 72.202.D.3.c NMAC)	
Minor Source Technical Permit Revision 20.2.72.219.B.1.d.vi NMAC for like-kind unit replacements.	
Other: i.e. SSM modeling. See #2 above.	
This application does not require modeling since this is a No Permit Required (NPR) application.	
This application does not require modeling since this is a Notice of Intent (NOI) application (20.2.73 NMAC).	
This application does not require modeling according to 20.2.70.7.E(11), 20.2.72.203.A(4), 20.2.74.303, 20.2.79.109.D NMAC and in accordance with the Air Quality Bureau's Modeling Guidelines.	

Check each box that applies:

☐ See attached, approved modeling **waiver for all** pollutants from the facility.
☐ See attached, approved modeling **waiver for some** pollutants from the facility.
☐ Attached in Universal Application Form 4 (UA4) is a **modeling report for all** pollutants from the facility.
☐ Attached in UA4 is a **modeling report for some** pollutants from the facility.
☑ No modeling is required.

Modeling was submitted with the June 2015 application for revision of permit PSD-5217M1R1.

Section 17

Compliance Test History

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

To show compliance with existing NSR permits conditions, you must submit a compliance test history. The table below provides an example.

Compliance Test History Table

Unit No.	Test Description	Test Date
C-1E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-10-21 8-11-21 11-10-21
C-2E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-10-21 8-11-21 11-10-21
C-3E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-11-21 8-11-21 11-10-21
C-4E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-11-21 8-11-21 11-10-21
C-5E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-11-21 8-11-21 11-10-21
C-6E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-11-21 8-12-21 11-10-21
C-7E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-12-21 8-12-21 11-11-21
C-8E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-12-21 8-12-21 11-11-21
C-91E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-12-21 8-12-21 11-11-21
C-10E	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217M1R1.	2-9-21 5-12-21 8-12-21 11-11-21
H4 and H5	Tested in accordance with EPA test methods for NOx and CO as required by NSR Permit PSD-5217.	11-11-21

Section 19

Requirements for Title V Program

Who Must Use this Attachment:

* Any major source as defined in 20.2.70 NMAC.
* Any source, including an area source, subject to a standard or other requirement promulgated under Section 111 - Standards of Performance for New Stationary Sources, or Section 112 Hazardous Air Pollutants, of the 1990 federal Clean Air Act ("federal Act"). Non-major sources subject to Sections 111 or 112 of the federal Act are exempt from the obligation to obtain an 20.2.70 NMAC operating permit until such time that the EPA Administrator completes rulemakings that require such sources to obtain operating permits. In addition, sources that would be required to obtain an operating permit solely because they are subject to regulations or requirements under Section 112(r) of the federal Act are exempt from the requirement to obtain an Operating Permit.
* Any Acid Rain source as defined under title IV of the federal Act. The Acid Rain program has additional forms. See http://www.env.nm.gov/aqb/index.html. Sources that are subject to both the Title V and Acid Rain regulations are encouraged to submit both applications simultaneously.
* Any source in a source category designated by the EPA Administrator ("Administrator"), in whole or in part, by regulation, after notice and comment.

19.1 - 40 CFR 64, Compliance Assurance Monitoring (CAM) (20.2.70.300.D.10.e NMAC)

Any source subject to 40CFR, Part 64 (Compliance Assurance Monitoring) must submit all the information required by section 64.7 with the operating permit application. The applicant must prepare a separate section of the application package for this purpose; if the information is already listed elsewhere in the application package, make reference to that location. Facilities not subject to Part 64 are invited to submit periodic monitoring protocols with the application to help the AQB to comply with 20.2.70 NMAC. Sources subject to 40 CFR Part 64, must submit a statement indicating your source's compliance status with any enhanced monitoring and compliance certification requirements of the federal Act.

This regulation defines compliance assurance monitoring. Emission from the amine unit and loading (Unit L1) at the facility are subject to a CAM plan. The units have potential pre-control emission levels of an applicable major source threshold [40 CFR 64.2(a)(3)]. The control devices for the amine unit at the facility are the two AGI wells (Units AGI1 and AGI2) and the acid gas flare (Unit FL2). The control device for the loading is the vapor combustion device (Unit VCD1).

Engines (Units C1 to C8) are subject to MACT Subpart ZZZZ and are therefore not subject to 40 CFR 64.
The dehydrator (Unit Dehy) is subject to NSPS Subpart HH and is therefore not subject to 40 CFR 64.

19.2 - Compliance Status (20.2.70.300.D.10.a & 10.b NMAC)

Describe the facility's compliance status with each applicable requirement at the time this permit application is submitted. This statement should include descriptions of or references to all methods used for determining compliance. This statement should include descriptions of monitoring, recordkeeping and reporting requirements and test methods used to determine compliance with all applicable requirements. Refer to Section 2, Tables 2-N and 2-O of the Application Form as necessary. (20.2.70.300.D.11 NMAC) For facilities with existing Title V permits, refer to most recent Compliance Certification for existing requirements. Address new requirements such as CAM, here, including steps being taken to achieve compliance.

Based on the information and belief formed after reasonable inquiry, DCP believes that the Zia II Gas Plant is in compliance with each requirement applicable to the facility.

19.3 - Continued Compliance (20.2.70.300.D.10.c NMAC)

Provide a statement that your facility will continue to be in compliance with requirements for which it is in compliance at the time of permit application. This statement must also include a commitment to comply with other applicable requirements as they come into effect during the permit term. This compliance must occur in a timely manner or be consistent with such schedule expressly required by the applicable requirement.

As described in Section 19.2 and based on information and belief formed after reasonable inquiry, DCP states that Zia II Gas Plant will continue to be operated in compliance with applicable requirements for which it is in compliance as of the date of submittal of this application.

In addition, DCP will meet additional applicable requirements that become effective during the permit term in a timely manner or on such a time schedule as expressly required by the applicable requirement. In the event that DCP should discover new information affecting the compliance status of the Zia II Gas Plant, DCP will make appropriate notifications and/or take corrective actions as appropriate.

19.4 - Schedule for Submission of Compliance (20.2.70.300.D.10.d NMAC)

You must provide a proposed schedule for submission to the department of compliance certifications during the permit term. This certification must be submitted annually unless the applicable requirement or the department specifies a more frequent period. A sample form for these certifications will be attached to the permit.

DCP is proposing a compliance certification schedule of report submittal every 12 months.

19.5 - Stratospheric Ozone and Climate Protection

In addition to completing the four (4) questions below, you must submit a statement indicating your source's compliance status with requirements of Title VI, Section 608 (National Recycling and Emissions Reduction Program) and Section 609 (Servicing of Motor Vehicle Air Conditioners).

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1. Does your facility have any air conditioners or refrigeration equipment that uses CFCs, HCFCs or other ozone-depleting substances? ☑ **Yes** ☐ **No**
2. Does any air conditioner(s) or any piece(s) of refrigeration equipment contain a refrigeration charge greater than 50 lbs? ☐ **Yes** ☑ **No**

   (If the answer is yes, describe the type of equipment and how many units are at the facility.)
3. Do your facility personnel maintain, service, repair, or dispose of any motor vehicle air conditioners (MVACs) or appliances ("appliance" and "MVAC" as defined at 82. 152)? ☐ **Yes** ☑ **No**
4. Cite and describe which Title VI requirements are applicable to your facility (i.e. 40 CFR Part 82, Subpart A through G.)

This regulation establishes requirements for protection of the stratospheric ozone. The regulation is not applicable because the facility does not “service”, “maintain” or “repair” class I or class II appliances nor “disposes” of the appliances [40 CFR Part 82.1(a)].

19.6 - Compliance Plan and Schedule

Applications for sources, which are not in compliance with all applicable requirements at the time the permit application is submitted to the department, must include a proposed compliance plan as part of the permit application package. This plan shall include the information requested below:

A. Description of Compliance Status: (20.2.70.300.D.11.a NMAC)
A narrative description of your facility's compliance status with respect to all applicable requirements (as defined in 20.2.70 NMAC) at the time this permit application is submitted to the department.

B. Compliance plan: (20.2.70.300.D.11.B NMAC)
A narrative description of the means by which your facility will achieve compliance with applicable requirements with which it is not in compliance at the time you submit your permit application package.

C. Compliance schedule: (20.2.70.300D.11.c NMAC)
A schedule of remedial measures that you plan to take, including an enforceable sequence of actions with milestones, which will lead to compliance with all applicable requirements for your source. This schedule of compliance must be at least as stringent as that contained in any consent decree or administrative order to which your source is subject. The obligations of any consent decree or administrative order are not in any way diminished by the schedule of compliance.

D. Schedule of Certified Progress Reports: (20.2.70.300.D.11.d NMAC)
A proposed schedule for submission to the department of certified progress reports must also be included in the compliance schedule. The proposed schedule must call for these reports to be submitted at least every six (6) months.

E. Acid Rain Sources: (20.2.70.300.D.11.e NMAC)
If your source is an acid rain source as defined by EPA, the following applies to you. For the portion of your acid rain source subject to the acid rain provisions of title IV of the federal Act, the compliance plan must also include any additional requirements under the acid rain provisions of title IV of the federal Act. Some requirements of title IV regarding the schedule and methods the source will use to achieve compliance with the acid rain emissions limitations may supersede the requirements of title V and 20.2.70 NMAC. You will need to consult with the Air Quality Bureau permitting staff concerning how to properly meet this requirement.

NOTE: The Acid Rain program has additional forms. See http://www.env.nm.gov/aqb/index.html. Sources that are subject to both the Title V and Acid Rain regulations are **encouraged** to submit both applications **simultaneously**.

Based on information and belief formed after reasonable inquiry and as described in Section 19.2, and with this filing, DCP states that the Zia II Gas Plant is in compliance with applicable requirements. No compliance plan, compliance schedule, or compliance reports are required.

19.7 - 112(r) Risk Management Plan (RMP)

Any major sources subject to section 112(r) of the Clean Air Act must list all substances that cause the source to be subject to section 112(r) in the application. The permittee must state when the RMP was submitted to and approved by EPA.

Based on information and belief formed after reasonable inquiry, DCP states that Zia II Gas Plant is subject to 40 CFR 68, Chemical Accident Prevention Provisions. The facility is an affected facility, as it will use flammable process chemicals such as propane at quantities greater than the thresholds. The facility will develop and maintain an RMP for these chemicals.

19.8 - Distance to Other States, Bernalillo, Indian Tribes and Pueblos

Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B NMAC)?

(If the answer is yes, state which apply and provide the distances.)

Other States: Texas ~ 70 km
Indian Tribes: > 80 km
Class I Areas: > 80 km
Bernalillo County: > 80 km

19.9 - Responsible Official

Provide the Responsible Official as defined in 20.2.70.7.AD NMAC:

The responsible official is:
Responsible Official: Randy Deluane
R.O. Title: Vice President - Permian
R. O. Address: 15718 Westheimer Road, Suite 1900, Houston, TX 77057
Phone: (713) 268-7488
R.O. e-mail: RCDeLuane@dcpmidstream.com

Section 20

Other Relevant Information

<u>Other relevant information</u>. Use this attachment to clarify any part in the application that you think needs explaining. Reference the section, table, column, and/or field. Include any additional text, tables, calculations or clarifying information.

Additionally, the applicant may propose specific permit language for AQB consideration. In the case of a revision to an existing permit, the applicant should provide the old language and the new language in track changes format to highlight the proposed changes. If proposing language for a new facility or language for a new unit, submit the proposed operating condition(s), along with the associated monitoring, recordkeeping, and reporting conditions. In either case, please limit the proposed language to the affected portion of the permit.

No other relevant information is being submitted with this application.

Section 22: Certification

Company Name: DCP Operating Company, LP

I, Scot Millican, hereby certify that the information and data submitted in this application are true and as accurate as possible, to the best of my knowledge and professional expertise and experience.

Signed this 4 day of March, 2022, upon my oath or affirmation, before a notary of the State of

New Mexico

Scot Millican
*Signature

3-4-22
Date

Scot Millican
Printed Name

Asset Director
Title

Scribed and sworn before me on this 4 day of March, 2022.

My authorization as a notary of the State of New Mexico expires on the

2 day of May, 2023

Amanda Mason
Notary's Signature

3/4/2022
Date

Amanda Mason
Notary's Printed Name

AMANDA MASON
Notary Public - State of New Mexico
Commission # 1125978
My Comm. Expires May 2, 2023

*For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC.