PSD APPLICATION

DCP Midstream, LP
ZIA II Gas Plant

DCP MIDSTREAM, LP
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JHanna@dcpmidstream.com
10 Desta Drive
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Prepared By:

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April 23, 2015

Trinity Project Number: 143201.0195

Environmental solutions delivered uncommonly well

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Trinity Consultants

April 23, 2015

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

RE: PSD Application
DCP Midstream, LP's Zia II Gas Plant; PSD-5217

Dear Mr. Schooley:

On behalf of DCP Midstream, LP (DCP), we are submitting the Prevention of Significant Deterioration (PSD) application for Zia II Gas Plant. The facility will be a major source for PSD and Title V Operating Permit programs and will be a major source of hazardous air pollutants (HAPs). DCP is submitting this application to apply for a PSD permit per 20.2.74.200.A NMAC. The facility is currently permitted under PSD-5217 and is under construction. The proposed facility will result in emissions of NO_x, CO, VOC, PM_{10}, SO_2 and $PM_{2.5}$ greater than PSD major source thresholds or their respective significant emission rates. Per 20.2.74.7.AG NMAC, any major source that is major for nitrous oxides (NO_x) or volatile organic compounds (VOC) shall be considered major for ozone. Therefore the facility is also major for ozone. In the Tailoring Rule, EPA established a major source threshold of 100,000 tons per year (tpy) of CO_2e emissions. DCP has also determined that the greenhouse gas (GHG) emissions from the proposed project will exceed this threshold. Therefore, GHG emissions are subject to regulation and the proposed action represents a major NSR permitting action with respect to greenhouse gas emissions and the aforementioned criteria pollutants.

The format and content of this application are consistent with the Bureau's current policy regarding PSD applications; it is a complete application package using the latest Universal Application Form set.

Enclosed are two hard copies of the application (the original and a photocopy) and two discs containing the electronic files. Please feel free to contact me at (505) 266-6611 or Jennifer Hanna from DCP Midstream at (432) 249-2702 if you have any questions regarding this application.

Sincerely,

Adam Erenstein
Managing Consultant

Cc: Jennifer Hana (DCP Midstream, LP)
Trinity Project File 143201.0195

THE FACE OF THIS DOCUMENT HAS A COLORED BACKGROUND ON WHITE PAPER WITH VISIBLE FIBERS AND A TRUE WATERMARK ON THE REVERSE SIDE.

DCP Midstream, LP
370 17th Street, Suite 2500
Denver, CO 80202

JPMORGAN CHASE BANK, N.A. 50-937/213
Syracuse, NY

Vendor No.	Check Date	Check Number
0000078217	4/13/2015	0000424467

Pay *Five hundred and xx / 100 Dollars*

NOT NEGOTIABLE AFTER 120 DAYS

Check Amount
***$500.00

To The Order Of
STATE OF NEW MEXICO GENERAL FUND
NEW MEXICO ENVIRONMENTAL DEPARTMENT
GENERAL FUND AIR OUALITY BUREAU
C/O COMPLINCE ENFRCEMNT MNGR
525 CAMINO DE LOS MARQUEZ STE1
SANTA FE, NM 87505

Authorized Signature

HOLD BETWEEN THUMB AND FOREFINGER, OR BREATHE ON COLORED BOX, COLOR WILL DISAPPEAR, THEN REAPPEAR.

⑈0000424467⑈ ⑆021309379⑆ 601895196⑈

Mail Application To: 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.nmenv.state.nm.us/aqb		**For Department use only:** 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.

This application is being 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/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 (update to permit for facility currently under construction – not a modification)
☐ minor modification to a PSD source ☐ a PSD major modification

Acknowledgements: ☑ I acknowledge that a pre-application meeting is available to me upon request ☐ NPR (no fee)
☑ $500 NSR Permit Filing Fee enclosed OR ☐ The full permit fee associated with 10 fee points (required w/ streamline applications).
☑ Check No.: 0000424467 in the amount of $500 ☐ This facility meets the applicable requirements to register as a Small Business and a check for 50% of the normal fee is enclosed (only applicable **provided** that NMED has a Small Business Certification Form from your company on file found at: http://www.nmenv.state.nm.us/aqb/permit/app_form.html).

Citation: Please provide the **low level citation** under which this application is being submitted: **20.2.74.200.A NMAC**
(i.e. an example of an application for a new minor source would be 20.2.72.200.A NMAC, one example of a low level cite for a Technical Revision could be: 20.2.72.219.B.1.b NMAC, or a Title V acid rain cite would be: 20.2.70.200.C NMAC)

Synthetic Minor Source Information: A source is synthetic minor if its uncontrolled emissions are above major source applicability thresholds, but the facility is minor because it has federally enforceable requirements (federal requirements or permit conditions) that limit controlled emissions below major source thresholds. Facilities can be synthetic minor for either Title V (20.2.70 NMAC) or PSD (20.2.74 NMAC) or both. The Department tracks synthetic minor sources that are within 20% of either TV or PSD major source thresholds, referring to these as Synthetic Minor 80 Sources (abbreviated SM80). Please check all that apply:
Prior to this permitting action this source is a ☐ TV major source, ☐ a TV synthetic minor source, ☐ a TV SM80 source.
Prior to this permitting action this source is a ☑ PSD major source, ☐ a PSD synthetic minor source, ☐ a PSD SM80 source.
This permitting action results in a ☐ TV synthetic minor source and/or ☐ PSD synthetic minor source.

Section 1 – Facility Information

Section 1-A: Company Information

		AI # (if known): N/A	Updating Permit/NOI #: PSD-5217
1	Facility Name: Zia II Gas Plant	Plant primary SIC Code (4 digits): 1311	
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 Midstream, LP	Phone/Fax: (432) 249-2702 / (432) 620-4143	
a	Plant Operator Address: 10 Desta Drive, Suite 400 West, Midland, TX 79705		
b	Plant Operator's New Mexico Corporate ID or Tax ID: NM oil & gas revenue tax ID number: 036785		

3	Plant Owner(s) name(s): DCP Midstream, LP	Phone/Fax: (432) 249-2702 / (432) 620-4143
a	Plant Owner(s) Mailing Address(s): 10 Desta Drive, Suite 400 West, Midland, TX 79705	
4	Bill To (Company): DCP Midstream, LP	Phone/Fax: (432) 249-2702 / (432) 620-4143
a	Mailing Address: 10 Desta Drive, Suite 400 West, Midland, TX 79705	E-mail: JHanna@dcpmidstream.com
5	☑Preparer: ☑ Consultant: Adam Erenstein / Trinity Consultants	Phone/Fax: (505) 266-6611 / (505) 266-7738
a	Mailing Address: 9400 Holly Ave NE, Building 3, Suite 300, Albuquerque, NM, 87122	E-mail: aerenstein@trinityconsultants.com
6	Plant Operator Contact: Jennifer Hanna	Phone/Fax: (432) 249-2702 / (432) 620-4143
a	Address: 10 Desta Drive, Suite 400 West, Midland, TX 79705	E-mail: JHanna@dcpmidstream.com
7	Air Permit Contact: Jennifer Hanna	Title: Senior Environmental Specialist
a	E-mail: JHanna@dcpmidstream.com	Phone/Fax: (432) 249-2702 / (432) 620-4143
b	Mailing Address: 10 Desta Drive, Suite 400 West, Midland, TX 79705	

Section 1-B: Current Facility Status

1.a	Has this facility already been constructed? ☐ Yes ☐ No **Facility is currently under construction.**	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: N/A
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 NMAC)? ☐ Yes ☑ No	If yes, the permit No. is: N/A
10	Is this facility registered under a General permit (GCP-1, GCP-2, etc.)? ☐ Yes ☑ No	If yes, the register No. is: N/A
	This facility has been issued a PSD Permit; the permit number is PSD-5217	

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: N/A*	Daily: N/A*	Annually: N/A*
b	Proposed	Hourly: 9.6 MMscf/day	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: N/A*	Daily: N/A*	Annually: N/A*
b	Proposed	Hourly: 9.6 MMscf/day	Daily: 230 MMscf	Annually: 83,950 MMscf

*The facility has not completed construction and therefore does not have a current capacity or production rate.

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			UTM N (in meters, to nearest 10 meters): 3,612,340	
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.nmenv.state.nm.us/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 m				
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		($\frac{hours}{year}$): 8,760	
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: In progress					
4	Month and year of anticipated construction completion: TBD					
5	Month and year of anticipated startup of new or modified facility: TBD					
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: N/A		
a	If yes, NOV date or description of issue: N/A		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: N/A		
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 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)		
b	If 4.a is Yes, identify the subparts in 40 CFR 61 & 40 CFR 63 that apply to this facility (If no subparts apply, enter "N/A."): 40 CFR 63 Subparts A, HH, ZZZZ, DDDDD		
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: Title V Specific Information

(Fill this section out only if this is a Title V application.)

1	Responsible Official (20.2.70.300.D.2 NMAC):N/A – This is not a Title V application.		Phone: N/A
a	R.O. Title: N/A	R.O. e-mail: N/A	
b	R. O. Address: N/A		
2	Alternate Responsible Official (20.2.70.300.D.2 NMAC): N/A		Phone: N/A
a	A. R.O. Title: N/A	A. R.O. e-mail: N/A	
b	A. R. O. Address: N/A		
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. If 'head-to-toe printing' is not possible, print single sided. 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.

2) If the application is for a NSR or Title V permitting action, include one working hard **copy** for Department use. This copy does not need to be 2-hole punched. Technical revisions only need to fill out Section 1-A, 1-B, 3, and should fill out those portions of other Section(s) relevant to the technical revision. TV Minor Modifications need only fill out Section 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 on compact disk(s) (CD). For 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.

4) If **air dispersion modeling** is required by the application type, include the **NMED Modeling Waiver OR** one additional electronic copy of the air dispersion modeling including the input and output files. The dispersion modeling ***summary report only*** should be submitted as hard copy(ies) unless otherwise indicated by the Bureau. The complete dispersion modeling study, including all input/output files, should be submitted electronically as part of the electronic submittal.

5) If subject to PSD review under 20.2.74 NMAC (PSD) include,
   a. one additional hard copy and one additional CD copy for US EPA,
   b. one additional hard copy and one additional CD copy for each federal land manager affected (NPS, USFS, FWS, USDI) and,
   c. one additional hard copy and one additional CD copy for each affected regulatory agency other than the Air Quality Bureau.

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

1) All required electronic documents shall be submitted in duplicate (2 separate CDs). 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 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 with the number of additional hard copies corresponding to the number of CD copies required. 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 3 electronic files (2 MSWord docs: Universal Application section 1 and Universal Application section 3-19) and 1 Excel file of the tables (Universal Application section 2) on the CD(s). 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 # (0 for original, 1, 2, etc.; which will help keep track of subsequent partial update(s) to the original submittal. 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	Manufacturer	Model #	Serial #	Maximum or Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture or Reconstruction[2] Date of Installation /Construction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	Applicable State & Federal Regulation(s) (i.e. 20.2.X, JJJJ, …)	Replacing Unit No.
C1-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00911	4735 hp	4735 hp	May-14 Mar-15	C1-E C1-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C1-C*	Compressor	Ariel	NA	F-46710	NA	N/A	Oct-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C2-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00912	4735 hp	4735 hp	May-14 Mar-15	C2-E C2-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C2-C*	Compressor	Ariel	NA	F-46929	NA	NA	Oct-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C3-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00915	4735 hp	4735 hp	Jun-14 Mar-15	C3-E C3-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C3-C*	Compressor	Ariel	NA	F-46790	NA	NA	Jan-15 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C4-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00918	4735 hp	4735 hp	Jun-14 Mar-15	C4-E C4-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C4-C*	Compressor	Ariel	NA	F-47105	NA	NA	Jan-15 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C5-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00917	4735 hp	4735 hp	Jun-14 Mar-15	C5-E C5-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C5-C*	Compressor	Ariel	NA	F-46800	NA	NA	Oct-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A

Unit Number[1]	Source Description	Manufacturer	Model #	Serial #	Maximum or Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture or Reconstruction[2] / Date of Installation /Construction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	Applicable State & Federal Regulation(s) (i.e. 20.2.X, JJJJ, …)	Replacing Unit No.
C6-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00913	4735 hp	4735 hp	Jun-14 Mar-15	C6-E C6-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C6-C*	Compressor	Ariel	NA	F-47007	NA	NA	Oct-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C7-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00916	4735 hp	4735 hp	Jun-14 Mar-15	C7-E C7-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C7-C*	Compressor	Ariel	NA	F-46617	NA	NA	Oct-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C8-E	4-stroke, lean burn natural gas engine	Caterpillar	G3616	BLB00914	4735 hp	4735 hp	Jun-14 Mar-15	C8-E C8-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C8-C*	Compressor	Ariel	NA	F-46687	NA	NA	Nov-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C9-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	BEN01006	2370hp	2370hp	Jun-14 Mar-15	C9-E C9-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C9-C*	Compressor	Ariel	NA	F-46794	NA	NA	Mar-15 Nov-14	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
C10-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	BEN01001	2370hp	2370hp	Jun-14 Mar-15	C10-E C10-E	2020 0254	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
C10-C*	Compressor	Ariel	NA	F-46690	NA	NA	Dec-14 Mar-15	N/A N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A

Unit Number[1]	Source Description	Manufacturer	Model #	Serial #	Maximum or Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture or Reconstruction[2] / Date of Installation /Construction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	Applicable State & Federal Regulation(s) (i.e. 20.2.X, JJJJ, …)	Replacing Unit No.
C11-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	TBD	2370hp	2370hp	x	C11-E	2020 0254	☐ Existing (unchanged) ☑ **To be Removed** ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
							x	C11-E				
C11-C**	Screw Compressor	GEA FES	1210GLE	XC0344	NA	NA	2014	N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC	N/A
							2015	N/A				
C12-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	TBD	2370hp	2370hp	x	C12-E	2020 0254	☐ Existing (unchanged) ☑ **To be Removed** ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
							x	C12-E				
C12-C**	Screw Compressor	GEA FES	1210GLE	XC0355	NA	NA	2014	N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC	N/A
							2015	N/A				
C13-E	4-stroke, lean burn natural gas engine	Caterpillar	G3608 LE	TBD	2370hp	2370hp	x	C13-E	2020 0254	☐ Existing (unchanged) ☑ **To be Removed** ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS JJJJ MACT ZZZZ 40 CFR 64	N/A
							x	C13-E				
C13-C**	Screw Compressor	GEA FES	1210GLE	XC0348	NA	NA	2014	N/A		☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC	N/A
							2015	N/A				
C14-C*	Compressor	Ariel	JGC/6	F-46848	NA	NA	2014	N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
							2015	N/A				
C15-C*	Compressor	Ariel	JGC/6	F-47006	NA	NA	2014	N/A	2020 0254	☑ **Existing (unchanged)** ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.77 NMAC NSPS OOOO	N/A
							2015	N/A				
H1	Trim Reboiler Heater	Heatec	HCI-10010-40-D	HI-13-170	26.0 MMBtu/hr	26.0 MMBtu/hr	Mar-14	N/A	3100 0404	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS Dc MACT DDDDD	N/A
							Mar-15	H1				
H2	Stabilizer Heater	x	x	x	7.0 MMBtu/hr	7.0 MMBtu/hr	x	N/A	3100 0404	☐ Existing (unchanged) ☑ **To be Removed** ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.74 NMAC 20.2.82 NMAC MACT DDDDD	N/A
							x	H2				
H3	Regeneration Gas Heater	Heatec	HCI-5010-40-G	HI-13-165	10.0 MMBtu/hr	10.0 MMBtu/hr	Mar-14	N/A	3100 0404	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.82 NMAC MACT DDDDD NSPS Dc	N/A
							Mar-15	H3				
H4	Hot Oil Heater	OPF	OPF	J121104	99.0 MMBtu/hr	99.0 MMBtu/hr	2014	N/A	3100 0404	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS Dc MACT DDDDD	N/A
							2015	H4				

Unit Number[1]	Source Description	Manufacturer	Model #	Serial #	Maximum or Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture or Reconstruction[2] / Date of Installation /Construction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	Applicable State & Federal Regulation(s) (i.e. 20.2.X, JJJJ, …)	Replacing Unit No.
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	20.2.74 NMAC 20.2.77 NMAC 20.2.82 NMAC NSPS Dc MACT DDDDD	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	20.2.74 NMAC 20.2.82 NMAC MACT DDDDD	N/A
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	20.2.74 NMAC 20.2.77 NMAC 40 CFR 60.18	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	20.2.74 NMAC 20.2.77 NMAC 40 CFR 60.18	N/A
FL3	Lusk Emergency Flare	Flare King	NA	FL-201583	13 MMscf/d	13 MMscf/d	2011 2011	N/A FL-3	3100 0205	☐ Existing (unchanged) ☐ To be Removed ☑ **New/Additional** ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.74 NMAC	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	20.2.74 NMAC 20.2.77 NMAC 40 CFR 60.18	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	20.2.74 NMAC 20.2.82 NMAC MACT HH 40 CFR 64	N/A
TK-2100[4]	Condensate Tank	Tank and Vessel Builders	NA	201429	1000 bbl	1000 bbl	2014 Feb-15	VCD1 VCD1	4040 0311	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC NSPS OOOO	N/A
TK-2200[4]	Condensate Tank	Tank and Vessel Builders	NA	201430	1000 bbl	1000 bbl	2014 Feb-15	VCD1 VCD1	4040 0311	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC NSPS OOOO	N/A
TK-C	Treated Water Tank	x	x	x	100 bbl	100 bbl	x x	N/A N/A	4040 0311	☐ Existing (unchanged) ☑ **To be Removed** ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC NSPS OOOO	N/A
TK-6100[5]	Produced Water Tank	Palmer	NA	ST1046541	300 bbl	300 bbl	Oct-14 Feb-15	N/A N/A	4040 0311	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC NSPS OOOO	N/A
TK-6150[5]	Produced Water Tank	Palmer	NA	ST1406066	300 bbl	300 bbl	Oct-14 Feb-15	N/A N/A	4040 0311	☐ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☑ **To Be Modified** ☐ To be Replaced	20.2.74 NMAC 20.2.77 NMAC NSPS OOOO	N/A

Unit Number[1]	Source Description	Manufacturer	Model #	Serial #	Maximum or Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture or Reconstruction[2] Date of Installation /Construction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	Applicable State & Federal Regulation(s) (i.e. 20.2.X, JJJJ, …)	Replacing Unit No.
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	20.2.74 NMAC 40 CFR 64	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	20.2.74 NMAC	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	20.2.74 NMAC NSPS OOOO	N/A
Amine[6]	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	20.2.74 NMAC 20.2.77 NMAC NSPS OOOO 40 CFR 64	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	20.2.74 NMAC	N/A
GEN-1	Diesel Generator (500 hrs/yr)	Cummins	DSFAC	TBD	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	20.2.77 NMAC NSPS IIII	N/A
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	20.2.74 NMAC	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	20.2.74 NMAC	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] Condensate tank TK-2100 is currently permitted as TK-1. Condensate tank TK-2200 is currently permitted as TK-2. These unit numbers are being updated in this application.

[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.nmenv.state.nm.us/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.nmenv.state.nm.us/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. / Serial No.	Max Capacity / Capacity Units	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5) / Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Manufacture /Reconstruction[2] / Date of Installation /Construction[2]	For Each Piece of Equipment, Check Onc
TK-7015	Engine/Compressor Oil Tank	Willborn Bros	NA	1,036	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	N/A	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	N/A	2/1/2015	
TK-7025	Used Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
TK-7035	Jacket/Aux Water Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
TK-7045	Engine/Compressor Oil Tank	Willborn Bros	NA	1,036	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	N/A	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	N/A	2/1/2015	
TK-7055	Used Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
TK-7065	Jacket/Aux Water Storage Tank	Willborn Bros	NA	1,036	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	N/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	N/A	2/1/2015	
TK-7075	Compressor Crank Case Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
TK-7085	Used Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	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-7095	Compressor Lubrication Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
TK-7105	Compressor Lubrication Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
TK-7115	Compressor Lubrication Oil Storage Tank	Willborn Bros	NA	1,036	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	N/A	2/1/2015	
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	N/A	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	N/A	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	N/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	N/A	3/1/2015	
TK-7700	Methanol Storage Tank	Highland	NA	1,500	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	N/A	2/1/2015	
TK-7750	Methanol Storage Tank	Highland	NA	1,500	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	N/A	2/1/2015	
TK-7800	Methanol Storage Tank	Highland	NA	1,036	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	N/A	2/1/2015	
TK-WATER	Raw Water Storage Tank	Power Pipe and Tank	NA	1,000	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	N/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	N/A	TBD	
TK-L2	Lusk Methanol Tank	Palmer	NA	443	Not a regulated source of emissions.	Sep-83	☐ Existing (unchanged) ☐ To be Removed ☑ **New/Additional** ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			AT-2784	bbl	N/A	Sep-83	
TK-3	Diesel Tank	N/A	NA	1,000	Not a regulated source of emissions.	NA	☐ Existing (unchanged) ☐ To be Removed ☑ **New/Additional** ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced
			NA	gal	N/A	May-15	

[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	Mar-15	CO, VOC, and HCHO	C1-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C2-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C2-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C3-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C3-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C4-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C4-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C5-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C5-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C6-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C6-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C7-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C7-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C8-E	Oxidation Catalyst	Mar-15	CO, VOC, and HCHO	C8-E	98% CO, 68% VOC, 98% HCHO	Catalyst Mfg
C9-E	Oxidation Catalyst	Mar-15	CO and VOC	C9-E	94% CO, 52% VOC	Catalyst Mfg
C10-E	Oxidation Catalyst	Mar-15	CO and VOC	C10-E	94% CO, 52% VOC	Catalyst Mfg
FL2	Emergency Acid Gas Flare	Mar-15	H_2S	Amine	98%	Eng Estimate
VCD1	Vapor Combustion Device	Mar-15	VOC and HAPs	TK1, TK2, TK-C, TK-G, TK-H, L1, and Dehy	98%	Eng Estimate
AGI1, AGI2	AGI Wells	Mar-15	H_2S and CO_2	Amine	100%	Eng Estimate
H6	TEG Regeneration Heater	Mar-15	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 with a minimum of two significant figures[1]. If there are any significant figures to the left of a decimal point, there shall be no more than one significant figure to the right of the decimal point.

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	5.2	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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
FL3[3]	0.16	0.68	0.84	3.7	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
VCD1[4]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Dehy[4]	-	-	-	-	48.4	211.9	-	-	-	-	-	-	-	-	-	-	-	-
TK-2100[4]	-	-	-	-	6.7	29.2	-	-	-	-	-	-	-	-	-	-	-	-
TK-2200[4]	-	-	-	-	6.7	29.2	-	-	-	-	-	-	-	-	-	-	-	-
TK-6100	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-
TK-6150	-	-	-	-	-	0.29	-	-	-	-	-	-	-	-	-	-	-	-
L1[4]	-	-	-	-	-	114.5	-	-	-	-	-	-	-	-	-	-	-	-
HAUL	-	-	-	-	-	-	-	-	0.39	0.24	0.078	0.048	0.019	0.0117	-	-	-	-
FUG	-	-	-	-	7.2	31.5	-	-	-	-	-	-	-	-	0.16	0.68	-	-
Amine[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	0.0075	0.033	0.00020	0.00088	2.1E-06	9.1E-06	-	-	-	-
GEN-1	0.51	0.13	0.58	0.14	0.027	0.0068	0.00	0.000	0.0035	0.00086	0.0035	0.00086	0.0035	0.00086	-	-	-	-
Totals	61.8	268.5	272.9	1193.1	129.5	682.0	7.5	32.8	5.0	21.0	4.7	20.7	4.6	20.7	0.16	0.68		

[1] **Significant Figures Examples:** One significant figure – 0.03, 3, 0.3. Two significant figures – 0.34, 34, 3400, 3.4

[2] **Condensables:** Include condensable particulate matter emissions in particulate matter calculations.

[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 with a minimum of two significant figures[1]. If there are any significant figures to the left of a decimal point, there shall be no more than one significant figure to the right of the decimal point. Please do not change the column widths on this table.

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	5.2	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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	-	-	-	-
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	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
FL3[3]	0.16	0.68	0.84	3.7	0.012	0.054	-	-	-	-	-	-	-	-	-	-	-	-
VCD1[4]	0.24	1.1	0.20	0.89	1.8	7.7	-	-	-	-	-	-	-	-	-	-	-	-
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	0.0117	-	-	-	-
FUG	-	-	-	-	7.2	31.5	-	-	-	-	-	-	-	-	0.16	0.68	-	-
Amine[5]	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT-1	-	-	-	-	-	-	-	-	0.0019	0.008	0.00005	0.00022	5.2E-07	2.3E-06	-	-	-	-
GEN-1	0.51	0.13	0.58	0.14	0.027	0.0068	0.00	0.000	0.0035	0.00086	0.0035	0.00086	0.0035	0.00086	-	-	-	-
Totals	62.0	269.6	21.1	90.4	29.7	130.7	7.5	32.8	5.0	20.3	4.7	20.1	4.6	20.1	0.16	0.68	-	-

[1] **Significant Figures Examples**: One significant figure – 0.03, 3, 0.3. Two significant figures – 0.34, 34, 3400, 3.4

[2] **Condensables:** Include condensable particulate matter emissions in particulate matter calculations.

[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 as all SSM emissions at this facility do not require an increase in Requested Allowables greater than those listed in Table 2-E. If you are required to report GHG emissions as described in Section 21, include any GHG emissions due Startup, Shutdown, and/or Scheduled Maintenance in Table 2-P. Provide explanation in Section 6.

All applications, including NOI applications, must fill out this table, reporting Maximum Emissions during Startup, Shutdown and Scheduled Maintenance (20.2.7 NMAC, 20.2.72.203.A.3 NMAC, 20.2.73.200.D.2 NMAC). Only report SSM emissions greater than the cooresponding Table 2-E emissions[1]. Not providing emissions for a unit indicates that SSM emissions for this unit are less than the Requested Allowables for that unit in Table 2-E. In Section 6, provide emissions calculations for any emissions listed in this table. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.nmenv.state.nm.us/aqb/permit/app_form.html) for more detailed instructions. List all units and SSM fugitives, except GHGs, in this table. Refer to Table 2-E for instructions on use of the "-" symbol and on significant figures.

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	695.0	3.5	3781.7	18.8	2558.4	10.3	13023.6	52.1	-	-	-	-	-	-	141.6	0.57	-	-
FL2	101.4	0.88	551.9	4.8	7.8	0.069	5427.4	10.85	-	-	-	-	-	-	59.0	0.12	-	-
SSM (CB)	-	-	-	-	358.8	0.83	-	-	-	-	-	-	-	-	0.050	0.00011	-	-
SSM (PV)	-	-	-	-	1500.0	12.0	-	-	-	-	-	-	-	-	7.3	0.058	-	-
Totals	796.4	4.3	4333.6	23.6	4425.0	23.2	18451.0	62.9	-	-	-	-	-	-	208.0	0.74	-	-

[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 the table below. 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.

[2] **Condensables**: Include condensable particulate matter emissions in particulate matter calculations.

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

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.

Stack Number	Serving Unit Number(s) from Table 2-A	Orientation (H-Horizontal V=Vertical)	Rain Caps (Yes or No)	Height Above Ground (ft)	Temp. (F)	Flow Rate (acfs)	Flow Rate (dscfs)	Moisture by Volume (%)	Velocity (ft/sec)	Inside Diameter or L x W (ft)
C1-E	C1	V	No	50	856	535.0	-	-	75.7	3.0
C2-E	C2	V	No	50	856	535.0	-	-	75.7	3.0
C3-E	C3	V	No	50	856	535.0	-	-	75.7	3.0
C4-E	C4	V	No	50	856	535.0	-	-	75.7	3.0
C5-E	C5	V	No	50	856	535.0	-	-	75.7	3.0
C6-E	C6	V	No	50	856	535.0	-	-	75.7	3.0
C7-E	C7	V	No	50	856	535.0	-	-	75.7	3.0
C8-E	C8	V	No	50	856	535.0	-	-	75.7	3.0
C9-E	C9-E	V	No	50	857	269.1	-	-	101.9	1.8
C10-E	C10-E	V	No	50	857	269.1	-	-	101.9	1.8
H1	H1	V	No	20	730	199.9	-	-	28.3	3.0
H3	H3	V	No	20	718	76.1	-	-	15.5	2.5
H4	H4	V	No	129	512	621.7	-	-	9.8	9.0
H5	H5	V	No	129	512	621.7	-	-	9.8	9.0
H6	H6	V	No	25	600	24.0	-	-	30.5	1.0
FL1	FL1	V	No	100	1832	227.3	-	-	65.6	2.1
FL2	FL2	V	No	150	1832	227.3	-	-	65.6	2.1
FL3	FL3	V	No	50	1832	35.5	-	-	65.6	0.83
VCD1	VCD1	V	No	30	1400	44.9	-	-	2.8	4.5
GEN-1	GEN-1	V	No	6.7	754	10.5	-	-	214.6	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	0.0008	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	0.0008	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	0.0008	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	0.0008	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	0.0008	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	0.0008	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	0.0008	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	0.0008	0.0036
C9-E	C9-E	1.3	5.8	0.97	4.2	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	0.0004	0.0019
C10-E	C10-E	1.3	5.8	0.97	4.2	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	0.0004	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	*	0.000032	-	-
N/A	TK-6150	-	0.0044	-	-	-	-	-	-	-	-	*	0.0013	*	0.0014	*	9.4E-05	*	0.00039	*	0.0012	*	0.000032	-	-
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	225.5	0.90	-	-	-	-	-	-	-	-	3.4	0.014	4.0	0.016	0.92	0.0037	4.6	0.018	212.6	0.85	-	-	-	-
FL2	FL2 SSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	SSM (CB)	0.050	0.00011	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
N/A	SSM (PB)	7.3	0.058	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Totals:		246.0	58.3	2.8	12.1	1.0	4.4	2.8	12.2	1.6	7.0	3.8	1.9	4.5	2.1	1.4	2.3	5.0	2.0	213.4	4.4	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 (No. 2 Diesel, Natural Gas, Coal, …)	Specify Units				
		Lower Heating Value	Hourly Usage	Annual Usage	% Sulfur	% Ash
C1-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C2-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C3-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C4-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C5-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C6-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C7-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C8-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	31.6 Mscf/hr	276.4 MMscf/yr	5 g S/100 scf	-
C9-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	15.8 Mscf/hr	138.8 MMscf/yr	5 g S/100 scf	-
C10-E	Pipeline Quality Natural Gas	991 MMbtu/MMscf	15.8 Mscf/hr	138.8 MMscf/yr	5 g S/100 scf	-
H1	Pipeline Quality Natural Gas	991 MMbtu/MMscf	26.2 Mscf/hr	229.8 MMscf/yr	5 g S/100 scf	-
H3	Pipeline Quality Natural Gas	991 MMbtu/MMscf	10.1 Mscf/hr	88.4 MMscf/yr	5 g S/100 scf	-
H4	Pipeline Quality Natural Gas	991 MMbtu/MMscf	99.9 Mscf/hr	874.9 MMscf/yr	5 g S/100 scf	-
H5	Pipeline Quality Natural Gas	991 MMbtu/MMscf	99.9 Mscf/hr	874.9 MMscf/yr	5 g S/100 scf	-
H6	Pipeline Quality Natural Gas	991 MMbtu/MMscf	3.5 Mscf/hr	30.9 MMscf/yr	5 g S/100 scf	-
FL1	Pipeline Quality Natural Gas	991 MMbtu/MMscf	2.5 Mscf/hr	21.9 MMscf/yr	5 g S/100 scf	-
FL2	Pipeline Quality Natural Gas	991 MMbtu/MMscf	2.3 Mscf/hr	20.1 MMscf/yr	5 g S/100 scf	-
FL3	Pipeline Quality Natural Gas	991 MMbtu/MMscf	2.3 Mscf/hr	20.1 MMscf/yr	5 g S/100 scf	-
VCD1	VOC*	1513.3 MMBtu/MMscf	1.1 Mscf/hr	9.7 MMscf/yr	-	-
GEN-1	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	66.0	63.3	5.5	70.8	6.4
TK-2200	40400311	Condensate	Hydrocarbons and Water	5.6	66.0	63.3	5.5	70.8	6.4
TK-6100	40400311	Produced Water	Water plus trace hydrocarbons	8.3	18.0	72.3	0.4	86.3	0.6
TK-6150	40400311	Produced Water	Water plus trace hydrocarbons	8.3	18.0	72.3	0.4	86.3	0.6

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	Mar-15	Condensate	N/A	FX	1,000	159	6.1	2.4	tan	tan	Good	38,325,000	453.0
TK-2200	Mar-15	Condensate	N/A	FX	1,000	159	6.1	2.4	tan	tan	Good		453.0
TK-6100	Mar-15	Produced Water	N/A	FX	300	48	3.7	2.43	tan	tan	Good	766,500	30.4
TK-6150	Mar-15	Produced Water	N/A	FX	300	48	3.7	2.43	tan	tan	Good		30.4

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
FX: Fixed Roof	**Mechanical Shoe Seal**	**Liquid-mounted resilient seal**	**Vapor-mounted resilient seal**	**Seal Type**	**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: Green House Gas Emissions

Applications submitted under 20.2.70, 20.2.72, & 20.2.74 NMAC that are Major for GHGs as determined in Section 22 of this application are required to complete this Table if so directed in Section 22 or are major for GHGs and have an existing GHG BACT. Applicants must report potential emission rates in short tons per year. Include GHG emissions during Startup, Shutdown, and Scheduled Maintenance in this table.

		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**	16,024	0.030	0.30	-	-									16,024	
	CO_2e	16024	9.0	7.5	-	-										16040
C2-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C3-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C4-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C5-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C6-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C7-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C8-E	**mass GHG**	16,024	0.030	0.30	-	-									16024	
	CO_2e	16024	9.0	7.5	-	-										16040
C9-E	**mass GHG**	10,092	0.015	0.15	-	-									10093	
	CO_2e	10092	4.5	3.79	-	-										10101
C10-E	**mass GHG**	10,092	0.02	0.152	-	-									10093	
	CO_2e	10092	5	3.79	-	-										10101
H1	**mass GHG**	13,321	0.025	0.25	-	-									13322	
	CO_2e	13321	7	6	-	-										13335
H3	**mass GHG**	5124	0.0097	0.10	-	-									5124	
	CO_2e	5124	3	2	-	-										5129
H4	**mass GHG**	50724	0.096	0.96	-	-									50725	
	CO_2e	50724	28	24	-	-										50776
H5	**mass GHG**	50724	0.096	0.96	-	-									50725	
	CO_2e	50724	28	24	-	-										50776
H6	**mass GHG**	1793	0.003	0.0338	-	-									1793	
	CO2e	1793	1	0.84	-	-										1795
FL1	**mass GHG**	1,191	0.0024	8.5	-	-									1199	
	CO_2e	1191	1	213	-	-										1404
FL2	**mass GHG**	1,191	0.0024	8.5	-	-									1199	
	CO_2e	1191	0.71	213	-	-										1404
FL3	**mass GHG**	1,191	0.0024	8.5	-	-									1199	
	CO_2e	1191	0.71	213	-	-										1404
VCD1	**mass GHG**	1910	0.0036	0.21	-	-									1910	
	CO_2e	1910	1	5	-	-										1916

Table 2-P: Green House Gas Emissions

Applications submitted under 20.2.70, 20.2.72, & 20.2.74 NMAC that are Major for GHGs as determined in Section 22 of this application are required to complete this Table if so directed in Section 22 or are major for GHGs and have an existing GHG BACT. Applicants must report potential emission rates in short tons per year. Include GHG emissions during Startup, Shutdown, and Scheduled Maintenance in this table.

		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**										
Dehy	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
TK-	**mass GHG**	-	-	-	-	-									-	
2100	**CO_2e**	-	-	-	-	-										-
TK-	**mass GHG**	-	-	-	-	-									-	
2200	**CO_2e**	-	-	-	-	-										-
TK-	**mass GHG**	-	-	-	-	-									-	
6100	**CO_2e**	-	-	-	-	-										-
TK-	**mass GHG**	-	-	-	-	-									-	
6150	**CO2e**	-	-	-	-	-										-
L1	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
HAUL	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
FUG	**mass GHG**	550	-	2001											2551	
	CO_2e	550	-	50037												50587
Amine[6]	**mass GHG**	-	-	-	-	-									-	
	CO2e	-	-	-	-	-										-
CT-1	**mass GHG**	-	-	-	-	-									-	
	CO_2e	-	-	-	-	-										-
GEN-1	**mass GHG**	28	2.3E-04	0.0011											28	
	CO2e	28	0.068	0.029												28
Startup, Shutdown, and Maintenance Emissions																
FL1	**mass GHG**	6302	0.011	26											6328	
	CO2e	6302	3	654												6960
FL2	**mass GHG**	1485	0.0031	10											1495	
	CO_2e	1485	1	253												1739
SSM	**mass GHG**	0.0072	-	0.61											1	
(CB)	**CO2e**	0.0072	-	15												15
SSM	**mass GHG**	4	-	134											138	
(PV)	**CO2e**	4	-	3352												3355
Total	**mass GHG**														286,115	
	CO_2e															339149

[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 effect the facility's operations and emissions, de-bottlenecking impacts, and changes to the facility's major/minor status (both PSD & Title V).

Routine or predictable emissions during Startup, Shutdown, and Maintenance (SSM): 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.nmenv.state.nm.us/aqb/permit/app_form.html) for more detailed instructions on SSM emissions.

DCP Midstream, LP (DCP) is submitting an application pursuant to 20.2.74.200.A NMAC for revision to its PSD Permit PSD-5217 for the Zia II Gas Plant (Zia II). The facility is a new 230 MMscf/day greenfield gas plant in Lea County, New Mexico approximately 25 miles northeast of Carlsbad. The facility is currently under construction and has not yet begun operation.

DCP proposes to update the current permit to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources. The table below lists all the units at the facility and describes any changes proposed in this application. Items highlighted in grey are not changing as a result of this application.

Unit	Description	Notes
Amine	Amine Sweetening Unit	This unit is not affected by the proposed changes.
C1-E	Caterpillar G3616 4SLB RICE	The stack diameter for these units is being updated from 2 feet to 3 feet.
C2-E	Caterpillar G3616 4SLB RICE	
C3-E	Caterpillar G3616 4SLB RICE	
C4-E	Caterpillar G3616 4SLB RICE	
C5-E	Caterpillar G3616 4SLB RICE	
C6-E	Caterpillar G3616 4SLB RICE	
C7-E	Caterpillar G3616 4SLB RICE	
C8-E	Caterpillar G3616 4SLB RICE	
C9-E	Caterpillar G3608LE 4SLB RICE	The stack height for these units is being updated from 40 feet to 50 feet.
C10-E	Caterpillar G3608LE 4SLB RICE	
C11-E	Caterpillar G3608LE 4SLB RICE	These units are being removed from the permit. The engines will be electric driven.
C12-E	Caterpillar G3608LE 4SLB RICE	
C13-E	Caterpillar G3608LE 4SLB RICE	
C1-C to C15-C	Compressors (reciprocating)	These units are not affected by the proposed changes.
Dehy	230 MMscf/d TEG Dehydrator Still Vent/Flash Tank	This unit is not affected by the proposed changes.
FL1	2.3 MMBtu/hr Inlet Gas Flare	Purge gas has increased from 1800 scf/hr to 2000 scf/hr
FL2	2.3 MMBtu/hr Acid Gas Flare	This unit is not affected by the proposed changes.
FL3	Lusk Emergency Flare	This unit, located at what was previously Lusk Booster Station, is being incorporated into the Zia II Gas Plant facility as an emergency flare.
FUG	Facility-wide Fugitives	This unit is being updated to reflect the proposed changes.
H1	26 MMBtu/hr Trim Reboiler Heater	The stack height for this unit is being updated from 86 feet to 20 feet. The exhaust temperature is being updated from 600˚F to 730˚F.
H2	7 MMBtu/hr Stabilizer Heater	This unit is being removed from the permit as it will not be installed at the facility. The process will use heat medium oil and will no longer require this heater.

H3	10 MMBtu/hr Regeneration Gas Heater	The capacity for this unit will be updated from 8 MMBtu/hr to 10 MMBtu/hr. The stack height is being updated from 40 ft to 20 ft. The exhaust temperature is being updated from 600˚F to 718˚F.
H4	99 MMBtu/hr Hot Oil Heater	The capacity for this unit will be updated from 114 MMBtu/hr to 99 MMBtu/hr.
H5	99 MMBtu/hr Hot Oil Heater	The capacity for this unit will be updated from 114 MMBtu/hr to 99 MMBtu/hr.
H6	3.5 MMBtu/hr TEG Regeneration Heater	The capacity for this unit will be updated from 3.0 MMBtu/hr to 3.5 MMBtu/hr.
HAUL	Paved Haul Roads	Calculations are being revised based on a new haul road route and paved roads.
L1	Truck Loadout 38,325 Mgal/yr	This unit is not affected by the proposed changes.
TK-1	1,000 bbl Condensate Tank	The unit number for this tank is being updated to TK-2100.
TK-2	1,000 bbl Condensate Tank	The unit number for this tank is being updated to TK-2200.
TK-C	100 bbl Produced Water Tank	This unit is being removed as part of this application.
TK-G	300 bbl Produced Water Tank	The unit number for this tank is being updated to TK-6100.
TK-H	300 bbl Produced Water Tank	The unit number for this tank is being updated to TK-6150.
VCD1	Vapor Combustion Device	This unit is not affected by the proposed changes.
GEN-1	70 hp Cummins Diesel Generator (500 hrs/year)	This unit will be added to the permit. The engine will operate for up to 500 hours per year.
CT-1	Wet Surface Air Cooler	This unit will be added to the permit.
SSM (CB)	Compressor Blowdown SSM	Startup, shutdown, and maintenance emissions from compressor blowdowns are being accounted for in this application.
SSM (PV)	Plant Venting SSM	Plant venting emission associated with startup, shutdown, and maintenance are being added to the permit.
Various	Tanks – Not sources of emissions	The list of tanks which are not regulated sources of emissions on Table 2-B is being updated.

Section 4

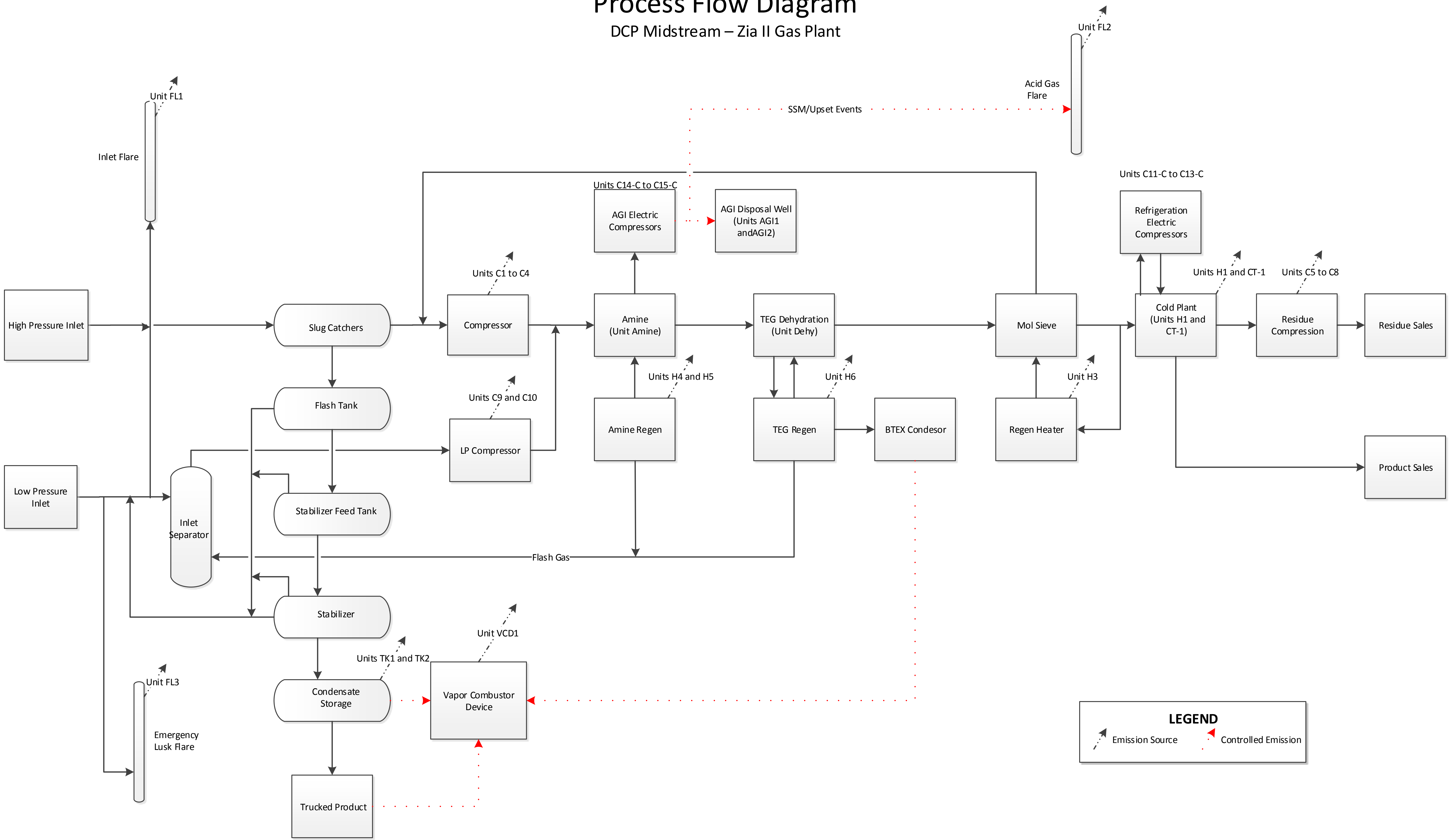
Process Flow Sheet

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 revised process flow diagram is attached.

Process Flow Diagram

DCP Midstream – Zia II Gas Plant



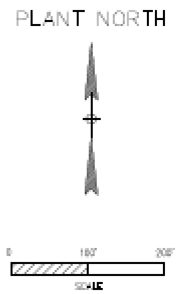
Trinity Consultants

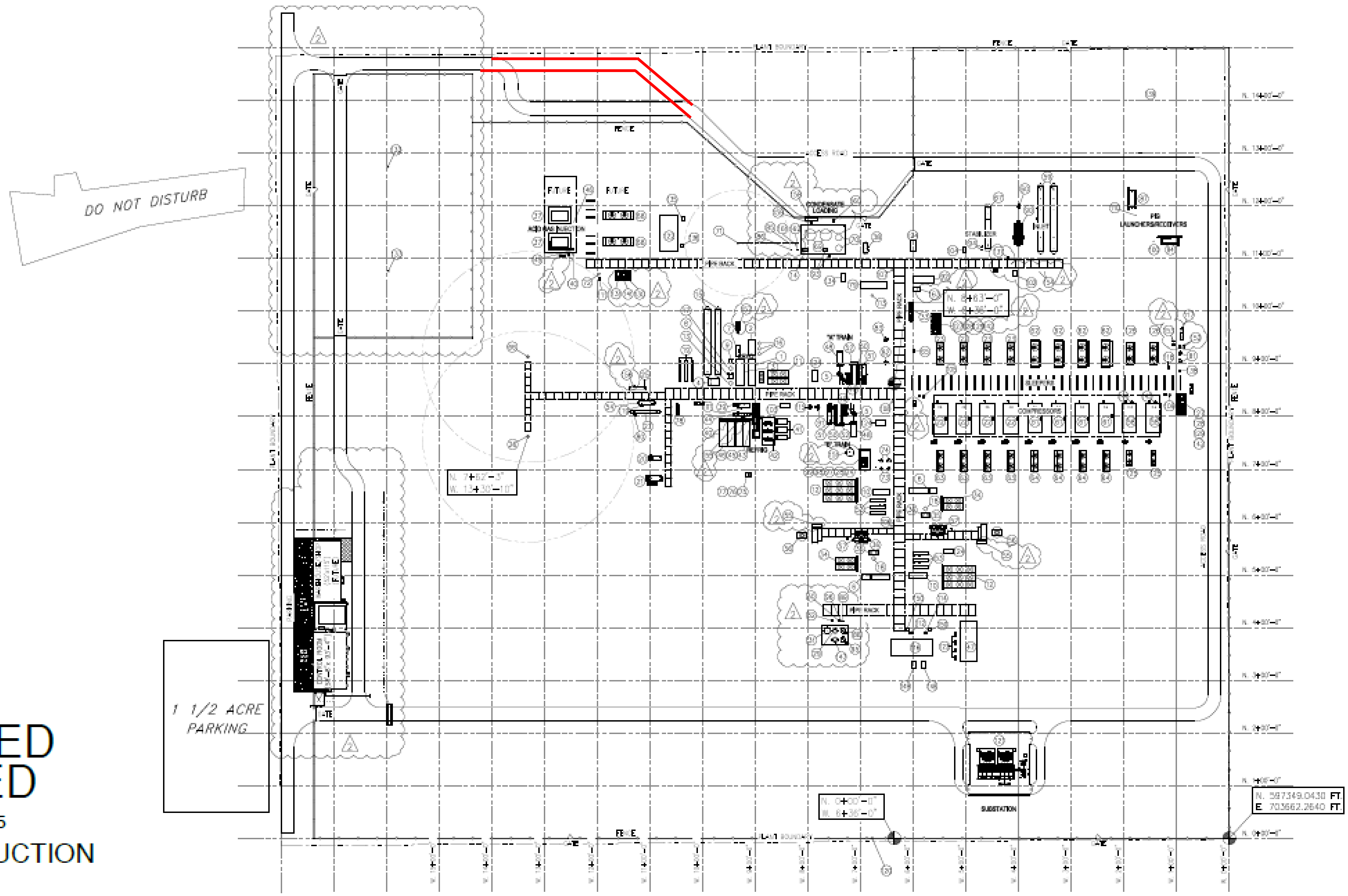
Section 5

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 revised 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
SAULSBURY

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.	REV
FILE NAME:	C03-100	D-9507-C03-100	2

\\enengi\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.nmenv.state.nm.us/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.

Emission methodologies for Steady State and SSM emissions are detailed in the following sections. Emission calculation spreadsheets are attached to this section. Support documents and materials are provided in Section 7 and are cross-referenced in the detailed discussions below. The following table describes units which have updated emission calculations or are being added.

Table 6.1 – Updates to Calculations		
Unit	**Description**	**Notes**
FL1	Inlet Gas Flare	Purge gas has increased from 1800 scf/hr to 2000 scf/hr
FL3	Lusk Emergency Flare	This flare, located at what was previously Lusk Booster Station, is being incorporated into the Zia II Gas Plant as an emergency flare.
FUG	Facility-wide Fugitives	This emission unit is being updated to reflect the proposed changes.
H3	Regeneration Gas Heater	The capacity for this unit will be updated to from 8 MMBtu/hr to 10 MMBtu/hr.
H4 and H5	Hot Oil Heaters	Capacity for these units is being updated from 114 MMBtu/hr to 99 MMBtu/hr.
H6	TEG Regeneration Heater	Capacity for these units is being updated from 3.0 MMBtu/hr to 3.5 MMBtu/hr.
HAUL	Paved Haul Roads	Calculations are being revised based on a new haul road route and paved roads.
GEN-1	70 hp Cummins Diesel Generator	This unit will be added to the permit. The engine will operate for up to 500 hours per year.
CT-1	Wet Surface Air Cooler	This unit will be added to the permit.
SSM (CB)	Compressor Blowdown SSM	Startup, shutdown, and maintenance emissions from compressor blowdowns are being accounted for in this application.
SSM (PV)	Plant Venting SSM	Plant venting emission associated with startup, shutdown, and maintenance are being added to the permit.

STEADY-STATE EMISSIONS

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:

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

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

Hourly emission rates for 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:

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

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

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

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

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

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

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)

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:

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

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

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:

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

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

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

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

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

Vapor Combustion Device (VCD1)

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:

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

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 16 MMscf/d. Each AGI well will handle 8 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 *(Not regulated sources of emissions)*

Units TK-7700, TK-7750, TK-7800, TK-L2

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

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 200 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	8,333,333 scf/hr	16,666,667 scf/event	66,667 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.

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 16 MMscf/d. Each AGI well will handle 8 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 (8 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	4.0 events/yr	1.0 hrs/event	4.0 hrs/yr	333,333 scf/hr	333,333 scf/event	1,333 Mscf/yr	822 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)]

Unit SSM (PV)

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)	695.0	3.5	3781.7	18.8	2558.4	10.3	13023.6	52.1	-	-	-	-	-	-	141.6	0.57	-	-	-	-	*	7,072
SSM (FL2)	101.4	0.88	551.9	4.8	7.8	0.069	5427.4	10.9	-	-	-	-	-	-	59.0	0.12	-	-	-	-	*	1,739
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	**796.4**	**4.3**	**4,333.6**	**23.6**	**4,425.0**	**23.2**	**18,451.0**	**62.9**	**-**	**-**	**-**	**-**	**-**	**-**	**208.0**	**0.74**	**7.314**	**5.8E-02**	**-**	**-**	**424,983.9**	**12,181.7**

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)	695.0	3.5	3781.7	18.8	2558.4	10.3	13023.6	52.1	-	-	-	-	-	-	141.6	0.57	225.5	0.90	-	-	*	7,072
SSM (FL2)	101.4	0.88	551.9	4.8	7.8	0.069	5427.4	10.85	-	-	-	-	-	-	59.0	0.12	-	-	-	-	*	1,739
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	**796.4**	**4.3**	**4,333.6**	**23.6**	**4,425.0**	**23.2**	**18,451.0**	**62.9**	**-**	**-**	**-**	**-**	**-**	**-**	**208.0**	**0.74**	**232.8**	**0.96**	**-**	**-**	**424,983.9**	**12,181.7**

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	0.000822	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	0.000822	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	0.000822	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	0.000822	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	0.000822	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	0.000822	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	0.000822	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	0.000822	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	0.000434	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	0.000434	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)	-	-	-	-	-	-	-	-	3.4	0.014	4.0	0.016	0.92	0.0037	4.6	0.018	212.6	0.85	-	-	-	-
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	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**3.38**	**0.014**	**3.99**	**0.016**	**0.92**	**0.0037**	**4.60**	**0.018**	**212.6**	**0.85**	**-**	**-**	**-**	**-**

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

NO_x[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).*

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

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 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).*

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

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

NOx[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 (AP-

H_2SO_4 Hourly Emissions (lb/hr) =	*0.37 lb SO2*	*0.03*	*98.08 lb H_2SO_4*	*1 lb-mol SO_2*	*=*	*0.017 lb/hr*
	hr		*1 lb-mol H_2SO_4*	*64.06 lb SO_2*		

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 form

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

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_i * 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_i = 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 HH\ 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

DCP Midstream, LP - Zia II Gas Plant

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) = $V_a * (1- \eta) * X_{CH4}$ *(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 = 0.9464 (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) = $\sum (\eta * V_a * Y_j * R_j)$ *(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 =	0.9464	(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).

$Mass_{s,i} = E_{s,i} * \rho_i * 0.0011023$ *(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

Pilot & Purge gas HH 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_i * R_i) *(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_i = 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_i = 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*

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.*

DCP Midstream, LP - Zia II Gas Plant

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)

DCP Midstream, LP - Zia II Gas Plant

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.*

DCP Midstream, LP - Zia II Gas Plant

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**

HAP Emissions

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.

GHG Emissions

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*

DCP Midstream, LP - Zia II Gas Plant

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

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

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

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

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)

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

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

Maximum Controlled Emissions

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

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

DCP Midstream, LP - Zia II Gas Plant

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.

DCP Midstream, LP - Zia II Gas Plant

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.

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	3488.05 ft/s		
Exit Temperature	1830 deg F (estimated)		
Volume Flow Rate	277,786 ft³/min		

Potential Emissions

Pollutant	Emission Factor	Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(lb/hr)	(tpy)	
NOx	0.0680	695.01	3.46	AP42
CO	0.3700	3781.66	18.82	AP42
VOC		2558.36	10.29	See Calcs Below
SO^2		13023.55	52.09	See Calcs Below
H_2S		141.61	0.57	See Calcs Below
n-Hexane		212.65	0.85	See Calcs Below
Benzene		3.38	0.014	See Calcs Below
Toluene		3.99	0.016	See Calcs Below
E-Benzene		0.92	0.0037	See Calcs Below
m-Xylene		4.60	0.018	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	
16,666,667	scf/event	200	mmscf/day
66,667	mscf/year	8.3	mmscf/hr
2.00	duration per event (hr)	8,333,333	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	205000.0	14916.0	0	0.00	-	-
Carbon Dioxide	0.06700	44.01	2.95	558333.3	63823.6	0	0.00	63823.59	255.29
Methane	0.67070	16.04	10.76	5589166.7	232899.9	1010	677.41	-	-
Ethane	0.11863	30.07	3.57	988583.3	77212.0	1770	209.94	-	-
Propane	0.06371	44.10	2.81	530916.7	60810.0	2516	160.31	1216.20	4.86
i-Butane	0.00767	58.12	0.45	63916.7	9649.6	3252	24.94	192.99	0.77
n-Butane	0.01952	58.12	1.13	162666.7	24558.0	3262	63.67	491.16	1.96
i-Pentane	0.00484	72.15	0.35	40333.3	7558.7	4001	19.36	151.17	0.60
n-Pentane	0.00512	72.15	0.37	42666.7	7996.0	4009	20.53	159.92	0.64
n-Hexane	0.00570	86.18	0.49	47500.0	10632.3	4756	27.11	212.65	0.85
n-Heptane	0.00200	100.21	0.20	16666.7	4337.9	5503	11.01	86.76	0.35
n-Octane	0.00070	114.23	0.08	5833.3	1730.8	6249	4.37	34.62	0.14
Benzene	0.00010	78.11	0.01	833.3	169.1	3742	0.37	3.38	0.01
Toluene	0.00010	92.14	0.01	833.3	199.4	4475	0.45	3.99	0.02
E-Benzene	0.00002	106.17	0.00	166.7	46.0	5208	0.10	0.92	0.00
m-Xylene	0.00010	106.17	0.01	833.3	229.8	5208	0.52	4.60	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	80000.0	7080.7	637	6.12	141.61	0.57
Total	1.00011		24.20	8334250.00	523849.6		1226.21	66523.56	266.09
Total VOC	0.1096			913166.67				2558.35	10.23

Heating Value	1226.21	Btu/scf
Heat Rate	10218.43	MMBtu/hr

Maintenance Event Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{10218.43 \text{ MMBtu}}{\text{hr}}$

= **694.85** **lb/hr NOx**

NOx (tpy): $\frac{694.85 \text{ lb}}{\text{hr}} \times \frac{8 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **2.78** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \times \frac{10218.43 \text{ MMBtu}}{\text{hr}}$

= **3780.82** **lb/hr CO**

CO (tpy): $\frac{3780.82 \text{ lb}}{\text{hr}} \times \frac{8 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **15.12** **tpy CO**

SO2 (lb/hr): $\frac{6939.11 \text{ lb H2S}}{\text{hr}} \times \frac{64.0 \text{ lb SO2}}{34.1 \text{ lb H2S}}$

= **13023.55** **lb/hr SO2**

SO2 (tpy): $\frac{13023.55 \text{ lb SO2}}{\text{hr}} \times \frac{8 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **52.09** **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	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	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): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \cdot \frac{1.78 \text{ MMBtu}}{\text{hr}}$

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

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

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

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

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

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

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

Maximum Velocity (During Events)

Maximum Tip Velocity calculation for non-assisted flares.

Volumetric Flow Rate	16,667,167	scf/hr (during event)
	4629.77	scf/sec
Flare Tip Area	1.33	square feet
Exit Velocity	3488.0	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- 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 = 0.6707 (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) = ∑ (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 =	0.6707	(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).

$Mass_{s,i}$ = $E_{s,i}$ * 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

SSM flaring gas HI 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	66,666,667	894267	4,466,667	88,151,000	867,070	4,330,826	85,470,139	18.35	251.11	4,955.64	0.00901	5668.2
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	**88,566,667**	**1,308,776**	**4,466,666.7**	**109,329,158**	**1,268,973**	**4,330,825.7**	**106,004,224**	**26.9**	**251.1**	**6,146.2**	**0.01140**	**7,072.2**

	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	4.00 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	70.24 ft/s		
Exit Temperature	1830 deg F (estimated)		
Volume Flow Rate	5,594 ft^3/min		

Potential Emissions

Pollutant	Emission Factor	Estimated Emissions		Source of Emission Factor
	(lb/MMBtu)	(lb/hr)	(tpy)	
NO_x	0.0680	101.43	0.88	AP42
CO	0.3700	551.90	4.80	AP42
VOC		7.83	0.07	See Calcs Below
SO_2		5,427.44	10.85	See Calcs Below
H_2S		59.02	0.12	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

4.00	Events per Year	AGI Rate	
333,333	scf/event	8	mmscf/day
1,333	mscf/year	0.33	mmscf/hr
1.00	duration per event (hr)	333,333	scf/hr
4.00	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	tons/yr
Nitrogen	0.00	28.0134	0.00	0.00	0.00	0	0.00	-	-
Carbon Dioxide	0.90	44.01	39.61	300000.00	34293.51	0	0.00	34293.51	68.59
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	33333.33	2950.82	637.02	63.70	59.02	0.12
Total	1.00		43.02	333333.33	37244.3		63.70	34352.52	68.71
Total VOC	0.0000			0.00				0.00	0.00

Heating Value	63.70	Btu/scf
Heat Rate	21.23	MMBtu/hr

Maintenance Event Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{21.23 \text{ MMBtu}}{\text{hr}}$

= **1.44** **lb/hr NOx**

NOx (tpy): $\frac{1.44 \text{ lb}}{\text{hr}} \times \frac{4 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.00** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \times \frac{21.23 \text{ MMBtu}}{\text{hr}}$

= **7.86** **lb/hr CO**

CO (tpy): $\frac{7.86 \text{ lb}}{\text{hr}} \times \frac{4 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.02** **tpy CO**

SO2 (lb/hr): $\frac{2891.81 \text{ lb H2S}}{\text{hr}} \times \frac{64.0 \text{ lb SO2}}{34.1 \text{ lb H2S}}$

= **5427.44** **lb/hr SO2**

SO2 (tpy): $\frac{5427.44 \text{ lb SO2}}{\text{hr}} \times \frac{4 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **10.85** **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 GasComponents	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): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{0.50 \text{ MMBtu}}{\text{hr}}$

= **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 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 GasComponents	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	0.0006	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): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \left| \frac{1.78 \text{ MMBtu}}{\text{hr}} \right.$

= **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**

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

	70.1	Btu/scf	Heating value of Pilot + Purge gas + Flared gas
	822	Btu/scf	target heat content
	991.2	Btu/scf	Assist gas-assumed sweet residue gas
	1.48	MMscf/hr	Assist gas volume
	1468.1	MMBtu/hr	Assist gas heat input
*Assist gas - Annual**	5.9	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 GasComponents	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	2.34
Ethane	0.01674	30.07	0.50	24,792.13	1,936.30	1770	29.62	38.73	0.08
Propane	0.00180	44.10	0.08	2,662.91	305.00	2516	4.52	6.10	0.01
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	0.00
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	34.08	16.76	1,481,110.10	64,472.22		991.23	1,214.63	2.43
Total VOC	0.0022			3,231.15				7.82	0.02

Heating Value	991.23	Btu/scf
Heat Rate	1468.120	MMBtu/hr (assist gas only)

Assist Emissions

NOx (lb/hr): $\frac{0.068 \text{ lb}}{\text{MMBtu}} \times \frac{1468.12 \text{ MMBtu}}{\text{hr}}$

= **99.83** **lb/hr NOx**

NOx (tpy): $\frac{99.83 \text{ lb}}{\text{hr}} \times \frac{4.00 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **0.200** **tpy NOx**

CO (lb/hr): $\frac{0.3700 \text{ lb}}{\text{MMBtu}} \times \frac{1468.12 \text{ MMBtu}}{\text{hr}}$

= **543.20** **lb/hr CO**

CO (tpy): $\frac{543.20 \text{ lb}}{\text{hr}} \times \frac{4.00 \text{ hr}}{\text{yr}} \times \frac{1 \text{ ton}}{2000 \text{ lb}}$

= **1.09** **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	335633.33	scf/hr (during event)
	93.23	scf/sec
Flare Tip Area	1.33	square feet
Exit Velocity	70.2	feet/sec

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

Pilot+ Purge Gas + Maintenance event+Assist Gas

21.58	g/mol	Flared gas molecular weight	Volume weighted mol. wt. of all components
1.04E+08	cal/sec	Heat release (q)	MMBtu/hr * 10^6 * 252 cal/Btu ÷ 3600 sec/hr
8.11E+07		q_n	$q_n = q(1-0.048(MW)^{1/2})$
9.0	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_i * R_i) *(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_i = 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 =	0.000	

R_i = 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 =	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	5,924,440	112134	0.00	5,729,166	108,724	0.00	5,554,930	2.30	0.00	322.08	0.00081	379.8

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) = $\sum (\eta * V_a * Y_i * R_i)$ *(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_i = 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 =	0.000	

R_i = 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 =	5

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

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

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 = 8.220E-04 MMBtu/scf

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	1,333,333	0	1,200,000	0	0	1,163,505	0	0	67.5	0	1.208E-04	67.5

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	5,924,440	112,134	0.00	5,729,166	108,724	0.00	5,554,930	2.30	0.00	322.1	0.00081	379.8
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	1,333,333	0	1,200,000	0	0	1,163,505	0	0	67.5	0	0.00012	67.5
Total	**27,405,774**	**493,482.7**	**1,200,000.0**	**25,213,071.7**	**478,474.9**	**1,163,505.4**	**24,446,288.0**	**10.1**	**67.5**	**1,417.4**	**0.0031**	**1,739.0**

	CO_2	CH_4	N_2O
GWP	1	25	298

DCP Midstream, LP - Zia II Gas Plant

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%

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

	From Inlet Gas Analysis		Emission Rates		
Constituent	mole %	MW * mol % (lb/lb-mol)	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 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)

- **Section 7.6**
  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.
- **Section 7.7**
  Truck Loading (Unit L1)
  - Section 7.7-1 – EPA AP-42 Section 5.2 for Condensate Truck Loading (Unit L1)
- **Section 7.8**
  Haul Road Emissions (Unit HAUL)
  - Section 7.8-1 – AP-42 Section 13.2.1 for Paved Haul Roads (Unit HAUL)
- **Section 7.9**
  Fugitive Emissions (Unit FUG)
  - Section 7.9-1 – EPA Protocol for Equipment Leak Emission Estimates, November 1995, Tables 2-4 and 2-10
- **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 7.1-3 - 40 CFR 98 Subpart W Table C-1 and C-2 (Refer to Section 7.1-7)
- **Section 7.11**
  Wet Surface Air Cooler (Unit CT-1)
  - Section 7.11-1 – EPA AP-42 Section 13.4
  - Section 7.11-2 – Manufacturer's data
- **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 sources of regulated emissions (Units TK-7700, TK-7750, TK-7800, TK-L2)
  - Section 7.14-1 – TANKS 4.0.9d output

Section 7.1 – 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)

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)

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Houston, TX 77024
Office: 307.673.0883 | Direct: 307.675.5073
cparisi@emittechnologies.com

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

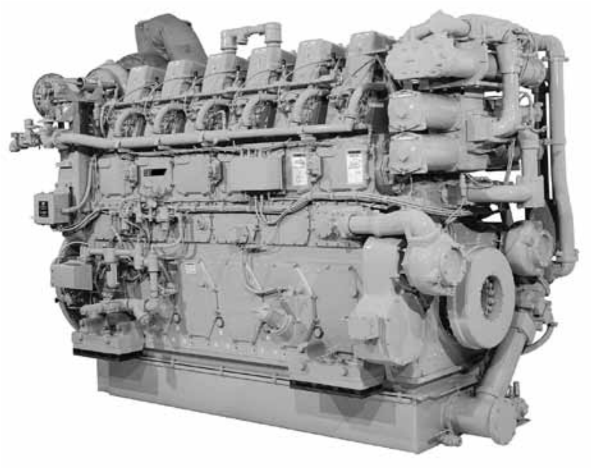
Catalyst Element

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

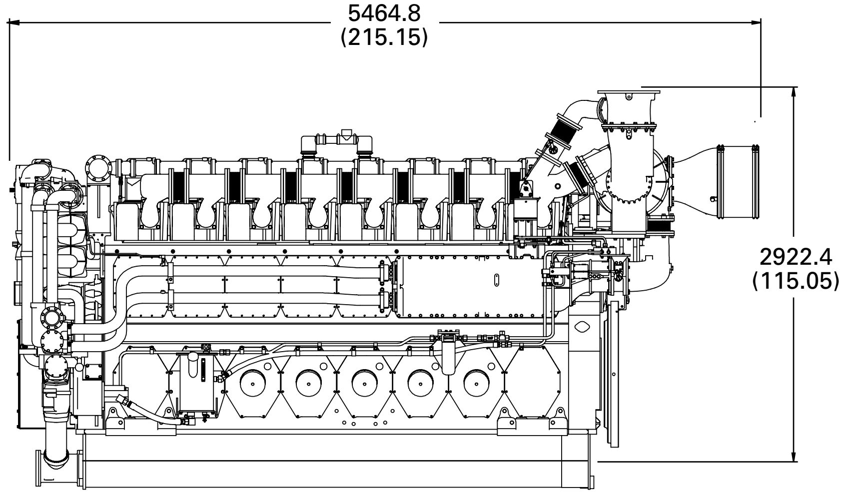
TECHNICAL DATA

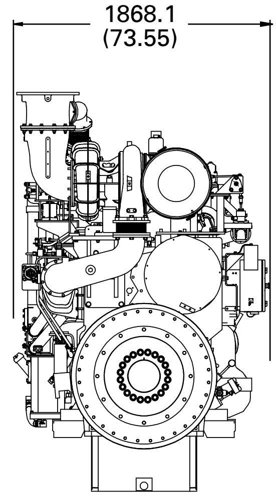
G3608 LE Gas Petroleum Engine — 1000 rpm

		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.

Performance Numbers: DM5561-03, DM5562-03, DM5136-03, DM8606-02
LEHW0040-02 (8-10)

EMIT TECHNOLOGIES

10497 Town & Country Way, Ste. 940
Houston, TX 77024
Office: 307.673.0883 | Direct: 307.675.5073
cparisi@emittechnologies.com

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)

Table 3.2-2. UNCONTROLLED EMISSION FACTORS FOR 4-STROKE LEAN-BURN ENGINES[a]
(SCC 2-02-002-54)

PM=PM10=PM2.5;
Emission Factor =
Filterable + Condensable=
7.71E-05 + 9.91E-03 =
9.99E-03

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:

$$\text{lb/hp-hr} = (\text{lb/MMBtu})(\text{heat input, MMBtu/hr})(1/\text{operating HP, } 1/\text{hp})$$

[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
CO2	16,584.0256	363.03769350	g/bhp-hr	EPA

Bloomberg BNA

Environment & Safety Resource Center™

Federal Environment and Safety Codified Regulations
TITLE 40—Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
SUBPART C—General Stationary Fuel Combustion Sources

Table C-1 to Subpart C of Part 98 —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	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO_2 /mmBtu
(Weighted U.S. Average)	1.028 x 10-3	53.02
Petroleum products	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	0.135	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.069	62.64
Ethanol	0.084	68.44
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22

Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
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	74.49
Other fuels-solid.	mmBtu/short ton	kg CO_2 /mmBtu
Municipal Solid Waste	9.95 [1]	90.7
Tires	26.87	85.97
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
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
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas [2]	1.388×10^{-3}	59.00
Biomass fuels—solid	mmBtu/short ton	kg CO_2 /mmBtu
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2 /mmBtu
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2 /mmBtu
Ethanol	0.084	68.44
Biodiesel	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] 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.

[2] 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.

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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 7.2 – 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. $CO_2[lb/10^6$ 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

Section 7.2-4 – 40 CFR 98 Subpart W Table C-1 and C-2 (Units H1 to H6)

Bloomberg BNA **Environment & Safety Resource Center™**

Federal Environment and Safety Codified Regulations
TITLE 40—Protection of Environment
PART 98—MANDATORY GREENHOUSE GAS REPORTING
SUBPART C—General Stationary Fuel Combustion Sources

Table C-1 to Subpart C of Part 98 —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	103.54
Bituminous	24.93	93.40
Subbituminous	17.25	97.02
Lignite	14.21	96.36
Coke	24.80	102.04
Mixed (Commercial sector)	21.39	95.26
Mixed (Industrial coking)	26.28	93.65
Mixed (Industrial sector)	22.35	93.91
Mixed (Electric Power sector)	19.73	94.38
Natural gas	mmBtu/scf	kg CO_2 /mmBtu
(Weighted U.S. Average)	1.028 x 10-3	53.02
Petroleum products	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	0.135	74.00
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.069	62.64
Ethanol	0.084	68.44
Ethylene	0.100	67.43
Isobutane	0.097	64.91
Isobutylene	0.103	67.74
Butane	0.101	65.15
Butylene	0.103	67.73
Naphtha (<401 deg F)	0.125	68.02
Natural Gasoline	0.110	66.83
Other Oil (>401 deg F)	0.139	76.22

Pentanes Plus	0.110	70.02
Petrochemical Feedstocks	0.129	70.97
Petroleum Coke	0.143	102.41
Special Naphtha	0.125	72.34
Unfinished Oils	0.139	74.49
Heavy Gas Oils	0.148	74.92
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	74.49
Other fuels-solid.	mmBtu/short ton	kg CO_2 /mmBtu
Municipal Solid Waste	9.95 [1]	90.7
Tires	26.87	85.97
Plastics	38.00	75.00
Petroleum Coke	30.00	102.41
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
Propane Gas	2.516×10^{-3}	61.46
Fuel Gas [2]	1.388×10^{-3}	59.00
Biomass fuels—solid	mmBtu/short ton	kg CO_2 /mmBtu
Wood and Wood Residuals	15.38	93.80
Agricultural Byproducts	8.25	118.17
Peat	8.00	111.84
Solid Byproducts	25.83	105.51
Biomass fuels—gaseous	mmBtu/scf	kg CO_2 /mmBtu
Biogas (Captured methane)	0.841×10^{-3}	52.07
Biomass Fuels—Liquid	mmBtu/gallon	kg CO_2 /mmBtu
Ethanol	0.084	68.44
Biodiesel	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] 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.

[2] 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.

ISSN 2167-8065

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)

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

		Normalized
	Inlet Gas mol%	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]		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

[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)

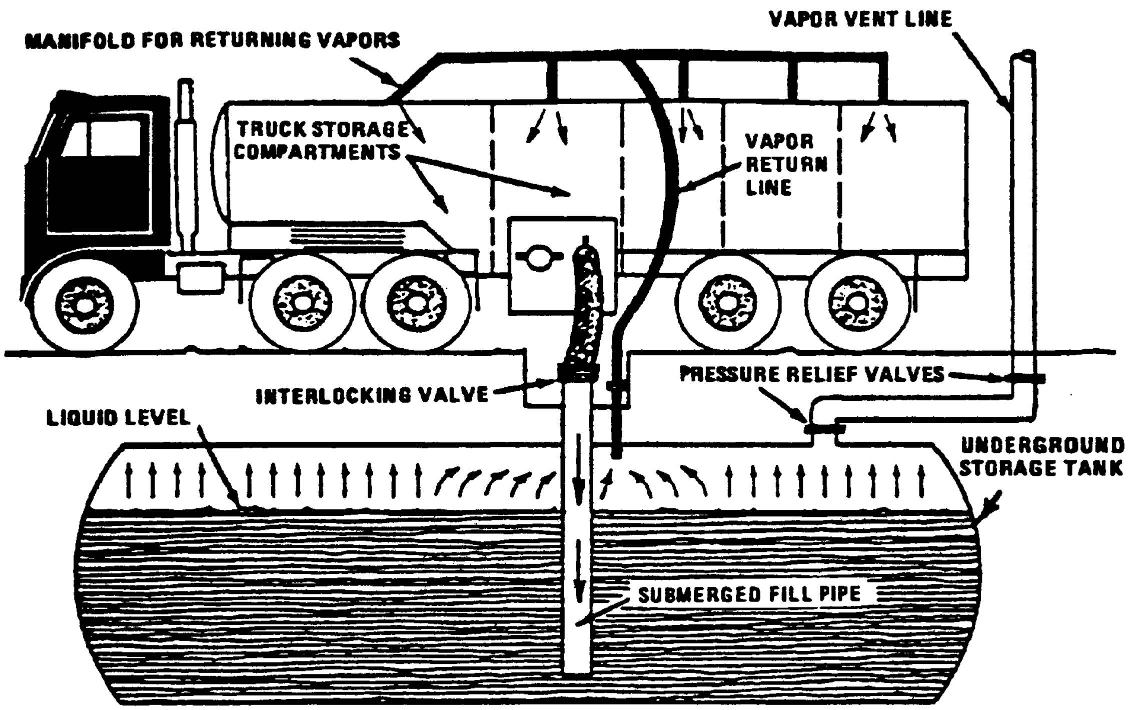

Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

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)

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.

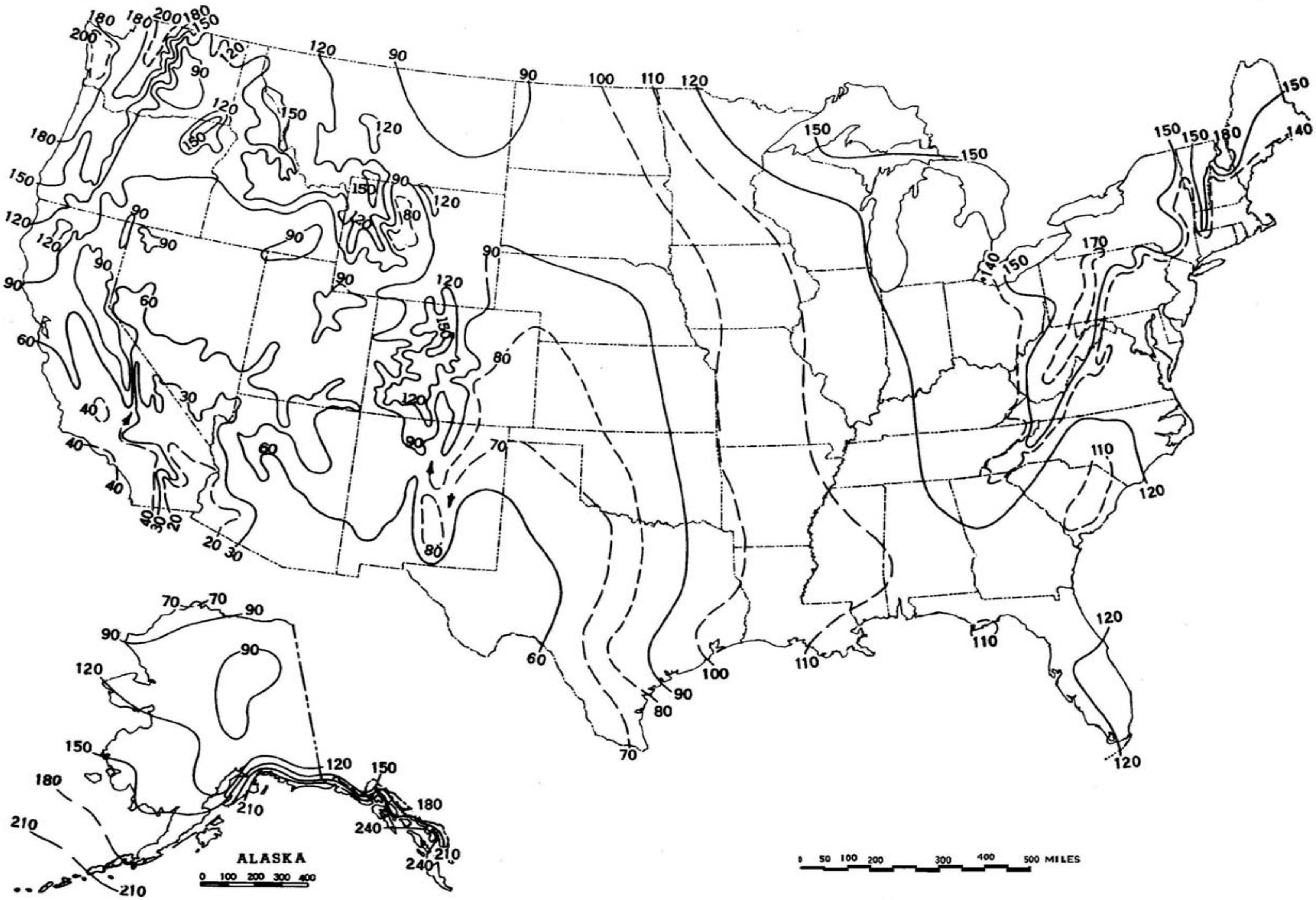

Figure 13.2.1-2. Mean number of days with 0.01 inch or more of precipitation in the United States.

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

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

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, kW_m (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, kW_m (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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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
$\frac{\text{kW x 1000}}{\text{Voltage x 1.73 x 0.8}}$	$\frac{\text{kW x Single Phase Factor x 1000}}{\text{Voltage}}$

Cummins Power Generation
1400 73rd Avenue N.E.
Minneapolis, MN 55432 USA
Telephone: 763 574 5000
Fax: 763 574 5298

Warning: Back feed to a utility system can cause electrocution and/or property damage. Do not connect to any building's electrical system except through an approved device or after building main switch is open.

Our energy working for you.™

www.cumminspower.com

D-3368 (2/08)

Power Generation

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) Emission Factor (lb/hp-hr) (power output)	Gasoline Fuel Emission Factor (lb/MMBtu) (fuel input)	Diesel Fuel (SCC 2-02-001-02, 2-03-001-01) Emission Factor (lb/hp-hr) (power output)	Diesel Fuel Emission Factor (lb/MMBtu) (fuel input)	EMISSION FACTOR RATING
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 ≤ 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.

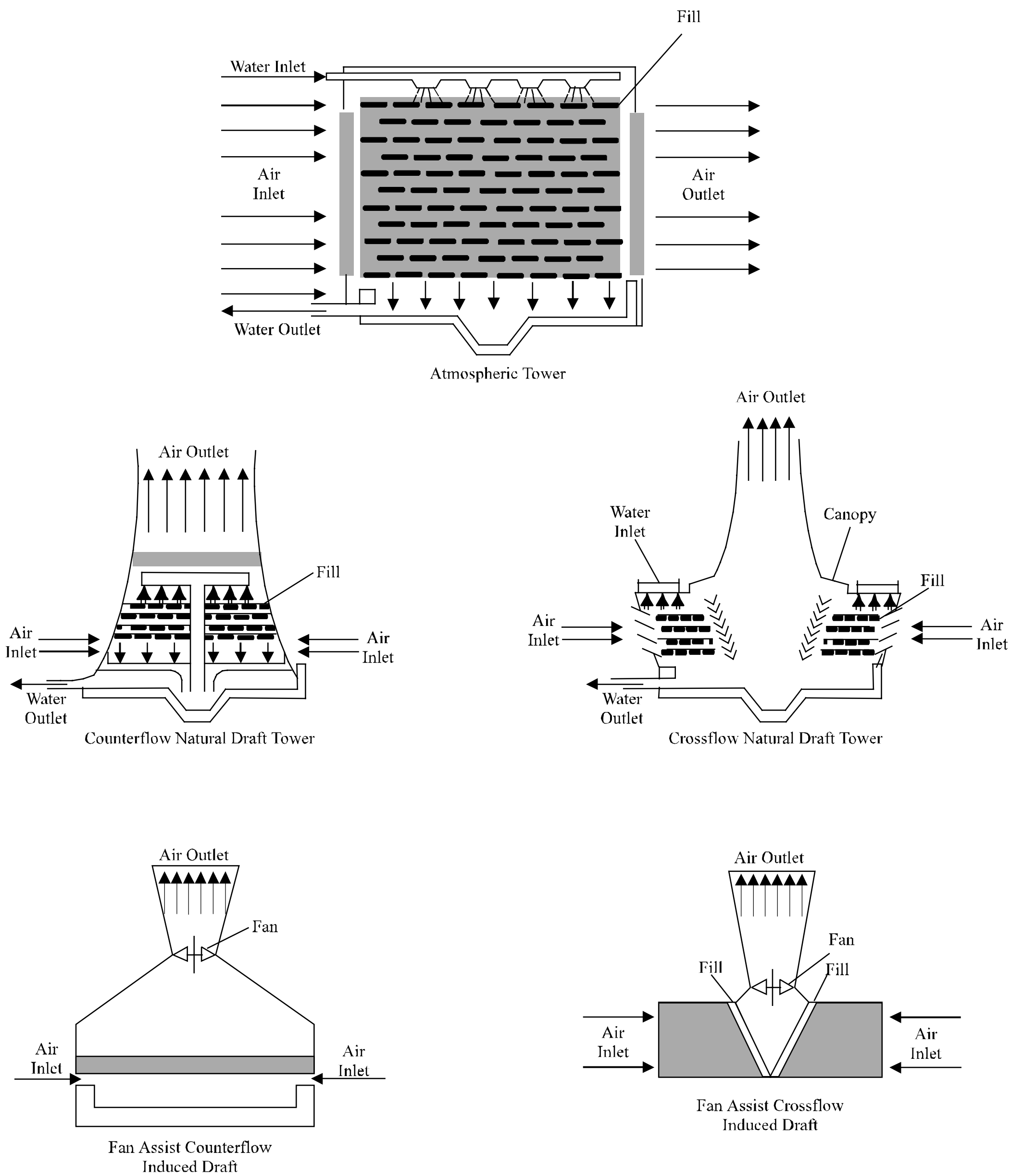


Figure 13.4-1 Atmospheric and natural draft cooling towers.

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.

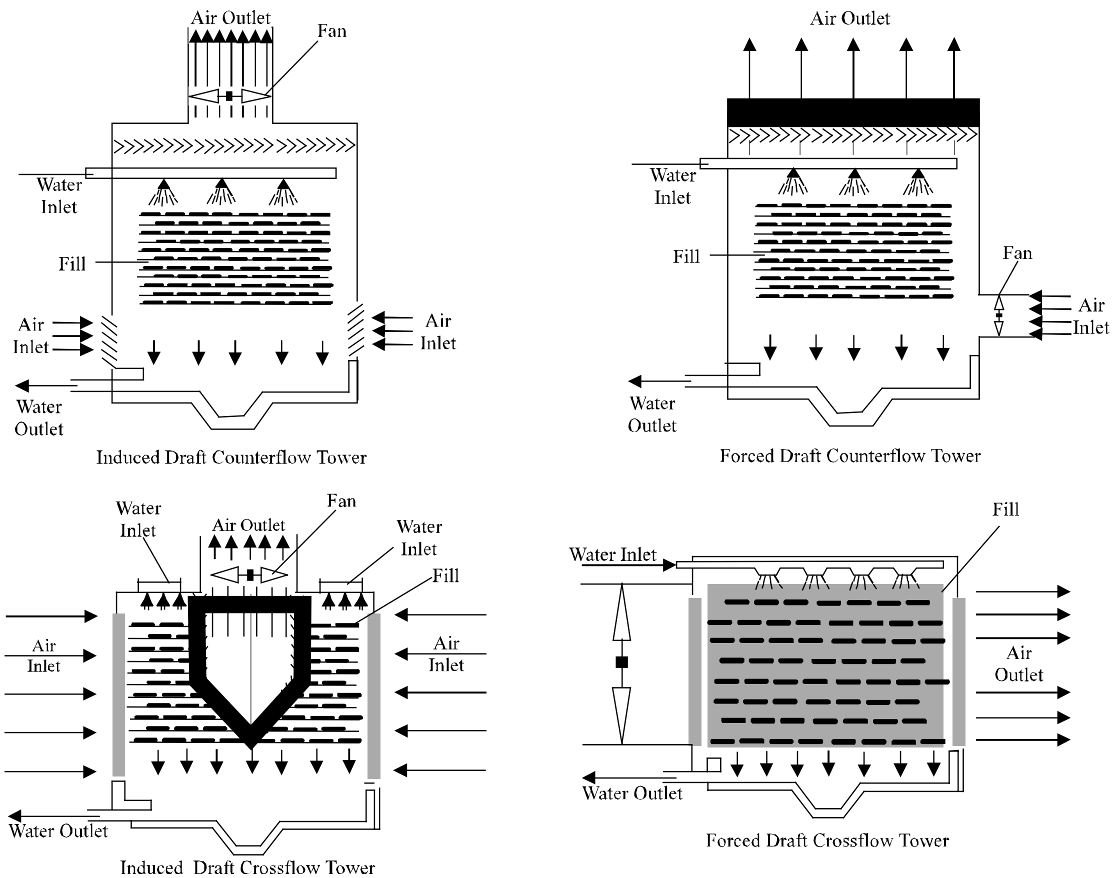


Figure 13.4-2. Mechanical draft cooling towers.

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]

Tower Type[d]	Total Liquid Drift[b]: Circulating Water Flow[b]	Total Liquid Drift[b]: g/daL	Total Liquid Drift[b]: lb/10^3 gal	Total Liquid Drift[b]: EMISSION FACTOR RATING	PM-10[c]: g/daL[e]	PM-10[c]: lb/10^3 gal	PM-10[c]: 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
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

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

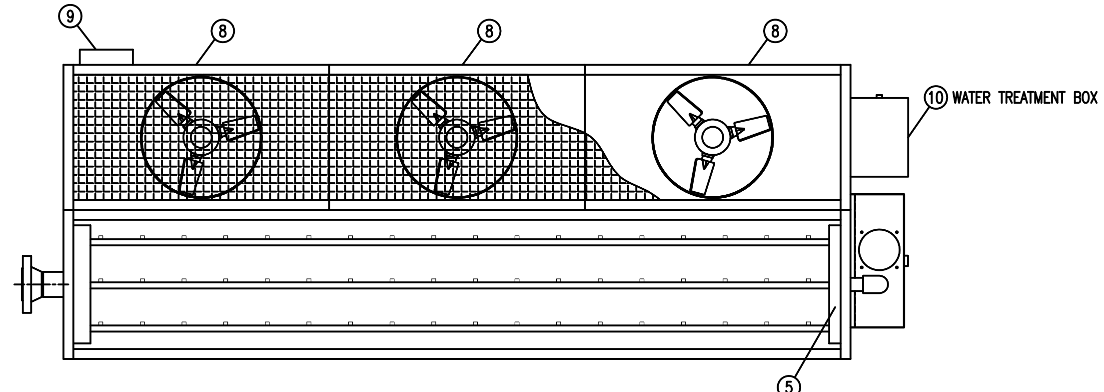
Terms and Conditions		
Progress Payments (Net 30 Days)	Warranty (From Startup/ Delivery)	12 / 18 months
10% with receipt of order	Approval Drawings	3 weeks + 2 weeks for customer approval
20% submission of approval drawings	Equipment Shipment Date	18 weeks from approved drawing(s)
25% receipt tube material	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

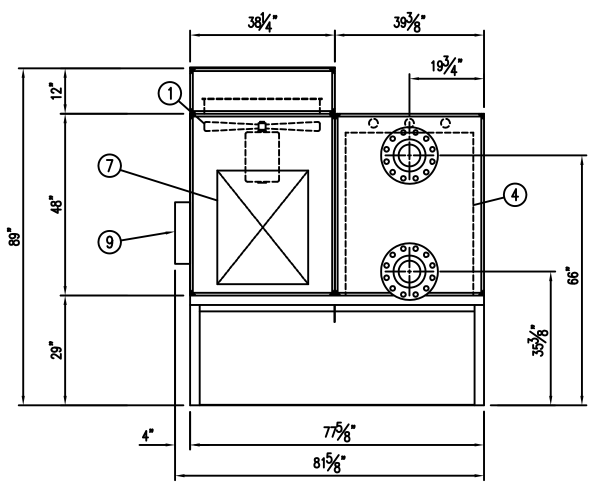
SCHEDULE OF CONNECTIONS

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

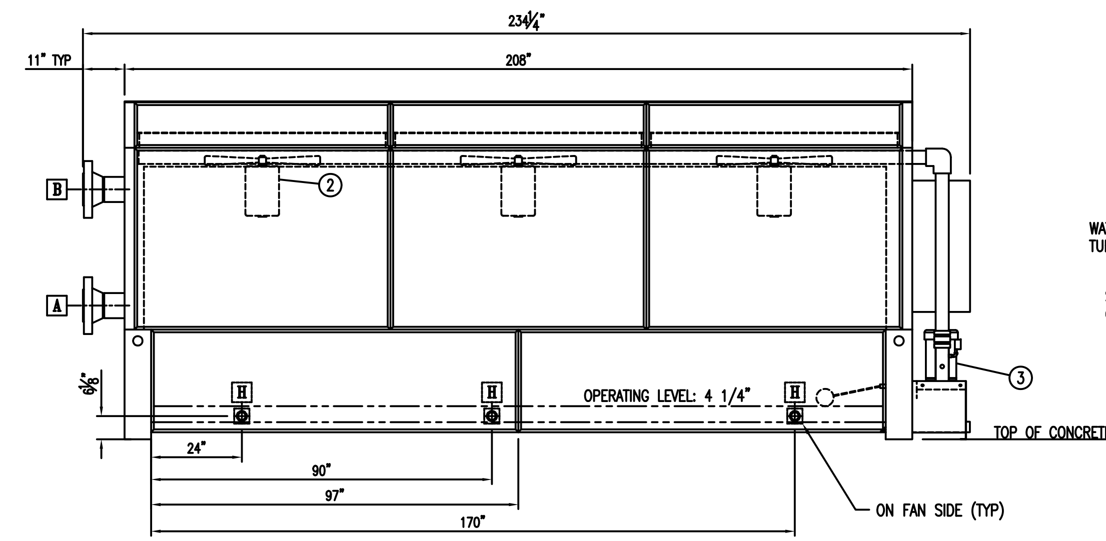
REVISION	LOCATION	MADE BY	CHECKED BY	DATE	REVISION OR ADDITION



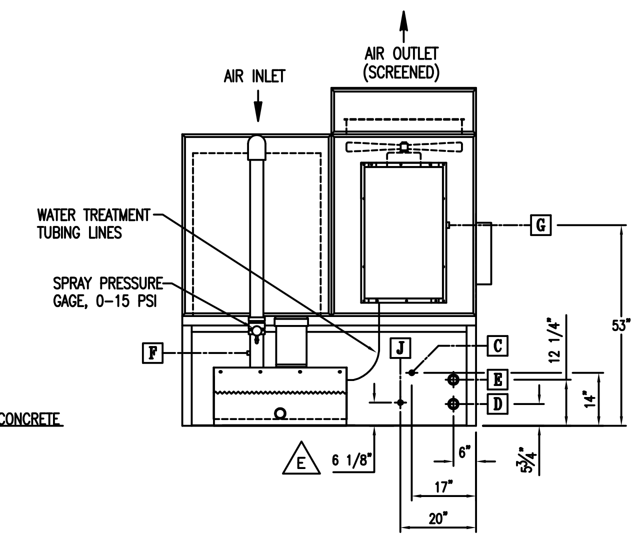
PLAN VIEW



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)

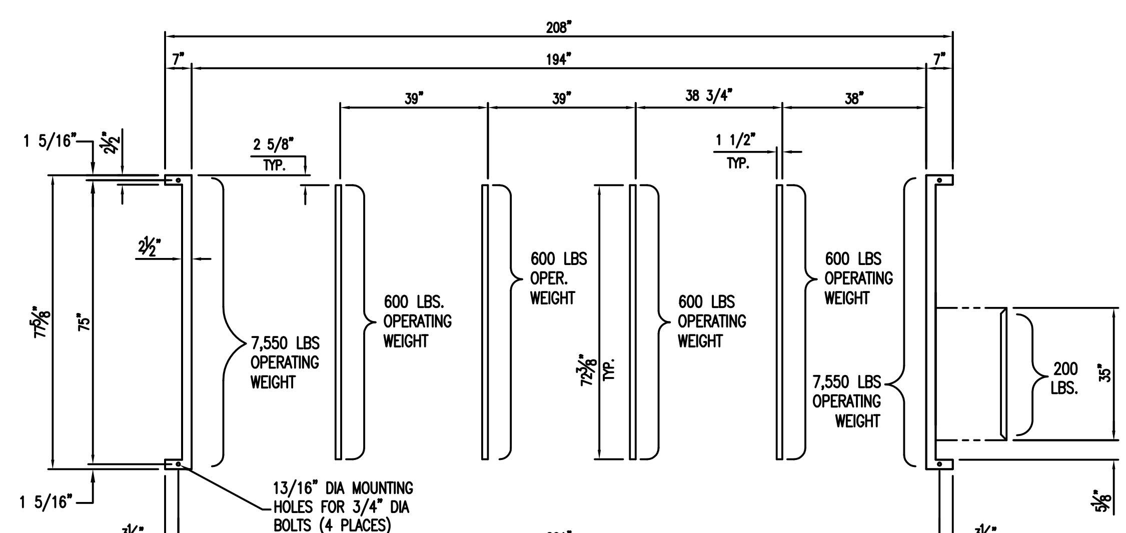
TOTAL AIRFLOW	35,400 CFM
FAN BHP (TOTAL)	7.5 BHP
RECIRCULATION SPRAY RATE	240 GPM
PUMP BHP (TOTAL)	2.1
EST. MAKE-UP WATER	5.3 GPM
MAKE-UP BASED ON	6 COC

PERFORMANCE DATA (SYSTEM)

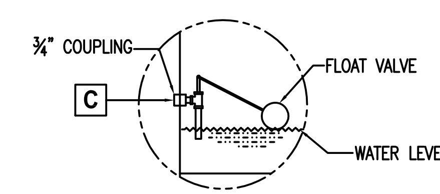
SERVICE	NGL PRODUCT COOLER
FLOW	131,500 LBS/HR
OPERATING TEMP. IN	130'F
OPERATING TEMP. OUT	100'F
DESIGN WET BULB	70'F
HEAT LOAD	2,532,684 BTU/HR
PRESSURE DROP	5 PSI
DESIGN PRESSURE	1440 PSIG
DESIGN TEMPERATURE	200/-20'F
BARE TUBE SURFACE AREA	991 SQ. FT.

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

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**

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

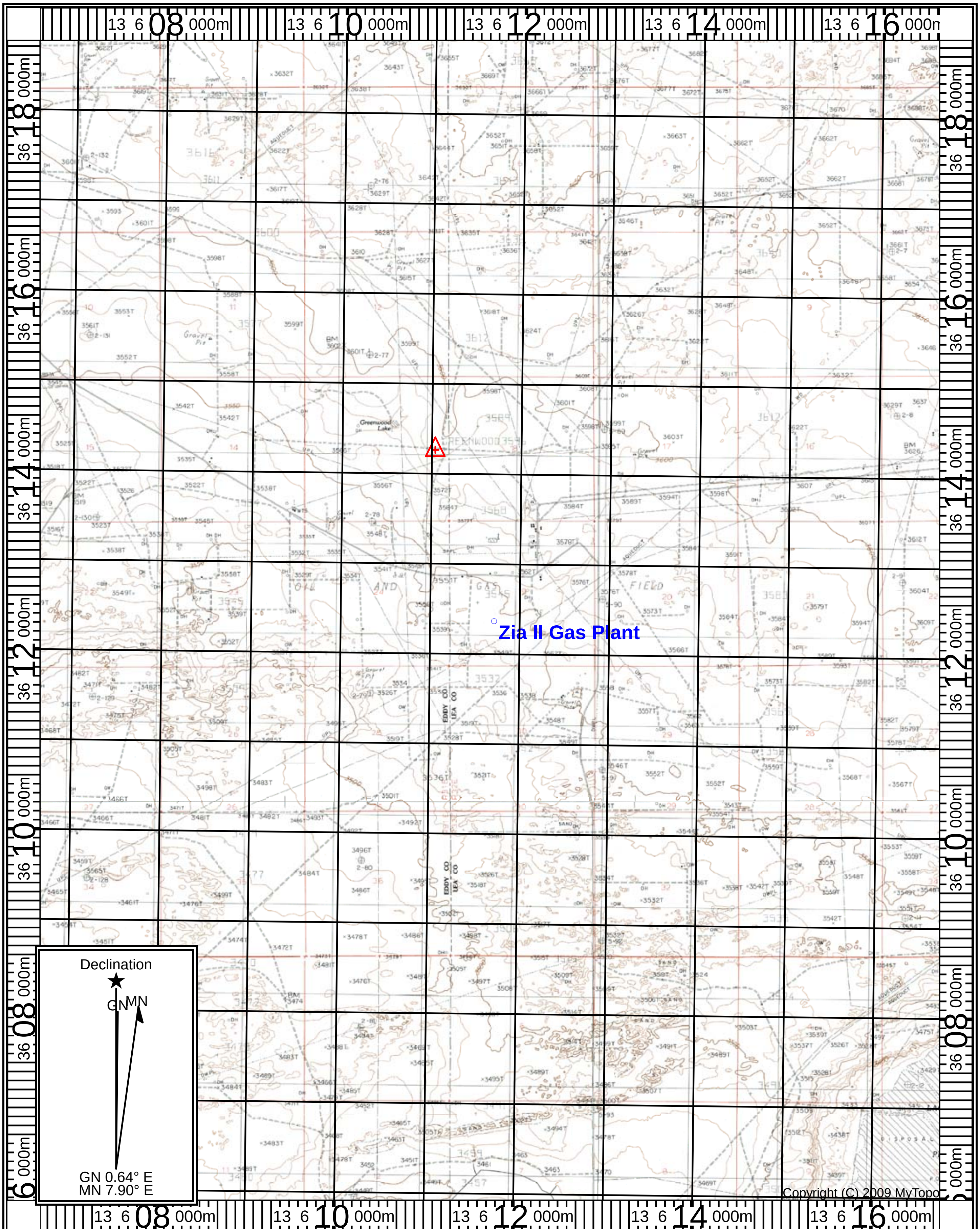
Section 8

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 map showing the location of the facility is attached.



Map Name: GREENWOOD LAKE
Print Date: 04/03/15

Scale: 1 inch = 4,761 ft.
Map Center: 13 0611666 E 3612377 N

Horizontal Datum: WGS84

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.

Proof of public notice is attached.

Section 9.1

Copy of Postmarked Certified Letter Receipts

7014 2870 0001 4723 0763

U.S. Postal Service™
CERTIFIED MAIL® RECEIPT
Domestic Mail Only

For delivery information, visit our website at www.usps.com®.

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

ALBUQUERQUE NM 87109-9998 APR 15 2015 USPS

Sent To
James K Stovall
BLM Carlsbad Office
620 E. Greene St.
Carlsbad, NM 88220

7014 2870 0001 4723 0756

U.S. Postal Service™
CERTIFIED MAIL® RECEIPT
Domestic Mail Only

For delivery information, visit our website at www.usps.com®.

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

ALBUQUERQUE NM 87109-9998 APR 15 2015 USPS

Sent To
JR Engineering & Construction Co.
PO Box 487
Carlsbad, NM 88221

PS Form 3800

7014 2870 0001 4723 0787

U.S. Postal Service™
CERTIFIED MAIL® RECEIPT
Domestic Mail Only

For delivery information, visit our website at www.usps.com®.

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

ALBUQUERQUE NM 87109-9998 APR 15 2015 USPS

Sent To
Eddy County – Manager's Office
101 W. Greene Street
Carlsbad, NM 88220

7014 2870 0001 4723 0770

U.S. Postal Service™
CERTIFIED MAIL® RECEIPT
Domestic Mail Only

For delivery information, visit our website at www.usps.com®.

OFFICIAL USE

Postage	$
Certified Fee	
Return Receipt Fee (Endorsement Required)	
Restricted Delivery Fee (Endorsement Required)	
Total Postage & Fees	$

Postmark Here

ALBUQUERQUE NM 87109-9998 2015

Sent To
Lea County - Manager's Office
100 N. Main
Lovington, NM 88260

Section 9.2

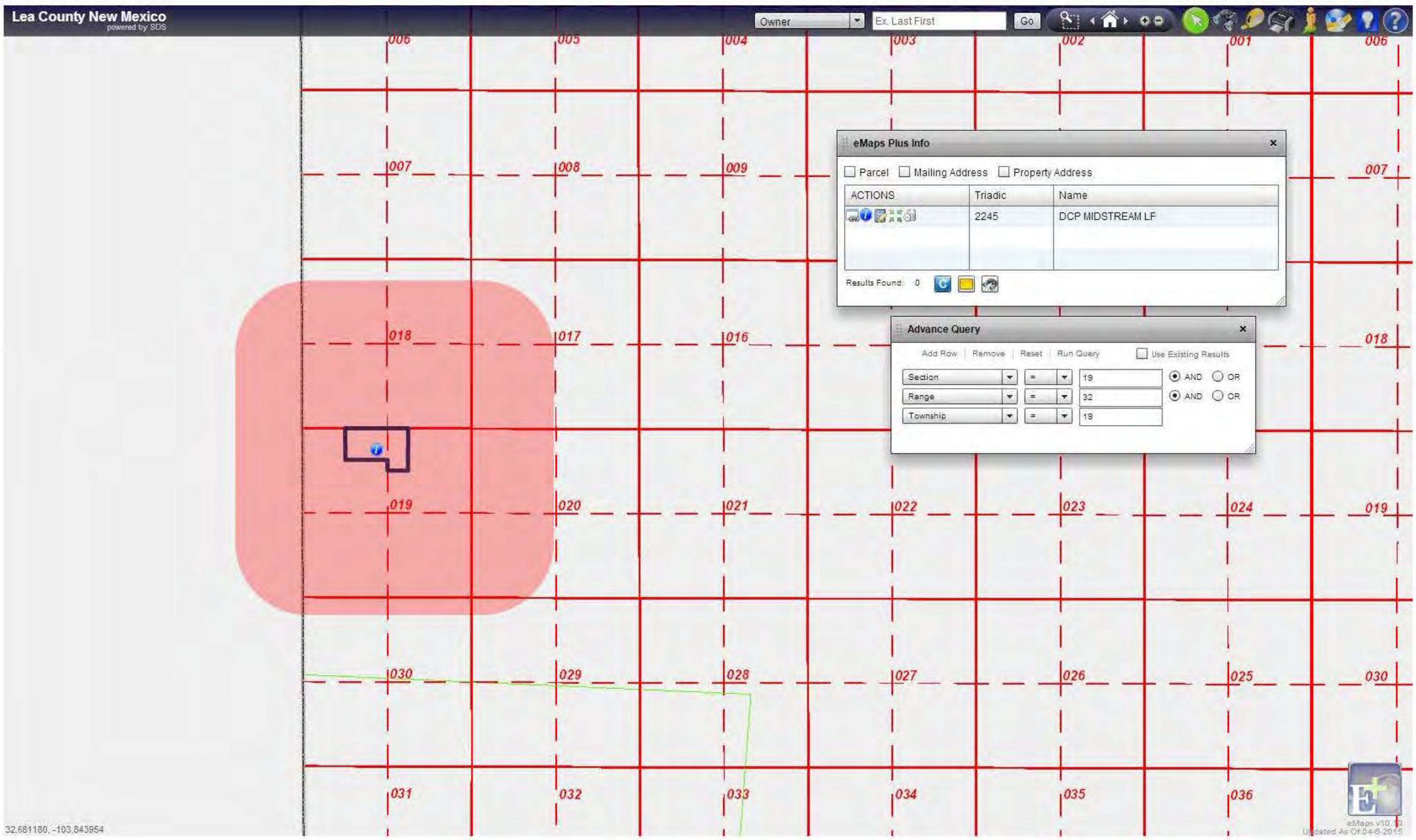
Public Notice Posting Locations

This information is provided in *Section 9.6: General Public Notice Posting – Certification*.

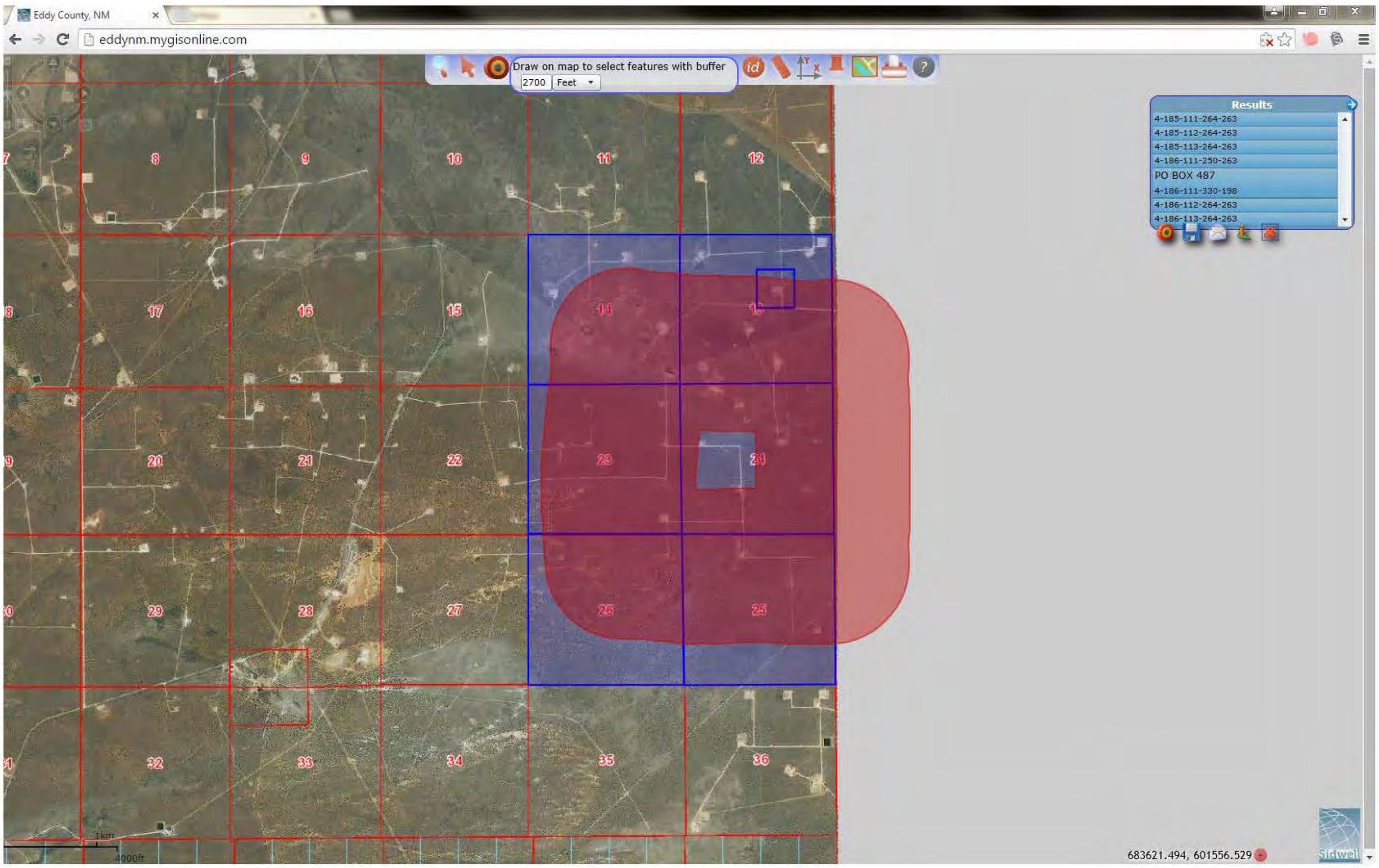
Section 9.3

Property Tax Record

Lea County



Eddy County



Eddy County, NM
eddynm.mygisonline.com
Draw on map to select features with buffer
2700
Feet
Results
4-185-111-264-263
4-185-112-264-263
4-185-113-264-263
4-186-111-250-263
PO BOX 487
4-186-111-330-198
4-186-112-264-263
4-186-113-264-263
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Sidwell

Section 9.4 & 9.5

Letter sent to owners of record and
Letter sent to counties, municipalities, and Indian tribes

The letter provided on the following page was sent to the following owners of record:

Land Owner	Street Address	City	State	Zip
JR Engineering & Construction Co	PO Box 487	Carlsbad	NM	88221
Bureau of Land Management - Carlsbad Office	620 E. Greene St.	Carlsbad	NM	88220

The letter provided on the following page was sent to the following counties, municipalities, and Indian tribes:

Landowners and Municipalities		Street Address	City	State	Zip
Eddy County	Manager's Office	101 W. Green St. Ste 110	Carlsbad	NM	88220
Lea County	Manager's Office	100 N. Main	Lovington	NM	88260
No Tribal Land Within 10 Miles					

April 15, 2015 CERTIFIED MAIL XXXX XXXX XXXX XXXX

To Whom It May Concern:

According to New Mexico air quality regulations, DCP Midstream, LP (DCP) must announce its intent to apply to the New Mexico Environment Department for a revision to its air quality permit PSD-5217 for its Zia II Gas Plant. The expected date of application submittal to the Air Quality Bureau is April 15, 2015**.**

The exact location for the facility, which is currently under construction, is at latitude 32 deg, 38 min, 34.88 sec and longitude -103 deg, 48 min, 31.92 sec. The approximate location of this facility is 15 miles southeast of Loco Hills, New Mexico in Lea County. To reach the facility 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.

The proposed modification consists of updating the current permit PSD-5217 to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources. The facility is currently under construction and has not yet begun operation.

The estimated maximum quantities of any regulated air contaminants will be:

Pollutant:	Pounds per hour	Tons per year
Total Suspended Particulates (TSP)	7 pph	25 tpy
PM_{10}	6 pph	25 tpy
$PM_{2.5}$	6 pph	25 tpy
Sulfur Dioxide (SO_2)	20,300 pph	105 tpy
Nitrogen Oxides (NO_x)	945 pph	300 tpy
Carbon Monoxide (CO)	4,790 pph	125 tpy
Volatile Organic Compounds (VOC)	4,890 pph	165 tpy
Total sum of all Hazardous Air Pollutants (HAPs)	270 pph	65 tpy
Formaldehyde (HCHO)	4 pph	15 tpy
Hydrogen Sulfide (H_2S)	230 pph	3 tpy
Toxic Air Pollutants (TAPs)	1 pph	3 tpy
Green House Gas Emissions as Total CO_2e		372,500 tpy

The standard operating schedule of the facility will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year. The maximum operating schedule will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year.

If you have any comments about the construction or operation of the above facility, and you want your comments to be made as part of the permit review process, you must submit your comments in writing to the address below:

Permit Programs Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505-1816
(505) 476-4300

Other comments and questions may be submitted verbally.

Please refer to the company name and facility name, as used in this notice or send a copy of this notice along with your comments, since the Department may not have received the permit application at the time of this notice. Please include a legible mailing address with your comments. Once the Department has performed a preliminary review of the application and its air quality impacts, the Department's notice will be published in the legal section of a newspaper circulated near the facility location.

Sincerely,
DCP Midstream, LP
10 Desta Drive, Suite 400 West,
Midland, TX 79705

Section 9.6

General Posting of Notices - Certification

General posting of notice information is on the next page.

General Posting of Notices – Certification

I, Jennifer Hanna, the undersigned, certify that on April 15, 2015, posted a true and correct copy of the attached Public Notice in the following publicly accessible and conspicuous places in the City of Hobbs of Lea County, State of New Mexico on the following dates:

1. Zia II Gas Plant
   Proposed Facility Site
   4/15/15

2. Hobbs City Hall
   200 E. Broadway
   Hobbs, NM 88240
   4/15/15

3. Hobbs Public Library
   509 N. Shipp
   Hobbs, NM 88240
   4/15/15

4. Hobbs Chamber of Commerce
   400 N. Marland
   Hobbs, NM 88240
   4/15/15

Signed this 15 day of April, 2015.

Signature ____________________ 4-15-15
Date

Jennifer Hanna
Printed Name

____
Title {APPLICANT OR RELATIONSHIP TO APPLICANT}

General Posting of Notices – Certification

I, ____Jennifer Hanna____, the undersigned, certify that on April 15, 2015, posted a true and correct copy of the attached Public Notice in the following publicly accessible and conspicuous places in the City of Carlsbad of Eddy County, State of New Mexico on the following dates:

1. Zia II Gas Plant
   Proposed Facility Site
   4/15/15

2. US Post Office
   301 North Canyon Street
   Carlsbad, NM 88220
   4/15/15

3. Carlsbad Public Library
   101 S. Halagueno
   Carlsbad, NM 88220
   4/15/15

4. Carlsbad Chamber of Commerce
   302 S Canal
   Carlsbad, NM 88220
   4/15/15

Signed this _15th_ day of April, 2015.

Signature

4-15-15
Date

Jennifer Hanna
Printed Name

Sr. Environmental Specialist
Title {APPLICANT OR RELATIONSHIP TO APPLICANT}

NOTICE

DCP Midstream, LP (DCP) announces its intent to apply to the New Mexico Environment Department for a revision to its air quality permit PSD-5217 for its Zia II Gas Plant. The Zia II Gas Plant will be a cryogenic gas processing plant designed to treat and process produced natural gas for DCP gathering systems located throughout central New Mexico. The expected date of application submittal to the Air Quality Bureau is April 15, 2015**.** This notice is a requirement according to New Mexico air quality regulations.

The exact location for the facility, which is currently under construction, is at latitude 32 deg, 38 min, 34.88 sec and longitude -103 deg, 48 min, 31.92 sec. The approximate location of this facility is 15 miles southeast of Loco Hills, New Mexico in Lea County. To reach the facility 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.

The proposed modification consists of updating the current permit PSD-5217 to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources. The facility is currently under construction and has not yet begun operation.

The estimated maximum quantities of any regulated air contaminants will be:

Pollutant:	Pounds per hour	Tons per year
Total Suspended Particulates (TSP)	7 pph	25 tpy
PM_{10}	6 pph	25 tpy
$PM_{2.5}$	6 pph	25 tpy
Sulfur Dioxide (SO_2)	20,300 pph	105 tpy
Nitrogen Oxides (NO_x)	945 pph	300 tpy
Carbon Monoxide (CO)	4,790 pph	125 tpy
Volatile Organic Compounds (VOC)	4,890 pph	165 tpy
Total sum of all Hazardous Air Pollutants (HAPs)	270 pph	65 tpy
Formaldehyde (HCHO)	4 pph	15 tpy
Hydrogen Sulfide (H_2S)	230 pph	3 tpy
Toxic Air Pollutants (TAPs)	1 pph	3 tpy
Green House Gas Emissions as Total CO_2e		372,500 tpy

The standard operating schedule of the facility will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year. The maximum operating schedule will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year.

The owner and operator of the Facility is:

DCP Midstream, LP
10 Desta Drive, Suite 400 West,
Midland, TX 79705

If you have any comments about the construction or operation of the above facility, and you want your comments to be made as part of the permit review process, you must submit your comments in writing to the address below:

Permit Programs Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505-1816
(505) 476-4300

Other comments and questions may be submitted verbally.

Please refer to the company name and facility name, as used in this notice or send a copy of this notice along with your comments, since the Department may not have received the permit application at the time of this notice. Please include a legible mailing address with your comments. Once the Department has performed a preliminary review of the application and its air quality impacts, the Department's notice will be published in the legal section of a newspaper circulated near the facility location. (505) 476-4300 or 1 800 224-7009 Fax: (505) 476-4375

Section 9.7

Notices Sent

Information provided in *Section 9.4: Letter sent to owners of record* and *9.5: Letter sent to counties, municipalities, and Indian tribes*.

Section 9.8

Submittal of Public Service Announcement – Certification

I, Andrea Carrier, the undersigned, certify that on Friday, April 17, 2015, submitted a public announcement to **KATK 92.1 FM** that serves the City of Carlsbad, Eddy County, New Mexico, in which the source is or is proposed to be located and **KATK 92.1 FM** did not respond that it would or would not air the announcement.

Signed this 17th day of April, 2015.

Andrea Carrier
Signature

April 17, 2015
Date

Andrea Carrier
Printed Name

Technical Assistant, Trinity Consultants
Title

* * * Communication Result Report (Apr. 17. 2015 9:31AM) * * *

1)
2)

Date/Time: Apr. 17. 2015 9:30AM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
3275	Memory TX general office	15758877000	P. 1	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
E. 5) Exceeded max. E-mail size

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

Trinity Consultants

FACSIMILE

To:	NEWS – KATK 92.1 FM	**From:**	Andrea Carrier, Trinity Consultants
Phone:	575-887-7563	**Pages:**	1 – including cover
Fax:	575-887-7000	**Phone:**	(505) 266-6611
Email:	n/a	**Email:**	acarrier@trinityconsultants.com
Subject:	PSA	**Date:**	*April 17, 2015*

☒ Urgent ☐ For Review ☐ Please Comment ☐ Please Reply ☐ Please Recycle

Comments:

As part of the air quality permit process, New Mexico requires applicants to submit a public service announcement identifying the proposed permit action and providing information as to how the public can comment on this action. Below is such an announcement. Would you air it as a PSA?

Radio Public Service Announcement

NOTICE

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The proposed modification consists of updating the current permit PSD-5217 to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources. The facility is currently under construction and has not yet begun operation.

The standard operating schedule of the facility will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year. The maximum operating schedule will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year.

The owner and operator of the Facility is DCP Midstream, LP, 10 Desta Drive, Suite 400 West, Midland, TX 79705

Public Notice of this application is posted at the Zia II Gas Plant Proposed Facility Site, the US Post Office located at 301 North Canyon Street in Carlsbad, New Mexico, the Carlsbad Public Library located at 101 S. Halagueno in Carlsbad, New Mexico and the Carlsbad Chamber of Commerce located at 302 S Canal in Carlsbad, New Mexico.

If you have any questions regarding this application, please contact Program Manager, Permit Section, New Mexico Environment Department, Air Quality Bureau, 525 Camino de Los Marquez, Suite 1, Santa Fe, New Mexico 87505-1816. Their phone number is (505) 476-4300. Other comments and questions may be submitted verbally. Please refer to the company name and site name, as used in this notice or send a copy of this notice along with your comments to help identify the facility being commented on, since the Department may not have received the permit application at the time of this notice. Once the Department has performed a preliminary review of the application and its air quality impacts, another notice from the Department will be published in the legal section of the newspaper.

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I, Andrea Carrier, the undersigned, certify that on Friday, April 17, 2015, submitted a public announcement to **KPER 95.7** that serves the City of Hobbs, Lea County, New Mexico, in which the source is or is proposed to be located and **KPER 95.7 FM** did not respond that it would or would not air the announcement.

Signed this 17th day of April, 2015.

Andrea Carrier

Signature

April 17, 2015

Date

Andrea Carrier

Printed Name

Technical Assistant, Trinity Consultants

Title

* * * Communication Result Report (Apr. 17. 2015 9:30AM) * * *

1)
2)

Date/Time: Apr. 17. 2015 9:29AM

File No.	Mode	Destination	Pg(s)	Result	Page Not Sent
3274	Memory TX general office	15753934310	P. 1	OK	

Reason for error
E. 1) Hang up or line fail
E. 2) Busy
E. 3) No answer
E. 4) No facsimile connection
E. 5) Exceeded max. E-mail size

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

Trinity Consultants

FACSIMILE

To:	NEWS – KPER 95.7 FM	**From:**	Andrea Carrier, Trinity Consultants
Phone:	575-393-1551	**Pages:**	1 – including cover
Fax:	575-393-4310	**Phone:**	(505) 266-6611
Email:	n/a	**Email:**	acarrier@trinityconsultants.com
Subject:	PSA	**Date:**	*April 17, 2015*

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Newspaper Classified/Legal Advertisement

Affidavit of Publication

State of New Mexico,
County of Eddy, ss.

Rynni Henderson, being first duly sworn, on oath says:

That she is the Publisher of the Carlsbad Current-Argus, a newspaper published daily at the City of Carlsbad, in said county of Eddy, state of New Mexico and of general paid circulation in said county; that the same is a duly qualified newspaper under the laws of the State wherein legal notices and advertisements may be published; that the printed notice attached hereto was published in the regular and entire edition of said newspaper and not in supplement thereof on the date as follows, to wit:

April 11 2015

That the cost of publication is **$205.96** and that payment thereof has been made and will be assessed as court costs.

Rynni Henderson

Subscribed and sworn to before me this 13th day of April, 2015

Shirley Maxwell

My commission Expires May 18, 2015

Notary Public

OFFICIAL SEAL
Shirley Maxwell
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires 5/18/15

April 11, 2015

NOTICE OF AIR QUALITY PERMIT APPLICATION

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Phone: Kathy 628.5522 | **Mail:** Carlsbad Current-Argus P. O. Box 1629 Carlsbad, NM 88220

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620 S. Main St. Carlsbad, NM 88220, classifieds@currentargus.com
Walk-In Business Hours: 8 a.m.-4:00 p.m. We accept most major credit cards.
Deadlines: Your ad must be received by 1pm the day prior to running for Tuesday-Friday, 10 am Friday for Saturday issue, 1 pm Friday for Sunday's issue. All ads must be prepaid.
Early Cancellations: Sorry, no refunds or adjustments for early cancellations. Thank You.

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notices 100-152

Lost Items 129

Lost One Grey Samsonite Case, One White Overnight Case Reward Call 575-234-3576

Lost Pets 130

Lost silver and brown Yorkie on 6th and Wyoming area on Sunday, answers to the name of Shelby, reward will be offered when returned. 302-2218 or 706-1709 Please call if you have any information.

Legal Notices 152

April 11, 2015

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PM 2.5	6 lb/hr	25 tpy
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SUDOKU

Difficulty: 4 (of 5)

5						2	8	
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	6				2			
4				7				8
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	9			1				
	2		6			5	3	

4-11-15 ©2015 JFS/KF Dist. by Universal Uclick for UFS

PREVIOUS SOLUTION

8	5	6	1	4	7	9	3	2
4	1	9	2	3	8	7	6	5
7	3	2	6	5	9	4	1	8
1	2	3	7	9	4	5	8	6
6	8	4	5	2	3	1	7	9
9	7	5	8	6	1	2	4	3
2	4	1	9	8	6	3	5	7
3	9	8	4	7	5	6	2	1
5	6	7	3	1	2	8	9	4

HOW TO PLAY: Each row, column and set of 3-by-3 boxes must contain the numbers 1 through 9 without repetition.

jobs 200-232

Automotive Help Wanted 207

Tate Branch Autoplex

AUTOMOTIVE TECHNICIANS,

Are you tired of working for owners and managers that do not care about your income? Are you tired of paying high cost for health insurance coverage? Call, text or email to find out if you could be a part of a new production system that we are building in Carlsbad New Mexico. Tate Branch Autoplex is taking applications now for highly motivated Mopar technicians that want to better themselves. We cover 100% of your health care coverage. Paid vacation and FRH.

575 703-1568, jonathan@tatebranch.com

Drivers 220

Drivers

Three Rivers Trucking
CDL Drivers Wanted
Class A CDL with a Tanker Endorsement Required. Must be able to Pass a Drug Test. Become Part of Our Team.
(575)628-0040

Hotel/ Motel 233

Hotel/Motel
Now hiring for Maids and maintenance. Apply in person at: Carlsbad Inn 2019 S. Canal. St

Restaurants & Clubs 247

Restaurants
HIRING FULL TIME DISHWASHER
Must be able to come every day. Duties are washing pots & pans. Apply in person at the Pecos River Cafe., 409 S. Canal.EOE.

Drivers 220

Drivers
M & R Trucking, Inc. has openings for **Experienced full-time Water Truck Drivers** at our Artesia NM Location. All drivers must have a valid CDL with Tanker Endorsement. We offer insurance, Safety Bonus Program, & 401k. DOT physical and drug test provided. Copy of driving record required. Apply in person @: **5834 Seven Rivers Hwy, Artesia, NM. Phone # 575-457-2070. E.O.E.**

General Help Wanted 230

Chandler Aviation, LLC is seeking a **Bookkeeper/Off. Mgr** with a min. of two years QuickBooks, Excel and MS Office experience. The successful applicant must be professional, organized, dependable and willing to learn the business, confident in decision making, have excellent customer service skills and must work well with others. Chandler Aviation offers a competitive salary and benefits. Desire a candidate seeking long term employment willing to grow and advance with the company. Send resume with references to terry@flycaverncity.com.

Universal Boiler and Mechanical Works, Inc
is seeking experienced
Single hand and rig welders
that can demonstrate great layout and fabrication skills.
Qualified applicants must be able to pass a 6G weld test at minimum and demonstrate safe work behavior and habits. UBW provides all consumables,pays mileage to job locations,and offers health, dental and vision benefits after 60 days.
Pay is based on experience and skill. .
Pre-employment drug screening is required.
Applications with resume are accepted in person at 3004 E Greene St, or by mail at PO Box 3210, Carlsbad, NM 88221.

Xcel Energy® RESPONSIBLE BY NATURE®

Journeyman

Calling all Journeyman! Looking for stable employment? Xcel Energy is looking to fill a Transmission Inspector Patrolman for the Carlsbad or Hobbs area.
In this position you will patrol, inspect, document and file annual ground and air patrols of SPS transmission lines and transmission facilities, in addition to assist line crew.

Interested candidates please apply to jobs.xcelenergy.com job posting #31074

rentals 300-383

PUBLISHER'S NOTICE
All real estate advertised here-in is subject to the Federal Fair Housing Act, which makes it illegal to advertise any preference, limitation, or discrimination because of race, color, religion, sex, handicap, familial status, or national origin, or intention to make any such preference, limitation, or discrimination." We will not knowingly accept any advertising for real estate which is in violation of the law. All persons are hereby informed that all dwellings advertised are available on an equal opportunity basis.

EQUAL HOUSING OPPORTUNITY

Unfurnished Home General 352

2 bed 1 bath house for rent, washer and dryer included, $1,290 505-948-4344

Huge 4 bed, 2 bath, remodeled. $1,790/month 505-948-4344

goods & services 600-688 & 2550-4137

Hot off the Press 603

China Cabinet, Vintage Piano 1896 Upright, $200 each, or best offer, 885-9145

Garage/ Yard Sales 628

107 S. Ash, Friday and Saturday, 7am - ?, everything must go

1132 Tracy Pl., 7-noon, various lawn equipment, children's clothes, patio furniture, miscellaneous

1202 Owens, Saturday, 7am, miscellaneous items and burritos

1307 Gamma, Saturday, 7am, Cash only, lots of miscellaneous items, clothes

206 Hamilton St., Sat only 8a-1p, gun cabinet, Avon's CapeCod collection, Campbell Soup items, clothes, lots of misc

Garage/ Yard Sales 628

2510 San Jose Blvd, Burrito's, Menudo, Misc. itmes, Benefit for Angela Reina Juarez, 7-?

309 N. 5th St., Saturday, 8 am, Tools clothes and lots of miscellaneous

508 N. Maple, 7am, baby/girls clothes, miscellaneous

801 E. Wood Ave., miscellaneous items

Backyard Sale, 2609 W. Florida, Home furnishings, new doors and windows, 2 desks, etc.

Backyard Sale, 916 Countryside, Saturday and Sunday, 8AM, lots of tools, household items, and miscellaneous stuff

Backyard Sale, 1915 Solana, Saturday, 7am - noon

Garage Sale
407 N. Oak Sat. 8am-?
Antique furniture,couches & other misc. items

Garage Sale, 1810 Hays, 7am

Good running van , nice clothes each, home decor, table with chairs , lots of goodies for good prices Saturday & Sunday

Inside Sale, 1108 W. Ural, 8am, gas grill, recliner chair, pecans, and much more

Yard Sale, 1502 Westridge, 8am, lots of stuff and burritos.

Yard Sale, 1809 Pebble Hill Rd., Friday, Saturday and Sunday, 8am - dark

Yard Sale, 1007 Bonbright Sat 7:30 AM girl clothes 3T to 5T, toys, power tools, table, books, collectibles, miscellaneous

Yard Sale, 2303 Iris St., Friday 1 - 6, Saturday 8 - ?

WONDERWORD®

By DAVID OUELLET

HOW TO PLAY: All the words listed below appear in the puzzle — horizontally, vertically, diagonally, even backward. Find them and **CIRCLE THEIR LETTERS ONLY. DO NOT CIRCLE THE WORD.** The leftover letters spell the Wonderword.

LONDON LUXURY QUARTER Solution: 8 letters

T	S	V	M	S	I	R	U	O	T	A	S	R	A	B
E	E	A	B	R	A	N	D	S	L	P	T	W	C	S
E	D	E	S	U	I	T	E	S	U	P	R	I	A	T
R	A	A	R	Q	Y	N	F	W	L	E	A	N	D	S
T	C	L	U	T	S	R	O	L	I	A	T	E	E	I
S	R	E	E	B	S	R	U	S	A	L	Y	S	M	L
T	A	N	H	I	E	D	H	X	A	G	E	O	Y	A
N	S	I	C	L	S	O	N	C	U	M	S	R	R	I
U	E	D	I	F	E	U	A	O	A	L	O	H	I	C
O	N	V	N	S	O	S	R	J	B	T	E	X	I	E
M	A	Y	F	A	I	R	T	E	S	D	A	T	C	P
S	L	F	I	N	E	S	T	I	L	T	L	E	O	S
C	I	R	O	T	S	I	H	N	S	P	A	O	N	H
M	R	A	H	C	C	U	L	T	U	R	E	Y	I	O
E	N	I	S	I	U	C	S	U	O	M	A	F	C	P

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Academy, Appeal, Arcades, Arts, Bars, Brands, Casino, Charm, Cuisine, Culture, Dine, Famous, Fine, Flagship, Fortnum, Historic, History, Hotel, Iconic, Lanes, Leisure, Luxury, Mason, Mayfair, Mount Street, Niche, Old Bond Street, Royal, Savile Row, Shoes, Shop, Spa, Specialists, Stay, St. James, Suites, Tailors, Taxi, Tourism, Unique, Wines

Yesterday's Answer: Hamada

Affidavit of Publication

State of New Mexico,
County of Lea.

I, DANIEL RUSSELL
PUBLISHER
of the Hobbs News-Sun, a newspaper published at Hobbs, New Mexico, do solemnly swear that the clipping attached hereto was published in the regular and entire issue of said newspaper, and not a supplement thereof for a period

of 1 issue(s).
Beginning with the issue dated
April 11, 2015
and ending with the issue dated
April 11, 2015

Daniel Russell
PUBLISHER

Sworn and subscribed to before me
this 11th day of
April, 2015

Gussie Black
Notary Public

My commission expires
January 29, 2019
(Seal)

OFFICIAL SEAL
GUSSIE BLACK
Notary Public
State of New Mexico
My Commission Expires 1-29-19

This newspaper is duly qualified to publish legal notices or advertisments within the meaning of Section 3, Chapter 167, Laws of 1937 and payment of fees for said publication has been made.

LEGAL LEGAL LEGAL

LEGAL NOTICE
April 11, 2015

NOTICE OF AIR QUALITY PERMIT APPLICATION

DCP Midstream, LP (DCP) announces its intent to apply to the New Mexico Environment Department for a revision to its air quality permit PSD-5217 for its Zia II Gas Plant. The Zia II Gas Plant will be a cryogenic gas processing plant designed to treat and process produced natural gas for DCP gathering systems located throughout central New Mexico. The expected date of application submittal to the Air Quality Bureau is April 15, 2015. This notice is a requirement according to New Mexico air quality regulations.

The exact location for the facility, which is currently under construction, is at latitude 32 deg, 38 min, 34.88 sec and longitude -103 deg, 48 min, 31.92 sec. The approximate location of this facility is 15 miles southeast of Loco Hills, New Mexico in Lea County. To reach the facility 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.

The proposed modification consists of updating the current permit PSD-5217 to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources. The facility is currently under construction and has not yet begun operation.

The estimated maximum quantities of any regulated air contaminants will be:

Pollutant:	Pounds per hour	Tons per year
Total Suspended Particulates (TSP)	7 pph	25 tpy
PM_{10}	6 pph	25 tpy
$PM_{2.5}$	6 pph	25 tpy
Sulfur Dioxide (SO_2)	20,300 pph	105 tpy
Nitrogen Oxides (NO_x)	945 pph	300 tpy
Carbon Monoxide (CO)	4,790 pph	125 tpy
Volatile Organic Compounds (VOC)	4,890 pph	165 tpy
Total sum of all Hazardous Air Pollutants (HAPs)	270 pph	65 tpy
Formaldehyde (HCHO)	4 pph	15 tpy
Hydrogen Sulfide (H_2S)	230 pph	3 tpy
Toxic Air Pollutants (TAPs)	1 pph	3 tpy
Green House Gas Emissions as Total CO_2e		372,500 tpy

The standard operating schedule of the facility will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year. The maximum operating schedule will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year.

The owner and operator of the Facility is:
DCP Midstream, LP
10 Desta Drive, Suite 400 West,
Midland, TX 79705

If you have any comments about the construction or operation of the above facility, and you want your comments to be made as part of the permit review process, you must submit your comments in writing to the address below:

Permit Programs Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505-1816
(505) 476-4300

Other comments and questions may be submitted verbally.

Please refer to the company name and facility name, as used in this notice or send a copy of this notice along with your comments, since the Department may not have received the permit application at the time of this notice. Please include a legible mailing address with your comments. Once the Department has performed a preliminary review of the application and its air quality impacts, the Department's notice will be published in the legal section of a newspaper circulated near the facility location. (505) 476-4300 or 1 800 224-7009 Fax: (505) 476-4375
#29985

01100104 00154759

TRINITY CONSULTANTS
9400 HOLLY AVE NE BLG 3 SUITE 300
ALBUQUERQUE, NM 87122

HOBBS GARAGE SALE MAP

Now people can find your garage sales more easily with our map.

JUMBLE

THAT SCRAMBLED WORD GAME
by David L. Hoyt and Jeff Knurek

Unscramble these four Jumbles, one letter to each square, to form four ordinary words.

DABIE

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TOLCH

ESUWIN

ROVYSA

Check out the new, free JUST JUMBLE app

Now arrange the circled letters to form the surprise answer, as suggested by the above cartoon.

A:

(Answers Monday)

Yesterday's Jumbles: NOTCH TINGE BESIDE ARTERY
Answer: The campground's population goes up when people become — "INHABIT-TENTS"

072 GENERAL HELP WANTED

Lea County

Director of Planning

• Under County Manager direction, administers daily operation of planning department
• Prepares reports and statistical data for comprehensive planning
• Leads, directs and plan ETZ, P&Z and LCWUA board meetings
• Plans and monitors department budget
• Coordinates and reviews the work of assigned staff

Submit resume with cover letter and application to: Human Resource Director 100 N Main, Suite 4 Lovington, NM 88260 575-396-8605

Complete job description available at: www.leacounty.net Position Close date: April 15, 2015

DAY'S INN is now taking applications for full- and part-time front desk clerks & maintenance. Apply at 211 N. Marland.

Miller Waldrop

Don't Read This!..........Unless? You genuinely like people. You have a warm smile for everyone especially strangers. It's easy for you to strike up a conversation. When others talk you not only listen to what they are saying but ask questions to learn more. You're a team player and support others. You own up to your mistakes learn from them and improve. You find joy and satisfaction in going the extra-mile for others even when you're not noticed. You understand the principle of reaping and sowing. You dress professionally and look your best when out in public. Are you willing to do menial tasks when asked? If this describes you then a career in selling home furnishing at Miller Waldrop Furniture in Hobbs may be just the place for you. Full time positions are available. 30K – 60K. Email resumes to beckey@millerwaldrop.com. No phone calls, please.

Eagle 9 Theater is now taking applications for future openings. Must be 16 years or older. Apply in person from 2-6 pm.

F/T Home Health Aides needed. Rotating weekends, evenings and days. GOOD pay scale. Must have vehicle. Apply at Total Care at Home 1706 N. Dal Paso

Family Time Visitation Center
Supervised visitation monitor
Part time employee sought 20+ hours per week Monday-Friday and some weekends. Applicants must be at least 21 years old and pass employment background checks. Send resume to 316 N. Dalmont.

First American Bank

First American Bank is seeking candidates for a full-time Teller position.

Must possess a high level of attention to detail, excellent interpersonal communication, and computer literacy skills. Confidentiality and the ability to multi-task are a must.

Ideal candidates must be able to successfully pass a pre-employment credit, background, and reference check. High school diploma or GED required, prior cash handling, or banking experience preferred.

Benefits include: VERY COMPETITIVE PAY, Quarterly bonuses, 2 weeks paid vacation, insurance, and 401 K.

Apply in person at: First American Bank 1220 W. Joe Harvey

Member FDIC/Equal Opportunity Employer

Hobbs Apartments is currently seeking a full-time Groundskeeper. Experience preferred, but not needed. Customer service attitude, flexibility and the ability to work in a team environment are the key to making this position a success. Serious inquiries only. You may apply in person at 2001 E. Clinton or send your resume to hobbs@monarchnm.com or call 575-393-2523 and ask for Sherry White.

Saturday's is hiring for servers, dishwashers and cooks. Apply in person at 312 W. Bender.

072 GENERAL HELP WANTED

HOLIDAZE BAR & GRILL IS NOW HIRING FOR ALL POSITIONS. APPLY IN PERSON AT 2827 N. DAL PASO. NO PHONE CALLS.

Housekeeper/Caregiver. 25 hours at $12 per hour. Nonsmoker. Must have dependable transportation. Driving record, background check, drug test required. Call 390-9900 for more info.

HydroSteam Oilield Services
NOW HIRING
• Vacuum truck operator
Requirements are Class A CDL tankers endorsements. Hazmat a plus, but not required. Experience necessary
• Receptionist
Must have QuickBooks experience, computer skills and reliable transportation
• Field supervisor (truck pusher)
Must have trucking experience and good driving record, customer service oriented, Class A CDL, willing to work long hours and have a good work ethic
Email resume to jam_357@yahoo.com 575-263-1183

INSURANCE AGENCY CUSTOMER SERVICE REPRESENTATIVE NEEDED
Good Career Opportunity!! Insurance experience a plus, but will train the right applicant. Competitive salary with excellent benefits. Great working atmosphere. Must have good written and oral communication skills, computer skills, and be good with people. Send cover letter & resume to sarahshafer@reidinsurance.biz

Lea County State Bank

Local Bank seeking a qualified Loan Administrative Assistant. Applicant must have proficient working knowledge of Microsoft Word, good telephone etiquette and possess great organizational skills. Competitive pay with complete benefit package. Apply in person at 1001 N Turner, 8:00 – 5:00 Monday – Friday. EOE

Looking for professional sales people and a lock technician. Will train. 401(k), health benefits, great opportunity. Apply at Permian Ford, 1000 N. Dal Paso, or call Billy Joe Sizemore at 575-318-1923 or email bjsizemore@yahoo.com. Guaranteed $7500 for sales people. Lock technician pay based on experience.

A Few Motivated Housekeepers needed. Criminal background check required. Must have vehicle.Apply at Happy Housekeepers. 1706 N. Dal Paso

BUDDY'S HOME FURNISHINGS

Now hiring assistant managers and managers. Must have good driving record and pass background and drug screen. Apply at 403 N. Turner or send resume to jellis@buddyrents.com

NOW HIRING Stylists & Receptionists. Sport Clips Haircuts is looking for qualified stylists. $1000 signing bonus and housing bonus available. Pay, $12 an hour plus commission and tips. Receptionists start at $9 an hour. Apply online at www.sportclips.com.

Pesticide applicator, licensed or will train. Apply in person at Pro Treat, 3419 Industrial.

072 GENERAL HELP WANTED

QUICKCUTS now hiring licensed stylists for Hobbs & Lovington locations. $1000 sign on bonus. Sunday & one day a week off. Hourly wage, plus paid holidays & birthday pay. Pick up application at 2400 N. Grimes, Suite B24 or call 392-4613.

★ **RECEPTIONIST**
needed Part Time for busy agency with multiple phone lines. Monday - Friday, Afternoons 12:30-4:30 occasional fill-in for morning. Professional appearance, mature attitude and good people skills required. Previous experience desired, but not necessary. Alcohol/Drug testing & fingerprinting. Applications taken at Leaders 115 W. Dunnam.

REF-CHEM, L.P.

Ref-Chem, L.P. an established (engineering, construction & maintenance) company since 1957 is currently seeking experienced plant maintenance employees & contract operators for positions in the Hobbs and Denver City areas. Pay is determined by experience. Qualified applicants should have good people skills, be able to work as a team, have knowledge of computer operating systems, and have the ability to work safe. This is a full time position with the following benefits provided: vacation, retirement, paid holidays, medical, dental and life insurance.

PLEASE SEND RESUME TO:
P.O. Box 231
Brownfield, Texas 79316
E-mail: Donny.lance@ref-chem.com
Company website @ www.ref-chem.com

REF-CHEM IS AN EQUAL OPPORTUNITY EMPLOYER

Shale Lodging is hiring for full time breakfast and dinner cook. Experience in homemade meals. Presentable appearance. Pay based on experience. Resume can be sent to nick@shale-lodging.com or fax 1-877-482-1840.

The First Tee at Rockwind Community Links is seeking a full-time program director in Hobbs, NM. Education and golf background required with preference to First Tee experience. Submit resume to thefirstteesoutheasternnm@gmail.com. 575-623-4444 Salary $35,000-$45,000.

074 MEDICAL HELP WANTED

Country Cottage Care & Rehabilitation Center
2101 N. Bensing Road
Hobbs NM 88240

New Positions Opening:

Nurses (RN & LPN) – FT & PT
CNA's – FT & PT
Activity Aide - PT

Competitive Wages, Medical, Dental & Vision Insurance, Vacation and Sick Time
EEOE

Interim

Interim Health Care is looking for a part time homemakers. Please stop by our office at 726 E. Michigan, Ste. 130. 575-391-0121.

078 LOANS & INVESTMENTS

YOUR CREDIT $200 - $2,000
"WE WANT TO MAKE YOU A LOAN"
(575) 393-4415

087 GARAGE SALES

01. 501 W. Silver, Saturday, 7:30-11. Multi-party sale. Children's and babies' clothes, baby items, housewares, furniture. Please, no early sales.

02. 6916 N. Country Rd (past Millen between Morales & Debaca), Saturday, 7a-4p. Tools, Hot Wheels, M&M's, Christmas, TV, plus size, housewares, misc.

03. 3502 N. Dal Paso, Saturday, 7:30-1:30. A little bit of everything. Look for signs.

04. 1526 N. Denson, Saturday, 7am-? 4 Family. Lots of nice kids clothes/toys, dishes, etc

05. 1515 Chuckwagon Dr., Saturday, 8a-12p. Lots of clothes, shoes, misc.

06. 412 Zia Saturday, 8-2. No early sales.

07. 1626 E. Kansas, Friday, Saturday, 8-3. 4-wheeler, 2 dirt bikes, kids' clothes.

08. 1230 N. Tasker, Saturday, 8-? Furniture, baby clothes, home decor and more.

09. 1324 N. Tasker, Saturday, 8a-? Rims, lots of clothes, little of everything.

10. 928 E. Greenacres (block between Dal Paso and Jefferson), Saturday, 7-11:30. No early sales. Moving sale. Don't miss it!

11. 605 E. Midwest, Saturday, 8-12. Baby and kids' clothes, lots of misc.

12. 1211 Gulf, Saturday, 7a-? Little bit of everything!!

13. 8107 N. Valdez, Fri., 9-2; Sat., 8-2. No early sales! Baby stuff, furniture, clothes.

14. 1027 Pueblo, Saturday, 8-12. Furniture, mattresses, clothes, tools, misc.

15. 509 E. Midwest, Saturday, 8a-12p. 4 Family. Window refrigerated air conditioner, prom dresses, furniture, pots and pans, misc.

087 GARAGE SALES

16. 2234 North Adobe Drive, Saturday, 7-? Workout equipment, couches, home decor lots of clothes.

17. 1417 Camino Real, Saturday, 9-? Girls' and boys' clothing, toys, decor.

18. 820 S. Cochran Sat. 10am-4pm. No early sales, moving sale. Lots of nice kid's clothes, toys, adult clothing, household items, elliptical, 4ft swimming pool, 2 bar stools, etc. No big bills

19. 1400 E. Humble, Saturday, 8-? Little bit of everything!!! Clothes, shoes, misc

20. 1126 N. Gulf, Saturday and Sunday, 8am-1pm. Furniture, home decor, misc.

STORE CLOSING. All kinds of great furniture for sale. New, used and vintage. Home Decor and gifts. Shandee Lane, 3420 N. Grimes, Ste. 400. Mon.-Sat, 11-4.

HUGE knife sale! All different kinds, from pocket to Bowie. All brands. Can be seen at 4024 Smith Lane, 7 days a week, 9a-5p.

Will pickup unwanted garage sale items every weekend, Hobbs area Only 631-9122

088 ESTATE SALES

ESTATE SALE
2300 N. CIELO
SATURDAY 7 AM-5 PM
Dining room table and chairs, household goods, home décor, linens, dishes, small appliances, microwave. Work tools, garden tools, mower, spreader, BBQ grill. Everything must go.

096 BOATS & MOTORS

2007 Four Winns Boat. 22 ft. Like New. Bought new, paid $43,000. Retired, need to sell, $25,000. 575-390-5208

105 FURNITURE

STORE CLOSING. All kinds of great furniture for sale. New, used and vintage. Home Decor and gifts. Shandee Lane, 3420 N. Grimes, Ste. 400. Mon.-Sat, 11-4.

Brown leather couch and loveseat, $500. Marble top coffee & 2 end tables, $150. 5 peice marble top pub set, $200. 575-390-6173

Leggett queen adjustable bed, $1000; sofa, $100; oversized plush recliner, $200; round dining table with chairs, $100; two box TVs, $50 each. 318-3796.

106 MISCELLANEOUS

16 foot all metal utility trailer. Upright freezer. 392-7310

25 KW Trailer Mount Generator. $4500. 575-390-5207

FREE FIREWOOD You cut - you haul 575-631-6586

Full size sofa/sleeper- $250.00 Good, twin bed/frame excellent $250.00, Apt. size, 2 door fridge/freezer good $85.00, secretary desk-excellent $100.00, Antique Oak, 4 drawer dresser- good $100.00. Call 575-691-7719

I need a Lift Recliner for a disabled senior citizen. 575-408-1908

Single Wide trailer house 14x66, Some repairs, $45, 000. buyer responsible for moving. Call 575-691-7547 leave message.

115 SPORTING GOODS

Electronic Score Board. 8 ft. x 3 ft.. Asking $2200. For more information or demonstration call 575-318-3894.

121 PETS

Ten 7-week-old German shepherd puppies. $200. First shots. 575-691-8002

122 LOST & FOUND PETS

LOST since 4/2 from N. Cibola. Black Chihuahua. Looks like a Min-Pin. Answers to Sophie. HELP! Office 393-7504, cell 605-1495.

MISSING: Brown, black and gray Yorkie with pink collar & brown harness. Disabled person needs her back. $500 Reward. 575-621-5558

LOST: Small all white dog with black collar. Vicinity of Copper and Grimes. Answers to Tink. Reward. 575-441-5966.

124 LIVESTOCK & EQUIPMENT

Good quality irrigated weed-free coastal hay. High protein. Located in Plains, TX. 4x5 ft. net wrapped round bales $85. Also available small square bales upon request. $10.75 in the field. Delivery available. $5 loaded mile. 806-893-1058 or 806-239-3866.

127 AUTOMOBILES FOR SALE

2012 Chrysler Touring 200, convertible, 18,500 miles. Retired, need to sale. $16,000, 575-390-5208

2013 Volvo XC90. 28,600 miles. 575-390-9943

133 RVS & CAMPERS

2012 Keystone/Outback 27 foot bumper pull trailer. Two slideouts, electric jack, front bedroom, rear living room, awning. Used by one person. No meals prepared in kitchen. Towed less than 500 miles. Located in Midland. Price negotiable. 214-755-7804

133 RVS & CAMPERS

Need to sell due to health. 2015 Keystone Cougar travel trailer. 30 ft., 3 slides, flat screen TV elec. fireplace, propane furnace. Located in Alamogordo, NM. 870-335-6546

LEGALS

LEGAL NOTICE
April 11, 2015

LEGAL NOTICE OF REQUEST FOR PROPOSAL
LEA COUNTY, NEW MEXICO

AIRLINE SERVICE
LEA COUNTY REGIONAL AIRPORT
PROPOSAL #06 - (14-15)
DUE DATE:
APRIL 24, 2015 - 3:00 P.M.

The County of Lea wi[ll] receive sealed proposals fo[r] "Airline Service, Lea Count[y] Regional Airport" in th[e] Finance Department, Fourt[h] Floor, Courthouse Lovington, New Mexic[o]

The Request for Proposal[s] and any future addenda ma[y] be obtained from Le[a] County's web site unde[r] "Procurement" a[t] www.leacounty.net or b[y] contacting the Financ[e] Department, 100 Nort[h] Main, Suite 11, Lovingto[n] New Mexico 88260-403[0] (575) 396-8656 kmclaughlin@leacounty.ne[t]

Gregg Fulfer, Chairman
#29929

LEGAL NOTICE
April 11, 2015

OWL SWD Operatin[g] L.L.C., 8214 Westcheste[r] Drive, Suite 850, Dallas, T[X] 75225 has filed for[m] C108(Application fo[r] Authorization to Inject) wit[h] the New Mexico Oi[l] Conservation Divisio[n] seeking administrativ[e] approval for the drilling an[d] conversion to commercia[l] Devonian salt wate[r] disposal. The Smith Ranc[h] Federal SWD # 1, Locate[d] 1980 FSL X 990 FEL, Un[it] Letter I, Section 6, T20S R34E, Lea County, Ne[w] Mexico. The disposa[l] interval would be th[e] Devonian formation thr[u] open hole from 14800 fee[t] 17,000 feet. Disposal flui[d] would be produced wate[r] from producing oil and ga[s] wells in the area. Anticipate[d] disposal rate 5000 BWP[D] with a maximum disposa[l] rate of 20000 BWPD Anticipated disposa[l] pressure of 0(Zero) psi wit[h] a maximum disposa[l] pressure of 2960 psi. Well i[s] located approximately 3[?] miles West of Hobbs , Ne[w] Mexico.

All interested partie[s] opposing the aforementioned must fil[e] objections with the Ne[w] Mexico Oil Conservatio[n] Divison, 1220 South S[t.] Francis Drive, Santa F[e] New Mexico 87505 with i[n] 15 days. Additiona[l] information can be obtaine[d] by contacting Billy Prichar[d] 432-934-7680
#29930

LEGAL

LEGAL NOTICE
April 11 and 18, 2015

FIFTH JUDICIAL DISTRICT COURT
STATE OF NEW MEXICO
COUNTY OF LEA

IN THE MATTER OF A PETITION FOR CHANGE OF NAME OF
JESSICA IOVANA WEBB CV-2015-329

NOTICE OF CHANGE OF NAME

TAKE NOTICE that in accordance with the provisions of Sec. 40-8-3 NMSA 1978, the Petitioner Jessica Iovana Webb will apply to the Honorable Mark Sánchez District Judge of the Fifth Judicial District court at lea county Courthouse in Lovington, New Mexico at 11:00 am on the 1st day of May, 2015, for an ORDER FOR CHANGE OF NAME from Jessica Iovana Webb to Jessica Elvia Magdalena Webb.

NELDA CUELLAR
DISTRICT COURT CLERK

/s/ Delma Madrid

Submitted by:
Jessica Webb
1618 W. Calle Sur, Apt A
Hobbs NM 88240
310-982-5678
#29926

LEGAL

LEGAL NOTICE
April 11, 2015

NOTICE OF AIR QUALITY PERMIT APPLICATION

DCP Midstream, LP (DCP) announces its intent to apply to the New Mexico Environment Department for a revision to its air quality permit PSD-5217 for its Zia II Gas Plant. The Zia II Gas Plant will be a cryogenic gas processing plant designed to treat and process produced natural gas for DCP gathering systems located throughout central New Mexico. The expected date of application submittal to the Air Quality Bureau is April 15, 2015. This notice is a requirement according to New Mexico air quality regulations.

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Green House Gas Emissions as Total CO_2e		372,500 tpy

The standard operating schedule of the facility will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year. The maximum operating schedule will be 24 hours a day, 7 days a week and a maximum of 52 weeks per year.

The owner and operator of the Facility is:

DCP Midstream, LP
10 Desta Drive, Suite 400 West,
Midland, TX 79705

If you have any comments about the construction or operation of the above facility, and you want your comments to be made as part of the permit review process, you must submit your comments in writing to the address below:

Permit Programs Manager
New Mexico Environment Department
Air Quality Bureau
525 Camino de los Marquez, Suite 1
Santa Fe, New Mexico 87505-1816
(505) 476-4300

Other comments and questions may be submitted verbally.

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#29985

LEGAL

LEGAL NOTICE
April 11, 18, 25 and May 2, 2015

STATE OF NEW MEXICO
COUNTY OF LEA
FIFTH JUDICIAL DISTRICT COURT

No. D-506-CV-2014-00357

PINTA, LLC FOR THE BENEFIT OF WACHOVIA CAPITAL MARKETS, LLC,

Plaintiff,

vs.

REYNALDO ORONA A/K/A REYNOLDO ORONA, DECEASED, MANUELA A. ORONA A/K/A MANUELA ORONA A/K/A NELLIE ORONA, BARCLAYSAMERICAN/FINANCIAL, INC AND UNKNOWN HEIRS, DEVISEES OR LEGATEES OF REYNALDO ORONA A/K/A REYNOLDO ORONA, DECEASED,

Defendants.

NOTICE OF SALE

Notice is hereby given that on May 8, 2015, at the hour of 11:00 am the undersigne[d] Special Master, or her designee, will, at the front entrance of the Lea County Courthouse 100 N. Main, Lovington, NM 88260, sell all of the rights, title and interest of the above named Defendants, in and to the hereinafter described real estate to the highest bidder fo[r] cash. The property to be sold is located at 400 E. Alston , Hobbs , New Mexico 88240 (there is a conflict between the legal description and the street address, the leg[al] description shall control), and is more particularly described as follows:

Lot Nine (9), Block One hundred and Twenty-Three (123), Highland Park Addition to the City of Hobbs, Lea County, New Mexico

including any improvements, fixtures, and attachments, such as, but not limited to, mobil[e] homes. Subject to all taxes, utility liens and other restrictions and easements of recor[d] and subject to a (1) month right of redemption by the Defendants upon entry of an orde[r] confirming sale. The foregoing sale will be made to satisfy an in rem foreclosure judgmen[t] rendered by this Court in the above-entitled and numbered cause on March 31, 201[5] being an action to foreclose a mortgage on the above-described property. The Plaintiff's i[n] rem judgment is $32,151.38, and the same bears interest at the rate of 9.95% per annu[m] which accrues at the rate of $8.76 per diem, commencing on December 31, 2014, with th[e] Court reserving entry of final in rem judgment against said Defendants Reynaldo Oron[a] a/k/a Reynoldo Orona, Deceased and Manuela A. Orona for the amount due afte[r] foreclosure sale, for costs and attorneys' fees, plus interest as may be assessed by th[e] Court. The Plaintiff has the right to bid at such sale all of its in rem judgment amount an[d] submit its bid verbally or in writing. The Plaintiff may apply all or any part of its in rem judgment to the purchase price in lieu of cash. The sale may be postponed an[d] rescheduled at the discretion of the Special Master.

The Court's decree, having duly appointed its Special Master to advertise an[d] immediately offer for sale the subject real estate and to apply the proceeds of sale, first t[o] the costs of sale and the Special Master's fees, then to pay the above-described in re[m] judgment, interest, and costs of sale, and to pay unto the registry of the Court any balanc[e] remaining to satisfy future adjudication of priority mortgage holders;

NOW, THEREFORE, notice is hereby given that in the event that said property is no[t] sooner redeemed, the undersigned will as set forth above, offer for sale and sell to th[e] highest bidder for cash or equivalent, the lands and improvements described above for th[e] purpose of satisfying, in the adjudged order of priorities, the in rem judgment describe[d] herein and decree of foreclosure together with any additional costs and attorney's fee[s] costs of advertisement and publication, a reasonable receiver and Special Master's fee t[o] be fixed by the Court. The total amount of the in rem judgment due is $32,151.38, plu[s] interest to and including date of sale of $1,130.04, for a total in rem judgment plus interes[t] of $33,281.42. Sale is subject to the entry of an in rem order of the Court approving th[e] terms and conditions of this sale.

Witness my hand this 9th day of April, 2015.

/s/ Jennifer Taylor
JENNIFER A. TAYLOR, Special Master
PO Box 91988
Albuquerque, NM 87199
Telephone: (505) 433-4576
Facsimile: (505) 433-4577
E-mail: sales@ancillaryls.com

#29928

Section 9.10

Newspaper Display Advertisement

Affidavit of Publication

State of New Mexico,
County of Eddy, ss.

Rynni Henderson, being first duly sworn, on oath says:

That she is the Publisher of the Carlsbad Current-Argus, a newspaper published daily at the City of Carlsbad, in said county of Eddy, state of New Mexico and of general paid circulation in said county; that the same is a duly qualified newspaper under the laws of the State wherein legal notices and advertisements may be published; that the printed notice attached hereto was published in the regular and entire edition of said newspaper and not in supplement thereof on the date as follows, to wit:

April 11 2015

That the cost of publication is **$250.37** and that payment thereof has been made and will be assessed as court costs.

Subscribed and sworn to before me this 13th day of April, 2015

Shirley Maxwell

My commission Expires
May 18, 2015

Notary Public

OFFICIAL SEAL
Shirley Maxwell
NOTARY PUBLIC
STATE OF NEW MEXICO
My Commission Expires: 5/18/15

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WEATHER

Tornado kills 2 people, destroys homes in Illinois town

By Michael Tarm and Sophia Tareen
The Associated Press

FAIRDALE, ILL. » A second woman from a tiny Illinois farming community has died, Gov. Bruce Rauner confirmed Friday, a day after tornadoes struck a six-county swath of the state, injuring about a dozen other people and sweeping homes off their foundations.

Crews embarked on detailed searches for missing residents Friday after at least one tornado brought chaos to Fairdale, a town of 150 people, around 7 p.m. the night before.

Residents reported the skies blackening and windows exploding as the severe weather struck. Crews combed through each structure twice into the evening hours and searched again by equipment and by hand Friday morning. The second person killed had initially been reported missing and her body was found Friday morning, Rauner said. Most other injuries were minor.

"We hope and pray that that is all the fatalities," Rauner said. "We are very blessed that more people were not hurt."

The two people killed were identified as Jacklyn K. Klosa, 69, and Geraldine M. Schultz, 67.

About 15 to 20 homes were destroyed in Fairdale, according to DeKalb County Sheriff Roger A. Scott. Matthew Knott, division chief for the Rockford Fire Department, told The Associated Press that just about every building in the town about 80 miles from Chicago "sustained damage of some sort."


SUNNY STRADER — ROCKFORD REGISTER STAR
Ann Schabacker sifts through her scattered belongings Friday morning after her home was destroyed the night before in Rochelle, Ill.

All homes were evacuated as a safety precaution and power was out across the area. The Red Cross and Salvation Army established a shelter at a local high school.

Trees, power lines and debris lay strewn on the ground. Some homes in the rural farming village were barely standing and many had shifted from their foundations. Roofs were missing. Metal siding from barns was wrapped around trees.

Residents gathered at a roadblock a mile from town Friday morning, eager to check the damage to their homes. Police, though, refused entry, saying it was too dangerous.

Resident Al Zammuto, a 60-year-old machinist, said he and other residents received cellphone alerts at 6:45 p.m., but he dismissed it as previous warnings hadn't amounted to anything.

Then his windows exploded.

He took cover as the severe weather struck. Bricks were torn off the side of his home. Minutes later he stepped outside and couldn't believe his eyes. He said the town "looked like a landfill" and the sounds were haunting.

"People were screaming and yelling," he said. "People were in total shock."

National Weather Service meteorologist Matt Friedlein said at least two tornadoes swept through six north-central Illinois counties, and that damage survey teams would visit the area to determine how long they stayed on the ground, their strength and the extent of the damage.

TECHNOLOGY

Online joy but no long lines for Apple Watch

By Brandon Bailey
The Associated Press

PALO ALTO, CALIF. » An online rush replaced the traditional overnight queues outside Apple stores Friday as the iconic tech company began taking orders and letting shoppers get their hands on its much-vaunted smartwatch for the first time.

Eager customers placed online orders for the Apple Watch as soon as Apple's website began accepting them, shortly after midnight Pacific Time. Within half an hour, the company appeared to sell out the initial batch of watches that were available for the first official day of shipping on April 24. By midmorning, Apple's website was showing the earliest shipping date for many watch models would be in June or later.

Demand was difficult to gauge, since Apple hasn't said how many watches were available for shipping in the first wave. And in contrast with earlier releases of new Apple products, there were no big lines of shoppers waiting all night outside the company's retail stores.


KIN CHEUNG — THE ASSOCIATED PRESS
A customer tries on an Apple Watch on Friday at an Apple Store in Hong Kong. From Beijing to Paris to San Francisco, the Apple Watch made its debut Friday. Customers were invited to try them on in stores and order them online.

That's because Apple encouraged customers to make appointments for a 15-minute opportunity to try on different models — which are priced starting at $349 and go up to $17,000 for a luxury edition — while specially trained employees explained their features. Apple is only accepting orders online, for now.

Analysts said Apple might have good reasons to sell the watch through pre-orders and appointments. Online ordering should help Apple manage its inventory and manufacturing. The try-on visits should help ensure that early buyers know what to expect and how to use the watch, said Carolina Milanesi, a tech analyst at Kantar Worldpanel. She said that could build positive "word of mouth" recommendations.

Apple, which is based in Cupertino, Calif., hasn't offered any estimates, but some analysts have predicted the company could sell 10 million to 20 million watches this year. By comparison, it sold more than 10 million of its new iPhone 6 and 6 Plus smartphones in the first weekend they were available in September.

PETS

Cat survives shock, 25-foot fall from pole

The Associated Press

GRANTS PASS, ORE. » The owner of a 17-pound Siamese cat named Liam says he has nearly used up his nine lives after getting shocked on a power pole in Grants Pass and falling 25 feet.

Jennifer Kagay told The Grants Pass Daily Courier that she and her husband were lying in bed early Tuesday when they heard a "bang" and the power went out.

Her husband, Jeff, went outside and the cat was lying still on the transformer at the top of the pole. They were relieved when Liam started to move, but horrified when he fell 25 feet to the ground. On the way down, he snagged a wire with a claw, then landed softly in some brush.

The Kagays took him to the vet, where he might have to have one leg amputated.


JENNIFER KAGAY — THE ASSOCIATED PRESS
This April 8 photo shows Liam the cat after he fell from a power pole in Grants Pass,

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Affidavit of Publication

State of New Mexico,
County of Lea.

I, DANIEL RUSSELL
PUBLISHER
of the Hobbs News-Sun, a newspaper published at Hobbs, New Mexico, do solemnly swear that the clipping attached hereto was published in the regular and entire issue of said newspaper, and not a supplement thereof for a period

of 1 issue(s).
Beginning with the issue dated
April 11, 2015
and ending with the issue dated
April 11, 2015

Daniel Russell
PUBLISHER
Sworn and subscribed to before me
this 11th day of
April, 2015

Gussie Black
Notary Public

My commission expires
January 29, 2019
(Seal)

OFFICIAL SEAL
GUSSIE BLACK
Notary Public
State of New Mexico
My Commission Expires 1-29-19

This newspaper is duly qualified to publish legal notices or advertisments within the meaning of Section 3, Chapter 167, Laws of 1937 and payment of fees for said publication has been made.

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01100104 00154760
TRINITY CONSULTANTS
9400 HOLLY AVE NE
BLG 3 SUITE 300
ALBUQUERQUE, NM 87122

Jordan Spieth makes Masters look like child's play

AUGUSTA, Ga. (AP) — Jordan Spieth is making the Masters look easy.

He opened with a 64 despite making a bogey at the easiest hole on the course. He followed with a bogey-free 66 in which he missed a pair of 6-foot birdie putts. He still broke the 36-hole Masters record that had stood for 39 years. His five-shot lead matched another Masters record.

For two rounds, he has 15 birdies, one bogey and no worries.

The plan Friday afternoon for the 21-year-old Texan was to hang out with his family and some high school friends from Dallas, "taking it easy and hopefully just acting like nothing's going on."

Don't be fooled. He knows exactly what's happened at Augusta National. And he knows the hard work is about to start.

"This is just the halfway point," Spieth said.

He was at 14-under 130, a two-day total matched by one three other players in major championship history and breaking the Masters mark set by Raymond Floyd in 1976. His five-shot lead over Charley Hoffman looked even larger considering that Spieth was a runner-up in his Masters debut a year ago, and he came to Augusta this year as the hottest player in the game.

Jordan Spieth hits on the 15th fairway during the second round of the Masters golf tournament Friday in Augusta, Ga.

AP PHOTO

It sure got the attention of the best player in the game.

Rory McIlroy went from trying to complete the career Grand Slam to trying to stick around for the weekend after a 40 on the front nine. He rallied with a 31 on the back nine to make it easily, though he was still 12 shots behind Spieth.

"It's really, really impressive," McIlroy said. "I think a few guys can still catch him. It will take, obviously, something extraordinary from myself to get up there, but you never know. I know better than most people what can happen with the lead around here."

McIlroy lost a four-shot lead in the final round in 2011.

Tiger Woods broke 70 at Augusta National for the first time since 2011. He had a 69 and joined McIlroy at 142, only his outlook was more upbeat.

"I'm still right there," Woods said. "I'm 12 back, but there's not a lot of guys ahead of me. And with 36 holes here to go, anything can happen — '96 proved that. So we have a long way to go."

He was referring to Greg Norman losing a six-shot lead on the final day in 1996.

Spieth might find comfort in another reference.

The three other players who had a five-shot lead after 36 holes at Augusta — Herman Keiser in 1946, Jack Nicklaus in 1975 and Floyd in 1976. All went on to win.

Spieth sure looked like a winner, even though it was just Friday. The fans treated him like one.

They rose to their feet and applauded when Spieth walked onto the 12th tee, and for the next two hours, ovations greeted him on tee boxes and greens. The red number next to his name on the leaderboard — 14-under par — was better than 11 of the last 13 winners.

"I got standing ovations walking to multiple greens," Spieth said. "I mean, that's something you can only dream about. It's Friday, too. I'd like to have the same thing happening on Sunday. Got a lot of work to do before that happens."

Hoffman tried to keep pace with Spieth and ran off three birdies on the back nine until closing with a bogey for a 68. He was five shots behind at 135, a score that would have been leading at 36 holes in the last three Masters. Hoffman didn't care about that.

"It's this year. It's not any other year," he said. "I'm just playing golf and I've only played 36 holes. And we've got a lot of golf left."

Dustin Johnson opened with a double bogey, and then became the first player in Masters history to make three eagles in one round. A bogey from the trees on the last hole gave him a 67, and he was seven shots behind, along with Justin Rose (70) and Paul Casey (68). Phil Mickelson (68) was eight behind.

Roundup

from PAGE 9

Briana Eoff finished the opening game by going 3-for-4 while Kendra Santillan was 2-for-2 with a double. USW's Taly Ramirez as 2-for-3 with two doubles and a run scored. Briana Gonzalez was 2-for-4 with two runs scored and a stolen base.

The Lady Mustangs continued to hit the ball with authority in game two, as USW pounded out 20 hits.

Gonzalez was 4-for-5 with a triple while Lynette Nikolao was 4-for-5 with a run scored and three RBI. Candi Hernandez added a 3-for-4 effort with two RBI and three runs scored. Ramirez went 3-for-5 with two RBI. Kelly Munoz was 2-for-5 with a double and two RBI.

Natalie Ortiz served as USW's starting pitcher, working 1 1/3 innings before being relieved by Eoff, who worked 5 2/3 innings, surrendering two runs on 10 hits to pair with one strikeout.

NON-VARSITY BASEBALL
Hobbs JV 13-11, Alamogordo JV 0-0

The Hobbs junior varsity baseball team swept the Alamogordo JV 13-0 and 11-0 on Friday in Alamogordo.

In the first game Gavin Hardison picked up the win for Hobbs (9-3) in the run-rule shortened game, tossing a one-hit shutout with three strikeouts and one walk.

At the plate Jaden Hutchins went 2-for-3 with an RBI and three runs for Hobbs, Hardison was 1-for-4 with two RBI and Tristan Zambrano was 2-for-2 with two RBI and three runs.

In game two Hutchins got the win for Hobbs, going four innings and giving up three hits with two strikeouts and a walk.

Chris Castillo went 2-for-3 for Hobbs with an RBI in game two, Blake Moore was 2-for-3 with an RBI and three runs while Tyrin Pacheco was 2-for-2 with two RBI and two runs.

NON-VARSITY SOFTBALL
Hobbs JV 4-4, Alamogordo JV 3-3

The Hobbs softball team remained undefeated by winning a pair of 4-3 games against Alamogordo on Friday in Hobbs.

In the first game Zoie Rodriguez picked up the win, going 6 1/3 innings and giving up three runs (none earned) on three hits with five strikeouts and one walk. Michaela Salmon pitched the final two outs to pick up the save.

Rodriguez also went 1-for-3 at the plate with a double and run for Hobbs (12-0), Solana Garza was 1-for-3 with a run and Larissa Benavides was also 1-for-3 with a run.

In the second game, Genesis Armandariz got the win for the Lady Eagles. She went the distance, giving up three runs (one earned) on five hits with six strikeouts and no walks.

Armandariz also had the game-winning RBI in the bottom of the seventh to score Rodriguez, who was 2-for-4 with a double. Kenzi Savell was 2-for-4, Kaitlynne Hicks was 1-for-3 with a triple and Tristan Torres was 1-for-3 with a double.

CLAYTON JONES/NEWS-SUN

Hobbs freshman Taylor Jones reaches for a shot Friday in Hobbs. Jones and Ashley Selman won the girls doubles division at the Paul Baker Invitational.

Tennis

from PAGE 7

Sivalis and McCray of Midland Classical.

Patel and Jimenez defeated the Lovington duo of Christian and Jace Crawford in the semifinals 6-2, 7-5, to reach the finals.

It was Hobbs' final tuneup before starting District 4-6A play Friday at home against Carlsbad.

Eagles

from PAGE 7

Nico Reyes got the loss for Alamogordo, going four innings and giving up seven runs (five earned) on six hits with two strikeouts and three walks.

Hobbs next travels to play Clovis on Tuesday.

Lottery numbers

N.M. PICK 3
6-8-0

ROADRUNNER CASH
2-9-16-20-21

MEGA MILLIONS
6-11-32-46-68 MB: 9

TEXAS PICK 3
8-6-3 (morning); 0-6-9 (day);
4-8-0 (evening); 2-0-4 (night)

TEXAS DAILY 4
0-7-2-1 (morning); 2-2-7-8 (day);
6-9-7-3 (evening); 2-3-8-3 (night)

CASH FIVE TEXAS
1-6-16-19-37

Lady Eagles

from PAGE 7

Lewis and Brianna McGill each had two hits.

Macie Perrin picked up the win, going the final five innings and giving up six runs on six hits with two strikeouts and two walks. Perrin was also 2-for-3 at the plate with two home runs and three RBI.

Gentry finished 3-for-5 with a home run, double and six RBI for the Lady Tigers while Courtney Grubbs was 3-for-4 with a home run, double and two RBI.

The first game had a much different tone as it turned into a pitcher's duel between the senior Perrin and Hobbs sophomore Zariah Duarte.

Alamogordo scored a run in the second and the third (Perrin's first of three home runs in the doubleheader) to take a 2-0 advantage before an RBI groundout by Lewis cut the Lady Tiger lead in half.

However, that's as close as Hobbs got as the the Lady Eagles couldn't get to Perrin as she finished giving up one run on five hits with seven strikeouts and two walks.

CLAYTON JONES/NEWS-SUN

Hobbs third baseman Brianna McGill throws to first base against Alamogordo on Friday in Hobbs.

Duarte went the distance as well, giving up three runs (two earned) on five hits with four strikeouts and no walks.

Heckard led Hobbs at the plate, going 2-for-3 with a run and two stolen bases.

Hobbs next plays at home Tuesday in a doubleheader against Clovis.

Abeyta

from PAGE 7

also qualified for state in the hurdles and is a member of Jal's state-bound 4x200-meter relay unit.

Her interest in pole vaulting stems from familial participation in the event.

"My cousin was a pole vaulter and I liked to watch," Abeyta said. "I thought it was a cool sport and it works for me. My brother is in the seventh grade and vaults, too. I encourage him to use good form and remember the things we learn in the different camps. He like to vault and wants to be good, too."

Loftis said getting athletes involved in pole vaulting prior to high school is key.

"If you get them involved in this event at an early age, it tends to become second nature to them," he said. "They hold on to that pole and clear some heights without giving it a second thought. It can be a scary event, because you're going upside down and you're looking at the ground anywhere from eight to ten feet in the air. It's not for everybody, but Danica is a special young lady, who also plays softball, volleyball and basketball. She's really fun to coach."

Duncan leads Spurs to win over Rockets

HOUSTON (AP) — The San Antonio Spurs hacked Josh Smith for most of the second half against the Houston Rockets on Friday night to keep the ball out of James Harden's hands.

Coach Gregg Popovich's strategy worked. The Spurs held Harden to 16 points and got their 10th straight victory, 104-103, and a leg up in the playoff standings.

Tim Duncan had 29 points and blocked Harden's layup with 2.9 seconds left to secure the victory.

San Antonio jumped into the third spot in the Western Conference and Houston dropped from third to sixth.

Popovich was pleased with the way his Hack-A-Smith routine changed the game.

"Absolutely, I'd trade it any day rather than have James Harden with the basketball," Popovich said. "That's kind of scary."

The Spurs had a four-point lead when Harden made a layup for his first points of the half with less than 90 seconds remaining.

Duncan missed a layup before Harden made a 3-pointer with 28.9 seconds left to get Houston to 104-103. Tony Parker turned it over to give Houston one last shot.

But Duncan blocked Harden's shot and grabbed the rebound to secure the victory.

"It was a good opportunity for me to get redemption at the end," Duncan said, noting his missed layup that would have put it away earlier.

Harden summed up the play simply.

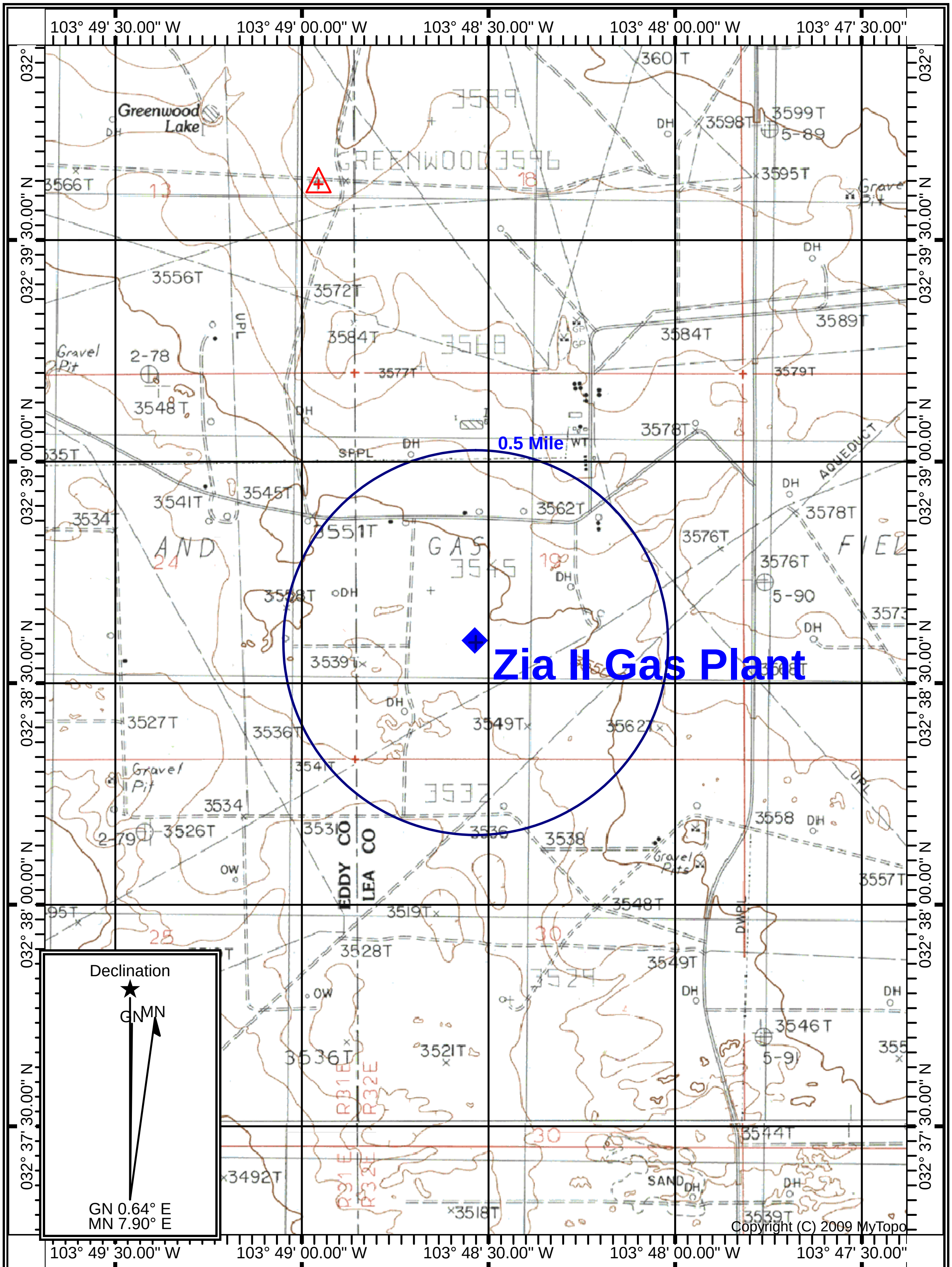
"Got to finish," he said. "I've just got to finish."

The close game ended a streak of nine straight wins by at least 12 points, which had tied an NBA record.

Section 9.11
Facility Boundary Map

Facility Boundary Map is on the next page

Facility Boundary Map is on the next page



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 10

Written Description of the Routine Operations of the Facility

A written description of the routine operations of the facility. 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 will be 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.** The "project" emissions for this modification are significant. See the discussion below on the facility. This application is being submitted as a continuation of the original PSD application as the facility is still under construction. The "project" emissions listed below only result from changes described in this permit application. This is a new facility therefore there is no debottlenecking associated with this facility. The project emissions (before netting) for this project are as follows [see Table 2 in 20.2.74.502 NMAC for a complete list of significance levels]:

a. **NOx: 273.9 TPY**
b. **CO: 113.9 TPY**
c. **VOC: 153.9 TPY**
d. **SOx: 95.7 TPY**
e. **TSP (PM): 20.3 TPY**
f. **PM10: 20.1 TPY**
g. **PM2.5: 20.1 TPY**
h. **Fluorides: N/A TPY**
i. **Lead: N/A TPY**
j. **Sulfur compounds (listed in Table 2): 97.2 TPY**
k. **GHG: 339,035.0 TPY**

C. **Netting** is not required as this is a new PSD facility which is currently under construction and has not commenced operation.

D. **BACT** was originally submitted for NO_X, CO, SO_2, VOC, PM_{10}, $PM_{2.5}$, and CO_2e and is being updated with this application.

E. This is a new PSD facility which is currently under construction and therefore does not have any related projects.

DCP Midstream, LP (DCP) is submitting an application pursuant to 20.2.74.200.A NMAC for revision to its PSD Permit PSD-5217 for the Zia II Gas Plant (Zia II). The facility is a new 230 MMscf/day greenfield gas plant in Lea County, New Mexico approximately 25 miles northeast of Carlsbad. The facility is currently under construction and has not yet begun operation.

DCP proposes to update the current permit to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources. This application is being submitted as a continuation of the original PSD application as the facility is still under construction. All emissions are considered an increase for PSD applicability. Below is a table showing a comparison of the project totals to the PSD thresholds.

PSD Applicability: PSD Threshold Comparison

	NO_x (ton/yr)	CO (ton/yr)	VOCs (ton/yr)	SO_x (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	CO_2e (ton/yr)
Project Total	273.9	113.9	153.9	95.7	20.1	20.1	339,035.0
PSD Threshold	250 tpy	250 tpy	250 tpy	250 tpy	250 tpy	250 tpy	100,000 tpy
Are project emissions above PSD thresholds?	**YES**	NO	NO	NO	NO	NO	**YES**

The project emissions are greater than the PSD threshold of 250 tpy for NO_X and 100,000 tpy for CO_2e. Each pollutant must now be compared to the PSD Signification Emission Rate (SER) to determine which pollutants are significant for this project. Per 20.2.74.7.AG NMAC, any major source that is major for nitrous oxides (NO_X) or volatile organic compounds (VOC) shall be considered major for ozone. Therefore the facility is also major for ozone. In the GHG Tailoring rule, in order for there to be a major modification in regards to GHG emissions, the total facility GHG emissions must be over the 100,000 tpy PSD threshold for the facility and the increase in emissions must be over 75,000 tpy. Below is a table comparing the total project emissions to the corresponding SER emission rates.

PSD Applicability: SER Comparison

	CO (ton/yr)	VOCs (ton/yr)	SO_x (ton/yr)	PM_{10} (ton/yr)	$PM_{2.5}$ (ton/yr)	CO_2e (ton/yr)
Project Total	113.9	153.9	95.7	20.1	20.1	339,035.0
SER Threshold	100 tpy	40 tpy	40 tpy	15 tpy	10 tpy	75,000 tpy
Are project emissions above SER thresholds?	**YES**	**YES**	**YES**	**YES**	**YES**	**YES**

The above tables show this project will trigger PSD for the following pollutants: NO_X, CO, VOC, SO_X, PM_{10}, $PM_{2.5}$, CO_2e, and ozone. A BACT analysis and other accompanying documents are required in this section. The following documents are attached to this section:

- **Section 12.1 – Updated BACT Analysis**
- **Section 12.2 – Updated Pre-Construction Monitoring Analysis**
- **Section 12.3 – Additional Impact Analysis Waiver**

The modeling waiver can be found in Section 16 of the application.

Section 12.B
Special Requirements for a PSD Application

(Submitting under 20.2.74 NMAC)

Prior *to Submitting a PSD application*, the permittee shall:

- ☑ Submit the BACT analysis for review prior to submittal of the application. No application will be ruled complete until the final determination regarding BACT is made, as this determination can ultimately affect information to be provided in the application. A pre-application meeting is recommended to discuss the requirements of the BACT analysis.
- ☐ Submit a modeling protocol prior to submitting the permit application. **[Except for GHG]**
- ☐ Submit the monitoring exemption analysis protocol prior to submitting the application. **[Except for GHG]**

For PSD applications, the permittee shall also include the following:

- ☐ Documentation containing an analysis on the impact on visibility. **[Except for GHG]**
- ☐ Documentation containing an analysis on the impact on soil. **[Except for GHG]**
- ☐ Documentation containing an analysis on the impact on vegetation, including state and federal threatened and endangered species. **[Except for GHG]**
- ☐ Documentation containing an analysis on the impact on water consumption and quality. **[Except for GHG]**
- ☑ Documentation that the federal land manager of a Class I area within 100 km of the site has been notified and provided a copy of the application, including the BACT and modeling results. The name of any Class I Federal area located within one hundred (100) kilometers of the facility.

This application is being submitted as a continuation of the original PSD application as the facility is still under construction. The original BACT analysis is being updated to reflect the changes proposed in this application. Air dispersion modeling and the additional impacts analysis have been waived as facility-wide pollutant emission rates are decreasing.

Section 12.1– BACT Analysis

- Attached is the updated BACT analysis for the facility.

BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

DCP Midstream, LP > Zia II Gas Plant

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April 2015

Project 143201.0195

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LIST OF TABLES

1. BACT DEFINITION

This report discusses the regulatory basis and approach used in completing the Best Available Control Technology (BACT) analysis for pollutants triggering this requirement for the DCP Midstream, LP (DCP) Zia II Gas Plant (Zia). In addition, this report also documents the emission units for which the BACT analyses were performed.

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

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

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

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

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

1.1. EMISSION LIMITATION

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is prefaced upon the application of technologies reflecting the maximum reduction rate achievable, the final result of BACT is an emission limit. Typically when quantifiable and measurable,[1] this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr).[2] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as 30- or 365-day rolling average.[3]

---

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

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

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

1.2. EACH POLLUTANT

Since BACT applies to "each pollutant subject to regulation under the Act," the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[4] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act (CAA) is the sum of six greenhouse gases and not a single pollutant.[5] In the final Tailoring Rule preamble, EPA went beyond applying this combined pollutant approach for GHGs to PSD applicability and made the following recommendations that suggest applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG:

> *However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.*[6]

For the proposed project, the GHG emissions are driven primarily by CO_2. CO_2 emissions represent more than 99% of the total CO_2e for the project as a whole. As such, the top-down GHG BACT analysis in the relevant sections should and will focus on CO_2.

1.3. BACT APPLIES TO THE PROPOSED SOURCE

BACT applies to the type of source proposed by the applicant. BACT does not redefine the source. The applicant defines the source (i.e., its goals, aims and objectives). Although BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. A key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. The proposed project is discussed in Form UA3, Section 3 and a process description has been included in Form UA3, Section 10 of this application to aid the technical reviewers in need and scope of this project and how BACT should be reviewed in light of this detailed information.

1.4. CASE-BY-CASE BASIS

Unlike many of the CAA programs, the PSD program's BACT evaluation is case-by-case. BACT permit limits are not simply the requirement for a control technology because of its application elsewhere or the direct transference of the lowest emission rate found in other permits for similar sources, applied to the proposed source. EPA has explained how the top-down BACT analysis process works on a case-by-case basis. To assist applicants and regulators with the case-by-case process, in 1990 EPA issued a Draft Manual on New Source Review permitting which included a "top-down" BACT analysis.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative.*

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[4] 40 CFR §52.21(b)(12)

[5] 40 CFR § 52.21(b)(49)(i)

[6] 75 FR 31,531, Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule, June 3, 2010.

That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.[7]

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

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

Additionally, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under the PSD regulations.[8]

1.5. ACHIEVABLE

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

In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable" under most adverse circumstances which can reasonably be expected to recur."[9]

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

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

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7 Draft NSR Manual at B-2. "The NSR Manual has been used an a guidance document in conjunction with new source review workshops and training, and as a simple guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding Agency regulation, the NSR Manual has been looked to be this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen Energy Ctr*., 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass*, *GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

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

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

extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.[10]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

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

1.6. PRODUCTION PROCESS

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

1.7. AVAILABLE

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

1.8. FLOOR

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

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

2. PROJECT DEFINITION

DCP is proposing to construct a 230 million standard cubic feet per day (MMscfd) natural gas plant in Lea County, New Mexico, approximately 25 miles northwest of the city of Carlsbad, NM. The facility will be composed of the following:

- Eight (8) Caterpillar G3616 natural gas fired compressors rated at 4,735 hp each:
  - 4-stroke lean burn natural gas engines: (C1-E through C8-E) and,
  - Compressors: C-1C through C-8C.
- Two (2) Caterpillar G3608 natural gas fired compressors rated at 2,370 hp each (C9-E and C10-E);
  - Three (3) additional compressors (C-11C through C-13C) that will be fired by electric motors.
- One (1) trim reboiler heater rated at 26.0 MMBtu/hr (H1);
- One (1) regeneration gas heater rated at 10 MMBtu/hr (H3);
- Two (2) hot oil heaters rated at 99 MMBtu/hr each (H4 and H5);
- One (1) TEG regeneration heater rated at 3.0 MMBtu/hr (H6);
- One (1) triethylene glycol (TEG) dehydrator rated at 230 MMscfd gas throughput (Dehy);
- One (1) amine unit for acid gas sweetening rated at 230 MMscfd gas throughput (Amine);
- One (1) Inlet Gas Flare (FL1);
- One (1) Acid Gas Flare (FL2);
- One (1) Emergency Lusk Flare (FL-3);
- Two (2) condensate tanks with 1,000 bbl capacity each controlled by a vapor combustion unit (VCD1) (TK-2100 and TK-2200);
- Two (2) produced water tanks; each of 300 bbl capacity each controlled by a vapor combustion unit (VCD) (TK-6100, and TK-6150);
- One (1) vapor combustion device for control of emissions from condensate tanks (VCD-1) with a capacity of 3.6 MMBtu/hr;
- Truck loadout (L1);
- Facility-wide fugitives (FUG);
- Paved Haul Roads (HAUL);
- Cummins Diesel Generator (model DSFAC) rated to 70 hp and 500 hrs per year (GEN-1);
- Wet Surface Air Cooler (model A4407SL) rated at 131,500 lbs/hr (CT-1);
- Tanks that are not a source of emissions:
  - Engine/Compressor Oil Tank (TK-7015) rated at 1,036 gallons;
  - Amine Storage Tank with Blanket Gas Tank (TK-7020) rated at 400 bbl;
  - Used Oil Storage Tank (TK-7025) rated at 1,036 gallons;
  - Jacket/Aux Water Storage Tank (TK-7035) rated at 1,036 gallons and;
  - Engine/Compressor Oil Tank (TK-7045) rated at 1,036 gallons and;
  - R.O. Waste Storage Tank (TK-7050) rated at 175 bbl and;
  - Used Oil Storage Tank (TK-7055) rated at 1,036 gallons and;
  - Jacket/Aux Water Storage Tank (TK-7065) rated at 1,036 gallons and;
  - R.O. Waste Storage Tank (TK-7070) rated at 195 bbl and;
  - Compressor Crank Case Oil Storage Tank (TK-7075) rated at 1,036 gallons and;
  - Used Oil Storage Tank (TK-7085) rated at 1,036 gallons and;
  - Compressor Lubrication Oil Storage Tank (TK-7095) rated at 1,036 gallons and;
  - Compressor Lubrication Oil Storage Tank (TK-7105) rated at 1,036 gallons and;
  - Compressor Lubrication Oil Storage Tank (TK-7115) rated at 1,036 gallons and;
  - Refrigerant Compressor Lube Oil Storage Tank (TK-7400) rated at 500 gallons and;
  - Used Refrigerant Compressor Oil Storage Tank (TK-7410) rated at 500 gallons and;

- H.M.O. Make-up Tank (TK-7500) rated at 150 gallons and;
- Glycol Storage Tank (TK-7600) rated at 150 gallons and;
- Methanol Storage Tank (TK- 7700) rated at 1,500 gallons and;
- Methanol Storage Tank (TK-7750) rated at 1,500 gallons and;
- Methanol Storage Tank (TK-7800) rated at 1,036 gallons and;
- Raw Water Storage Tank (TK- WATER) rated at 1,000 bbl and;
- Lusk Slop Tank (TK-L1) rated at 210 bbl and;
- Lusk Methanol Tank (TK-L2) rated at 443 bbl and;
- Diesel Tank (TK-3) rated at 1,000 gallons.

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

Additionally, EPA's March 2011 GHG Permitting Guidance generally directed that a BACT review for GHGs should be done in the same manner as it is done for any other regulated pollutant.[11] It should be noted that the scope of a BACT review was clarified in two ways with respect to GHGs:

- EPA stressed that applicants should clearly define the scope of the project being reviewed.[12] DCP has provided this information in Section 1 and Section 9 (Attachment G) of this application.
- EPA clarified that the scope of the BACT should focus on the project's largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review.[13]

3.1. STEP 1 – IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

Available control technologies with the practical potential for application to the emission unit and regulated air pollutant in question are identified. Available control options include the application of alternate production processes and control methods, systems, and techniques including fuel cleaning and innovative fuel combustion, when applicable and consistent with the proposed project. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

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

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

For GHGs, DCP will rely on items (2) through (5) and preliminary information from the EPA BACT GHG Workgroup for data to establish BACT.

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1.[14] For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. DCP proposes the use of

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

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

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

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

pipeline quality natural gas only for all combustion equipment associated with the proposed project which produces lesser CO_2 per unit of heat released compared to more carbon intensive fuels such as fuel oil or coal. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (MMBtu) for a wide variety of industrial fuel types. Only biogas (captured methane) and coke oven gas result in lower CO_2 emissions per unit heat input than natural gas, but these fuel types are not readily available for this project.

Additionally, EPA's GHG BACT guidance suggests that carbon capture and sequestration (CCS) be evaluated as an available control for substantial, large projects such as steel mills, refineries, and cement plants where CO_2e emissions levels are in the order of 1,000,000 tpy, or for industrial facilities with high-purity CO_2 streams.[15] However, EPA explained that "this does not necessarily mean CCS should be selected as BACT for such sources." The proposed project emissions are approximately 326,486.0 tpy CO_2e. All the emission sources result in low purity CO_2 streams. Nonetheless, CCS is evaluated as a control option for the proposed project.

3.2. STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling individual pollutant emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination, although a source may cite specific site-specific differences to eliminate a technology form consideration.

> Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[16]

An undemonstrated technology is only technically feasible if it is "available" and "applicable." A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is "commercially available".[17] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration."[18] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

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[15] *PSD and Title V Permitting Guidance for Greenhouse Gases*. March 2011, pages 32-33.

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

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

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

3.3. STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

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

3.4. STEP 4 – EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified. EPA recognized in its BACT guidance for GHGs that "[e]ven if not eliminated at Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[19]

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares, combustors and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the GWP of CH_4 is 25 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

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

3.5. STEP 5 – SELECT BACT

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

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

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts.

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

Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Workgroup has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, NAAQS are not established for GHGs in the Tailoring Rule and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, DCP proposes only an annual average GHG BACT limit.

For the Zia II Gas Plant, the BACT requirement applies to each emission unit from which there are emissions increases of pollutants subject to PSD review. The proposed facility is subject to PSD permitting for CO, NO_X, VOC, PM_{10}, $PM_{2.5}$, SO_2, and GHGs. Therefore, the proposed project is subject to BACT analysis for these pollutants.

Table 4-1 identifies the pollutants considered in the PSD BACT analysis for each emission unit.

Table 4-1. Pollutants Evaluated in the BACT Analysis for Each Emission Unit

Equipment	NO_X (Yes/No)	CO (Yes/No)	$PM_{10}/PM_{2.5}$ (Yes/No)	VOC (Yes/No)	SO_2 (Yes/No)	GHG (Yes/No)
Compressor Engines	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Heaters < 100 MMBtu/hr	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Heaters < 10 MMBtu/hr	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**
Amine Unit Still Vent	No	No	No	**Yes**	No	**Yes**
Dehydrator Still Vent	No	No	No	**Yes**	No	**Yes**
Storage Tanks	No	No	No	**Yes**	No	No*
Truck Loading	No	No	No	**Yes**	No	No*
Vapor Combustion Device	**Yes**	**Yes**	No	**Yes**	No	**Yes**
Flares	**Yes**	**Yes**	No	**Yes**	**Yes**	**Yes**
Facility-Wide Fugitives	No	No	No	**Yes**	No	**Yes**
Haul Roads	No	No	**Yes**	No	No	No
Wet Surface Air Cooler	No	No	**Yes**	No	No	No
Diesel Fuel Engine	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**	**Yes**

* There are no methane or carbon dioxide fractions in the stabilized condensate; therefore no GHG BACT is evaluated for this source.

The following sections provide detail on the BACT assessment methodology utilized in preparing the BACT analysis for the proposed Zia II facility. The minimum control efficiency to be considered in a BACT assessment must result in an emission rate less than or equal to any applicable NSPS or NESHAP emission rate for the source. The following NSPS or NESHAP emission limits will apply to proposed equipment and effectively set the floor for BACT for these units for certain pollutants:

Table 4-2. BACT Floor Emission Limits

Subpart	Description	Applicability	Affected Sources (EPN)	Applicable Emission Limits
Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	Yes	Compressor Engines (C1-E through C10-E)	NO_X - 1.0 g/hp-hr or 82 ppmvd CO - 2.0 g/hp-hr or 270 ppmvd VOC - 0.7 g/hp-hr or 60 ppmvd
Subpart IIII	Standard of Performance for Stationary Compression Ignition Internal Combustion Engine	Yes	Diesel Fuel Engine (GEN-1)	NO_X – 6.9 g/hp-hr
40 CFR Part 89	Control of Emissions from New and In-Use Nonroad Compression-Ignition Engines	Yes	Diesel Fuel Engine (GEN-1)	NO_X – 3.3 g/hp-hr CO – 3.7 g/hp-hr VOC - 0.18 g/hp-hr $PM_{10}/PM_{2.5}$ - 0.18 g/hp-hr SO_2 - 15 ppm sulfur
Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution	Yes	Reciprocating Compressors (C1-C through C13-C), Amine Sweetening Unit (Amine), Condensate Tanks (TK-2100 and TK-2200), Facility-Wide Fugitives (FUG)	VOC - 95% Control Requirement from Tanks, VOC – 500 ppm leak detection requirement from fugitives
Subpart ZZZZ	National Emission Standards for Hazardous Air Pollutants For Stationary Reciprocating Internal Combustion Engines	Yes	Compressor Engines (C1-E through C10-E)	Comply with the emission limits of NSPS Subpart IIII and Subpart JJJJ

4.1. IDENTIFICATION OF POTENTIAL CONTROL TECHNOLOGIES

Potentially applicable emission control technologies were identified by researching the U.S. EPA control technology database (RBLC), technical literature, control equipment vendor information, state permitting authority files, and by using process knowledge and engineering experience. The RBLC, a database made available to the public through the U.S. EPA's Office of Air Quality Planning and Standards (OAQPS) Technology Transfer Network (TTN), lists technologies and corresponding emission limits that have been approved by regulatory agencies in major source permit actions. These technologies are grouped into industry categories and can be referenced in determining what emissions levels were proposed for similar types of emissions units.

An RBLC database search was performed in March 2015 to identify the emission control technologies and emission levels that were determined by permitting authorities as BACT within the past ten years for sources comparable to those proposed for Zia. The following categories were searched:

- Large Internal Combustion Engines > 500 hp (RBLC Code 17.100);
- Heater < 100 to ≥ 50 MMBtu/hr | < 50 to > 10 MMBtu/hr | ≤ 10 MMBtu/hr (RBLC Code 13.310);
- Glycol Units (RBLC Code 50.005);
- Amine Units (RBLC Code 50.006);
- Flares (RBLC Code 19.330);
- Storage Tanks (RBLC Code 42.009);
- Truck Loadout (RBLC Code 50.004);
- Fugitive Equipment Leaks (RBLC Code 50.007);
- Paved Haul Roads (RBLC Code 99.150);
- Diesel Generator (RBLC Code 17.210); and
- Cooling Tower (RBLC Code 99.009)

Appendix A includes the RBLC search results. Since the RBLC database is still very limited in the number of entries for GHG emissions, DCP relied on items (2) through (5) in Section 3.1 and preliminary information from the EPA BACT GHG Workgroup for data to establish BACT.

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

- *PSD and Title V Permitting Guidance for Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)*[20]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Industrial Boilers (hereafter referred to as GHG BACT Guidance for Boilers)*[21]
- *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries)*[22]

4.2. PROPOSED PRIMARY BACT LIMITS SUMMARY

Based on BACT assessment, DCP proposes the BACT limits shown in Table 4-3. A detailed discussion of the determination for each emission source is provided in the following Sections of this report.

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

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

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

Table 4-3. Proposed Primary BACT Limits Summary

Unit	Pollutant	Limit	Proposed BACT
Compressor Engines (C1-E through C8-E)	NO_x	0.5 g/bhp-hr	Clean burn technology and good combustion practices
	CO	0.05 g/bhp-hr for	Catalytic Oxidation and good combustion practices
	VOC	0.20 g/bhp-hr for	Catalytic Oxidation and good combustion practices
	$PM_{10}/PM_{2.5}$	9.99 E-03 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	15,445 tpy	Pipeline quality natural gas, good combustion practices, lean burn engines, and air/fuel meters.
Compressor Engines (C9-E through C10-E)	NO_x	0.5 g/bhp-hr	Clean burn technology and good combustion practices
	CO	0.18 g/bhp-hr	Catalytic Oxidation and good combustion practices
	VOC	0.30 g/bhp-hr	Catalytic Oxidation and good combustion practices
	$PM_{10}/PM_{2.5}$	9.99 E-03 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	10,618 tpy	Pipeline quality natural gas, good combustion practices, lean burn engines, and air/fuel meters.
Heaters < 100 to ≥ 50 MMBtu/hr (H4, H5)	NO_x	0.060 lb/MMBtu	Low NO_X burners and good combustion practices
	CO	0.041 lb/MMBtu	Good combustion practices
	VOC	0.0054 lb/MMBtu	Good combustion practices
	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, good combustion practices, heat integration, and efficient heater design
Heaters < 50 to > 10 MMBtu/hr (H1)	NO_x	0.049 lb/MMBtu	Low NO_X burners and good combustion practices
	CO	0.082 lb/MMBtu	Good combustion practices
	VOC	0.0054 lb/MMBtu	Good combustion practices
	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, good combustion practices, heat integration, and efficient heater design
Heaters ≤ 10 MMBtu/hr (H3, H6)	NO_x	0.49 lb/MMBtu	Low NO_X burners and good combustion practices
	CO	0.082 lb/MMBtu	Good combustion practices
	VOC	0.0054 lb/MMBtu	Good combustion practices
	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, good combustion practices, heat integration, and efficient heater design
Amine Sweetening Unit Still Vent (Amine)	VOC	-	Acid gas injection well
	CO_2e	-	Acid gas injection well
TEG Dehydrator Still Vent (Dehy)	VOC	-	Vapor Combustion Device – 98% DRE, Condenser
	CO_2e	-	Vapor Combustion Device – 98% DRE, Proper design and operation, Tank off-gas recovery systems, and Condenser
Storage Tanks (TK-2100, TK-2200, TK-6100, TK-6150)	VOC	-	Fixed roof with submerged fill and tanks vented to VCD1

Tank Loadout (L1)	VOC	-	Submerged loading & VCD1
Vapor Combustion Device (VCD1)	NO_x	0.098 lb/MMBtu	Good combustion practices
	CO	0.082 lb/MMBtu	Good combustion practices
	VOC	0.21 lb/MMBtu	Good combustion practices
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, proper VCD design, and proper operation and maintenance procedures
Flares (FL1, FL2, FL3)	NO_x, CO, VOC, $PM_{10}/PM_{2.5}$, SO_2, CO_2e	-	Good flare design, good combustion, operating and maintenance practices, use of pipeline quality natural gas for pilot, and limiting vent gas releases
Facility-Wide Fugitives (FUG)	VOC	-	40 CFR 60 Subpart OOOO equipment leak standards/LDAR Program
Paved Haul Roads (HAUL)	$PM_{10}/PM_{2.5}$	-	Paved road and a transit speed limit of 25 mph.
Diesel PowerEngines (GEN-1)	NO_x	3.3 g/bhp-hr	EPA Tier 3 Emission Standards and Good Combustion Practices
	CO	3.7 g/bhp-hr for	EPA Tier 3 Emission Standards and Good Combustion Practices
	VOC (as NMHC)	0.18 g/bhp-hr for	EPA Tier 3 Emission Standards and Good Combustion Practices
	$PM_{10}/PM_{2.5}$	0.02 g/bhp-hr	Pipeline quality natural gas, good combustion practices and Ultra Low Sulfur Diesel (USLD)
	SO_2	15 ppm of Sulfur	Ultra Low Sulfur Diesel (ULSD)
	CO_2e	163 lb/MMBtu	Pipeline quality natural gas, good combustion practices, lean burn engines, and air/fuel meters.
Wet Surface Air Cooler (CT-1)	PM	99.995% Control	Drift Eliminator

4.3. PROPOSED GOOD COMBUSTION PRACTICES

For several sources in the following sections, good combustion practices are proposed as one of the best available control technologies. Table 4-4 provides a listing of the practices that DCP proposes as part of good combustion techniques.

Table 4-4. Proposed Good Combustion Practices

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

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

The BACT evaluation for the proposed compressor engines (C1-E through C10-E) for NO_X, CO, VOC, PM_{10}/$PM_{2.5}$, SO_2, and CO_2e is provided in Sections 5.1 through 5.7. Appendix A provides a summary of RBLC and permit search results.

5.1. NO_X BACT

5.1.1. Background on Pollutant Formation

In combustion processes, NO_X is formed by two fundamentally different mechanisms: Fuel NO_X and thermal NO_X. NO_X formation from natural gas combustion is primarily thermal NO_X.

"Fuel NO_X" forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since natural gas contains little or no fuel-bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from natural gas-fired compressor engines.[23]

Thermal NO_X is formed by a series of chemical reactions in which oxygen and nitrogen present in the combustion air dissociate and react to form NO_X. Prompt NO_X, a form of thermal NO_X, is formed in the proximity of the flame front as intermediate combustion products such as HCN, N, and NH are oxidized to form NO_X.

In addition to prompt NO_X, thermal NO_X is formed through the Zeldovich mechanism. The amount of NO_X generated through this mechanism increases exponentially as a function of temperature and linearly as a function of residence time. The rate of NO_X generation decreases significantly at temperatures below 2,780 °F. Therefore, reducing combustion temperature is a common approach to reducing NO_X emissions.[24]

In lean premix systems, atmospheric nitrogen acts as a diluent, as fuel is mixed with air upstream of the combustor at fuel-lean conditions. The fuel to air ratio is maintained well below the ideal stoichiometric level to limit NO_X formation, as lean conditions cannot produce the high temperatures that create thermal NO_X. In addition, premixing prevents local "hot spots" within the combustor that can lead to significant NO_X formation. [25]

In stationary source combustion, little of the nitrogen oxide (NO) is converted to nitrogen dioxide (NO_2) in the combustion process. However, the NO continues to oxidize in the atmosphere.

5.1.2. Identify All Available Control Technologies

NO_X reduction in internal combustion engines can be accomplished by combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for

[23] U.S. DOE, Office of Fossil Energy, National Technology Energy Laboratory, *The Gas Turbine Handbook*, 2006. http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/TableofContents.html

[24] U.S. DOE, Office of Fossil Energy, National Technology Energy Laboratory, *The Gas Turbine Handbook*, 2006. http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/TableofContents.html

[25] U.S. DOE, Office of Fossil Energy, National Technology Energy Laboratory, *The Gas Turbine Handbook*, 2006. http://www.netl.doe.gov/technologies/coalpower/turbines/refshelf/handbook/TableofContents.html

example) that limit initial NO_X formation, or both. Post-combustion NO_X control technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for large internal combustion engines were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-1 outlines the top down BACT analysis for NO_X emissions from the compressor engines.

5.1.3. Selection of BACT for NO_X

The compressor engines will be subject to NSPS Subpart JJJJ[26]. NSPS JJJJ provides a NO_X limit of 1.0 g/bhp-hr for compressor engines when burning natural gas. The most stringent RBLC and permit entries for NO_X control are provided in Appendix A.   DCP has determined that NO_X BACT for normal operation is a limit of 0.5 g/bhp-hr at 15% O_2 based on the average of three 1-hour or longer runs, per NSPS Subpart JJJJ Table 2, utilizing lean burn technology and good combustion practices.

[26] Table 1 to Subpart JJJJ of Part 60 – NO_X, CO, VOC Emission Standards for Stationary non-emergency engines

Table 5-1. BACT Analysis for Natural Gas Fired Internal Combustion Compressor Engines - NO_X

		Control Technology	**Selective Catalytic Reduction (SCR)[a]**	**Non-Selective Catalytic Reduction (NSCR)**	**Clean Burn Technology**	**Good Combustion Practices**
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_X. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_X. The excess hydrocarbons, CO, and NO_X pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_X to N_2.[b]	Natural gas fueled engines that operate with a fuel-lean air/fuel ratio are capable of low NO_X emissions.	NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and fuel quality analysis and fuel handling.
		Typical Operating Temperature	480 - 800 °F (variations of ± 200 °F)	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 20 ppm (efficiency improves with increased concentration up to 150 ppm)	N/A	N/A	N/A
		Other Considerations	Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a sootblower.	N/A	N/A	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not included in RBLC for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of NO_X emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of NO_X emissions from large combustion engines.	Included in RBLC for the control of NO_X emissions from large combustion engines.
		Feasibility Discussion	Technically infeasible. For engines which typically operate at variable loads, such as engines on gas transmission pipelines, an SCR system may not function effectively, causing either periods of ammonia slip or insufficient ammonia to gain the reductions needed.[b]	Technically infeasible. The NSCR technique is limited to engines with normal exhaust oxygen levels of 4 percent or less. This includes 4-stroke rich-burn naturally aspirated engines and some 4-stroke richburn turbocharged engines. Lean-burn engines could not be retrofitted with NSCR control because of the reduced exhaust temperatures.[b]	Technically feasible.	Technically feasible.
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**			Base Case	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**				
Step 5.	**SELECT BACT**					

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
b. U.S. EPA, AP-42, Section 3.2, "Natural Gas-Fired Reciprocating Engines'

5.2. CO BACT

5.2.1. Background on Pollutant Formation

CO from large internal combustion engines is a by-product of incomplete combustion. Conditions leading to incomplete combustion include insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

5.2.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable CO control technologies for large internal combustion engines were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-2 outlines the top-down BACT analysis for CO emissions from the combustion engines.

5.2.3. Selection of BACT for CO

The compressor engines will be subject to NSPS Subpart JJJJ. NSPS JJJJ provides a CO limit of 2 g/bhp-hr for compressor engines when burning natural gas. The most stringent RBLC and permit entries for CO control are provided in Appendix A. DCP has determined that CO BACT for normal operation is a limit of 0.05 g/bhp-hr for the Caterpillar G3616 compressor engines and 0.18 g/bhp-hr for the Caterpillar G3608 compressor engines on a 3-hour rolling average basis, per NSPS Subpart JJJJ Table 2, utilizing catalytic oxidation and good combustion practices.

Table 5-2. BACT Analysis for Natural Gas Fired Internal Combustion Compressor Engines – CO

		Control Technology	Regenerative Thermal Oxidizer	Recuperative Thermal Oxidizer	Catalytic Oxidation[e]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation of the engine at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation.
		Typical Operating Temperature	1,400 - 1,500 °F[b]	1,100 - 1,200 °F[c]	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	5,000 - 500,000 scfm[b]	500 - 50,000 scfm[c]	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less[b]	As low as 100 ppmv or less[b]	As low as 1 ppmv	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[c]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of CO emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of CO emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Widely accepted as BACT for control of CO emissions from internal combustion engines.	Included in RBLC for the control of CO emissions from internal combustion engines.
		Feasibility Discussion	Technically infeasible. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.	Technically infeasible. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			93-98%	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)				
Step 5.	SELECT BACT				👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020
d. California EPA, Air Resources Board, "Report to the Legislature: Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts," http://www.arb.ca.gov/research/apr/reports/l2069.pdf
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

5.3. VOC BACT

5.3.1. Background on Pollutant Formation

The formation of VOC is the result of incomplete combustion of natural gas. VOC results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation.

5.3.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for large internal combustion engines were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-3 outlines the top-down BACT analysis for VOC emissions from the combustion engines. Generally, the control technologies for VOC are identical to those for CO.

5.3.3. Selection of BACT for VOC

The compressor engines will be subject to NSPS Subpart JJJJ. NSPS JJJJ provides a VOC limit of 0.7 g/bhp-hr at 15 percent O_2 for compressor engines when burning natural gas. The most stringent RBLC and permit entries for VOC control are provided in Appendix A. DCP has determined that VOC BACT for normal operation is a limit of 0.20 g/bhp-hr for the Caterpillar G3616 compressor engines and 0.30 g/bhp-hr for the Caterpillar G3608 compressor engines at 15% O_2 on a 3-hour rolling average basis, per NSPS Subpart JJJJ Table 2, utilizing catalytic oxidation and good combustion practices.

Table 5-3. BACT Analysis for Natural Gas Fired Internal Combustion Compressor Engines – VOC

		Control Technology	Regenerative Thermal Oxidizer	Recuperative Thermal Oxidizer	Catalytic Oxidation[e]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation of the engine at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation.
		Typical Operating Temperature	1,400 - 1,500 °F[b]	1,100 - 1,200 °F[c]	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	5,000 - 500,000 scfm[b]	500 - 50,000 scfm[c]	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less[b]	As low as 100 ppmv or less[b]	As low as 1 ppmv	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[c]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of CO emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of CO emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Widely accepted as BACT for control of CO emissions from internal combustion engines.	Included in RBLC for the control of CO emissions from internal combustion engines.
		Feasibility Discussion	Technically infeasible. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.	Technically infeasible. Thermal oxidizers do not reduce emissions of CO from properly operated natural gas combustion units without the use of a catalyst.	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			93-98%	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)				
Step 5.	SELECT BACT				👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020
d. California EPA, Air Resources Board, "Report to the Legislature: Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts," http://www.arb.ca.gov/research/apr/reports/l2069.pdf
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

5.4. $PM_{10}/PM_{2.5}$ BACT

5.4.1. Background on Pollutant Formation

Filterable PM emissions from natural gas combustion are formed by ash and sulfur in the fuel. Combustion of natural gas generates low filterable PM emissions in comparison to other fuels due to its low ash and sulfur contents. Condensable particulate matter results from sulfur in the fuel and the resultant H_2SO_4, NO_X being oxidized to nitric acid (HNO_3), and high molecular weight organics.

5.4.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable particulate control technologies were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-4 outlines the top-down BACT analysis for filterable particulate emissions from the compressor engines. Table 5-45 outlines the top-down BACT analysis for condensable particulate emissions from the compressor engines.

5.4.3. Selection of BACT for $PM_{10}/PM_{2.5}$

Based on the review of the RBLC search and other permit review results, DCP has determined that the $PM_{10}/PM_{2.5}$ BACT limit is 9.99E-03 lb/MMBtu by implementing good combustion practices and use of pipeline quality natural gas.

Table 5-4. BACT Analysis for Natural Gas Fired Internal Combustion Compressor Engines Filterable $PM_{10}/PM_{2.5}$

		Control Technology	Baghouse / Fabric Filter[a]	Electrostatic Precipitator (ESP)[b,c,d]	Cyclone[e]	Pipeline Quality Natural Gas[f]	Good Combustion Practices
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Process exhaust gas passes through a tightly woven or felted fabric arranged in sheets, cartridges, or bags that collect PM via sieving and other mechanisms. The dust cake that accumulates on the filters increases collection efficiency. Various cleaning techniques include pulse-jet, reverse-air, and shaker technologies.	Electrodes stimulate the waste gas and induce an electrical charge in the entrained particles. The resulting electrical field forces the charged particles to the collector walls from which the material may be mechanically dislodged and collected in dry systems or washed with a water deluge in wet systems.	Centrifugal forces drive particles in the gas stream toward the cyclone walls as the waste gas flows through the conical unit. The captured particles are collected in a material hopper below the unit.	Combusting only natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.
		Typical Operating Temperature	Up to 500 °F (Typical)	Up to 1,300 °F (dry) Lower than 170 - 190 °F (wet)	Up to 1,000 °F	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	100 - 100,000 scfm (Standard) 100,000 - 1,000,000 scfm (Custom)	1,000 - 100,000 scfm (Wire-Pipe) 100,000 - 1,000,000 scfm (Wire-Plate)	1.1 - 63,500 scfm (single) Up to 106,000 scfm (in parallel)	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	0.5 - 10 gr/dscf (Typical) 0.05 - 100 gr/dscf (Achievable)	0.5 - 5 gr/dscf (Wire-Pipe) 1 - 50 gr/dscf (Wire-Plate)	0.44 - 7,000 gr/dscf	N/A	N/A
		Other Considerations	Fabric filters are susceptible to corrosion and blinding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazards.	Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial.	Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop.	N/A	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not included in RBLC for the control of PM emissions for natural gas-fired stationary internal combustion engines.	Not included in RBLC for the control of PM emissions for natural gas-fired stationary internal combustion engines.	Not included in RBLC for the control of PM emissions for natural gas-fired stationary internal combustion engines.	Included in RBLC for the control of PM emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of PM emissions from large natural gas-fired lean-burn stationary internal combustion engines.
		Feasibility Discussion	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.	Feasible	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**				Base Case	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**					
Step 5.	**SELECT BACT**						

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Fabric Filter - Pulse-Jet Cleaned Type)," EPA-452/F-03-025.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Pipe Type)," EPA-452/F-03-027.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Plate Type)," EPA-452/F-03-028.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Wet Electrostatic Precipitator(ESP) - Wire-Pipe Type)," EPA-452/F-03-029.
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Cyclone)," EPA-452/F-03-005.
f. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr/100 scf or less.

Table 5-5. BACT Analysis for Natural Gas Fired Internal Combustion Compressor Engines Condensable $PM_{10}/PM_{2.5}$

		Control Technology	Thermal Incineration	Catalytic Oxidation[e]	Pipeline Quality Natural Gas	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Oxidizes some particulate matter commonly composed as soot, which are formed as a result of incomplete combustion of hydrocarbons, by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Combusting only natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.
		Typical Operating Temperature	1,100 - 1,200 °F [c]	600 - 800 °F (not to exceed 1,250 °F)	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm [c]	700 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less [b]	As low as 1 ppmv	N/A	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of condensable PM emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Not included in RBLC for the control of condensable PM emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of PM emissions from large natural gas-fired lean-burn stationary internal combustion engines.	Included in RBLC for the control of PM emissions from large natural gas-fired lean-burn stationary internal combustion engines.
		Feasibility Discussion	Technically infeasible. Thermal oxidizers do not reduce emissions of condensable PM from properly operated natural gas combustion units without the use of a catalyst.	Feasible	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency		25-99.9%	Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)		No specific removal rate is identified for natural gas combustion. Further, a literature review found no studies onf the removal efficiencies achieved by catalytic oxidation for exhaust streams from natural gas combustion. Therefore, what percent removal (if any) actually achieved on removal of organic condensable PM is not known. Regardless, the engine will include an oxidation catalyst due to CO and VOC control requirements.		
Step 5.	SELECT BACT			👍	👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020.
d. California EPA, Air Resources Board, "Report to the Legislature: Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts," http://www.arb.ca.gov/research/apr/reports/l2069.pdf
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018.

5.5. SO_2 BACT

5.5.1. Background on Pollutant Formation

SO_2 emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel.

5.5.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable SO_2 control technologies were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-6 outlines the top-down BACT analysis for SO_2 emissions from the compressor engines.

5.5.3. Selection of BACT for SO_2

Based on the review of the RBLC search and other permit review results, DCP has determined that the SO_2 BACT limit is 5 gr S/100 scf of sulfur in the fuel inlet by utilizing pipeline quality natural gas.

Table 5-6. BACT Analysis for Natural Gas Fired Internal Combustion Compressor Engines – SO_2

		Control Technology	Flue Gas Desulfurization[a]	Pipeline Quality Natural Gas[b]
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Absorption of SO_2 is accomplished by the contact between the exhaust and an alkaline reagent, which results in the formation of neutral salts. Wet systems employ reagents using packed or spray towers and generate wastewater streams, while dry systems inject slurry reagent into the exhaust stream to react, dry and be removed downstream by particulate control equipment.	Combusting only natural gas, which has an inherently low sulfur content, rather than higher sulfur content fuels alone or in combination with natural gas.
		Typical Operating Temperature	300 - 700 °F (wet) 300 - 1,830 °F (dry)	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	2,000 ppmv	N/A
		Other Considerations	Chlorine emissions can result in salt deposition within the absorber and in downstream equipment. Wet systems may require flue gas re-heating downstream of the absorber to prevent corrosive condensation. Inlet streams for dry systems must be cooled as appropriate, and dry systems require use of particulate controls to collect the solid neutral salts.	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not included in RBLC for the control of SO_2 emissions for natural gas-fired stationary internal combustion engines.	Included in RBLC for the control of SO_2 from natural gas-fired stationary internal combustion engines.
		Feasibility Discussion	Technically infeasible. Technology has not been applied to natural gas combustion engines due to very low SO_2 and H_2SO_4 emissions. Controls would not provide any measurable emission reduction.	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**		Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**			👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Flue Gas Desulfurization)," EPA-452/F-03-034.

b. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr S/100 scf or less.

5.6. GHG BACT

GHG emissions from the proposed engines (C1-E through C10-E) include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The following section presents BACT evaluations for GHG emissions from the proposed engines.

5.6.1. Step 1 – Identify All Available Control Technologies

A search of the RBLC database showed GHG BACT records for CO_2e. However, since it is a new requirement, the records do not contain sources applicable to the Zia II facility. The available GHG emission control strategies for the engines that were analyzed as part of this BACT analysis include[27]:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/Fuel Ratio Controllers; and
- Efficient Engine Design

5.6.1.1. Carbon Capture and Sequestration (CCS)

The contribution of CO_2e emissions from each engine is a fraction of the scale for sources where CCS might ultimately be feasible. Although we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance[28], a detailed rationale is provided to support this conclusion.

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

Larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed.[29] Additionally, these demonstration projects are for post-combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slip stream as compared to a more dilute stream from the combustion of natural gas.[30] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[31]

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

[28] PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011, page 32.

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

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

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

5.6.1.2. Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel for engines proposed at this facility. Additionally, the engines selected can only fire natural gas exclusively.

5.6.1.3. Good Combustion, Operating, and Maintenance Practices

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

5.6.1.4. Air/Fuel Ratio Controllers

Air/fuel ratio controllers minimize CO_2e emissions from reciprocating engines. Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the air/fuel mixture and reduce the amount of energy required to heat the stream and, therefore, reduce the CO_2e emissions. Please note because these engines are equipped with the ultra-lean burn technology, air/fuel ratio controllers are inherent to the process in the engines.

5.6.1.5. Efficient Engine Design and Selection

To select the most efficient engine for the Zia II facility, the following factors were taken into account: Available footprint, operational fluctuations and flexibility, emissions performance, and energy efficiency.

To meet the compression needs of this project, larger engines with high horsepower ratings are required to move the large amounts of gas at the facility. Engines can be manufactured to be rich-burn or lean-burn. Rich burn is an inherently inefficient combustion process that results in increased fuel usage compared to lean burn engines. Therefore, rich burn engines were eliminated from the selection process. DCP then focused on energy efficient lean burn technology.

Caterpillar offers three engine models that could satisfy all the needs of this project: the G3608LE, G3612LE, and G3616LE. The "LE" in the model names means low emission, so these engines also have lower levels of criteria pollutants, which meet the criteria PSD-BACT requirements.

Electric motors will be used in compressor units C-11C to C-13C.

5.6.2. Step 2 – Eliminate Technically Infeasible Options

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

5.6.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the engines and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[32] The engines emit CO_2 in small and more diluted quantities. In addition, the CO_2 concentration in the flue gas stream is approximately 4.6%. Carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale. The use of solid sorbents and membranes are considered to be in the research and development phase. Implementing CCS on the engine flue gas streams would require considerable additional gas processing equipment to separate the CO_2 from the exhaust. The low purity and concentration of CO_2 in the engines' exhaust means that the per ton cost of removal and storage will be much higher than the public data estimates for much larger carbon rich fossil fuel facilities due to the loss of economies of scale. Even using low-side published estimates for CO_2 capture and storage of $256 per ton for equipment with similar flue gas characteristics such as a new natural gas combined cycle turbine, assuming a conservative $6/MBtu gas price (Anderson, S., and Newell, R. 2003. Prospects for Carbon Capture and Storage Technologies. Resources for the Future. Washington DC) means added cost to the project over $42,059,654 per year, which adds a significant cost to the scope of the project. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed compressor engines. CCS is not considered as a control option for further analysis.

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

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

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/Fuel Ratio Controllers; and
- Efficient Engine Design.

There is insufficient grid capacity in this area to operate all thirteen compressor with electric motors, but three compressor (C-11C to C-13C) will operate with electric driven motors while the remaining 10 compressors will ran with natural gas engines. Thus, based on the above, DCP proposes to implement all of the other control options, ranking these control options is not necessary.

5.6.4. Step 4 – Evaluate Most Effective Control Options

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

5.6.5. Step 5 – Select BACT for the Engines

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

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

[32] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology86 that is "available"87 for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed project is not any of the cases EPA suggests above.

- Air/Fuel Ratio Controllers; and
- Efficient Engine Design.

DCP proposes the CO_2e emission limits for the engines:

- For each engine (EPNs: C1 – C8): 16,029 short tons of CO_2e per year per engine
- For each engine (EPNs: C9 – C10): 10,101 short tons of CO_2e per year per engine

These proposed emission limits are based on a 12-month rolling average basis and include CO_2, CH_4, and N_2O emissions.

Compliance with these emission limits will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

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

- All compressor engines will be equipped with lean-burn and low NO_X technology, and will be operated using good combustion practices.
- All engines will be tuned once per year, or more frequently, per manufacturer recommendations.
- CO_2 emitted from the engines will be calculated on a monthly basis using equation C-2a in 40 CFR Part 98 Subpart C.
- CH_4 and N_2O emissions will be calculated on a monthly basis using the default CH_4 and N_2O emission factors contained in Table C-2, equation C-9a of 40 CFR Part 98, and the measured actual heat input (HHV).
- The CO_2e emissions will be calculated on a 12-month rolling average, based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395).
- The high heat value (HHV) of the fuel will be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6).
- The fuel combusted in the compressor engines will be measured and recorded using an operational non-resettable elapsed flow meter. Flow meters will be calibrated annually.

5.7. COMPRESSOR ENGINES BACT SUMMARY

Based on the BACT analysis presented in the preceding subsections, Table 5-7 summarizes the BACT determinations for the compressor engines.

Table 5-7 Compressor Engines BACT Summary

Unit	Pollutant	Limits	Proposed BACT
Compressor Engines (C1-E through C8-E)	NO_X	0.50 g/bhp-hr	Clean burn technology and good combustion practices
	CO	0.05 g/bhp-hr	Catalytic Oxidation and good combustion practices
	VOC	0.20 g/bhp-hr	Catalytic Oxidation and good combustion practices
	$PM_{10}/PM_{2.5}$	9.99 E-03 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	15,445 tpy	Pipeline quality natural gas, good combustion practices, lean burn engines, and air/fuel meters
Compressor Engines (C9-E through C10-E)	NO_X	0.50 g/bhp-hr	Clean burn technology and good combustion practices
	CO	0.18 g/bhp-hr	Catalytic Oxidation and good combustion practices
	VOC	0.30 g/bhp-hr	Catalytic Oxidation and good combustion practices
	$PM_{10}/PM_{2.5}$	9.99 E-03 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	10,618 tpy	Pipeline quality natural gas, good combustion practices, lean burn engines, and air/fuel meters

6. BACT EVALUATION FOR HEATERS FROM < 100 TO ≥ 50 MMBTU/HR

The BACT evaluation for combustion emissions from the proposed heater rated from < 100 to ≥ 50MMBtu/hr (H4 and H5) for NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, SO_2, and CO_2e are provided in Sections 6.1 through 6.6. Appendix A provides a summary of RBLC and permit search results.

6.1. NO_X BACT

6.1.1. Background on Pollutant Formation

The formation of NO_X in heaters and engines follow the same mechanisms. Thermal NO_X and prompt NO_X are the two dominant mechanisms of NO_X formation in the combustion zone of the heaters. Please refer to Section 5.1.1 for a detailed description of NO_X formation.

6.1.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for heaters rated from < 100 to ≥ 50MMBtu/hr were identified. Table 6-6-1 outlines the top-down BACT analysis for NO_X emissions from the heater.

6.1.3. Selection of BACT for NO_x

Based on the review of the RBLC search and other permit review results, DCP has determined that the NO_X BACT for units H4 and H5 is 0.060 lb/MMBtu by utilizing good combustion practices and low NO_X burners.

Table 6-6-1. BACT Analysis for Natural Gas Fired Heaters (< 100 to ≥ 50 MMBtu/hr) – NO_X

		Control Technology	Ultra Low NO_X Burners[a]	Low NO_X Burners[b]	Good Combustion Practices
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	These burners are designed to recirculate flue gas from the flame back into the combustion zone which reduces the average oxygen content within the flame without reducing the flame temperature below the optimum combustion zone.	NOx control from these special burners is based on combustion modification techniques. Precise mixing of fuel and air is used to keep the flame temperature low and to dissipate heat quickly through the use of low excess air, off stoichiometric combustion and combustion gas recirculation	NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and fuel quality analysis and fuel handling.
		Typical Operating Temperature	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	N/A
		Other Considerations	N/A	N/A	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 100 MMBtu/hr)	Included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 100 MMBtu/hr)
		Feasibility Discussion	Technically infeasible. Not implemented on heaters of this size.	Technically feasible.	Technically feasible.
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	80%	75-80%	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**			
Step 5.	**SELECT BACT**				

a. U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document -- NOx Emissions from Process Heaters (Revised)" EPA-453/R-93-034
b. U.S. EPA, Office of Air Quality Planning and Standards, "Technical Bulletin Nitrogen Oxides (NOx), Why and How They are Controlled" EPA 456/F-99-006R

6.2. CO BACT

6.2.1. Background on Pollutant Formation

CO from combustion sources is a by-product of incomplete combustion. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

6.2.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable CO control technologies for heaters rated from < 100 to ≥ 50 MMBtu/hr were identified. Table 6-6-2 outlines the top-down BACT analysis for CO emissions from the heater.

6.2.3. Selection of BACT for CO

Based on the review of the RBLC search and other permit review results, DCP has determined that the CO BACT for units H4 and H5 0.041 lb/MMBtu by utilizing good combustion practices.

Table 6-6-2. BACT Analysis for Natural Gas Fired Heaters (< 100 to ≥ 50 MMBtu/hr) – CO

Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology**	**Catalytic Oxidation[a]**	**Good Combustion Practices**
		Control Technology Description	Waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv	N/A
		Other Considerations	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of CO emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Not implemented on heaters of this size..	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**		Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**			

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)." EPA-452/F-03-018

6.3. VOC BACT

6.3.1. Background on Pollutant Formation

The formation of VOC is the result of incompletion combustion from natural gas. VOC results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation.

6.3.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for heaters rated from < 100 to ≥ 50 MMBtu/hr were identified. Table 6-6-3 outlines the top-down BACT analysis for VOC emissions from the heater.

6.3.3. Selection of BACT for VOC

Based on the review of the RBLC search and other permit review results, DCP has determined that the VOC BACT is 0.0054 lb/MMBtu for units H4 and H5 by utilizing good combustion practices.

Table 6-6-3. BACT Analysis for Natural Gas Fired Heaters (< 100 to ≥ 50 MMBtu/hr) – VOC

		Control Technology	Catalytic Oxidation[a]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv	N/A
		Other Considerations	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of VOC emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Not implemented on heaters of this size.	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency		Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)		
Step 5.	SELECT BACT			

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

6.4. $PM_{10}/PM_{2.5}$ BACT

6.4.1. Background on Pollutant Formation

Filterable PM emissions from natural gas combustion are formed by ash and sulfur in the fuel. Combustion of natural gas generates low filterable PM emissions in comparison to other fuels due to its low ash and sulfur contents. Condensable particulate results from sulfur in the fuel and the resultant H_2SO_4, NO_X being oxidized to nitric acid (HNO_3), and high molecular weight organics.

6.4.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable $PM_{10}/PM_{2.5}$ control technologies for heaters rated from < 100 to ≥ 50 MMBtu/hr were identified. Table 6-6-4 outlines the top-down BACT analysis for filterable $PM_{10}/PM_{2.5}$ emissions from the heater. Table 6-6-5 outlines the top-down BACT analysis for condensable $PM_{10}/PM_{2.5}$ emissions from the heater.

6.4.3. Selection of BACT for $PM_{10}/PM_{2.5}$

Based on the review of the RBLC search and other permit review results, DCP has determined that the $PM_{10}/PM_{2.5}$ BACT is 0.0075 lb/MMBtu for units H4 and H5 by utilizing good combustion practices and use of pipeline quality natural gas.

Table 6-6-4. BACT Analysis for Natural Gas Fired Heaters (< 100 to ≥ 50 MMBtu/hr) Filterable $PM_{10}/PM_{2.5}$

		Control Technology	Good Combustion Practices	Pipeline Quality Natural Gas[e]	Electrostatic Precipitator (ESP)[a,b,c]	Cyclone[d]
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.	Use of pipeline quality natural gas results in lower emissions.	Electrodes stimulate the waste gas and induce an electrical charge in the entrained particles. The resulting electrical field forces the charged particles to the collector walls from which the material may be mechanically dislodged and collected in dry systems or washed with a water deluge in wet systems.	Centrifugal forces drive particles in the gas stream toward the cyclone walls as the waste gas flows through the conical unit. The captured particles are collected in a material hopper below the unit.
		Typical Operating Temperature	N/A	N/A	Up to 1,300 °F (dry) Lower than 170 - 190 °F (wet)	Up to 1,000 °F
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	1,000 - 100,000 scfm (Wire-Pipe) 100,000 - 1,000,000 scfm (Wire-Plate)	1.1 - 63,500 scfm (single) Up to 106,000 scfm (in parallel)
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	0.5 - 5 gr/dscf (Wire-Pipe) 1 - 50 gr/dscf (Wire-Plate)	0.44 - 7,000 gr/dscf
		Other Considerations	N/A	N/A	Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial.	Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop.
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC for the control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Included in RBLC for the control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Not included in RBLC for control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Not included in RBLC for control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Feasible	Feasible	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	Base Case	Base Case		
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**				
Step 5.	**SELECT BACT**					

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Pipe Type)," EPA-452/F-03-027.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Plate Type)," EPA-452/F-03-028.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Wet Electrostatic Precipitator(ESP) - Wire-Pipe Type)," EPA-452/F-03-029.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Cyclone)," EPA-452/F-03-005.
e. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr/100 scf or less.

Table 6-6-5. BACT Analysis for Natural Gas Fired Heaters (< 100 to ≥ 50 MMBtu/hr) Condensable $PM_{10}/PM_{2.5}$

		Control Technology	**Thermal Incineration**	**Catalytic Oxidation**[e]	**Good Combustion Practices**	**Pipeline Quality Natural Gas**
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Oxidizes some particulate matter commonly composed as soot, which are formed as a result of incomplete combustion of hydrocarbons, by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.	Use of pipeline quality natural gas results in lower emissions.
		Typical Operating Temperature	1,100 - 1,200 °F[c]	600 - 800 °F (not to exceed 1,250 °F)	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm[c]	700 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less[b]	As low as 1 ppmv	N/A	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not listed in RBLC. Not implemented on heaters of this size.	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of PM emissions from natural gas fired-heaters (> 100 MMBtu/hr).	Included in RBLC for the control of PM emissions from natural gas fired-heaters (> 100 MMBtu/hr).
		Feasibility Discussion	Technically infeasible. Thermal oxidizers do not reduce emissions of condensable PM from properly operated natural gas combustion units without the use of a catalyst.	Technically infeasible. Not implemented on heaters of this size. Not proven as a condensable PM emission control device.	Feasible	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**			Base Case	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**				
Step 5.	**SELECT BACT**					

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020
d. California EPA, Air Resources Board, "Report to the Legislature: Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts," http://www.arb.ca.gov/research/apr/reports/l2069.pdf
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

6.5. SO_2 BACT

6.5.1. Background on Pollutant Formation

SO_2 emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel.

6.5.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable SO_2 control technologies for heaters rated from < 100 to ≥ 50 MMBtu/hr were identified. Table 6-6-6 outlines the top-down BACT analysis for SO_2 emissions from the heater.

6.5.3. Selection of BACT for SO_2

Based on the review of the RBLC search and other permit review results, DCP has determined that the SO_2 BACT is 5 gr S/100 scf in the fuel inlet by utilizing pipeline quality natural gas as fuel for units H4 and H5.

Table 6-6-6. BACT Analysis for Natural Gas Fired Heaters (< 100 to ≥ 50 MMBtu/hr) – SO_2

		Control Technology	Pipeline Quality Natural Gas[a]
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Use of low sulfur and natural gas will reduce emissions
		Typical Operating Temperature	N/A
		Typical Waste Stream Inlet Flow Rate	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A
		Other Considerations	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC for the control of SO2 emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**	
Step 5.	**SELECT BACT**		

a. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr S/100 scf.

6.6. GHG BACT

GHG emissions from the heaters rated from < 100 to ≥ 50 MMBtu/hr include CO_2, CH_4, and N_2O which result from the combustion of natural gas. The following section presents BACT evaluations for GHG emissions from the heaters.

6.6.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the heater that were analyzed as part of this BACT analysis for heaters rated < 100 to ≥ 50 MMBtu/hr include:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

6.6.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from the heater is a fraction of the scale for sources where CCS might ultimately be feasible. Therefore, we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance.[33]

6.6.1.2. Fuel Selection

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

6.6.1.3. Good Combustion, Operating, and Maintenance Practices

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

6.6.1.4. Heat Integration

The plant is equipped with multiple process-to-process cross heat exchangers for maximum heat integration and high efficiency mass transfer equipment to recover heat and reduce the overall energy use at the plant. The process-to-process cross heat exchangers minimizes the size of the heater to meet the process demands of the plant.

6.6.1.5. Efficient Heater Design

Efficient heater design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since DCP is proposing to install a new heater, this heater will be designed to optimize combustion efficiency. Other design options that can be utilized include intelligent flame ignition, flame intensity controls, and flue gas recirculation. DCP will maintain a record of the manufacturer's certificate and maintain the heater as suggested by the manufacturer.

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[33] PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011, page 32.

6.6.2. Step 2 – Eliminate Technically Infeasible Options

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

6.6.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for this heater and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[34] This project and these emission units, by comparison, emit CO_2 in small quantities. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heater. CCS is not considered as a control option for further analysis.

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

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

- Low Carbon Fuel Selection;
- Implementation of Good combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

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

6.6.4. Step 4 – Evaluate Most Effective of Control Options

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

6.6.5. Step 5 – Select BACT for the Process Heater

DCP proposes the following design elements and work practices as BACT for the proposed heater:

- Use of Natural Gas as Fuel;
- Implementation of Good Combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

DCP proposes the following CO_2e emission limit for the heater:

[34] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology86 that is "available"87 for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed project is not any of the cases EPA suggests above.

- Heaters (H4 and H5): 117 lb CO_2e/MMBtu. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

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

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed this limit.

6.7. HEATERS FROM < 100 TO ≥ 50 MMBTU/HR BACT SUMMARY

Based on the BACT analysis presented in the preceding subsections, Table 6-6-7 summarizes the BACT determinations for the heaters rated from < 100 to ≥ 50 MMBtu/hr.

Table 6-6-7 Heaters (< 100 to ≥ 50 MMBtu/hr) BACT Summary

Unit	Pollutant	Limits	Proposed BACT
Heaters < 100 to ≥ 50 MMBtu/hr	NO_X	0.060 lb/MMBtu	Low NO_X burners and good combustion practices
	CO	0.041 lb/MMBtu	Good combustion practices
	VOC	0.054 lb/MMBtu	Good combustion practices
	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, good combustion practices, heat integration, and efficient heater design

7. BACT EVALUATION FOR HEATERS FROM < 50 TO > 10 MMBTU/HR

The BACT evaluation for combustion emissions from the proposed heater rated from < 50 to > 10 MMBtu/hr (H1) for NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, SO_2, and CO_2e are provided in Sections 6.1 through 6.6. Appendix A provides a summary of RBLC and permit search results.

7.1. NO_X BACT

7.1.1. Background on Pollutant Formation

The formation of NO_X in heaters and engines follow the same mechanisms. Thermal NO_X and prompt NO_X are the two dominant mechanisms of NO_X formation in the combustion zone of the heaters. Please refer to Section 5.1.1 for a detailed description of NO_X formation.

7.1.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for heaters rated from < 50 to > 10 MMBtu/hr were identified. Table 6-6-1 outlines the top-down BACT analysis for NO_X emissions from the heater.

7.1.3. Selection of BACT for NO_x

Based on the review of the RBLC search and other permit review results, DCP has determined that the NO_X BACT for unit H1 is 0.049 lb/MMBtu by utilizing good combustion practices and low NO_X burners.

Table 7-1. BACT Analysis for Natural Gas Fired Heaters (< 50 to > 10 MMBtu/hr) – NO_X

		Control Technology	Ultra Low NO_X Burners[a]	Low NO_X Burners[b]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	These burners are designed to recirculate flue gas from the flame back into the combustion zone which reduces the average oxygen content within the flame without reducing the flame temperature below the optimum combustion zone.	NOx control from these special burners is based on combustion modification techniques. Precise mixing of fuel and air is used to keep the flame temperature low and to dissipate heat quickly through the use of low excess air, off stoichiometric combustion and combustion gas recirculation	NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and fuel quality analysis and fuel handling.
		Typical Operating Temperature	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	N/A
		Other Considerations	N/A	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 100 MMBtu/hr)	Included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 100 MMBtu/hr)
		Feasibility Discussion	Technically infeasible. Not implemented on heaters of this size.	Technically feasible.	Technically feasible.
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	80%	75-80%	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)			
Step 5.	SELECT BACT				

a. U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document -- NOx Emissions from Process Heaters (Revised)" EPA-453/R-93-034
b. U.S. EPA, Office of Air Quality Planning and Standards, "Technical Bulletin Nitrogen Oxides (NOx), Why and How They are Controlled" EPA 456/F-99-006R

7.2. CO BACT

7.2.1. Background on Pollutant Formation

CO from combustion sources is a by-product of incomplete combustion. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

7.2.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable CO control technologies for heaters rated from < 50 to > 10 MMBtu/hr were identified. Table 6-6-2 outlines the top-down BACT analysis for CO emissions from the heater.

7.2.3. Selection of BACT for CO

Based on the review of the RBLC search and other permit review results, DCP has determined that the CO BACT for unit H1 is 0.082 lb/MMBtu by utilizing good combustion practices.

Table 7-2. BACT Analysis for Natural Gas Fired Heaters (< 50 to > 10 MMBtu/hr) – CO

		Control Technology	Catalytic Oxidation[a]	Good Combustion Practices
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv	N/A
		Other Considerations	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of CO emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Not implemented on heaters of this size..	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**		Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**			

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

7.3. VOC BACT

7.3.1. Background on Pollutant Formation

The formation of VOC is the result of incompletion combustion from natural gas. VOC results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation.

7.3.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for heaters rated from < 50 to > 10 MMBtu/hr were identified. Table 6-6-3 outlines the top-down BACT analysis for VOC emissions from the heater.

7.3.3. Selection of BACT for VOC

Based on the review of the RBLC search and other permit review results, DCP has determined that the VOC BACT is 0.0054 lb/MMBtu for units H1 by utilizing good combustion practices.

Table 7-3. BACT Analysis for Natural Gas Fired Heaters (< 50 to > 10 MMBtu/hr) – VOC

		Control Technology	Catalytic Oxidation[a]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv	N/A
		Other Considerations	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of VOC emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Not implemented on heaters of this size.	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency		Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)		
Step 5.	SELECT BACT			

a. U.S. EPA. Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

7.4. $PM_{10}/PM_{2.5}$ BACT

7.4.1. Background on Pollutant Formation

Filterable PM emissions from natural gas combustion are formed by ash and sulfur in the fuel. Combustion of natural gas generates low filterable PM emissions in comparison to other fuels due to its low ash and sulfur contents. Condensable particulate results from sulfur in the fuel and the resultant H_2SO_4, NO_X being oxidized to nitric acid (HNO_3), and high molecular weight organics.

7.4.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable $PM_{10}/PM_{2.5}$ control technologies for heaters rated from < 50 to > 10 MMBtu/hr were identified. Table 6-6-4 outlines the top-down BACT analysis for filterable $PM_{10}/PM_{2.5}$ emissions from the heater. Table 6-6-5 outlines the top-down BACT analysis for condensable $PM_{10}/PM_{2.5}$ emissions from the heater.

7.4.3. Selection of BACT for $PM_{10}/PM_{2.5}$

Based on the review of the RBLC search and other permit review results, DCP has determined that the $PM_{10}/PM_{2.5}$ BACT is 0.0075 lb/MMBtu for units H1 by utilizing good combustion practices and use of pipeline quality natural gas.

Table 7-4. BACT Analysis for Natural Gas Fired Heaters (< 50 to > 10 MMBtu/hr) Filterable PM_{10}/$PM_{2.5}$

		Control Technology	Good Combustion Practices	Pipeline Quality Natural Gas[e]	Electrostatic Precipitator (ESP)[a,b,c]	Cyclone[d]
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	**Control Technology Description**	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.	Use of pipeline quality natural gas results in lower emissions.	Electrodes stimulate the waste gas and induce an electrical charge in the entrained particles. The resulting electrical field forces the charged particles to the collector walls from which the material may be mechanically dislodged and collected in dry systems or washed with a water deluge in wet systems.	Centrifugal forces drive particles in the gas stream toward the cyclone walls as the waste gas flows through the conical unit. The captured particles are collected in a material hopper below the unit.
		Typical Operating Temperature	N/A	N/A	Up to 1,300 °F (dry) Lower than 170 - 190 °F (wet)	Up to 1,000 °F
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	1,000 - 100,000 scfm (Wire-Pipe) 100,000 - 1,000,000 scfm (Wire-Plate)	1.1 - 63,500 scfm (single) Up to 106,000 scfm (in parallel)
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	0.5 - 5 gr/dscf (Wire-Pipe) 1 - 50 gr/dscf (Wire-Plate)	0.44 - 7,000 gr/dscf
		Other Considerations	N/A	N/A	Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial.	Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop.
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	**RBLC Database Information**	Included in RBLC for the control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Included in RBLC for the control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Not included in RBLC for control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).	Not included in RBLC for control of PM emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Feasible	Feasible	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	**Overall Control Efficiency**	Base Case	Base Case		
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	**Cost Effectiveness ($/ton)**				
Step 5.	SELECT BACT					

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Pipe Type)," EPA-452/F-03-027.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Plate Type)," EPA-452/F-03-028.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Wet Electrostatic Precipitator(ESP) - Wire-Pipe Type)," EPA-452/F-03-029.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Cyclone)," EPA-452/F-03-005.
e. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr/100 scf or less.

Table 7-5. BACT Analysis for Natural Gas Fired Heaters (< 50 to > 10 MMBtu/hr) Condensable $PM_{10}/PM_{2.5}$

		Control Technology	Thermal Incineration	Catalytic Oxidation[e]	Good Combustion Practices	Pipeline Quality Natural Gas
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Oxidizes some particulate matter commonly composed as soot, which are formed as a result of incomplete combustion of hydrocarbons, by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.	Use of pipeline quality natural gas results in lower emissions.
		Typical Operating Temperature	1,100 - 1,200 °F[c]	600 - 800 °F (not to exceed 1,250 °F)	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm[c]	700 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less[b]	As low as 1 ppmv	N/A	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not listed in RBLC. Not implemented on heaters of this size.	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of PM emissions from natural gas fired-heaters (> 100 MMBtu/hr).	Included in RBLC for the control of PM emissions from natural gas fired-heaters (> 100 MMBtu/hr).
		Feasibility Discussion	Technically infeasible. Thermal oxidizers do not reduce emissions of condensable PM from properly operated natural gas combustion units without the use of a catalyst.	Technically infeasible. Not implemented on heaters of this size. Not proven as a condensable PM emission control device.	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)				
Step 5.	SELECT BACT					

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020
d. California EPA, Air Resources Board, "Report to the Legislature: Gas-Fired Power Plant NO_x Emission Controls and Related Environmental Impacts," http://www.arb.ca.gov/research/apr/reports/l2069.pdf
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

7.5. SO_2 BACT

7.5.1. Background on Pollutant Formation

SO_2 emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel.

7.5.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable SO_2 control technologies for heaters rated from < 50 to > 10 MMBtu/hr were identified. Table 6-6-6 outlines the top-down BACT analysis for SO_2 emissions from the heater.

7.5.3. Selection of BACT for SO_2

Based on the review of the RBLC search and other permit review results, DCP has determined that the SO_2 BACT is 5 gr S/100 scf in the fuel inlet by utilizing pipeline quality natural gas as fuel for units H1.

Table 7-6. BACT Analysis for Natural Gas Fired Heaters (< 50 to > 10 MMBtu/hr) – SO_2

Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology	Pipeline Quality Natural Gas[a]
		Control Technology Description	Use of low sulfur and natural gas will reduce emissions
		Typical Operating Temperature	N/A
		Typical Waste Stream Inlet Flow Rate	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A
		Other Considerations	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of SO2 emissions from natural gas fired-heaters (< 100 MMBtu/hr).
		Feasibility Discussion	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)	
Step 5.	SELECT BACT		

a. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr S/100 scf.

7.6. GHG BACT

GHG emissions from the heaters rated from < 50 to > 10 MMBtu/hr include CO_2, CH_4, and N_2O which result from the combustion of natural gas. The following section presents BACT evaluations for GHG emissions from the heaters.

7.6.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the heater that were analyzed as part of this BACT analysis for heaters rated from < 50 to > 10 MMBtu/hr include:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

7.6.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from the heater is a fraction of the scale for sources where CCS might ultimately be feasible. Therefore, we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance.[35]

7.6.1.2. Fuel Selection

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

7.6.1.3. Good Combustion, Operating, and Maintenance Practices

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

7.6.1.4. Heat Integration

The plant is equipped with multiple process-to-process cross heat exchangers for maximum heat integration and high efficiency mass transfer equipment to recover heat and reduce the overall energy use at the plant. The process-to-process cross heat exchangers minimizes the size of the heater to meet the process demands of the plant.

7.6.1.5. Efficient Heater Design

Efficient heater design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since DCP is proposing to install a new heater, this heater will be designed to optimize combustion efficiency. Other design options that can be utilized include intelligent flame ignition, flame intensity controls, and flue gas recirculation. DCP will maintain a record of the manufacturer's certificate and maintain the heater as suggested by the manufacturer.

[35] PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011, page 32.

7.6.2. Step 2 – Eliminate Technically Infeasible Options

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

7.6.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for this heater and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[36] This project and these emission units, by comparison, emit CO_2 in small quantities. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heater. CCS is not considered as a control option for further analysis.

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

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

- Low Carbon Fuel Selection;
- Implementation of Good combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

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

7.6.4. Step 4 – Evaluate Most Effective of Control Options

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

7.6.5. Step 5 – Select BACT for the Process Heater

DCP proposes the following design elements and work practices as BACT for the proposed heater:

- Use of Natural Gas as Fuel;
- Implementation of Good Combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

DCP proposes the following CO_2e emission limit for the heater:

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[36] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology86 that is "available"87 for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed project is not any of the cases EPA suggests above.

- Heater (H1): 117 lb CO_2e/MMBtu. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

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

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed this limit.

7.7. HEATERS (< 50 TO > 10 MMBTU/HR) BACT SUMMARY

Based on the BACT analysis presented in the preceding subsections, Table 6-6-7 summarizes the BACT determinations for the heaters rated from < 50 to > 10 MMBtu/hr.

Table 7-7 Heater (< 50 to > 10 MMBtu/hr) BACT Summary

Unit	Pollutant	Limits	Proposed BACT
Heaters < 50 to > 10 MMBtu/hr	NO_X	0.049 lb/MMBtu	Low NO_X burners and good combustion practices
	CO	0.082 lb/MMBtu	Good combustion practices
	VOC	0.054 lb/MMBtu	Good combustion practices
	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, good combustion practices, heat integration, and efficient heater design

8. BACT EVALUATION FOR HEATERS ≤ 10 MMBTU/HR

The BACT evaluation for combustion emissions from proposed heaters rated ≤ 10 MMBtu/hr (H3 and H6) for NO_X, CO, VOC, PM_{10}/$PM_{2.5}$, SO_2, and CO_2e are provided in Sections 8.1 through 8.7. Appendix A provides a summary of RBLC and permit search results.

8.1. NO_X BACT

8.1.1. Background on Pollutant Formation

The formation of NO_X in heaters and engines follow the same mechanisms. Thermal NO_X and prompt NO_X are the two dominant mechanisms of NO_X formation in the combustion zone of the heaters. Please refer to Section 5.1.1 for a detailed description of NO_X formation.

8.1.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for heaters rated ≤ 10 MMBtu/hr were identified.

Table 8-1 outlines the top-down BACT analysis for NO_X emissions from the heaters.

8.1.3. Selection of BACT for NO_X

Based on the review of the RBLC search and other permit review results, DCP has determined that the NO_X BACT is 0.49 lb/MMBtu by utilizing good combustion practices.

Table 8-1. BACT Analysis for Natural Gas Fired Heaters (≤ 10 MMBtu/hr) – NO_X

		Control Technology	Ultra Low NO_X Burners[a]	Low NO_X Burners[b]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	These burners are designed to recirculate flue gas from the flame back into the combustion zone which reduces the average oxygen content within the flame without reducing the flame temperature below the optimum combustion zone.	NOx control from these special burners is based on combustion modification techniques. Precise mixing of fuel and air is used to keep the flame temperature low and to dissipate heat quickly through the use of low excess air, off stoichiometric combustion and combustion gas recirculation	NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and fuel quality analysis and fuel handling.
		Typical Operating Temperature	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	N/A
		Other Considerations	N/A	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 10 MMBtu/hr)	Not included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 10 MMBtu/hr)	Included in RBLC for the control of NO_X emissions from natural gas fired-heaters (< 10 MMBtu/hr)
		Feasibility Discussion	Technically infeasible. Not implemented on heaters of this size.	Technically feasible.	Technically feasible.
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	80%	75-80%	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)			
Step 5.	SELECT BACT				

a. U.S. EPA, Office of Air Quality Planning and Standards, "Alternative Control Techniques Document -- NOx Emissions from Process Heaters (Revised)" EPA-453/R-93-034
b. U.S. EPA, Office of Air Quality Planning and Standards, "Technical Bulletin Nitrogen Oxides (NOx), Why and How They are Controlled" EPA 456/F-99-006R

8.2. CO BACT

8.2.1. Background on Pollutant Formation

CO from combustion sources is a by-product of incomplete combustion. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

8.2.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable CO control technologies for heaters rated ≤ 10 MMBtu/hr were identified. Table 8-2 outlines the top-down BACT analysis for CO emissions from the heaters.

8.2.3. Selection of BACT for CO

Based on the review of the RBLC search and other permit review results, DCP has determined that the CO BACT is 0.082 lb/MMBtu by utilizing good combustion practices.

Table 8-2. BACT Analysis for Natural Gas Fired Heaters (≤ 10 MMBtu/hr) – CO

		Control Technology	Catalytic Oxidation[a]	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation at the appropriate oxygen range and temperature to promote complete combustion and minimize CO formation.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv	N/A
		Other Considerations	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of CO emissions from natural gas fired-heaters (< 10 MMBtu/hr).
		Feasibility Discussion	Infeasible. Not implemented on heaters of this size..	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency		Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)		
Step 5.	SELECT BACT			

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

8.3. VOC BACT

8.3.1. Background on Pollutant Formation

The formation of VOC is the result of incompletion combustion from natural gas. VOC results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation.

8.3.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for heaters rated ≤ 10 MMBtu/hr were identified. Table 8-3 outlines the top-down BACT analysis for VOC emissions from the heaters.

8.3.3. Selection of BACT for VOC

Based on the review of the RBLC search and other permit review results, DCP has determined that the VOC BACT is 0.0054 lb/MMBtu by utilizing good combustion practices.

Table 8-3. BACT Analysis for Natural Gas Fired Heaters (≤ 10 MMBtu/hr) – VOC

Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology**	**Catalytic Oxidation[a]**	**Good Combustion Practices**
		Control Technology Description	Waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Continued operation at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)	N/A
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv	N/A
		Other Considerations	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of VOC emissions from natural gas fired-heaters (< 10 MMBtu/hr).
		Feasibility Discussion	Not implemented on heaters of this size.	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**		Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**			

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

8.4. $PM_{10}/PM_{2.5}$ BACT

8.4.1. Background on Pollutant Formation

Filterable PM emissions from natural gas combustion are formed by ash and sulfur in the fuel. Combustion of natural gas generates low filterable PM emissions in comparison to other fuels due to its low ash and sulfur contents. Condensable particulate results from sulfur in the fuel and the resultant H_2SO_4, NO_X being oxidized to nitric acid (HNO_3), and high molecular weight organics.

8.4.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable $PM_{10}/PM_{2.5}$ control technologies for heaters rated ≤ 10 MMBtu/hr were identified. Table 8-4 outlines the top-down BACT analysis for filterable $PM_{10}/PM_{2.5}$ emissions from the heaters. Table 8-5 outlines the top-down BACT analysis for condensable $PM_{10}/PM_{2.5}$ emissions from the heaters.

8.4.3. Selection of BACT for $PM_{10}/PM_{2.5}$

Based on the review of the RBLC search and other permit review results, DCP has determined that the $PM_{10}/PM_{2.5}$ BACT is 0.0075 lb/MMBtu by utilizing good combustion practices and use of pipeline quality natural gas.

Table 8-4. BACT Analysis for Natural Gas Fired Heaters (≤ 10 MMBtu/hr) – Filterable $PM_{10}/PM_{2.5}$

		Control Technology	Good Combustion Practices	Pipeline Quality Natural Gas[e]	Electrostatic Precipitator (ESP)[a,b,c]	Cyclone[d]
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.	Use of pipeline quality natural gas results in lower emissions.	Electrodes stimulate the waste gas and induce an electrical charge in the entrained particles. The resulting electrical field forces the charged particles to the collector walls from which the material may be mechanically dislodged and collected in dry systems or washed with a water deluge in wet systems.	Centrifugal forces drive particles in the gas stream toward the cyclone walls as the waste gas flows through the conical unit. The captured particles are collected in a material hopper below the unit.
		Typical Operating Temperature	N/A	N/A	Up to 1,300 °F (dry) Lower than 170 - 190 °F (wet)	Up to 1,000 °F
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	1,000 - 10,000 scfm (Wire-Pipe) 10,000 - 1,000,000 scfm (Wire-Plate)	1.1 - 63,500 scfm (single) Up to 106,000 scfm (in parallel)
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	0.5 - 5 gr/dscf (Wire-Pipe) 1 - 50 gr/dscf (Wire-Plate)	0.44 - 7,000 gr/dscf
		Other Considerations	N/A	N/A	Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial.	Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop.
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC for the control of PM emissions from natural gas fired-heaters (< 10 MMBtu/hr).	Included in RBLC for the control of PM emissions from natural gas fired-heaters (< 10 MMBtu/hr).	Not included in RBLC for control of PM emissions from natural gas fired-heaters (< 10 MMBtu/hr).	Not included in RBLC for control of PM emissions from natural gas fired-heaters (< 10 MMBtu/hr).
		Feasibility Discussion	Feasible	Feasible	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.	Technically Infeasible. Natural-gas fired internal combustion engines generate low PM emissions and have large exhaust flowrates, resulting in very low concentrations of PM. Add-on control devices would not provide any measurable emission reduction.
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	Base Case	Base Case		
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**				
Step 5.	**SELECT BACT**		👍	👍		

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Pipe Type)," EPA-452/F-03-027.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Plate Type)," EPA-452/F-03-028.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Wet Electrostatic Precipitator(ESP) - Wire-Pipe Type)," EPA-452/F-03-029.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Cyclone)," EPA-452/F-03-005.
e. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr/100 scf or less.

Table 8-5. BACT Analysis for Natural Gas Fired Heaters (≤ 10 MMBtu/hr) – Condensable $PM_{10}/PM_{2.5}$

		Control Technology	Thermal Incineration	Catalytic Oxidation[e]	Good Combustion Practices	Pipeline Quality Natural Gas
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Oxidizes some particulate matter commonly composed as soot, which are formed as a result of incomplete combustion of hydrocarbons, by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.	Use of pipeline quality natural gas results in lower emissions.
		Typical Operating Temperature	1,100 - 1,200 °F[c]	600 - 800 °F (not to exceed 1,250 °F)	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm[c]	700 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less[b]	As low as 1 ppmv	N/A	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not listed in RBLC. Not implemented on heaters of this size.	Not listed in RBLC. Not implemented on heaters of this size.	Included in RBLC for the control of PM emissions from natural gas fired-heaters (> 100 MMBtu/hr).	Included in RBLC for the control of PM emissions from natural gas fired-heaters (> 100 MMBtu/hr).
		Feasibility Discussion	Technically infeasible. Thermal oxidizers do not reduce emissions of condensable PM from properly operated natural gas combustion units without the use of a catalyst.	Technically infeasible. Not implemented on heaters of this size. Not proven as a condensable PM emission control device.	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency			Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)				
Step 5.	SELECT BACT				👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020
d. California EPA, Air Resources Board, "Report to the Legislature: Gas-Fired Power Plant NO_X Emission Controls and Related Environmental Impacts," http://www.arb.ca.gov/research/apr/reports/l2069.pdf
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018

8.5. SO_2 BACT

8.5.1. Background on Pollutant Formation

SO_2 emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel.

8.5.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable SO_2 control technologies for heaters rated < 10 MMBtu/hr were identified. Table 8-6 outlines the top-down BACT analysis for SO_2 emissions from the heaters.

8.5.3. Selection of BACT for SO_2

Based on the review of the RBLC search and other permit review results, DCP has determined that the SO_2 BACT is 5 gr S/100 scf in the fuel inlet by utilizing pipeline quality natural gas as fuel.

Table 8-6. BACT Analysis for Natural Gas Fired Heaters (< 10 MMBtu/hr) – SO_2

		Control Technology	**Pipeline Quality Natural Gas[a]**
		Control Technology Description	Use of low sulfur and natural gas will reduce emissions
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Typical Operating Temperature**	N/A
		Typical Waste Stream Inlet Flow Rate	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A
		Other Considerations	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC for the control of SO_2 emissions from natural gas fired-heaters (< 10 MMBtu/hr).
		Feasibility Discussion	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**	
Step 5.	**SELECT BACT**		👍

a. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr S/100 scf.

8.6. GHG BACT

GHG emissions from the heaters rated ≤ 10 MMBtu/hr include CO_2, CH_4 and N_2O which result from the combustion of natural gas. The following section presents BACT evaluations for GHG emissions from the heaters.

8.6.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

8.6.1.1. Carbon Capture and Sequestration

As previously discussed, the contribution of CO_2e emissions from the heater is a fraction of the scale for sources where CCS might ultimately be feasible. Therefore, we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance.[37]

8.6.1.2. Fuel Selection

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

8.6.1.3. Good Combustion, Operating, and Maintenance Practices

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

8.6.1.4. Heat Integration

The plant is equipped with multiple process-to-process cross heat exchangers for maximum heat integration and high efficiency mass transfer equipment to recover heat and reduce the overall energy use at the plant. The process-to-process cross heat exchangers minimizes the size of the heaters to meet the process demands of the plant.

8.6.1.5. Efficient Heater Design

Efficient heater design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since DCP is proposing to install new heaters, these heaters will be designed to optimize combustion efficiency. Other design options that can be utilized include intelligent flame ignition, flame intensity controls, and flue gas recirculation. DCP will maintain a record of the manufacturer's certificate and maintain the heaters as suggested by the manufacturer.

[37] PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011, page 32.

8.6.2. Step 2 – Eliminate Technically Infeasible Options

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

8.6.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for these heaters and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[38] This project and these emission units, by comparison, emit CO_2 in small quantities. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed heaters. CCS is not considered as a control option for further analysis.

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

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

- Low Carbon Fuel Selection;
- Implementation of Good combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

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

8.6.4. Step 4 – Evaluate Most Effective of Control Options

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

8.6.5. Step 5 – Select BACT for the Process Heater

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

- Use of Natural Gas as Fuel;
- Implementation of Good Combustion, Operating, and Maintenance Practices;
- Heat Integration; and
- Efficient Heater Design.

DCP proposes the following CO_2e emission limit for the heaters:

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[38] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology86 that is "available"87 for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed project is not any of the cases EPA suggests above.

- Heaters (H3, H6): 117 lb CO_2e/MMBtu. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

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

Compliance with this emission limit will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

8.7. HEATERS ≤ 10 MMBTU/HR BACT SUMMARY

Based on the BACT analysis presented in the preceding subsections, Table 8-7 summarizes the BACT determinations for the heaters rated ≤ 10 MMBtu/hr.

Table 8-7 Heaters ≤ 10 MMBtu/hr BACT Summary

Unit	Pollutant	Limits	Proposed BACT
Heaters ≤ 10 MMBtu/hr	NO_X	0.49 lb/MMBtu	Low NO_X burners and good combustion practices
	CO	0.082 lb/MMBtu	Good combustion practices
	VOC	0.054 lb/MMBtu	Good combustion practices
	$PM_{10}/PM_{2.5}$	0.0075 lb/MMBtu	Pipeline quality natural gas and good combustion practices
	SO_2	5 gr S/100 scf	Pipeline quality natural gas
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, good combustion practices, heat integration, and efficient heater design

The BACT evaluation for the proposed amine sweetening unit still vent (Amine) for CO_2e is provided in Section 9.1 through 9.2. Appendix A provides a summary of RBLC and permit search results.

9.1. VOC BACT

9.1.1. Background on Pollutant Formation

VOC emissions are formed due to partial removal from the processed gas stream as a result of removal of acidic contaminants from natural gas.

9.1.2. Step 1 - Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies were identified based on the principles of control technology and engineering experience for the amine units. The available emission control options include:

- Acid gas injection; and
- Catalytic or thermal oxidation.

9.1.2.1. Acid Gas Injection

This control option injects the acid gas still vent stream from the amine unit into a Class II well. See Section 9.2.2.1 for a detailed description. This control option offers 100% control of emissions.

9.1.2.2. Catalytic or Thermal Oxidation

This control option is similar to thermal incineration where the waste stream is heated by a flame and is then passed through a catalyst bed that increases the oxidation rate. This control option offers 98% control of VOC emissions.

9.1.3. Step 2 - Eliminate Technically Infeasible Options

All above options are considered technically feasible for the amine unit still vent.

9.1.4. Step 3 - Rank the technically feasible control technologies by control effectiveness

AGI is the most effective control option for the control of the VOC from the amine unit still vent, since it provides 100% control of the amine acid gas stream, based on literature review.

Catalytic or thermal oxidation are less effective control options as the maximum reduction is only 98% of the amount of VOC produced by the amine unit.

9.1.5. Step 4 - Evaluate most effective controls

DCP is proposing AGI as the control method for the VOC emissions resulting from the amine unit still vent. Since this is the best control technology available for this unit, no further control options are evaluated.

9.1.6. Step 5 - Select BACT

DCP proposes acid gas injection (AGI) as the control mechanism for the amine unit still vent stream. By controlling the acid gases from this stream, the VOC will also be controlled 100%. Further discussion of AGI is provided in Section 9.2.2.1 below.

9.2. GHG BACT

9.2.1. Background on Pollutant Formation

The amine unit at Zia II facility will be used to remove CO_2 and H_2S in order to meet pipeline specifications for transportation of the natural gas. Since the amine unit is designed to remove CO_2 from the inlet gas stream, the generation of CO_2 is inherent to the process, and any reduction of the CO_2 emissions by process changes would reduce process efficiency. This would result in a greater CO_2 content in the natural gas that would eventually be emitted.

9.2.2. Step 1 – Identify all Available Control Technologies

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

- Carbon Capture and Sequestration;
- Flare/Combustor;
- Thermal Oxidizer;
- Proper Design and Operation; and
- Use of Tank Off-gas Recovery Systems.

9.2.2.1. Carbon Capture and Sequestration

As CO_2 separation is one of the primary objectives of the amine unit, the amine regeneration unit produces a gas stream with a high CO_2 content compared to a typical exhaust stream from a combustion unit. Accordingly, CCS is one possible option for control of GHG emissions from the amine regeneration unit. The presumed goal of CCS is to sequester 100% of the CO_2 from the source in question.

An effective CCS system would require three elements:

- Separation technology for the CO_2 exhaust stream (i.e., "carbon capture" technology),
- Transportation of CO_2 to a storage site, and
- A viable location for long-term storage of CO_2.

These three elements work in series. To execute a CCS program as BACT, all three elements must be 'available' for this project. Geologic sequestration of CO_2 can be achieved by one of three methods: (1) a well dedicated to CCS (i.e., a Class VI well) can be drilled and permitted, or (2) CO_2 can be used in Enhanced Oil Recovery (EOR) projects, or (3) CO_2 and other acid gases can be injected in an acid gas injection (AGI) Class II well.

<u>CCS and Class VI wells</u>

DCP conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer. Since most of the CO_2 emissions from the proposed project are generated from the amine unit, DCP evaluated potential options to capture and transfer the CO_2, from the amine unit still vent, to an off-site facility for injection.

The CO_2 portion of the amine unit still vent stream will need to be separated from the other components such as H_2S and VOCs from the stream in order to be routed to a CO_2 transfer pipeline. The H_2S and VOCs will require further treatment prior to being released.

Class VI wells are wells used for injection of carbon dioxide (CO_2) into underground subsurface rock formations for long-term storage. A Class VI well requires rigorous monitoring and testing to ensure the well is constructed and operated appropriately. The permitting requirements for Class VI wells are listed under 40 CFR 146 Subpart H and regulated under the Safe Drinking Water Act. The wells are designed to sequester only CO_2, and the requirements for these wells are onerous including the submittal of five specific project plans including the area of review and correction action, testing and monitoring, injection well plugging, post-injection site care and closure, and emergency and remedial response.[39]

Based on the results of these studies, capture and transfer of CO_2 from the amine treatment unit is technically feasible assuming that a Class VI well is available for injection of CO_2. The transfer of the CO_2 stream would require further treatment to remove H_2S and other contaminants and compression for transfer via a new pipeline. In order to satisfy BACT requirements, following EPA guidance, this option is further evaluated for energy, environmental, and economic impacts assuming a Class VI injection well is available.

Enhanced Oil Recovery

EOR technology enhances oil recovery rates by reinjecting CO_2 and hydrocarbon gases recovered from the well (and CO_2 from external sources, as needed) into the geologic formation to maintain well pressure. This technology also requires separation of CO_2 from the other components of the amine unit still vent such as H_2S and VOC, which would require subsequent treatment prior to being released. CO_2 is a good choice for EOR because CO_2 is partially miscible in oil and lowers the viscosity and surface tension of the fluid for easy displacement.[40] EOR is designed to maintain pressure in an active well, rather than for the long term sequestration of CO_2. Consequently, EOR projects are not designed with the same considerations for permanent CO_2 sequestration when compared to Class VI wells intended specifically for CCS. While EOR has been commercially demonstrated EOR cannot be considered an available technology in this BACT assessment for the following reason:

The DCP Zia II facility is not designed to perform EOR. If DCP sold CO_2 as a commodity to EOR injection fields, the lifetime of the contract(s) must equal the lifetime of the facility; else EOR would not be a sustainable control option for the facility. This would pose significant logistical challenges, such as matching the relatively constant output of CO_2 at the facility to the varying CO_2 demand of an EOR system. As EOR operation continues and the CO_2 content of a formation increases, more CO_2 would be recovered from the well(s) for reinjection, resulting in a declining demand for supplemental CO_2 from external sources over the lifetime of a given EOR project.[41] For these reasons EOR is not considered an available technology for the permanent sequestration of CO_2 from the DCP Zia II facility. However, to ensure that the option to use EOR to capture CO_2 emissions from the Zia II facility is thoroughly evaluated in this application, discussions of the economic feasibility of EOR are presented in Step4 of this BACT analysis.

[39] http://water.epa.gov/type/groundwater/uic/class6/upload/module03permitinfo.pdf

[40] American Petroleum Institute, "Summary of Carbon Dioxide Enhanced Oil Recovery (CO_2 EOR) Injection Well Technology".

[41] MIT Laboratory for Energy and the Environment, "The Economics of CO_2 Storage," August 2003, p. 37.

Acid Gas Injection and Class II Wells

DCP is assessing a third form of capture which can be achieved by AGI wells, specifically dry gas injection systems. AGI stores the acid gas in an isolated subsurface reservoir and are Class II wells that are regulated by New Mexico's Oil Conservation District pursuant to the 19.15.26 of the New Mexico Administrative Code (NMAC). There are a number of Class II injection wells in New Mexico, which is a good indication of availability and consequently, implementation of AGI for this project.[42] As opposed to Class VI wells that are specific to CO_2 injection, Class II wells are intended for all oil and gas related fluid injection. Specifically, acid gas injection wells are designed to accept CO_2 as well as other acid gases from sour gas processing streams, such as the amine still vent stream at the Zia II facility which is rich in H_2S. The additional processing required for injection in a Class VI well with regards to separating out the CO_2 portion is not required for a Class II well which saves energy as well as reduces other pollutants such as H_2S and VOC associated with the emission source.

The ideal reservoir for AGI wells should be located in areas which cannot be compromised by future exploration of oil and gas resources, and are far enough below any potable water sources. Reliability of the sequestration depends on natural geologic features of the chosen reservoir such as faulting or fracturing that could allow the acid gas to escape from the reservoir.[43] Looking at all these factors, DCP has determined that a potential AGI well can be located on or immediately adjacent to the facility eliminating a significant portion of the transportation costs.

DCP has determined that the proposed AGI wells are a safe and environmentally-sound project for the disposal of acid gas.[44] Furthermore, the project provides additional environmental benefit by permanently sequestering a significant volume of CO_2 which would otherwise be released to the atmosphere if H_2S was flared. Implementation of AGI is presumed to have a 100% control rate of the amine unit still vent emissions. The well will be designed to New Mexico Oil Conservation Division (NMOCD) regulatory standards.

9.2.2.2. Flares/Combustor

One option to reduce the GHGs emitted from the Zia II facility is to send stripped amine acid gases and to a flare or a combustor. Flares and combustors are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. The control of CH_4 in the process gas at the flare or combustor results in the creation of additional CO_2 emissions via the combustion reaction mechanism. Most of the GHG from the amine unit still vent are generated as CO_2, and this may not be the most effective control technology.

9.2.2.3. Thermal Oxidizers

Another option to reduce the GHGs emitted from the Zia II facility is to send stripped amine acid gases to a thermal oxidizer (TO). The TO is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions, the control of CH_4 in the process gas at the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. Most of the GHG from the amine unit still vent are generated as CO_2, and this may not be the most effective control technology. In contrast with a flare or a combustor, which requires the use of additional fuel to maintain a constant pilot, a RTO only uses additional natural gas to get up to the optimum temperature for combustion resulting in lower use of assist gas and lower GHG emissions due to pilot burning when compared to a flare or a combustor.

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[42] http://water.epa.gov/type/groundwater/uic/upload/UIC-Well-Inventory_2010-2.pdf

[43] http://www.geolex.com/Projects/AGIS%202010%20Final.pdf

[44] NMOCD C-108 Application for Authority to Inject for DCP Zia II Gas Plant

9.2.2.4. Proper Design and Operation

The amine unit will be a brand new, state of the art equipment installed on site. The amine unit will operate at an optimal circulation rate with consistent amine concentrations. By optimizing the circulation rate, the amine unit avoids pulling out additional GHGs in the amine streams, which would increase GHG emissions into the atmosphere.

9.2.2.5. Use of Tank Off-gas Recovery Systems

The amine unit will be equipped with a flash tank. The flash tank will be used to recycle the off-gases back into the plant for reprocessing, instead of venting to the atmosphere or combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

9.2.3. Step 2 - Eliminate technically infeasible options

All above options are considered technically feasible for the amine unit still vent except for CCS which is discussed below.

9.2.3.1. Carbon Capture and Sequestration

<u>CCS and Class VI Well Injection</u>

As explained in EPA's 1990 Draft New Source Review Manual:

> *"[I]f the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible. For control technologies that are not demonstrated in the sense indicated above the analysis is somewhat more involved."*
>
> *"Two key concepts are important in determining whether an undemonstrated technology is feasible: 'availability' and 'applicability.' . . . . a technology is considered 'available' if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is 'applicable' if it can reasonably be installed and operated on the source type under construction. A technology that is available and applicable is technically feasible".*[45]

Carbon sequestration in Class VI wells poses a number of issues before the technology can be safely and effectively deployed on the commercial scale. For example, the following items still need to be proven and documented on a large-scale (greater than 1 million metric tons CO_2 injected).

- Permanent storage must be proven by validating that CO_2 will be contained in the target formations.
- Technologies and protocols must be developed to quantify potential releases and to confirm that the projects do not adversely impact underground sources of drinking water (USDWs) or cause CO_2 to be released to the atmosphere.
- Long term monitoring of the migration of CO_2 during and after project completion must be completed. Methodologies to determine the presence/absence of release pathways must be developed.
- Effective regulatory and legal framework must be developed for the safe, long term injection and storage of CO_2 into geological formations.

Therefore, geologic CO_2 storage in Class VI wells is not currently a feasible technology. To this date no Class VI wells have been permitted in the US, making this option "not-available". The first wells are expected to come

[45] U.S. EPA, Draft New Source Review Manual, p. B.17, 1990.

online by 2016 at the earliest, which is much later than the anticipated construction of the Zia II facility.[46] A need for the gas processing capabilities of Zia II is required in this field at this time, and delaying the project start-date due to availability of a Class VI well will extend the timeline, waste the resources that currently require processing, and will result in a financial loss for DCP.

Large-scale sequestration projects using carbon sequestration are at the very early stages of testing and development. It is still unclear, at this time, what the long term outcome of these projects will be. The National Energy Technology Laboratory (NETL), which is part of the DOE's national laboratory system, is currently working on (and in some instances economically supporting) a number of large-scale field tests in different geologic storage formations to confirm that CO_2 capture, transportation, injection, and storage can be achieved safely, permanently, and economically over extended periods of time. However, according to the NETL, carbon sequestration technologies will not be ready for commercial deployment until 2020.[47] Hence, such technologies are not considered available or technically feasible.[48]

EOR and AGI are considered technically feasible and are addressed in Steps 3 and 4 below. All other control technologies listed in Step 1 are considered technically feasible for implementation at the Zia II facility.

9.2.4. Step 3 - Rank the technically feasible control technologies by control effectiveness

EOR or AGI are the most effective control options for the control of the CO_2 streams from the amine unit, since they both provide 100% CO_2 control of the amine acid gas stream, based on literature review. However, as discussed above, EOR may not be available as a CO_2 sink for the entire duration of the Zia II facility and will not address the H_2S and VOC portion of the amine still vent which will require further processing.

Although flares and oxidizers will control CH_4 they will not control CO_2 produced by the amine unit as compared to an AGI.

9.2.5. Step 4 - Evaluate most effective controls

Under Carbon Capture and Sequestration, Class VI well injection has been eliminated in Step 2 of the analysis, but EOR and AGI remain the most effective control options for GHG.

<u>Enhanced Oil Recovery</u>

EOR can have additional energy, environmental, and economic impacts. While the process exhaust stream is relatively high in CO_2 content, additional processing of the exhaust gas will be required to implement EOR. These include separation (removal of other pollutants such as H_2S from the waste gases), capture and compression of CO_2, transfer of the CO_2 stream, and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipelines.

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[46] http://water.epa.gov/type/groundwater/uic/wells.cfm

[47] NETL, "Carbon Sequestration Program: Technology Program Plan," DOE/NETL-2011/1464, February 2011, p. 10. "The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established… Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades."

[48] See "In re: Cardinal FG Company," 12 E.A.D. 153 (E.A.B. 2005) ("[T]echnologies in the pilot scale testing stages of development would not be considered available for BACT review"), quoting from EPA, Draft New Source Review Workshop Manual (Oct. 1990) at B-18).

These units would require additional electricity and generate additional air emissions, of both criteria pollutants and GHG pollutants which would result in negative environmental and energy impacts.

As part of the CO_2 transfer feasibility analysis, DCP reviewed currently active CO_2 pipelines.[49] This document provides the details of registered wells and permitted fluids for injection. Based on the aerial distance from the proposed Zia II facility, the nearest CO_2 pipeline is located at approximately 15 miles.

The cost of pipeline installation and operation are obtained from the National Energy Technology Laboratory (NETL)'s Document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447* attached in Appendix B. Per this document, the pipeline costs include pipeline installation costs, other related capital costs, and operation and maintenance (O&M) costs.

Estimated additional equipment that would be needed to be installed at the plant to compress the amine vent stream into a pipeline would include:

- Approximately >2000 hp motor
- A fan cooling unit
- Motor Control Center (MCC) building for electric switchgear
- Suction scrubbers on each compressor stage and a final scrubber
- Sampling equipment
- Controls/Instrumentation
- Glycol Unit, contactors and regeneration units with VRU to dehydrate the CO_2 stream since the amine unit is upstream of the dehydrator
- Additional power and building costs.

A conservative estimate on the cost of equipment for the above purposes is assumed to be $50,000,000.[50] DCP estimates the net capital cost for the project is equal to about $250,000,000. The capital cost for DCP's Zia II facility and the expected EOR capital cost were both annualized.[51] A ratio of the CCS capital cost to DCP's project cost was taken to determine the additional amount that DCP would need to invest in order to successfully implement CCS. The project specific ratio is determined to be roughly 27%. Therefore, the employment of CCS in the current system is conclusively proved to be an economically infeasible option.

In addition to being economically infeasible, installation of EOR will also increase energy demand by approximately 15-30%.[52] In addition to increased emissions from the additional equipment, the addition of compressors will drive the emissions of other pollutants, such as NO_X and CO, up. The H_2S separated from the CO_2 stream will also require treatment which will drive up costs and in turn increase GHG emissions due to combustion equipment that will be required for oxidation of the stream.

In conclusion, while EOR is an attractive option for an amine vent stream that contains fairly concentrated CO_2, there are other reasons for technical, economical, and environmental infeasibility.

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[49] Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Permian Basin

http://www.fe.doe.gov/programs/oilgas/publications/eor_co2/Rocky_Mountain_Basin_Document.pdf

[50] $50 million based on best engineering estimate for the units required.

[51] Note that this capital cost only accounts for equipment related to compression and transfer of CO_2 and does not account for further processing required of the H_2S and VOC in the amine still vent stream that will be required prior to release.

[52] Prospects for Carbon Capture and Storage Technologies

http://www.rff.org/documents/RFF-DP-02-68.pdf

Acid Gas Injection

AGI in Class II wells allows the opportunity to sequester the CO_2 as well as other acid gases in the stream without further processing or additional GHG emissions. Although compression and a transfer pipeline framework will be required, this control option provides the best control efficiency while minimizing additional impacts. Consequently, DCP is proposing AGI as the control method for the GHG emissions resulting from the amine unit still vent. Since this is the best control technology available for this unit, no further control options are evaluated.

9.2.6. Step 5 - Select BACT

DCP is choosing AGI as the control method for the GHG emissions resulting from the amine unit still vent. This control method offers 100% control of GHG emissions from the unit.

The proposed AGI wells potential location would be within the Delaware Mountain Group which is represented by transitional (slope detrital) Bell and Cherry Canyon limestone and sandstone, and the underlying Brushy Canyon sandstone member. The Brushy Canyon is underlain by the upper Bone Spring limestone. The proposed AGI potential injection zone falls specifically within the lower 200 feet of the Cherry Canon Member and the upper 400 feet of the Brushy Canyon Member which have the required sandstone porosity for injection and limestone caps and basins for containment. [53]

[53] GEOLEX Preliminary Overview of DCP ZIA Plant AGI Facility, April 12, 2013

10. BACT EVALUATION FOR TEG DEHYDRATOR STILL VENT

The BACT evaluation for the proposed TEG dehydrator (Dehy) for VOC and CO_2e is provided in Sections 10.1 through 10.3. Appendix A provides a summary of RBLC and permit search results.

10.1. VOC BACT

10.1.1. Background on Pollutant Formation

VOC emissions are produced as a result of water and volatiles removed from the wet gas stream during the glycol recovery process.

10.1.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies were identified based on the principles of control technology and engineering experience for the TEG dehydration unit. Table 10-1 outlines the top-down BACT analysis for VOC emissions from glycol dehydration units.

10.1.3. Selection of BACT for VOC

Based on the review of the RBLC search and other permit review results, DCP has determined that the VOC BACT is utilizing a condenser and a vapor combustion device (VCD) with 98% efficiency for the dehydrator still vent. The material emitted from the glycol dehydrator flash tank separator is recycled back to inlet compression.

Table 10-1 BACT Analysis for TEG Dehydrator – VOC

		Control Technology	Catalytic/Thermal Oxidation	Thermal Incineration[a]	Condenser[b]
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.[a]	A closed-flame control device like a VCD used for disposing of waste gas streams.	Condensers are supplemental emissions control devices that reduce the temperature of the still column vent vapors on dehydration units to condense water and VOC. They are frequently used prior to control devices.
		Typical Operating Temperature	600 - 800 °F (not to exceed 1,250 °F)[a]	1100-1200°F	-
		Typical Waste Stream Inlet Flow Rate	700 - 50,000 scfm[a]	500 - 50,000 scfm	-
		Typical Waste Stream Inlet Pollutant Concentration	As low as 1 ppmv[a]	1500 - 3000 ppmv	N/A
		Other Considerations	Catalyst can be deactivated by certain catalyst poisons or other fouling contaminants such as silicone, sulfur, heavy hydrocarbons, and particulates.[a]	Typically not cost-effective for low-concentrations, high-flow organic vapor streams.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of VOC emissions. However, DCP has safety concerns with thermal oxidation of high Btu content streams such as that of the dehydrator still vent. Unsafe explosions have occurred at other facilities, and DCP considers thermal oxidation technically infeasible for this process.	Included in RBLC for the control of VOC emissions from dehydrator units.	Included in RBLC for the control of VOC emissions from dehydrator units.
		Feasibility Discussion	Technically Infeasible	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	98%	99% for certain compounds with up to three carbons, 98% otherwise.	80%
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)			
Step 5.	SELECT BACT			👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018
b. U.S. EPA, Air Pollution Control Cost Manual - Sixth Edition (EPA 452/B-02-001), Chapter 2

10.2. GHG BACT

10.2.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control options for the process emissions, primarily emitted as CH_4, are:

- Carbon Capture and Sequestration;
- Flare/Combustor;
- Thermal Oxidizer;
- Condenser;
- Proper Design and Operation; and
- Use of Tank Off-gas Recovery Systems.

10.2.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 5.6.1.1 above.

10.2.1.2. Flare/Combustor

One option to reduce the GHGs emitted from the dehydrator is to send dehydrator still vent gases to a flare or a combustor. Flares and combustors are examples of control devices in which the control of certain pollutants causes the formation of collateral GHG emissions. The control of CH_4 in the process gas at the flare or combustor results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. In general, flares and combustors have a destruction efficiency rate (DRE) of 98%, resulting in minor CH_4 emissions from the process flare due to incomplete combustion of CH_4. Additionally, flares and combustors require the use of a continuous pilot ignition system or equivalent that results in additional GHG emissions.

10.2.1.3. Thermal Oxidizer

Another option to reduce the GHGs emitted from the dehydrator still vent is to send the stream to a thermal oxidizer (TO). The TO is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions, the control of CH_4 in the process gas at the TO results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. A regenerative thermal oxidizer (RTO) has a high efficiency heat recovery. This allows the facility to recover heat from the exhaust stream, reducing the overall heat input of the plant. In general, TOs have a destruction efficiency rate (DRE) greater than of 99%, resulting in minor CH_4 emissions from the process flare due to incomplete combustion of CH_4. In contrast with a flare or a combustor, which requires the use of additional fuel to maintain a constant pilot, a RTO only uses additional natural gas to get up to the optimum temperature for combustion resulting in lower use of assist gas and lower GHG emissions due to pilot burning when compared to a flare or a combustor.

10.2.1.4. Condenser

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

10.2.1.5. Proper Design and Operation

The TEG dehydrator will be a brand new, state of the art, equipment installed on site. The new equipment will operate at an optimized circulation rate. By optimizing the circulation rate, the equipment avoids pulling out additional VOCs and GHGs in the glycol stream, which would increase VOC and GHG emissions into the atmosphere. The TEG dehydrator regeneration overhead stream will be controlled with a condenser and a vapor combustion device with a 98% DRE. The unit is equipped with a flash tank for recycling off-gas back to the plant inlet, including CO_2 and CH_4, from the rich dehydrator stream prior to regeneration, resulting in a reduction of waste gases created.

10.2.1.6. Use of Tank Off-gas Recovery Systems

The TEG dehydrator will be equipped with a flash tank. The flash tank will be used to recycle the off-gases back into the plant for reprocessing, instead of venting to the atmosphere or combustion device. The use of flash tanks increases the effectiveness of other downstream control devices.

10.2.2. Step 2 - Eliminate technically infeasible options

All the above options, except CCS, are technically feasible. The CO_2 content in the vent stream from the dehydrator is much lower than the compressor engines and the heaters; accordingly, refer to the feasibility of CCS discussion in Section 5.6.2.1.

10.2.3. Step 3 - Rank the technically feasible control technologies by control effectiveness

Given the relative GWPs of CO_2 and CH_4, 1 and 25 respectively, and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions. RTO have higher destruction efficiencies compared to flares/combustors, 99% and 98% respectively, and uses less pilot gas fuel, resulting in overall lower GHG emissions. However, DCP has safety concerns with thermal oxidation of high Btu content streams such as that of the dehydrator still vent. Unsafe explosions have occurred at other facilities and DCP considers thermal oxidation technically infeasible for this process.

The implementation of good combustion, operating, and maintenance practices; and the use of condensers and flash tanks for off-gas recycle are technically feasible control options for minimizing GHG emissions from the still vent gas stream.

10.2.4. Step 4 - Evaluate most effective controls

Vent gases resulting from the processing of natural gas through TEG dehydrators are often combusted by using a flare or VCD before they are released into the atmosphere to reduce the amount of released VOCs and HAPs. These control options have varying destruction efficiency rates which ultimately results in higher or lower GHG emissions. DCP has elected to use a VCD as the primary control technology for the TEG dehydrator. A BTEX condenser is also proposed to be used for VOC control and will offer the same principle of control on the methane portion of the still vent stream. The condenser lowers the temperature to recover volatile compounds. Although methane is not a VOC, the still vent contains methane that is also recovered in the condenser which is then sent to a VCD for additional control.

10.2.5. Step 5 - Select BACT

DCP proposes the following design elements and work practices as BACT for the TEG dehydrator:

- VCD;
- Proper Design and Operation of TEG dehydrators;
- Use of Tank Off-gas Recovery Systems; and
- Use of a Condenser.

In addition, DCP proposes a numerical BACT limit for the TEG dehydrator vent stream combustion under the VCD BACT limit in Section 13.4.5 below. This includes CO_2 and CH_4 emissions, with CO_2 emissions being more than 99% of the total emissions. Additionally, DCP also proposes a numerical BACT limit for the uncontrolled portion of the TEG dehydrator vent stream of 0.107 lb CO_2e/MMscf (wet) based on 230 MMscfd gas flow through the facility.

Compliance with these emission limits and throughput limits will be demonstrated by monitoring inlet gas throughput rate and performing calculations consistent with those in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average ratio of short tons of CO_2e per year emission rates per throughput do not exceed these limits.

10.3. TEG DEHYDRATOR BACT SUMMARY

Based on the BACT analysis presented in the preceding subsections, Table 10-2 summarizes the BACT determinations for the TEG dehydrator.

Table 10-2 TEG Dehydrator BACT Summary

Unit	Pollutant	Limit	Proposed BACT
TEG Dehydrator Still Vent (Dehy)	VOC	-	Vapor Combustion Device – 98% DRE, Condenser
	CO_2e	-	Vapor Combustion Device – 98% DRE, Proper design and operation, Tank off-gas recovery systems, and Condenser

11. BACT EVALUATION FOR STORAGE TANKS

The BACT evaluation for the proposed condensate tanks (TK-2100, TK-2200) for VOC is provided in Section 11.1. Section 11.2 includes the BACT evaluation for the proposed water tanks (TK-6100, TK-6150). Appendix A provides a summary of RBLC and permit search results. There are no methane or carbon dioxide fractions in the stabilized condensate; therefore no GHG BACT is evaluated for this source.

11.1. VOC BACT- CONDENSATE TANKS

11.1.1. Background on Pollutant Formation

VOC emissions are formed as a result of working, and breathing losses of the tank contents. The condensate is processed through a stabilization process before entering the storage tanks. Stabilized condensate has no flashing losses.

11.1.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies were identified based on the principles of control technology and engineering experience for the storage tanks. Table 11-1 outlines the top-down BACT analysis for VOC emissions from storage tanks.

11.1.3. Selection of BACT for VOC

The storage tanks will be subject to NSPS Subpart OOOO[54]. NSPS OOOO provides a control efficiency requirement of 95% for each storage vessel. The most stringent RBLC and permit entries for VOC control are provided in Appendix A. DCP has determined that the VOC BACT is utilizing a vapor combustion device (VCD) with 98% efficiency for the storage tanks.

[54] Per 40 CFR §60.5395b.

Table 11-1. BACT Analysis for Condensate Tanks – VOC

		Control Technology	Thermal Incineration[a]	Submerged fill, mechanical/liquid mounted seals
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	An open-flame control device used for disposing of waste gas streams.	Filling tanks via a submerged fill pipe and equipping tanks with mechanical/liquid mounted primary and secondary seals helps contain fugitive vapors.
		Typical Operating Temperature	1100-1200°F	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	1500 - 3000 ppmv	N/A
		Other Considerations	Typically not cost-effective for low-concentrations, high-flow organic vapor streams.	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC for the control of VOC emissions from storage tanks.	Included in RBLC for the control of VOC emissions from storage tanks.
		Feasibility Discussion	Feasible	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	99% for certain compounds with up to three carbons, 98% otherwise.	
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**			

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incineration)," EPA-452/F-03-022

11.2. VOC BACT - WATER TANKS

11.2.1. Background on Pollutant Formation

VOC emissions are formed as a result of working, and breathing losses of the tank contents. Produced water is separated from the inlet natural gas stream and stored in tanks.

11.2.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies were identified based on the principles of control technology and engineering experience for the water tanks. Table 11-2 outlines the top-down BACT analysis for VOC emissions from water tanks.

11.2.3. Selection of BACT for VOC

The water tanks are not subject to NSPS Subpart OOOO[55] as the emissions from the tanks are less than 6 ton per year. Even though the tanks are not required by regulation to be controlled, DCP has determined that the VOC BACT is utilizing a vapor combustion device (VCD) with 98% efficiency for the water tanks.

Table 11-2. BACT Analysis for Water Tanks – VOC

		Control Technology	Thermal Incineration[a]	Submerged fill, mechanical/liquid mounted seals
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	An open-flame control device used for disposing of waste gas streams.	Filling tanks via a submerged fill pipe and equipping tanks with mechanical/liquid mounted primary and secondary seals helps contain fugitive vapors.
		Typical Operating Temperature	1100-1200°F	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm	N/A
		Typical Waste Stream Inlet Pollutant Concentration	1500 - 3000 ppmv	N/A
		Other Considerations	Typically not cost-effective for low-concentrations, high-flow organic vapor streams.	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of VOC emissions from storage tanks.	Included in RBLC for the control of VOC emissions from storage tanks.
		Feasibility Discussion	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	99% for certain compounds with up to three carbons, 98% otherwise.	
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)		
Step 5.	SELECT BACT		👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incineration)," EPA-452/F-03-022.

[55] Per 40 CFR §60.5395b.

The BACT evaluation for the proposed truck loadout (L1) for VOC is provided in Section 12.1. Appendix A provides a summary of RBLC and permit search results. There are no methane or carbon dioxide fractions in the stabilized condensate; therefore no GHG BACT is evaluated for this source.

12.1. VOC BACT

12.1.1. Background on Pollutant Formation

VOC emissions are formed as a result of evaporative losses of the condensate during loading on to trucks.

12.1.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies were identified based on the principles of control technology and engineering experience for the loading operations. Table 12-1 outlines the top-down BACT analysis for VOC emissions from truck loading.

12.1.3. Selection of BACT for VOC

However, DCP has chosen to use submerged loading coupled with a VCD for the control of VOCs and HAPs. The most stringent RBLC and permit entries for VOC control are provided in Appendix A. DCP has chosen to use submerged loading coupled with a VCD for VOC BACT with 98% efficiency for the loading operations.

Table 12-1. BACT Analysis for Condensate Loadout – VOC

		Control Technology	Thermal Incineration[a]	Submerged fill	Pipeline Transfer
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	An open-flame control device used for disposing of waste gas streams.	Filling trucks via a submerged fill pipe help reduce fugitive vapors.	Material is transferred from the facility via pipeline thereby preventing any loading emissions.
		Typical Operating Temperature	1100-1200°F	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	500 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	1500 - 3000 ppmv	N/A	N/A
		Other Considerations	Typically not cost-effective for low-concentrations, high-flow organic vapor streams.	N/A	Typically not cost effective if infrastructure is not in place.
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC for the control of VOC emissions from truck loading	Included in RBLC for the control of VOC emissions from truck loading.	Not included in RBLC for the control of VOC emissions from truck loading.
		Feasibility Discussion	Feasible	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	99% for certain compounds with up to three carbons, 98% otherwise.		100% control since no VOC emissions from loading losses.
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)			Removal of condensate through a pipeline is not feasible at this time because the cost to DCP for each mile of pipeline is approximately $150,000 per mile. The closest pipeline to which DCP can route the condensate is approximately 17 miles away. Therefore, this adds a total of $2,550,000 for the pipeline addition. For a total VOC control of 111 tpy, this equates to roughly $23,000/ton VOC controlled. Therefore, at this time removal of condensate through a pipeline is considered economically infeasible.
Step 5.	SELECT BACT				

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incineration)," EPA-452/F-03-022.

13. BACT EVALUATION FOR VAPOR COMBUSTION DEVICE

Emissions from the glycol dehydrator still vent, condensate storage tanks, and truck loading are routed to a Vapor Combustion Device (VCD), Unit VCD1. Emissions will be generated by the combustion of natural gas as well as the combustion of the vent gas sent to the VCD. The BACT evaluation for the proposed VCD for NO_X, CO, VOC, and GHG is provided in Sections 13.1 through 13.4. Appendix A provides a summary of RBLC and permit search results.

13.1. NO_X BACT

13.1.1. Background on Pollutant Formation

The formation of NO_X in the VCD follow the same mechanisms as the engines or heaters. Thermal NO_X and prompt NO_X are the two dominant mechanisms of NO_X formation in the combustion zone of the VCD. Please refer to Section 5.1.1 for a detailed description of NO_X formation.

13.1.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for flares, which are similar to VCDs, were identified. Table 13-1 outlines the top-down BACT analysis for NO_X emissions from the VCD.

13.1.3. Selection of BACT for NO_X

Based on the review of the RBLC search and other permit review results, DCP has determined that the NO_X BACT is 0.098 lb/MMBtu of gas processed through the facility by utilizing good combustion practices.

13.2. CO BACT

13.2.1. Background on Pollutant Formation

CO from combustion sources is a by-product of incomplete combustion. Conditions leading to incomplete combustion include the following: insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

13.2.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable CO control technologies for flares, which are similar to VCDs, were identified. Table 13-1 outlines the top-down BACT analysis for CO emissions from the VCD.

13.2.3. Selection of BACT for CO

Based on the review of the RBLC search and other permit review results, DCP has determined that the CO BACT is 0.082 lb/MMBtu of gas processed through the facility by utilizing good combustion practices.

13.3. VOC BACT

13.3.1. Background on Pollutant Formation

The formation of VOC is the result of incompletion combustion from natural gas. VOC results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation. Additionally, the VCD is a unit that is used to control emissions of VOC from the glycol dehydrator still vent, condensate storage tanks, and truck loading operations. In addition to incomplete combustion emissions, additional emissions of VOC result from the un-destructed portion of the vent streams.

13.3.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for flares, which are similar to VCDs, were identified. Table 13-1 outlines the top-down BACT analysis for VOC emissions from the VCD.

13.3.3. Selection of BACT for VOC

Based on the review of the RBLC search and other permit review results, DCP has determined that the VOC BACT is 0.21 lb/MMBtu of gas processed through the facility by utilizing good combustion practices and will offer 98% control for VOC from the vent gas.

Table 13-1. BACT Analysis for Vapor Combustion Device – NO_X, CO and VOC

		Control Technology	Pipeline Quality Natural Gas (GHG)[a]	Good Combustion, Operating, and Maintenance Practices (for all criteria pollutants)
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Use of natural gas as fuel results in low GHG emissions due to the lower carbon intensity of the fuel.	Good combustion and operating practices are a potential control option for improving the combustion efficiency of the vapor combustion device (VCD). Good combustion practices include proper operation, maintenance, and tune-up of the VCD at least annually per the manufacturer's specifications.
		Typical Operating Temperature	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A
		Other Considerations	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC	Included in RBLC
		Feasibility Discussion	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)		
Step 5.	SELECT BACT			

a. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr S/100 scf or less.

13.4. GHG BACT

GHG emissions from the VCD include CO_2, CH_4 and N_2O which result from the combustion of natural gas as well as conversion of the VOC and CH_4 content of the vent streams controlled by the VCD to CO_2. The following section presents the BACT evaluation for GHG emissions from the VCD.

13.4.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;
- Proper VCD Design, Operation, and Maintenance;
- Fuel Selection; and
- Good Combustion Practices.

13.4.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 5.6.1.1.

13.4.1.2. Proper VCD Design, Operation, and Maintenance

Good VCD design can be employed to destroy any VOCs and CH_4 entrained in the vent stream encompassing the glycol dehydrator still vent, condensate storage tank emissions, and the truck loading emissions. Good VCD design includes flow measurement and monitoring/control of waste gas heating values. In addition, periodic tune-up and maintenance will be performed per the manufacturer recommendation.

13.4.1.3. Fuel Selection

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

13.4.1.4. Good Combustion, Operating, and Maintenance Practices

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

13.4.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

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

CCS (i.e., sequestration or transfer of CO_2) is the most effective control option for the control of the CO_2 stream from the VCD, since it provides a presumed 100% CO_2 control of the gas stream, based on literature review.

Good VCD design and operation result in approximately 1-15% and 1-10% reduction in GHG emissions, respectively.[56]

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

13.4.4. Step 4 – Evaluate Most Effective Control Options

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

The VCD vent stream does not contain a pure CO_2 stream since most of the CO_2 is stripped out in the upstream amine unit. Therefore, in addition to compression and transmission of CO_2, a process to isolate and purify the CO_2 is also required. This is because CCS stands for *carbon* capture and sequestration, isolating the carbon portion of the exhaust gas. CCS always involves separation and capture of CO_2 from the exhaust gas, pressurization of the captured CO_2, transportation of the CO_2 via pipeline, and finally injection and long-term geologic storage of the captured CO_2. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipelines. These units would require additional

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

electricity and generate additional air emissions, of both criteria pollutants and GHG pollutants. This would result in negative environmental and energy impacts.

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

13.4.5. Step 5 – Select BACT for the VCD

DCP proposes the following design elements and work practices as BACT for the VCD:

- Proper VCD design,
- Proper operation and maintenance procedures; and
- Use of natural gas as fuel.

In addition, DCP proposes a numerical BACT limit for total GHG emissions emitted from the VCD during normal operation of 117 lb CO_2e/MMBtu of gas processed through the facility. These emissions include process related emissions from the dehydrator still vent. This includes CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with this emission limit will be demonstrated by monitoring inlet gas throughput rate and performing calculations consistent with those in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average throughput and short tons of CO_2e per year emission rates do not exceed this limit.

13.5. VCD BACT SUMMARY

Based on the BACT analysis presented in the preceding subsections, Table 13-2 summarizes the BACT determinations for the VCD.

Table 13-2 VCD BACT Summary

Unit	Pollutant	Limit	Proposed BACT
Vapor Combustion Device (VCD1)	NO_x	0.098 lb/MMBtu	Good combustion practices
	CO	0.082 lb/MMBtu	Good combustion practices
	VOC	0.21 lb/MMBtu	Good combustion practices
	CO_2e	117 lb/MMBtu	Pipeline quality natural gas, proper VCD design, and proper operation and maintenance procedures

The Inlet Gas Flare (FL1), Acid Gas Flare (FL2) and Emergency Lusk Flare (FL3) are used during maintenance or upset conditions. The flares utilize natural gas and thus result in combustion emissions. The BACT evaluation for fuel combustion emissions from the proposed flares (FL1, FL2 and FL3) for NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, SO_2, and GHG is provided in Section 14.1. Appendix A provides a summary of RBLC and permit search results.

14.1. BACT FOR NO_X, CO, VOC, SO_2, $PM_{10}/PM_{2.5}$, GHG

14.1.1. Background on Pollutant Formation

Emissions result from the destruction of the off-gas produced during the emergency situations and during planned maintenance, startup and shutdown activities.

14.1.2. Identify all Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable control technologies for flares were identified. Table 14-1 outlines the top-down BACT analysis for criteria pollutant emissions from flares.

14.1.3. Selection of BACT for NO_X, CO, VOC, SO_2, $PM_{10}/PM_{2.5}$, GHG

The flares will meet the minimum requirements set out in 40 CFR §60.18 (General control device and work practice requirements) with the following control efficiency requirements.

- Destruction efficiency of 98% for VOCs, methane, and H_2S;
- No flaring of halogenated compounds allowed.

Based on the review of the RBLC search and other permit review results, DCP has determined that the BACT for flares is good flare design, good combustion, operating and maintenance practices and use of pipeline quality natural gas as fuel.

Table 14-1. BACT Analysis for Fuel Combustion Emissions from Flares – NO_X, CO, VOC, $PM_{10}/PM_{2.5}$

Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology	Pipeline Quality Natural Gas (for SO_2, PM_{10}, $PM_{2.5}$, and GHG)[a]	Good Combustion, Operating, and Maintenance Practices (for all criteria pollutants)	Good Flare Design (for all criteria pollutants)
		Control Technology Description	Use of low-sulfur, natural gas as fuel results in low SO_2, PM, PM_{10}, $PM_{2.5}$, and GHG emissions.	Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare at least annually per the manufacturer's specifications.	Good flare design can be employed to destroy large fractions of the flare gas. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.
		Typical Operating Temperature	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A	N/A	N/A
		Other Considerations	N/A	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Included in RBLC	Included in RBLC	Included in RBLC
		Feasibility Discussion	Feasible	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency	Base Case	Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)			
Step 5.	SELECT BACT		👍	👍	👍

a. Pipeline quality natural gas is defined as gas having sulfur content of 5 gr/100 scf or less

14.2. GHG BACT

The emergency flares at the facility will be used to destroy the off-gas produced during emergency situations and during planned maintenance emissions from compressor blowdowns. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas to the flare.

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

The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas by the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[57]

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

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[57] For example, combusting 1 lb of CH4 (25 lb CO2e) at the flare will result in 0.5 lb CH4 and 2.7 lb CO2 (0.02 lb CH4 x 25 CO2e/CH4 + 2.7 lb CO2 x 1 CO2e/CO2 = 3.2 lb CO2e), and therefore, on a CO2e emissions basis, combustion control of CH4 is preferable to venting the CH4 uncontrolled.

14.2.1. Step 1 – Identify All Available Control Technologies

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

- Carbon Capture and Sequestration;
- Fuel Selection;
- Flare Gas Recovery;
- Good Combustion, Operating, Maintenance Practices;
- Good Flare Design; and
- Limited Vent Gas Releases to Flare

14.2.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 5.6.1.1.

14.2.1.2. Fuel Selection

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

14.2.1.3. Flare Gas Recovery

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

14.2.1.4. Good Combustion, Operating, and Maintenance Practices

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

14.2.1.5. Good Flare Design

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. The flare tip is designed to allow for the proper flame temperature, residence time, mixing, and available oxygen to ensure as complete destruction as possible. Additional design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.

14.2.1.6. Limited Vent Gas Releases to Flare

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

14.2.2. Step 2 – Eliminate Technically Infeasible Options

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

14.2.2.1. *Carbon Capture and Sequestration*

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

14.2.2.2. *Flare Gas Recovery*

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

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

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

- Fuel Selection
- Good Combustion, Operating, and Maintenance Practices
- Good Flare Design
- Limited Vent Gas Releases to Flare

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

14.2.4. Step 4 – Evaluate Most Effective Control Options

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

14.2.5. Step 5 – Select BACT for the Flare

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

- Use of Natural Gas as Pilot Fuel;
- Implementation of Good combustion, Operating, and Maintenance Practices;
- Good Flare Design; and
- Limiting Vent Gas Releases to the Flare.

The flares will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. Emission sources whose maintenance blowdown and other venting emissions are routed to the flares will be operated in a manner to minimize the frequency and duration of such flaring activities and therefore, the amount of maintenance emissions from the vent gas released to the flare.

DCP is not proposing a numerical BACT limit on GHG emissions from the flares since it is used to destroy the off-gas produced during emergency situations and during planned maintenance activities. BACT for the emergency flares are the aforementioned work practice standards.

15. BACT EVALUATION FOR FACILITY-WIDE FUGITIVE EMISSIONS

15.1. BACT FOR VOC AND GHG

The following sections present a BACT evaluation of fugitive VOC, CO_2 and CH_4 emissions. It is anticipated that the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for VOC, CO_2 and CH_4. Fugitive components included in the proposed facility include traditional components such as valves and flanges.

15.1.1. Step 1 - Identify All Available Control Technologies

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

- Installing leakless technology components to eliminate fugitive emission sources;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for odorous compounds; and
- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

15.1.1.1. Leakless Technology Components

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

15.1.1.2. LDAR Programs

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

15.1.1.3. Alternative Monitoring Program

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

15.1.1.4. AVO Monitoring Program

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

15.1.1.5. High Quality Components

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

15.1.2. Step 2 - Eliminate Technically Infeasible Options

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

All other control options are considered technically feasible.

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

15.1.3.1. LDAR Programs

Instrumented monitoring is effective for identifying leaking VOC and CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. The facility will conduct quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance and adhere to 40 CFR 60 Subpart OOOO equipment leak standards.

15.1.3.2. Alternative Monitoring Program

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

15.1.3.3. AVO Monitoring Program

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

15.1.3.4. High Quality Components

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

15.1.4. Step 4 - Evaluate Most Effective Control Options

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

15.1.5. Step 5 - Select BACT for Fugitive Emissions

Monitoring will be conducted at the facility following the protocol established in 40 CFR Subpart OOOO. Any leaks discovered via LDAR will be repaired as quickly as practical. The selected BACT for the fugitives was compared to the RBLC results. Several facilities proposed implementation of LDAR as BACT for fugitive emissions.

Since DCP is implementing the most effective control options available, additional analysis is not necessary. In addition, since fugitive VOC and GHG emissions are estimations only, DCP proposes no numerical BACT limit.

Table 15-1. BACT Analysis for Facility-Wide Fugitives – VOC

		Control Technology	Installation of Leakless Equipment	Implementation of LDAR [a]	Alternative Monitoring Program - Remote Sensors / Infrared Technologies	Audio/Visual/Olfactory (AVO) Monitoring Program[a]	Use High Quality Components and Materials of Construction Compatible with Process
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used.	The LDAR program has traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs.	Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.	Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods.	The use of high quality equipment that is designed for the specific service in which it is employed results in effective control of fugitive emissions.
		Typical Operating Temperature	-	-	-	-	-
		Typical Waste Stream Inlet Flow Rate	-	-	-	-	-
		Typical Waste Stream Inlet Pollutant Concentration	-	-	-	-	-
		Other Considerations	-	-	-	-	-
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	-	Included in RBLC for the control of VOC emissions from fugitive VOC emissions.	-	-	-
		Feasibility Discussion	Technically Infeasible. Not implemented for VOC compounds.	Technically feasible.	Technically feasible.	Technically feasible for the identification of larger leaks.	Technically feasible.
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency		LDAR and Adhere to 40 CFR 60 Subpart OOOO Equipment Leak Requirements	Choosing a higher ranked control technology, therefore no further evaluation required.	Choosing a higher ranked control technology, therefore no further evaluation required.	Choosing a higher ranked control technology, therefore no further evaluation required.
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)					
Step 5.	SELECT BACT						

a. EPA document "Leak Detection and Repair - A Best Practices Guide" (http://www.epa.gov/Compliance/resources/publications/assistance/ldarguide.pdf)

16. BACT EVALUATION FOR PAVED HAUL ROADS

16.1.1. Background on Pollutant Formation

This section presents the BACT analysis for haul roads. The only haul road at the facility is for trucks hauling condensate off site (less than 1/2 of a mile of a paved haul road segment).

Haul roads have the potential to generate dust particles as vehicles traveling on the roads cause particles on the surface of the roads to become suspended in the atmosphere. The particle loading of the road surfaces is an indicator of the potential for vehicles traveling on the roads to generate these suspended dust particles. Paved haul roads have a lower potential for particle loading than unpaved haul roads, as vehicles traveling on unpaved roads can cause pulverization of the unpaved road surface, and the pulverized material contributes to the particle loading of the road.

The dust particles that are generated as vehicles travel on paved haul roads are filterable particulate matter – $PM_{10}/PM_{2.5}$. Therefore, the BACT evaluation for the haul roads addresses filterable particulate matter. The BACT analysis has been evaluated using the "top-down" approach as shown in Table 16-1.

16.1.2. Step 1 - Identify all Available Control Technologies

Control options for haul roads are designed to suppress or eliminate road dust. $PM_{10}/PM_{2.5}$ reduction options from fugitive sources include:

- Road paving; and
- Speed limits

16.1.3. Step 2 - Eliminate Technically Infeasible Options

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. Under normal circumstances paving of roads is not feasible for industrial roads subject to very heavy vehicles, but in this particular case it is viable option. The abovementioned soil, Caliche, is an excellent road construction material that is used as a sub base layer for the construction of an asphalt (or concrete) road that with an adequate design and construction can wind stand heavy truck traffic. Therefore, all options are technically feasible for control of $PM_{10}/PM_{2.5}$ from the haul road at Zia II facility.

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

The following ranks the remaining control technologies:
- Paved road; and
- Speed Reduction

16.1.5. Step 4 - Evaluate Most Effective Control Options

The most effective control option is paving the haul road because soil particles will not be in direct contact with the truck tires causing them to become airbone causing fugitive dust as a consequence of this activity. Since this is the most effective control option no additional evaluation is required for the other less effective options.

16.1.6. Step 5 - Select BACT for Haul Roads

DCP proposes to pave the haul road and at the same time limit the speed of haul trucks to 25 mph by posting speed limit signs at the entrance of the facility, including speed bumps at regular intervals to ensure the speed limit is met. This will result in approximately a reduction of 72 to 90% of PM emission expected for a unpaved road under this same operational conditions.

Table 16-1. BACT Analysis for Paved Haul Roads – $PM_{10}/PM_{2.5}$

		Control Technology	**Paving[a]**	**Speed Reduction**
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	A durable surface material like asphalt or concrete is laid out on the road, to sustain vehicular traffic.	A limit on the speed of the vehicular traffic is imposed, which prevents disturbance of particulate matter from the surface of the road.
		Typical Operating Temperature	–	–
		Typical Waste Stream Inlet Flow Rate	–	–
		Typical Waste Stream Inlet Pollutant Concentration	–	–
		Other Considerations	–	–
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC	Included in RBLC
		Feasibility Discussion	Feasible	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	Paving is feasible for industrial roads (as in the current facility) that will be subject to very heavy vehicles and/or spillage of material in transport.	Since the emissions from this source are minor, limiting the speed at the facility to 25 mph will extend life of the covering surface (asphalt or concrete) while at the same time will reduced the emission of particulate matter deposited on the paved road transported by the surrounding environment (wind) or in the truck's undercarriage.
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**		👍	👍

[a] WRAP Fugitive Dust Handbook, Fugitive Dust Control Measures Applicable for the WRAP Region (September 7, 2006).

17.1.1. Background on Pollutant Formation

This section presents the BACT analysis for Wet Surface Air Cooler (WSAC) cooling tower. The designed mass flow rate for the WSAC, Unit CT-1, is 131,500 lb/hr.

Cooling towers are heat exchangers that are used to dissipate large heat loads to the atmosphere. Since WSAC provide direct contact between the cooling water and the air passing through the unit, some of the liquid water can be entrained in the air stream and could be carried out of the tower as "drift" droplets. Therefore, the particulate matter constituent of the drift droplets is classified as an emission, specifically PM.

The BACT analysis has been evaluated using the "top-down" approach as shown in Table 16-1 .

17.1.2. Step 1 - Identify all Available Control Technologies

Control options for wet cooling towers are designed reduce the drift droplets generated at the cooling tower. PM_{10}/$PM_{2.5}$ reduction options cooling towers include:

- Drift Eliminators and;
- Good Maintenance and Operation Practice (GMOP)

17.1.3. Step 2 - Eliminate Technically Infeasible Options

After the identification of control options, the second step in the BACT assessment is to eliminate technically infeasible options. A control option is eliminated from consideration if there are process-specific conditions that would prohibit the implementation of the control or if the highest control efficiency of the option would result in an emission level that is higher than any applicable regulatory limits. Drift eliminators is the most widely used control technology used in cooling towers to reduce PM emissions. GMOP is also a well stablished supporting control technology used in these units, therefore, all the above control are feasible.

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

The following ranks the remaining control technologies:

- Drift Eliminators and,
- Good Maintenance and Operation Practices (GMOP).

17.1.5. Step 4 - Evaluate Most Effective Control Options

The most effective control option is Drift Eliminators combined with Good Maintenance and Operational Practices, therefore both technologies will be adopted.

17.1.6. Step 5 - Select BACT for Wet Cooling Tower

DCP proposes to use a BACT Control Drift Eliminator in combination with Good Maintenance and Operational practices to a PM_{10} control efficiency for 99.995 %.

Table 17-1. BACT Analysis for Wet Surface Air Cooler– $PM_{10}/PM_{2.5}$

		Control Technology	**Drift Eliminator**[a]	**Good Maintenance and Operational Practices**[b]
		Control Technology Description	Removes droplets from the air stream before exiting the WSAC relying on inertia separation caused by directional changes while passing though the eliminator.	Excess water and air flow as well as bypassing Drift Eliminators promotes and increase drift emissions.
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Typical Operating Temperature**	–	–
		Typical Waste Stream Inlet Flow Rate	–	–
		Typical Waste Stream Inlet Pollutant Concentration	–	–
		Other Considerations	–	–
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC	Included in RBLC
		Feasibility Discussion	Feasible	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	99.995%	Varies
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**		
Step 5.	**SELECT BACT**			

[a] RBLC ID: CO-0057 and RBLC ID: IA-0105. AP-42 Section 13.4 Wet Cooling Towers 1/95

[b] AP-42 Section 13.4 Wet Cooling Towers 1/95

18. BACT EVALUATION FOR THE DIESEL FUEL ENGINE

The BACT evaluation for the proposed diesel fuel emergency power generator (GEN-1) for NO_X, CO, VOC, $PM_{10}/PM_{2.5}$, SO_2, and CO_2e is provided in Sections 5.1 through 5.7. Appendix A provides a summary of RBLC and permit search results.

18.1. NO_X BACT

18.1.1. Background on Pollutant Formation

In combustion processes, NO_X is formed by two fundamentally different mechanisms: Fuel NO_X and thermal NO_X. NO_X formation from internal combustion engines is primarily thermal NO_X.

"Fuel NO_X" forms when fuels containing nitrogen are burned. When these fuels are burned, the nitrogen bonds break and some of the resulting free nitrogen oxidizes to form NO_X. With excess air, the degree of fuel NO_X formation is primarily a function of the nitrogen content of the fuel. Therefore, since diesel as well as most distillate oils contains little or no fuel-bound nitrogen, fuel NO_X is not a major contributor to NO_X emissions from diesel fuel engines.[58]

18.1.2. Identify All Available Control Technologies

NO_X reduction in internal combustion engines can be accomplished by combustion control techniques and post-combustion control methods. Combustion control techniques incorporate fuel or air staging that affect the kinetics of NO_X formation (reducing peak flame temperature) or introduce inerts (combustion products, for example) that limit initial NO_X formation, or both. Post-combustion NO_X control technologies employ various strategies to chemically reduce NO_X to elemental nitrogen (N_2) with or without the use of a catalyst.

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable NO_X control technologies for small internal combustion engines were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-1 outlines the top down BACT analysis for NO_X emissions from the diesel fuel engines.

18.1.3. Selection of BACT for NO_X

The diesel fuel engines will be subject to NSPS Subpart IIII and to 40 CFR Part 89 Non Road compression – ignition engines emission standards. 40 CFR Part 89 provides a NO_X limit for an engine of this capacity (70 hp) of 3.3 g/bhp-hr. Thus, based on the above DCP proposed to use as BACT the 40 CFR Part 89 Non-Road emission factors as well as Good Combustion Practices.

[58] US EPA AP-42 Section 3.3 Gasoline and Diesel Industrial Engines. 10/96

Table 18-1. BACT Analysis for Diesel Fuel Internal Combustion Engines - NO_X

Step		Control Technology	Selective Catalytic Reduction (SCR)[a]	Non-Selective Catalytic Reduction (NSCR)	NSPS Subpart IIII and EPA Tier 3 Regulatory Emissions	Good Combustion Practices
Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology Description**	A nitrogen-based reagent (e.g., ammonia, urea) is injected into the exhaust stream downstream of the combustion unit. The reagent reacts selectively with NO_X to produce molecular N_2 and water in a reactor vessel containing a metallic or ceramic catalyst.	This technique uses residual hydrocarbons and CO in rich-burn engine exhaust as a reducing agent for NO_X. In an NSCR, hydrocarbons and CO are oxidized by O_2 and NO_X. The excess hydrocarbons, CO, and NO_X pass over a catalyst (usually a noble metal such as platinum, rhodium, or palladium) that oxidizes the excess hydrocarbons and CO to H_2O and CO_2, while reducing NO_X to N_2.[b]	This unit falls under NSPS Subpart IIII Table 1 (Emission standards), fuel requirements, monitoring and compliance and reporting requirements. In addition, this units needs to meet 40 CFR Part 89 Non-road compression-ignition engines emission standards.	NO_X emissions are caused by oxidation of nitrogen gas in the combustion air during fuel combustion. This occurs due to high combustion temperatures and insufficiently mixed air and fuel in the cylinder where pockets of excess oxygen occur. These effects can be minimized through air-to-fuel ratio control, ignition timing reduction, and fuel quality analysis and fuel handling. This practice includes the use of Ultra Low Sulfur Diesel.
		Typical Operating Temperature	480 - 800 °F (variations of ± 200 °F)	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	N/A	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 20 ppm (efficiency improves with increased concentration up to 150 ppm)	N/A	N/A	N/A
		Other Considerations	Unreacted reagent may form ammonium sulfates which may plug or corrode downstream equipment. Particulate-laden streams may blind the catalyst and may necessitate the application of a sootblower.	N/A	N/A	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Not included in RBLC for the control of NO_X emissions from small diesel fuel stationary internal combustion engines.	Not included in RBLC for the control of NO_X emissions from small diesel fuel stationary internal combustion engines.	Included in RBLC for the control of NO_X emissions from small diesel fuel combustion engines.	Included in RBLC for the control of NO_X emissions from small diesel fuel combustion engines.
		Feasibility Discussion	Technically infeasible. For small diesel fuel engines which typically operate as back up power generator units. These units only operate during power failure outages for very few hours per year.	Technically infeasible. For small diesel fuel engines which typically operate as back up power generator units. These units only operate during power failure outages for very few hours per year.	Technically feasible.	Technically feasible.
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**			Base Case	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**				
Step 5.	**SELECT BACT**				👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Selective Catalytic Reduction (SCR))," EPA-452/F-03-032.
b. U.S. EPA, AP-42, Section 3.3, "Stationary Internal Combustion Sources"

18.2. CO BACT

18.2.1. Background on Pollutant Formation

CO from internal combustion engines is a by-product of incomplete combustion. Conditions leading to incomplete combustion include insufficient oxygen availability, poor fuel/air mixing, reduced combustion temperature, reduced combustion gas residence time, and load reduction.

18.2.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable CO control technologies for small diesel fuel internal combustion engines were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-2 outlines the top-down BACT analysis for CO emissions from the combustion engines.

18.2.3. Selection of BACT for CO

The diesel fuel engines will be subject to NSPS Subpart IIII and to 40 CFR Part 89 Non Road compression – ignition engines emission standards. 40 CFR Part 89 provides a CO limit of 3.7 g/bhp-hr. Thus, based on the above DCP proposed to use as BACT the 40 CFR Part 89 Non-Road emission factors as well as Good Combustion Practices.

Table 18-2. BACT Analysis for Diesel Fuel Internal Combustion Engines – CO

		Control Technology	Regenerative Thermal Oxidizer	Recuperative Thermal Oxidizer	Catalytic Oxidation[d]	NSPS Subpart IIII and EPA Tier 3 Regulatory Emissions	Good Combustion Practices[e]
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	This unit falls under NSPS Subpart IIII Table 1 (Emission standards), fuel requirements, monitoring and compliance and reporting requirements. In addition, this units needs to meet 40 CFR Part 89 Non-road compression-ignition engines emission standards.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.
		Typical Operating Temperature	1,400 - 1,500 °F [b]	1,100 - 1,200 °F [c]	600 - 800 °F (not to exceed 1,250 °F)	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	5,000 - 500,000 scfm [b]	500 - 50,000 scfm [c]	700 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less [b]	As low as 100 ppmv or less [b]	As low as 1 ppmv	N/A	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[c]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of CO emissions from small diesel fuel internal combustion engines.	Not included in RBLC for the control of CO emissions from small diesel fuel internal combustion engines.	Not included in RBLC for the control of CO emissions from small diesel fuel internal combustion engines.	Included in RBLC for the control of CO emissions from small diesel fuel combustion engines.	Included in RBLC for the control of CO emissions from internal combustion engines.
		Feasibility Discussion	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically feasible.	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency				Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)					
Step 5.	SELECT BACT						

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018.
e. U.S. EPA, AP-42, Section 3.3, "Stationary Internal Combustion Sources"

18.3. VOC BACT

18.3.1. Background on Pollutant Formation

The formation of VOC is the result of incomplete combustion of diesel. VOC results when there is insufficient residence time at high temperature to complete the final step in hydrocarbon oxidation.

18.3.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable VOC control technologies for small diesel fuel internal combustion engines were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-3 outlines the top-down BACT analysis for VOC emissions from the combustion engines. Generally, the control technologies for VOC are identical to those for CO.

18.3.3. Selection of BACT for VOC

The diesel fuel engines will be subject to NSPS Subpart IIII and to 40 CFR Part 89 Non Road compression – ignition engines emission standards. 40 CFR Part 89 provides a VOC limit of 0.18 g/bhp-hr. Thus, based on the above DCP proposed to use as BACT the 40 CFR Part 89 Non-Road emission factors as well as Good Combustion Practices.

Table 18-3. BACT Analysis for Diesel Fuel Internal Combustion Engines – VOC

		Control Technology	Regenerative Thermal Oxidizer	Recuperative Thermal Oxidizer	Catalytic Oxidation[d]	NSPS Subpart IIII and EPA Tier 3 Regulatory Emissions	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	**Control Technology Description**	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Oxidizes combustible materials by raising the temperature of the material above the auto-ignition point in the presence of oxygen and maintaining the high temperature for sufficient time to complete combustion.[a]	Similar to thermal incineration; waste stream is heated by a flame and then passes through a catalyst bed that increases the oxidation rate more quickly and at lower temperatures.	This unit falls under NSPS Subpart IIII Table 1 (Emission standards), fuel requirements, monitoring and compliance and reporting requirements. In addition, this units needs to meet 40 CFR Part 89 Non-road compression-ignition engines emission standards.	Continued operation of the engines at the appropriate oxygen range and temperature to promote complete combustion and minimize VOC formation.
		Typical Operating Temperature	1,400 - 1,500 °F [b]	1,100 - 1,200 °F [c]	600 - 800 °F (not to exceed 1,250 °F)	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	5,000 - 500,000 scfm [b]	500 - 50,000 scfm [c]	700 - 50,000 scfm	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	As low as 100 ppmv or less [b]	As low as 100 ppmv or less [b]	As low as 1 ppmv	N/A	N/A
		Other Considerations	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[a]	Additional fuel is required to reach the ignition temperature of the waste gas stream. Oxidizers are not recommended for controlling gases with sulfur containing compounds because of the formation of highly corrosive acid gases.[c]	Oxidation efficiency depends on exhaust flow rate and composition. Residence time required for oxidation to take place at the active sites of the catalyst may not be achieved if exhaust flow rates exceed design specifications. Also, sulfur and other compounds may foul the catalyst, leading to decreased efficiency.	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	**RBLC Database Information**	Not included in RBLC for the control of VOC emissions from small diesel fuel stationary internal combustion engines.	Not included in RBLC for the control of VOC emissions from small diesel fuel stationary internal combustion engines.	Not included in RBLC for the control of VOC emissions from small diesel fuel stationary internal combustion engines.	Included in RBLC for the control of VOC emissions from small diesel fuel combustion engines.	Included in RBLC for the control of VOC emissions from small diesel fuel combustion engines.
		Feasibility Discussion	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically feasible.	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	**Overall Control Efficiency**				Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	**Cost Effectiveness ($/ton)**					
Step 5.	SELECT BACT						

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Thermal Incinerator)," EPA-452/F-03-022.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Regenerative Incinerator)," EPA-452/F-03-021.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Recuperative Incinerator)," EPA-452/F-03-020.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Catalytic Incinerator)," EPA-452/F-03-018.

18.4. $PM_{10}/PM_{2.5}$ BACT

18.4.1. Background on Pollutant Formation

Filterable PM emissions from diesel combustion are formed by ash and sulfur in the fuel.

18.4.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable particulate control technologies were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-4 outlines the top-down BACT analysis for particulate emissions from the diesel fuel engine.

18.4.3. Selection of BACT for $PM_{10}/PM_{2.5}$

Based on the review of the RBLC search and other permit review results, DCP has determined that the $PM_{10}/PM_{2.5}$ BACT limit is 0.02 g/bhp-hr by implementing EPA Tier III non-road regulatory emission requirements, using ultra low sulfur diesel fuel and good combustion practices.

Table 18-4. BACT Analysis for Diesel Fuel Internal Combustion Engines – $PM_{10}/PM_{2.5}$

		Control Technology	Baghouse / Fabric Filter[a]	Electrostatic Precipitator (ESP)[b,c,d]	Cyclone[e]	NSPS Subpart IIII and EPA Tier 3 Regulatory Emissions	Ultra Low Sulfur Diesel Fuel	Good Combustion Practices
Step 1.	IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES	Control Technology Description	Process exhaust gas passes through a tightly woven or felted fabric arranged in sheets, cartridges, or bags that collect PM via sieving and other mechanisms. The dust cake that accumulates on the filters increases collection efficiency. Various cleaning techniques include pulse-jet, reverse-air, and shaker technologies.	Electrodes stimulate the waste gas and induce an electrical charge in the entrained particles. The resulting electrical field forces the charged particles to the collector walls from which the material may be mechanically dislodged and collected in dry systems or washed with a water deluge in wet systems.	Centrifugal forces drive particles in the gas stream toward the cyclone walls as the waste gas flows through the conical unit. The captured particles are collected in a material hopper below the unit.	This unit falls under NSPS Subpart IIII Table 1 (Emission standards), fuel requirements, monitoring and compliance and reporting requirements. In addition, this units needs to meet 40 CFR Part 89 Non-road compression-ignition engines emission standards.	Diesel fuel containing 15 part per million (ppm) of Sulfur.	Operate and maintain the equipment in accordance with good air pollution control practices and with good combustion practices.
		Typical Operating Temperature	Up to 500 °F (Typical)	Up to 1,300 °F (dry) Lower than 170 - 190 °F (wet)	Up to 1,000 °F	N/A	N/A	N/A
		Typical Waste Stream Inlet Flow Rate	100 - 100,000 scfm (Standard) 100,000 - 1,000,000 scfm (Custom)	1,000 - 100,000 scfm (Wire-Pipe) 100,000 - 1,000,000 scfm (Wire-Plate)	1.1 - 63,500 scfm (single) Up to 106,000 scfm (in parallel)	N/A	N/A	N/A
		Typical Waste Stream Inlet Pollutant Concentration	0.5 - 10 gr/dscf (Typical) 0.05 - 100 gr/dscf (Achievable)	0.5 - 5 gr/dscf (Wire-Pipe) 1 - 50 gr/dscf (Wire-Plate)	0.44 - 7,000 gr/dscf	N/A	N/A	N/A
		Other Considerations	Fabric filters are susceptible to corrosion and blinding by moisture. Appropriate fabrics must be selected for specific process conditions. Accumulations of dust may present fire or explosion hazards.	Dry ESP efficiency varies significantly with dust resistivity. Air leakage and acid condensation may cause corrosion. ESPs are not generally suitable for highly variable processes. Equipment footprint is often substantial.	Cyclones typically exhibit lower efficiencies when collecting smaller particles. High-efficiency units may require substantial pressure drop.	N/A	N/A	N/A
Step 2.	ELIMINATE TECHNICALLY INFEASIBLE OPTIONS	RBLC Database Information	Not included in RBLC for the control of PM emissions from small diesel fuel stationary internal combustion engines.	Not included in RBLC for the control of PM emissions from small diesel fuel stationary internal combustion engines.	Not included in RBLC for the control of PM emissions from small diesel fuel stationary internal combustion engines.	Included in RBLC for the control of PM emissions from small diesel fuel combustion engines.	Included in RBLC for the control of SO_X emissions from small diesel fuel combustion engines.	Included in RBLC for the control of PM emissions from small diesel fuel combustion engines.
		Feasibility Discussion	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically infeasible. The installation of this control technology in such a small diesel engine used as a backup generator is impractical.	Technically feasible.	Feasible	Feasible
Step 3.	RANK REMAINING CONTROL TECHNOLOGIES	Overall Control Efficiency				Base Case	Base Case	Base Case
Step 4.	EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS	Cost Effectiveness ($/ton)						
Step 5.	SELECT BACT					👍	👍	👍

a. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Fabric Filter - Pulse-Jet Cleaned Type)," EPA-452/F-03-025.
b. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Pipe Type)," EPA-452/F-03-027.
c. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Dry Electrostatic Precipitator (ESP) - Wire-Plate Type)," EPA-452/F-03-028.
d. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Wet Electrostatic Precipitator(ESP) - Wire-Pipe Type)," EPA-452/F-03-029.
e. U.S. EPA, Office of Air Quality Planning and Standards, "Air Pollution Control Technology Fact Sheet (Cyclone)," EPA-452/F-03-005.

18.5. SO_2 BACT

18.5.1. Background on Pollutant Formation

SO_2 emissions result from the oxidation of fuel-bound sulfur, with emissions dependent upon the sulfur content of the fuel.

18.5.2. Identify All Available Control Technologies

Using the RBLC search and permit review results, as well as a review of technical literature, potentially applicable SO_2 control technologies were identified based on the principles of control technology and engineering experience for general combustion units. Table 5-6 outlines the top-down BACT analysis for SO_2 emissions from the diesel fuel engine.

18.5.3. Selection of BACT for SO_2

Based on the review of the RBLC search and other permit review results, DCP has determined that the SO_2 BACT limit is 15 ppm of sulfur in the fuel inlet by utilizing ultra-low sulfur diesel fuel.

Table 18-5 BACT Analysis for Diesel Fuel Internal Combustion Engines – SO_2

Step 1.	**IDENTIFY AIR POLLUTION CONTROL TECHNOLOGIES**	**Control Technology**	**Ultra Low Sulfur Diesel Fuel[a]**
		Control Technology Description	Diesel fuel containing 15 part per million (ppm) of sulfur.
		Typical Operating Temperature	N/A
		Typical Waste Stream Inlet Flow Rate	N/A
		Typical Waste Stream Inlet Pollutant Concentration	N/A
		Other Considerations	N/A
Step 2.	**ELIMINATE TECHNICALLY INFEASIBLE OPTIONS**	**RBLC Database Information**	Included in RBLC for the control of SO_X emissions from small diesel fuel combustion engines.
		Feasibility Discussion	Feasible
Step 3.	**RANK REMAINING CONTROL TECHNOLOGIES**	**Overall Control Efficiency**	Base Case
Step 4.	**EVALUATE AND DOCUMENT MOST EFFECTIVE CONTROLS**	**Cost Effectiveness ($/ton)**	
Step 5.	**SELECT BACT**		👍

[a] U.S. EPA, AP-42, Section 3.3, "Stationary Internal Combustion Sources"

18.6. GHG BACT

GHG emissions from the proposed power engine (GEN-1) include CO_2, CH_4 and N_2O and result from the combustion of diesel fuel. The following section presents BACT evaluations for GHG emissions from the proposed engine.

18.6.1. Step 1 – Identify All Available Control Technologies

A search of the RBLC database showed GHG BACT records for CO_2e. However, since it is a new requirement, the records do not contain sources applicable to the Zia II facility. The available GHG emission control strategies for the engine that were analyzed as part of this BACT analysis include[59]:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/Fuel Ratio Controllers; and
- Efficient Engine Design

18.6.1.1. Carbon Capture and Sequestration (CCS)

The contribution of CO_2e emissions from each engine is a fraction of the scale for sources where CCS might ultimately be feasible. Although we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance[60], a detailed rationale is provided to support this conclusion.

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

Larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed.[61] Additionally, these demonstration projects are for post-combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slip stream as compared to a more dilute stream from the combustion of natural gas.[62] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[63]

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

[60] PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011, page 32.

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

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

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

18.6.1.2. Fuel Selection

Ultra Low Sulfur Diesel has carbon intensity[64] of 94.71 gCO_2e/MJ that when compared to Compressed Natural Gas, Gasoline and Electricity, 67.70 94.71, 95.86 and 124.10 94.71 gCO_2e/MJ, respectively, it is a reasonable fuel option.

18.6.1.3. Good Combustion, Operating, and Maintenance Practices

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

18.6.1.4. Air/Fuel Ratio Controllers

Air/fuel ratio controllers minimize CO_2e emissions from reciprocating engines. Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the air/fuel mixture and reduce the amount of energy required to heat the stream and, therefore, reduce the CO_2e emissions.

18.6.1.5. Efficient Engine Design and Selection

To select the most efficient engine for the Zia II facility, the following factors were taken into account: Available footprint, operational fluctuations and flexibility, emissions performance, and energy efficiency.

To meet the power generation needs of this project, a small diesel fuel engine with a low horsepower rating is required to generate a low electricity demand for a specific area within this facility. Engine can be manufactured to be rich-burn or lean-burn. Rich burn is an inherently inefficient combustion process that results in increased fuel usage compared to lean burn engines but due to the power output require only a rich burn engine was found fir this purpose.

18.6.2. Step 2 – Eliminate Technically Infeasible Options

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

18.6.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the engine and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[65] The engines emit CO_2 in small and more diluted quantities.

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[64] http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf

[65] PSD and Title V permitting Guidance for Greenhouse Gases. March 2011, page 32. "For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology86 that is "available"87 for facilities emitting CO2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). The proposed project is not any of the cases EPA suggests above.

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

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

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/Fuel Ratio Controllers; and
- Efficient Engine Design.

Since DCP proposes to implement all of the abovementioned control options, ranking these control options is not necessary.

18.6.4. Step 4 – Evaluate Most Effective Control Options

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

18.6.5. Step 5 – Select BACT for the Engines

DCP proposes the following design elements and work practices as BACT for the diesel fuel engine:

- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Air/Fuel Ratio Controllers; and
- Efficient Engine Design.

DCP proposes the CO_2e emission limits for the diesel fuel engine to be 28 short tons of CO_2e per year

These proposed emission limits are based on a 12-month rolling average basis and include CO_2, CH_4, and N_2O emissions.

Compliance with these emission limits will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Form UA3, Section 6 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

APPENDIX A. RBLC TABLES

COMPRESSORS ENGINES

RBLC Data for Compressors Engines - NO_X Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT	EMISSION UNIT AVERAGING TIME	EMISSION LIMIT	EMISSION UNIT
CA-1131	CHOMP	09/02/2004 ACT	ICE: SPARK IGNITION, NATURAL GAS	528	BHP	3-WAY CATALYTIC CONVERTER	0.07	G/B-HP-H		0.07	G/B-HP-H
CO-0058	CHEYENNE STATION	06/12/2004 ACT	FREP ENGINE	13	MMBTU/H	LEAN BURN COMBUSTION TECHNOLOGY	0.8	G/B-HP-H	1-HR	0.80	G/B-HP-H
CO-0058	CHEYENNE STATION	06/12/2004 ACT	CPP ENGINE	16.47	MMBTU/H	LEAN BURN TECHNOLOGY	0.8	G/B-HP-H	1-HR	0.80	G/B-HP-H
LA-0257	SABINE PASS LNG TERMINAL	12/06/2011 ACT	GENERATOR ENGINES (2)	2012	HP	COMPLY WITH 40 CFR 60 SUBPART JJJJ	9.76	LB/H	HOURLY MAXIMUM	2.20	G/B-HP-H
LA-0232	STERLINGTON COMPRESSOR STATION	06/24/2008 ACT	COMPRESSOR ENGINE NO. 1	32.2	MMBTU/H	GOOD COMBUSTION PRACTICES	7.31	LB/H	HOURLY MAXIMUM	0.26	G/B-HP-H
MI-0390	WHITE PIGEON COMPRESSOR STATION - PLANT #3	11/24/2008 ACT	COMPRESSOR ENGINE	0			0.5	G/B-HP-H	TEST METHOD	0.50	G/B-HP-H
MS-0056	SOUTHERN NATURAL GAS CO. - ENTERPRISE COMPRESSOR	08/26/2003 ACT	IC ENGINE, COMPRESSOR ENGINE, NATURAL GAS(2)	4730	HP	USE OF LOW EMISSION (OR CLEAN BURN) TECHNOLOGY	7.3	LB/H	EACH	0.70	G/B-HP-H
OK-0109	MOORELAND CRYOGENIC PLT	01/21/2005 ACT	INTERNAL COMBUSTION ENGINE, (1)	2200	HP	LEAN BURN CONVERSION	2	G/B-HP-H		2.00	G/B-HP-H
OK-0109	MOORELAND CRYOGENIC PLT	01/21/2005 ACT	INTERNAL COMBUSTION ENGINE, (3)	842	HP	CATALYTIC CONVERTERS	5.57	LB/H	EACH	3.00	G/B-HP-H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8,EPN4&5	440	HP	NONE INDICATED	18.41	LB/H	EACH	18.98	G/B-HP-H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR-SVG-8, EPN10A&B	1330	HP	NONE INDICATED	59.31	LB/H	EACH	20.23	G/B-HP-H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(3) COOPER-BESSEMER ENGINES, #GMVH- 12C2, EPN21-23	3105	HP	NONE INDICATED	21.89	LB/H	EACH	3.20	G/B-HP-H
WV-0019	LOST RIVER COMPRESSOR STATION	02/19/2003 ACT	COMPRESSOR ENGINE, NATURAL GAS	4640	HP	CLEAN BURN TECHNOLOGY OF LEAN-BURN ENGINES	39	T/YR		0.87	G/B-HP-H
WV-0020	COLUMBIA GAS TRANSMISSIONS LOST RIVER	02/14/2003 ACT	IC ENGINE, NATURAL GAS, # 10	4640	HP		20.5	LB/H		2.00	G/B-HP-H

RBLC Data for Compressors Engines - CO Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
CO-0058	CHEYENNE STATION	06/12/2004 ACT	FREP ENGINE	13	MMBTU/H	OXIDATION CATALYST	0.21	G/B-HP-H
CO-0058	CHEYENNE STATION	06/12/2004 ACT	CPP ENGINE	16.47	MMBTU/H	OXIDATION CATALYST	0.21	G/B-HP-H
LA-0257	SABINE PASS LNG TERMINAL	12/06/2011 ACT	GENERATOR ENGINES (2)	2012	hp	COMPLY WITH 40 CFR 60 SUBPART JJJJ	4.40	G/B-HP-H
WV-0020	COLUMBIA GAS TRANSMISSIONS LOST RIVER	02/14/2003 ACT	IC ENGINE, NATURAL GAS, # 10	4640	HP		2.20	G/B-HP-H

RBLC Data for Compressors Engines - VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
CO-0058	CHEYENNE STATION	06/12/2004 ACT	FREP ENGINE	13	MMBTU/H	OXIDATION CATALYST	0.30	G/B-HP-H
CO-0058	CHEYENNE STATION	06/12/2004 ACT	CPP	16.47	MMBTU/H	OXIDATION CATATLYST	0.30	G/B-HP-H
IA-0077	STATION 204	06/08/2005 ACT	NATURAL GAS-FIRED INTERNAL	4735	HP	OXIDATIVE CATALYST	0.68	G/B-HP-H
LA-0232	STERLINGTON COMPRESSOR STATION	06/24/2008 ACT	COMPRESSOR ENGINE NO. 1	32.2	MMBTU/H	CATALYTIC OXIDATION ANDGOOD COMBUSTION PRACTICES	0.07	G/B-HP-H
LA-0257	SABINE PASS LNG TERMINAL	12/06/2011 ACT	GENERATOR ENGINES (2)	2012	HP	COMPLY WITH 40 CFR 60	1.00	G/B-HP-H
WV-0020	COLUMBIA GAS TRANSMISSIONS LOST	02/14/2003 ACT	IC ENGINE, NATURAL GAS, # 10	4640	HP		0.70	G/B-HP-H

RBLC Data for Compressors Engines - PM/PM_{10}/$PM_{2.5}$ Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0257	SABINE PASS LNG	12/06/2011 ACT	GENERATOR ENGINES(2)	2012	HP	FUELED BY NATURAL GAS	1.46E-01	lb/MMBtu
WV-0020	COLUMBIA GAS TRANSMISSIONS LOST	02/14/2003 ACT	IC ENGINE, NATURAL GAS, # 10	4640	HP		1.04E-01	lb/MMBtu

RBLC Data for Compressors Engines - SO_2 Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
TX-0364	SALT CREEK GAS PLANT	1/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR-	440	HP	NONE INDICATED	6.25E-01	lb/MMBtu
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) INGERSOLL-RAND ENGINES, #IR-	1330	HP	NONE INDICATED	9.75E-02	lb/MMBtu
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(3) COOPER-BESSEMER ENGINES,	3105	HP	NONE INDICATED	3.29E-02	lb/MMBtu
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	COOPER-BESSEMER ENGINE, #GMVH-	2400	HP	USE PIPELINE QUALITY SWEET	5.90E-02	lb/MMBtu
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) CLARK ENGINE, #TLAB-6,	2000	HP EACH	NONE INDICATED	6.09E-02	lb/MMBtu

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
WV-0020	COLUMBIA GAS TRANSMISSIONS LOST	02/14/2003 ACT	IC ENGINE, NATURAL GAS, # 10	4640	HP		2.60E-03	lb/MMBtu

RBLC Data for Engines – CO_2e Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0256	COGENERATION PLANT	12/06/2011 ACT	COGENERATION TRAINS 1-3 (1-10, 2-10, 3-10)	475	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	55576.77	LB/H
LA-0256	COGENERATION PLANT	12/06/2011 ACT	EMERGENCY GENERATOR	1818	HP	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	1509.23	LB/H
LA-0257	SABINE PASS LNG TERMINAL	12/06/2011 ACT	Generator Engines (2)	2012	hp	Fueled by natural gas, good combustion/operating practices	412	TONS/YR
*LA-0266	EUNICE GAS EXTRACTION PLANT	05/01/2013 ACT	Compressor Engines 1, 2, & 3 (EQT 0057, 0058, & 0059)	3550	HP	Compliance with NSPS JJJJ	0	

HEATER < 100 TO ≥ 50 MMBTU/HR

RBLC Data for Heater < 100 to ≥ 50 MMBtu/hr - NO_X Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/2007 ACT	L GAS-FIRED BOILERS WITH ULNB EGR (537-539)	64.9	MMBTU each	ULNB & EGR (ULTRA-LOW NOX BURNERS (ULNB)(EXHAUST GAS RECIRCULATION (EGR) ¿ SAME FLUE GAS RECIRCULATION (FGR)	0.035	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	06/12/2007 ACT	VACUUM DEGASSER BOILER	95	MMBTU/H	ULTRA LOW NOX BURNERS	0.035	LB/MMBTU
CA-1127	GENENTECH, INC.	09/27/2005 ACT	BOILER = 50 MMBTU/H	97	MMBTU/H	ULTRA LOW NOX BURNERS: NATCOM P-97-LOG-35-2127	9	PPMVD @ 3% O2
FL-0286	FPL WEST COUNTY ENERGY CENTER	01/10/2007 ACT	TWO 99.8 MMBTU/H GAS-FUELED AUXILIARY BOILERS	99.8	MMBTU/H		0.05	LB/MMBTU
LA-0203	OAKDALE OSB PLANT	06/13/2005 ACT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	7.82	LB/H
LA-0229	SHINTECH PLAQUEMINE PLANT 2	07/10/2008 ACT	EQT126, EQT127 - TWO THERMAL OXIDIZERS (2M-5, 2M-6)	72	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU
LA-0231	LAKE CHARLES GASIFICATION FACILITY	06/22/2009 ACT	METHANATION STARTUP HEATERS	56.9	MMBTU/H	GOOD DESIGN AND PROPER OPERATION	5.58	LB/H
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	11/29/2010 ACT	EQT0027 - PACOL CHARGE HEATER H-201	87.3	MMBTU/H	LOW NOX BURNERS	7.15	LB/H
MD-0040	CPV ST CHARLES	11/12/2008 ACT	BOILER	93	MMBTU/H	LOW NOX WITH FGR	0.011	LB/MMBTU
NV-0037	COPPER MOUNTAIN POWER	05/14/2004 ACT	AUXILIARY BOILER	60	MMBTU/H	LOW NOX BURNER (WITH EITHER INTERNAL OR EXTERNAL FLUE GAS RECIRCULATION)	0.035	LB/MMBTU

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
OH-0323	TITAN TIRE CORPORATION OF BRYAN	06/05/2008 ACT	BOILER	50.4	MMBTU/H		2.47	LB/H
OK-0135	PRYOR PLANT CHEMICAL	02/23/2009 ACT	BOILERS #1 AND #2	80	MMBTU/H	LOW-NOX BURNERS AND GOOD	4	LB/H
OK-0136	PONCA CITY REFINERY	02/09/2009 ACT	TB-1, TB-2, TB-3	95	MMBTU/H	ULTRA-LOW NOX BURNERS; 0.036	3.42	LB/H
OR-0048	CARTY PLANT	12/29/2010 ACT	NATURAL GAS-FIRED BOILER	91	MMBTU/H	LOW NOX BURNERS	4.5	LB/H
SC-0112	NUCOR STEEL - BERKELEY	05/05/2008 ACT	VACUUM DEGASSER BOILER	50.21	MMBTU/H	ULTRA-LOW NOX NATURAL GAS FIRED	0.035	LB/MMBTU
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	PELLETIZER	75	MMBTU/H	GOOD DESIGN AND OPERATING PRACTICES AND LOW NOX BURNERS.	2.25	LB/H
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H	LOW NOX BURNERS WILL BE USED AS CONTROLS FOR NOX EMISSIONS.	3.57	LB/H
SC-0115	GP CLARENDON LP	02/10/2009 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H	THE USE OF LOW NOX BURNERS WILL BE USED AS CONTROL FOR NOX EMISSIONS FROM THE THERMAL OIL HEATER	3.57	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	07/11/2006 ACT	POWER STEAM BOILER	93	MMBTU/H		8.39	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S50/B50, 60 MMBTU/H	60	MMBTU/H	LOW NOX BURNER	0.04	LB/MMBTU
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S51/B51, 80 MMBTU/H	80	MMBTU/H	NAT. GAS / PROPANE, LOW NOX BURNER	0.04	LB/MMBTU
WY-0067	ECHO SPRINGS GAS PLANT	04/01/2009 ACT	HOT OIL HEATER S38	84	MMBTU/H	LOW NOX BURNERS WITH FLUE GAS RECIRCULATION	0.03	LB/MMBTU

RBLC Data for Heater < 100 to ≥ 50 MMBtu/hr - CO Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AL-0191	HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	03/23/2004 ACT	BOILERS, NATURAL GAS, (3)	50	MMBTU/H	CLEAN FUEL	4.5	LB/H
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU each		0.04	LB/MMBTU
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	06/11/2004 ACT	VTD BOILER	50	MMBTU/H	GOOD COMBUSTION PRACTICE	4.2	LB/H
AZ-0049	LA PAZ GENERATING FACILIT	09/04/2003 ACT	AUXILIARY BOILER FOR SIEMENS TURBINES	55.34	MMBTU/H		0.14	LB/MMBTU
CA-1127	GENENTECH, INC.	09/27/2005 ACT	BOILER: = 50 MMBTU/H	97	MMBTU/H	ULTRA LOW NOX BURNERS: NATCOM P-97-LOG-35-2127	50	PPMVD @ 3% O2

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
MD-0040	CPV ST CHARLES	11/12/2008 ACT	BOILER	93	MMBTU/H		0.02	LB/MMBTU
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	09/07/2007 ACT	SMALL BOILERS & HEATERS(<100 MMBTU/H)	99	MMBTU/H		0.08	LB/MMBTU
OK-0135	PRYOR PLANT CHEMICAL	02/23/2009 ACT	BOILERS #1 AND #2	80	MMBTU/H	GOOD COMBUSTION PRACTICE	6.6	LB/H
OK-0136	PONCA CITY REFINERY	02/09/2009 ACT	TB-1, TB-2, TB-3	95	MMBTU/H	ULTRA-LOW NOX BURNERS AND GOOD COMBUSTION PRACTICE; 0.04 LB/MMBTU	3.8	LB/H
SC-0112	NUCOR STEEL - BERKELEY	05/05/2008 ACT	VACUUM DEGASSER BOILER	50.21	MMBTU/H	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.061	LB/MMBTU
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H	POLLUTION PREVENTION OF CO EMISSIONS WILL OCCUR BY PERFORMING SCHEDULED TUNE-UPS AND INSPECTIONS AS OUTLINED IN THE GOOD MANAGEMENT PRACTICE PLAN.	6.0	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILIT	07/11/2006 ACT	POWER STEAM BOILER	93	MMBTU/H		7.05	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S51/B51, 80 MMBTU/H	80	MMBTU/H	NAT. GAS / PROPANE, GOOD COMBUSTION CONTROL	0.08	LB/MMBTU
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004 ACT	NATURAL GAS FIRED AUXILLIARY BOILER	97.1	MMBTU/H	NATURAL GAS FUEL, GOOD COMBUSTION PRACTICES	7.77	LB/H
WY-0067	ECHO SPRINGS GAS PLANT	04/01/2009 ACT	HOT OIL HEATER S38	84	MMBTU/H	GOOD COMBUSTION PRACTICE	0.02	LB/MMBTU

RBLC Data for Heater < 100 to ≥ 50 MMBtu/hr – PM/PM$_{10}$/PM$_{2.5}$ Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AL-0191	HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	03/23/2004 ACT	BOILERS, NATURAL GAS, (3)	50	MMBTU/H	CLEAN FUEL	0.38	LB/H
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB EGR (537-539)	64.9	MMBTU each		0.0076	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	06/12/2007 ACT	VACUUM DEGASSER BOILER	95	MMBTU/H		0.0076	LB/MMBTU
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	06/11/2004 ACT	VTD BOILER	50	MMBTU/H	GOOD COMBUSTION PRACTICE	0.4	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0203	OAKDALE OSB PLANT	06/13/2005 ACT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	0.59	LB/H
LA-0229	SHINTECH PLAQUEMINE PLANT 2	07/10/2008 ACT	EQT125 - FOUR VCM CRACKING FURNACES	90	MMBTU/H	GOOD COMBUSTION PRACTICES AND CLEAN BURNING FUELS	0.007	LB/MMBTU
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	11/29/2010 ACT	EQT0027 - PACOL CHARGE HEATER H-201	87.3	MMBTU/H		0.86	LB/H
MD-0040	CPV ST CHARLES	11/12/2008 ACT	BOILER	93	MMBTU/H		0.005	LB/MMBTU
MN-0070	MINNESOTA STEEL INDUSTRIES, LLC	09/07/2007 ACT	SMALL BOILERS; HEATERS(100 MMBTU/H)	99	MMBTU/H		0.0025	GR/DSCF
OK-0135	PRYOR PLANT CHEMICAL	02/23/2009 ACT	BOILERS #1 AND #2	80	MMBTU/H		0.5	LB/H
OR-0048	CARTY PLANT	12/29/2010 ACT	NATURAL GAS-FIRED BOILER	91	MMBTU/H	CLEAN FUEL	2.5	LB/MMCF
SC-0112	NUCOR STEEL - BERKELEY	05/05/2008 ACT	VACUUM DEGASSER BOILER	50.21	MMBTU/H	GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0076	LB/MMBTU
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H		0.54	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	07/11/2006 ACT	POWER STEAM BOILER	93	MMBTU/H		0.64	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S51/B51, 80 MMBTU/H	80	MMBTU/H	NATURAL GAS, GOOD COMBUSTION CONTROL	0.0075	LB/MMBTU
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004 ACT	NATURAL GAS FIRED AUXILLIARY BOILER	97.1	MMBTU/H	NATURAL GAS FUEL, GOOD COMBUSTION PRACTICES	0.74	LB/H

RBLC Data for Heater < 100 to ≥ 50 MMBtu/hr – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU each		0.0055	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	06/12/2007 ACT	VACUUM DEGASSER BOILER	95	MMBTU/H		0.0026	LB/MMBTU
LA-0203	OAKDALE OSB PLANT	06/13/2005 ACT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	0.43	LB/H
MD-0035	DOMINION	08/12/2005 ACT	EMERGENCY VENT HEATER			BURN NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0054	LB/MMBTU
MN-0054	MANKATO ENERGY CENTER	12/04/2003 ACT	BOILER, COMMERCIAL	70	MMBTU/H	GOOD COMBUSTION	0.007	LB/MMBTU
OH-0323	TITAN TIRE CORPORATION OF BRYAN	06/05/2008 ACT	BOILER	50.4	MMBTU/H		0.27	LB/H
OH-0350	REPUBLIC STEEL	07/18/2012 ACT	STEAM BOILER	65	MMBtu/H	PROPER BURNER DESIGN AND GOOD COMBUSTION PRACTICES	0.35	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
SC-0112	NUCOR STEEL - BERKELEY	05/05/2008 ACT	VACUUM DEGASSER BOILER	50.21	MMBTU/H	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0026	LB/MMBTU
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	)N BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H	GOOD COMBUSTION PRACTICES WILL BE USED AS CONTROL FOR VOC EMISSIONS	0.39	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	07/11/2006 ACT	POWER STEAM BOILER	93	MMBTU/H		0.46	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S51/B51, 80 MMBTU/H	80	MMBTU/H	NAT. GAS / PROPANE; GOOD COMBUSTION CONTROL	0.0054	LB/MMBTU
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004 ACT	NATURAL GAS FIRED AUXILLIARY BOILER	97.1	MMBTU/H	NATURAL GAS FUEL, GOOD COMBUSTION PRACTICES	0.53	LB/H
WY-0067	ECHO SPRINGS GAS PLANT	04/01/2009 ACT	HOT OIL HEATER S38	84	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU

RBLC Data for Heater < 100 to ≥ 50 MMBtu/hr – SO_2 Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AL-0230	THYSSENKRUPP STEEL AND STAINLESS USA, LLC	08/17/2007 ACT	3 NATURAL GAS-FIRED BOILERS WITH ULNB & EGR (537-539)	64.9	MMBTU		0.0006	LB/MMBTU
AL-0231	NUCOR DECATUR LLC	06/12/2007 ACT	VACUUM DEGASSER BOILER	95	MMBTU/H		0.0006	LB/MMBTU
AR-0086	NUCOR-YAMATO STEEL COMPANY, BLYTHEVILLE MILL	06/11/2004 ACT	VTD BOILER	50	MMBTU/H	GOOD COMBUSTION PRACTICE, NATURAL GAS COMBUSTION	0.1	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/2004 ACT	AUXILIARY BOILER	38	MMBTU/H		0.0023	LB/MMBTU
AZ-0049	LA PAZ GENERATING FACILITY	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H		0.0025	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	34	MMBTU/H	COMPLIANCE BY USING NATURAL GAS	0.0006	LB/MMBTU
LA-0203	OAKDALE OSB PLANT	06/13/2005 ACT	AUXILIARY THERMAL OIL HEATER	66.5	MMBTU/H	USE OF NATURAL GAS AS FUEL AND GOOD COMBUSTION PRACTICES	0.05	LB/H
LA-0231	LAKE CHARLES GASIFICATION FACILITY	06/22/2009 ACT	METHANATION STARTUP HEATERS	56.9	MMBTU/H	FUELED BY NATURAL GAS OR SUBSTITUTE NATURAL GAS (SNG)	0.03	LB/H
MD-0040	CPV ST CHARLES	11/12/2008 ACT	BOILER	93	MMBTU/H		0.0001	LB/MMBTU
MN-0054	MANKATO ENERGY CENTER	12/04/2003 ACT	BOILER, COMMERCIAL	70	MMBTU/H	LOW SULFUR FUEL	0.001	LB/MMBTU
NV-0037	COPPER MOUNTAIN POWER	05/14/2004 ACT	AUXILIARY BOILER	60	MMBTU/H	USE OF LOW-SULFUR NATURAL GAS	0.04	LB/H
OK-0135	PRYOR PLANT CHEMICAL	02/23/2009 ACT	BOILERS #1 AND #2	80	MMBTU/H		0.2	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
SC-0112	NUCOR STEEL - BERKELEY	05/05/2008 ACT	VACUUM DEGASSER BOILER	50.21	MMBTU/H	NATURAL GAS COMBUSTION WITH GOOD COMBUSTION PRACTICES PER MANUFACTURER'S GUIDANCE	0.0006	LB/MMBTU
SC-0115	GP CLARENDON LP	02/10/2009 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H	GOOD COMBUSTION PRACTICES WILL BE USED AS CONTROL FOR SO2 EMISSIONS.	0.04	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	07/11/2006 ACT	POWER STEAM BOILER	93	MMBTU/H		0.05	LB/H
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004 ACT	NATURAL GAS FIRED AUXILLIARY BOILER	97.1	MMBTU/H	NATURAL GAS FUEL	0.06	LB/H

RBLC Search for Heater – CO_2e Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*CA-1212	PALMDALE HYBRID POWER PROJECT	LOS ANGELES	CA	10/18/2011	AUXILIARY HEATER	40	MMBTU/HR	ANNUAL BOILER TUNEUPS	0	
GA-0147	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	JEFFERSON	GA	1/27/2012	BOILERS	9.8	MMBTU/H	Good Combustion Practices, design, and thermal insulation.	5809	T/12-MO ROLLING AVG

HEATER <50 TO > 10 MMBTU/HR

RBLC Data for Heater <50 to > 10 MMBtu/hr - NO_X Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AK-0062	BADAMI DEVELOPMENT FACILITY	08/19/2005 ACT	NATCO PRODUCTION HEATER	34	MMBTU/H	LOW NOX BURNERS / FLUE GAS RECIRCULATION	0.095	LB/MMBTU
AL-0212	HYUNDAI MOTOR MANUFACTURING ALABAMA, LLC	11/22/2004 ACT	BOILER, NATURAL GAS (2)	24.5	MMBTU/H	LOW NOX BURNERS	0.35	LB/MMBTU
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	BOILERS	22	MMBTU/H	LOW NOX BURNERS	0.08	LB/MMBTU
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	FURNACES, HEATERS, & DRYERS	11	MMBTU/H	LOW NOX BURNERS	0.1	LB/MMBTU
AR-0090	NUCOR STEEL, ARKANSAS	04/03/2006 ACT	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	LOW NOX BURNERS	2.9	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/2004 ACT	AUXILIARY BOILER	38	MMBTU/H	LOW NOX BURNERS	0.37	LB/MMBTU
AZ-0049	LA PAZ GENERATING FACILITY	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H	LOW NOX BURNERS	0.027	LB/MMBTU

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
CA-1128	COTTAGE HEALTH CARE - PUEBLO STREET	05/16/2006 ACT	BOILER: 5 TO 33.5 MMBTU/H	25	MMBTU/H (75 MMBTU/H	ULTRA-LOW NOX BURNER	9	PPMV AT 3% O2
CO-0058	CHEYENNE STATION	06/12/2004 ACT	HEATERS	45	MMBTU/H	LOW NOX BURNERS	0.035	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	34	MMBTU/H	LOW NOX BURNERS, NATURAL GAS	0.035	LB/MMBTU
LA-0231	LAKE CHARLES GASIFICATION FACILITY	06/22/2009 ACT	GASIFIER STARTUP PREHEATER BURNERS (5)	35	MMBTU/H	GOOD DESIGN AND PROPER OPERATION	3.85	LB/H
LA-0244	LAKE CHARLES CHEMICAL COMPLEX - LAB UNIT	11/29/2010 ACT	EQT0028 - PACOL STARTUP HEATER H-202	21	MMBTU/H	LOW NOX BURNERS	2.71	LB/H
NV-0044	HARRAH'S OPERATING COMPANY, INC.	01/04/2007 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	LOW-NOX BURNER AND FLUE GAS RECIRCULATION	0.035	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT CP26	24	MMBTU/H	LOW NOX BURNER	0.0108	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT PA15	21	MMBTU/H	LOW NOX BURNER	0.0366	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT IP04	16.7	MMBTU/H	LOW NOX BURNER	0.049	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/2006 ACT	AUXILIARY BOILER	29.4	MMBTU/H	LOW NOX BURNERS & FLUE GAS RECIRCULATION	0.011	LB/MMBTU
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/28/2004 ACT	BOILERS (2)	30.6	MMBTU/H		1.07	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	TUNDISH PREHEATER, 3 UNITS	12	MMBTU/H		1.18	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	28.6	MMBTU/H	LOW NOX BURNER	2.8	LB/H
OK-0090	DUKE ENERGY STEPHENS, LLC STEPHENS ENERGY	03/21/2003 ACT	BOILER, AUXILIARY	33	MMBTU/H	LOW-NOX BURNERS	0.05	LB/MMBTU
OK-0097	QUAD GRAPHICS OKC FAC	02/03/2004 ACT	HEATERS/OXIDIZERS	16	MMBTU/H	MAINTENANCE/OPERATION PER MANUFACTURE'S SPECIFICATION, AND EXCLUSIVELY FIRING COMMERCIAL NATURAL GAS OR PROPANE.	2.48	LB/H
OK-0129	CHOUTEAU POWER PLANT	01/23/2009 ACT	AUXILIARY BOILER	33.5	MMBTU/H	LOW-NOX BURNERS	0.07	LB/MMBTU
OK-0134	PRYOR PLANT CHEMICAL	02/23/2009 ACT	NITRIC ACID PREHEATERS NO. 1 (EU 401, EUG 4)	20	MMBTUH	LOW NOX BURNERS/GOOD COMBUSTION PRACTICES	0.98	LB/H
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 18)	20.89	MMBTU/H		1.99	LB/H
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	75 MILLION BTU/HR BACKUP THERMAL OIL HEATER	75	MMBTU/H	LOW NOX BURNERS WILL BE USED AS CONTROLS FOR NOX EMISSIONS.	3.57	LB/H
SC-0115	GP CLARENDON LP	02/10/2009 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID	20.89	MMBTU/H		1.99	LB/H
TX-0501	TEXSTAR GAS PROCESS FACILITY	07/11/2006 ACT	POWER STEAM BOILER	93	MMBTU/H		8.39	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S53 / B53, 34 MMBTU/H	34	MMBTU/H	NATURAL GAS / PROPANE; LOW NOX BURNER	0.04	LB/MMBTU

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
WI-0223	LOUISIANA-PACIFIC HAYWARD	06/17/2004 ACT	THERMAL OIL HEATER, GTS ENERGY, S31, B31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	4.24	LB/H
WY-0066	MEDICINE BOW IGL PLANT	03/04/2009 ACT	GASIFICATION PREHEATER 2	21	MMBTU/H	LOW NOX BURNERS	0.05	LB/MMBTU
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	08/28/2012 ACT	INLET AIR HEATER (EP11)	16.1	MMBTU/H	ULTRA LOW NOX BURNERS	0.012	LB/MMBTU

RBLC Data for Heater <50 to > 10 MMBtu/hr - CO Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AK-0062	BADAMI DEVELOPMENT FACILIT	08/19/2005 ACT	NATCO PRODUCTION HEATER	34	MMBTU/H	GOOD OPERATIONAL PRACTICE	0.1	LB/MMBTU
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	BOILERS	22	MMBTU/H	GOOD COMBUSTION PRACTICE	0.84	LB/MMBTU
AR-0090	NUCOR STEEL, ARKANSAS	04/03/2006 ACT	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	GOOD COMBUSTION PRACTIC	3.2	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/2004 ACT	AUXILIARY BOILER	38	MMBTU/H		0.08	LB/MMBTU
AZ-0049	LA PAZ GENERATING FACILIT	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H		0.09	LB/MMBTU
CA-1128	COTTAGE HEALTH CARE - PUEBLO STREET	05/16/2006 ACT	BOILER: 5 TO 33.5 MMBTU/H	25	MMBTU/H (75 MMBTU/H	ULTRA-LOW NOX BURNER	50	PPMV AT 3% O2
CO-0058	CHEYENNE STATION	06/12/2004 ACT	HEATERS	45	MMBTU/H	GOOD COMBUSTION PRACTICE	0.037	LB/MMBTU
FL-0335	SUWANNEE MILL	09/05/2012 ACT	FOUR(4) NATURAL GAS BOILERS - 46 MMBtu/hour	46	MMBTU/H	GOOD COMBUSTION PRACTIC	0.039	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	34	MMBTU/H	GOOD COMBUSTION PRACTICES, NATURAL GAS	0.061	LB/MMBTU
LA-0231	LAKE CHARLES GASIFICATION FACILITY	06/22/2009 ACT	SHIFT REACTOR STARTUP HEATER	34.2	MMBTU/H	GOOD DESIGN AND PROPER OPERATIO	2.82	LB/H
LA-0231	LAKE CHARLES GASIFICATION FACILITY	06/22/2009 ACT	GASIFIER STARTUP PREHEATER BURNERS (5)	35	MMBTU/H	GOOD DESIGN AND PROPER OPERATIO	1.96	LB/H
LA-0240	FLOPAM INC.	06/14/2010 ACT	BOILERS	25.1	MMBTU/H	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION PRACTICES	0.93	LB/H
MN-0053	FAIRBAULT ENERGY PARK	07/15/2004 ACT	BOILER, NATURAL GAS (1)	40	MMBTU/H	GOOD COMBUSTION.	0.084	LB/MMBTU
NV-0044	HARRAH'S OPERATING COMPANY, INC.	01/04/2007 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	GOOD COMBUSTION DESIGN	0.036	LB/MMBTU
OH-0276	CHARTER STEEL	06/10/2004 ACT	TUNDISH PREHEATER, 3 UNITS	12	MMBTU/H		0.99	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	28.6	MMBTU/H		2.35	LB/H
OH-0309	TOLEDO SUPPLIER PARK-PAINT SHOP	05/03/2007 ACT	BOILER (2), NATURAL GAS	20.4	MMBTU/H		1.7	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS	20.89	MMBTU/H		1.67	LB/H
SC-0115	GP CLARENDON LP	02/10/2009 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS	20.89	MMBTU/H		1.67	LB/H
WA-0301	BP CHERRY POINT REFINERY	04/20/2005 ACT	PROCESS HEATER, IHT	13	MMBTU/H	GOOD COMBUSTION PRACTICE	70	PPM
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S52/B52, 11 MMBTU/H	11	MMBTU/H	NATURAL GAS / PROPANE ; GOOD COMBUSTION CONTROL	0.08	LB/MMBTU
WI-0223	LOUISIANA-PACIFIC HAYWARD	06/17/2004 ACT	THERMAL OIL HEATER, GTS ENERGY, S31, B31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	2.7	LB/H
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004 ACT	GAS HEATER (P06, S06)	10	MMBTU/H	NATURAL GAS FUEL	0.47	LB/H
WY-0066	MEDICINE BOW IGL PLANT	03/04/2009 ACT	GASIFICATION PREHEATER 2	21	MMBTU/H	GOOD COMBUSTION PRACTICE	0.08	LB/MMBTU
*WY-0070	CHEYENNE PRAIRIE GENERATING STATION	08/28/2012 ACT	INLET AIR HEATER (EP11)	16.1	MMBTU/H	GOOD COMBUSTION PRACTICE	0.08	LB/MMBTU

RBLC Data for Heater <50 to > 10 MMBtu/hr – PM/PM_{10}/$PM_{2.5}$ Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	BOILERS	22	MMBTU/H	NATURAL GAS COMBUSTION ONLY	0.0076	LB/MMBTU
AR-0090	NUCOR STEEL, ARKANSAS	04/03/2006 ACT	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	GOOD COMBUSTION PRACTICE	0.3	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/2004 ACT	AUXILIARY BOILER	38	MMBTU/H		0.0033	LB/MMBTU
AZ-0049	LA PAZ GENERATING FACILITY	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H		0.015	LB/MMBTU
FL-0335	SUWANNEE MILL	09/05/2012 ACT	FOUR(4) NATURAL GAS BOILERS - 46 MMBtu/hour	46	MMBTU/H	GOOD COMBUSTION PRACTICE	2	GR OF S/100 SCF
LA-0240	FLOPAM INC.	06/14/2010 ACT	BOILERS	25.1	MMBTU/H	GOOD EQUIPMENT DESIGN AND PROPER COMBUSTION PRACTICES, FUELED BY NATURAL GAS/ALCOHOL	0.1	LB/H
MN-0053	FAIRBAULT ENERGY PARK	07/15/2004 ACT	BOILER, NATURAL GAS (1)	40	MMBTU/H	CLEAN FUEL AND GOOD COMBUSTION.	0.008	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT PA15	21	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0076	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/2006 ACT	AUXILIARY BOILER	29.4	MMBTU/H	LOW SULFUR FUEL	0.0033	LB/MMBTU

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/28/2004 ACT	BOILERS (2)	30.6	MMBTU/H		0.31	LB/H
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	08/14/2003 ACT	BOILER	30.6	MMBTU/H		0.31	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	TUNDISH PREHEATER, 3 UNITS	12	MMBTU/H	BAGHOUSE	0.09	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	BOILER FOR VACUUM OXYGEN DEGASSER	28.6	MMBTU/H		0.21	LB/H
OH-0309	TOLEDO SUPPLIER PARK-PAINT SHOP	05/03/2007 ACT	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.04	LB/H
OH-0309	TOLEDO SUPPLIER PARK-PAINT SHOP	05/03/2007 ACT	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.15	LB/H
OK-0134	PRYOR PLANT CHEMICAL	02/23/2009 ACT	NITRIC ACID PREHEATERS NO. 1 (EU 401,	20	MMBTU/H	NATURAL GAS COMBUSTION	0.15	LB/H
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS	20.89	MMBTU/H		0.15	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S52/B52, 11 MMBTU/H	11	MMBTU/H	NATURAL GAS / PROPANE; GOOD COMBUSTION CONTROL	0.0075	LB/MMBTU
WI-0223	LOUISIANA-PACIFIC HAYWARD	06/17/2004 ACT	HEATER, GTS ENERGY, S31, B31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	0.84	LB/H
WI-0227	PORT WASHINGTON GENERATING STATION	10/13/2004 ACT	GAS HEATER (P06, S06)	10	MMBTU/H	NATURAL GAS FUEL	0.08	LB/H

RBLC Data for Heater <50 to > 10 MMBtu/hr – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	BOILERS	22	MMBTU/H	NATURAL GAS COMBUSTION ONLY	0.0055	LB/MMBTU
AR-0090	NUCOR STEEL, ARKANSAS	04/03/2006 ACT	PICKLE LINE BOILERS, SN-52	12.6	MMBTU EACH	GOOD COMBUSTION PRACTICE	0.2	LB/H
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/2004 ACT	AUXILIARY BOILER	38	MMBTU/H		0.0033	LB/MMBTU
AZ-0049	LA PAZ GENERATING FACILITY	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H		0.01	LB/MMBTU
CO-0058	CHEYENNE STATION	06/12/2004 ACT	HEATERS	45	MMBTU/H	GOOD COMBUSTION PRACTICES	0.016	LB/MMBTU
FL-0335	SUWANNEE MILL	09/05/2012 ACT	FOUR(4) NATURAL GAS BOILERS - 46 MMBTU/HOUR	46	MMBTU/H	GOOD COMBUSTION PRACTICE	0.003	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	34	MMBTU/H	COMPLIANCE BY USING NATURAL GAS	0.0026	LB/MMBTU
MD-0035	DOMINION	08/12/2005 ACT	EMERGENCY VENT HEATER			BURN NATURAL GAS AND GOOD COMBUSTION PRACTICES	0.0054	LB/MMBTU
MN-0053	FAIRBAULT ENERGY PARK	07/15/2004 ACT	BOILER, NATURAL GAS (1)	40	MMBTU/H	GOOD COMBUSTION.	0.006	LB/MMBTU
MS-0085	DART CONTAINER CORPORATION LLC	01/31/2007 ACT	NATURAL GAS FIRED BOILER	33.5	MMBTU/H		0.81	TONS/YR
NV-0044	HARRAH'S OPERATING COMPANY, INC.	01/04/2007 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	GOOD COMBUSTION DESIGN	0.005	LB/MMBTU
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/28/2004 ACT	BOILERS (2)	30.6	MMBTU/H		0.49	LB/H
OH-0254	DUKE ENERGY WASHINGTON COUNTY LLC	08/14/2003 ACT	BOILER	30.6	MMBTU/H		0.49	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	BOILER FOR VACUUM OXYGEN DEGASSER VESSEL	28.6	MMBTU/H		0.15	LB/H
OK-0134	PRYOR PLANT CHEMICAL	02/23/2009 ACT	NITRIC ACID PREHEATERS NO. 1 (EU 401, EUG 4)	20	MMBTUH	GOOD COMBUSTION	0.11	LB/H
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 18)	20.89	MMBTU/H		0.11	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	BOILER, S52/B52, 11 MMBTU/H	11	MMBTU/H	NATURAL GAS / PROPANE; GOOD COMBUSTION CONTROL	0.0054	LB/MMBTU
WI-0223	LOUISIANA-PACIFIC HAYWARD	06/17/2004 ACT	THERMAL OIL HEATER, GTS ENERGY, S31, B31	32	MMBTU/H	USE OF NATURAL GAS / DISTILLATE OIL, W/ RESTRICTION ON OIL USAGE	0.18	LB/H
WY-0067	ECHO SPRINGS GAS PLANT	04/01/2009 ACT	HOT OIL HEATER S38	84	MMBTU/H	GOOD COMBUSTION PRACTICES	0.02	LB/MMBTU

RBLC Data for Heater <50 to > 10 MMBtu/hr – SO_2 Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AK-0062	BADAMI DEVELOPMENT FACILITY	08/19/2005 ACT	NATCO PRODUCTION HEATER	34	MMBTU/H	LIMIT SULFUR CONTENT IN FUEL COMBUSTED	250	PPMV
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	BOILERS	22	MMBTU/H	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU
AZ-0047	WELLTON MOHAWK GENERATING STATION	12/01/2004 ACT	AUXILIARY BOILER	38	MMBTU/H		0.0023	LB/MMBTU
AZ-0049	LA PAZ GENERATING FACILITY	09/04/2003 ACT	AUXILIARY BOILER FOR GE TURBINE	41	MMBTU/H		0.0025	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	BOILER, NATURAL GAS, (2)	34	MMBTU/H	COMPLIANCE BY USING NATURAL GAS	0.0006	LB/MMBTU
NV-0044	HARRAH'S OPERATING COMPANY, INC.	01/04/2007 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILERS	35.4	MMBTU/H	USE OF NATURAL GAS AS THE ONLY FUEL	0.001	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT BA01	16.8	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS.	0.0042	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS CC001, CC002, AND CC003 AT CITY CENTER	41.64	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY.	0.0007	LB/MMBTU
NY-0095	CAITHNES BELLPORT ENERGY CENTER	05/10/2006 ACT	AUXILIARY BOILER	29.4	MMBTU/H	LOW SULFUR FUEL	0.0005	LB/MMBTU
OH-0252	DUKE ENERGY HANGING ROCK ENERGY FACILITY	12/28/2004 ACT	BOILERS (2)	30.6	MMBTU/H	THE MAXIMUM S CONTENT OF THE NATURAL GAS SHALL NOT EXCEED 2 GRAINS PER 100 CUBIC FEET.	0.031	LB/H
OH-0276	CHARTER STEEL	06/10/2004 ACT	TUNDISH PREHEATER, 3 UNITS	12	MMBTU/H		0.007	LB/H
OH-0309	TOLEDO SUPPLIER PARK-PAINT SHOP	05/03/2007 ACT	BOILER (2), NATURAL GAS	20.4	MMBTU/H		0.01	LB/H
OK-0134	PRYOR PLANT CHEMICAL	02/23/2009 ACT	NITRIC ACID PREHEATERS NO. 1 (EU 401, EUG 4)	20	MMBTUH	NATURAL GAS COMBUSTION	0.03	LB/H
SC-0114	GP ALLENDALE LP	11/25/2008 ACT	NATURAL GAS SPACE HEATERS - 14 UNITS (ID 18)	20.89	MMBTU/H		0.01	LB/H

RBLC Search for Heater – CO_2e Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*CA-1212	PALMDALE HYBRID POWER PROJECT	LOS ANGELES	CA	10/18/2011	AUXILIARY HEATER	40	MMBTU/HR	ANNUAL BOILER TUNEUPS	0	
GA-0147	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	JEFFERSON	GA	1/27/2012	BOILERS	9.8	MMBTU/H	Good Combustion Practices, design, and thermal insulation.	5809	T/12-MO ROLLING AVG

Heater ≤ 10 MMBtu/hr

RBLC Data for Heater ≤ 10 MMBtu/hr – NO_X Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AK-0062	BADAMI DEVELOPMENT FACILITY	08/19/2005 ACT	NATCO TEG REBOILER	1.34	MMBTU/H	CONVENTIONAL BURNER TECHNOLOGY	0.08	LB/MMBTU
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16	1.4	MMBTU/H	LOW-NOX BURNERS WITHOUT FLUE GAS RECIRCULATION.	0.2	LB/H
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	GALVANIZING LINE	9	MMBTU/H	LOW NOX BURNERS	0.15	LB/MMBTU
GA-0105	MCINTOSH COMBINED CYCLE FACILITY	04/17/2003 ACT	FUEL GAS HEATER	5	MMBTU/H		99	PPM @ 15% O2
GA-0107	TALBOT ENERGY FACILITY	06/09/2003 ACT	FUEL GAS PREHEATERS, (3)	5	MMBTU/H	DRY LOW NOX BURNERS	30	PPM @ 15% O2
IA-0064	ROQUETTE AMERICA	01/31/2003 ACT	DEW POINT HEATER	1.6	MMBTU/H	GOOD COMBUSTION PRACTICES	0.15	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	ACID REGENERATION	7.3	MMBTU/H		100	LB/MMCF
MD-0040	CPV ST CHARLES	11/12/2008 ACT	HEATER	1.7	MMBTU/H		0.1	LB/MMBTU
NC-0115	NC COMMUNICATION TECH	01/06/2007 ACT	DRYER OR OVEN, DIRECT OR INDIRECT	5.4	MMBTU/H	LOW NOX -BURNER	18	PPMVD@3%O2
NV-0042	CAPITAL CABINET CORPORATION	11/05/2004 ACT	FUEL COMBUSTION	8.8	MMBTU/H	USE OF NATURAL GAS AS THE ONLY FUEL FOR ALL THE COMBUSTION UNITS	0.5	T/MO
NV-0046	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.101	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT HA08	8.37	MMBTU/H	EQUIPPED WITH A LOW-NOX BURNER	0.0146	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	TURBINE GENERATORS - UNITS CC007 AND CC008 AT CITY CENTER	4.6	MMBTU/H	LEAN PRE-MIX TECHNOLOGY AND LIMITING THE FUEL TO NATURAL GAS ONLY	0.178	LB/MMBTU
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	BOILERS	5	MMBTU/H	GOOD DESIGN AND COMBUSTION PRACTICES, LOW NOX BURNERS, COMBUSTION OF NATURAL GAS/PROPANE.	0	
WA-0316	NORTHWEST PIPELINE CORP.-MT VERNON COMPRESSOR	06/14/2006 ACT	BOILER, NATURAL GAS	4.19	MMBTU/H	GOOD COMBUSTION PRACTICE	34	PPMDV @ 3% O2
WI-0228	WPS - WESTON PLANT	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	0.073	LB/H

RBLC Data for Heater ≤ 10 MMBtu/hr – CO Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AK-0062	BADAMI DEVELOPMENT FACILITY	08/19/2005 ACT	NATCO TEG REBOILER	1.34	MMBTU/H	GOOD OPERATIONAL PRACTICES	0.15	LB/MMBTU
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	GALVANIZING LINE	9	MMBTU/H	GOOD COMBUSTION PRACTICE	0.84	LB/MMBTU
CA-1185	SANTA BARBARA AIRPORT	06/07/2011 ACT	Boiler, Forced Draft	3	MMBTU/H	Forced draft, full modulation, flue gas recirculation	100	PPMVD@3% O2
GA-0107	TALBOT ENERGY FACILITY	06/09/2003 ACT	FUEL GAS PREHEATERS, (3)	5	MMBTU/H	GOOD COMBUSTION PRACTICE	0.022	LB/MMBTU
NV-0042	CAPITAL CABINET CORPORATION	11/05/2004 ACT	FUEL COMBUSTION	8.8	MMBTU/H	USE OF NATURAL GAS AS THE ONLY FUEL FOR ALL COMBUSTION UNITS	0.41	T/MO
NV-0046	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.083	LB/MMBTU
NV-0048	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.083	LB/MMBTU
NV-0049	ARRAH'S OPERATING COMPANY, INC.	08/20/2009 ACT	BOILER - UNIT HA08	8.37	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.037	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS CC004, CC005, AND 006 AT CITY CENTER	4.2	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES	0.0214	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW YORK	2	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILER - UNIT MB090 AT MANDALAY BAY	4.3	MMBTU/H	FLUE GAS RECIRCULATION AND GOOD COMBUSTION PRACTICES	0.0362	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO	2	MMBTU/H	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.037	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILER - UNIT BE111 AT BELLAGIO	2.1	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES	0.038	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK - NEW YORK	2	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY AND GOOD COMBUSTION PRACTICES	0.035	LB/MMBTU

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	BOILERS	5	MMBTU/H	GOOD COMBUSTION PRACTICES. CONSUMPTION OF NATURAL GAS AND PROPANE.	0	
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	GLYCOL REBOILER, EPN11	2.5	MMBTU/H	NONE INDICATED	0.25	LB/H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	HP TEG FIREBOX, EPN30	3	MMBTU/H	NONE INDICATED	0.25	LB/H
WI-0228	WPS - WESTON PLANT	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	0.06	LB/H

RBLC Data for Heater ≤ 10 MMBtu/hr – PM/PM_{10}/$PM_{2.5}$ Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16	1.4	MMBTU/H	NATURAL GAS ONLY.	0.1	LB/H
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	GALVANIZING LINE	9	MMBTU/H	NATURAL GAS COMBUSTION ONLY	0.0076	LB/MMBTU
MD-0040	CPV ST CHARLES	11/12/2008 ACT	HEATER	1.7	MMBTU/H		0.007	LB/MMBTU
NV-0046	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PRACTICE	0.0078	LB/MMBTU
NV-0049	HARRAH'S OPERATING COMPANY, INC.	08/20/2009	BOILER - UNIT HA08	8.37	MMBTU/H	OPERATING IN ACCORDANCE WITH THE MANUFACTURER'S SPECIFICATION	0.0075	LB/MMBTU
WI-0228	WPS - WESTON PLANT	10/19/2004	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS FUEL	0.006	LB/H
WI-0228	WPS - WESTON PLANT	10/19/2004	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	0.01	LB/H

RBLC Data for Heater ≤ 10 MMBtu/hr – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	GALVANIZING LINE	9	MMBTU/H	NATURAL GAS COMBUSTION ONLY	0.005	LB/MMBTU
IN-0108	NUCOR STEEL	11/21/2003 ACT	ACID REGENERATION	7.3	MMBTU/H		5.3	LB/MMCF
NV-0046	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	GOOD COMBUSTION PROCESS	0.0052	LB/MMBTU

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	BOILERS	5	MMBTU/H	GOOD COMBUSTION PRACTICES. CONSUMPTION OF NATURAL GAS AND PROPANE AS FUEL.	0	
WI-0228	WPS - WESTON PLANT	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	0.004	LB/H

RBLC Data for Heater ≤ 10 MMBtu/hr – SO_2 Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AK-0062	BADAMI DEVELOPMENT FACILITY	08/19/2005 ACT	NATCO TEG REBOILER	1.34	MMBTU/H	LIMIT SULFUR CONTENT OF FUEL COMBUSTED	250	PPMV
AR-0076	U.S. ARMY, PINE BLUFF ARSENAL	02/17/2004 ACT	BOILER, LABORATORY SN-PBCDF-16	1.4	MMBTU/H	LOW-SULFUR NATURAL GAS ONLY.	0.1	LB/H
AR-0077	BLUEWATER PROJECT	07/22/2004 ACT	GALVANIZING LINE	9	MMBTU/H	NATURAL GAS COMBUSTION ONLY	0.0006	LB/MMBTU
NV-0046	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL BOILER	3.85	MMBTU/H	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL FOR THE PROCESS.	0.0026	LB/MMBTU
NV-0048	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	COMMERCIAL/INSTITUTIONAL-SIZE BOILER (<100 MMBTU/H)	3.85	MMBTU/H	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL USED BY THE UNIT.	0.0015	LB/MMBTU
NV-0048	GOODSPRINGS COMPRESSOR STATION	05/16/2006 ACT	LARGE INTERNAL COMBUSTION ENGINE (>500 HP)	5.91	MMBTU/H	LOW-SULFUR NATURAL GAS IS THE ONLY FUEL USED BY THE UNIT.	0.0052	G/B-HP-H
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS CC004, CC005, AND CC006 AT CITY CENTER	4.2	MMBTU/H	FUEL IS LIMITED TO NATURAL GAS ONLY.	0.0024	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	WATER HEATERS - UNITS NY037 AND NY038 AT NEW YORK - NEW YORK	2	MMBTU/H	LIMITING FUEL TO NATURAL GAS ONLY.	0.0006	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILER - UNIT MB090 AT MANDALAY BAY	4.3	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY	0.0006	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS BE102 THRU BE105 AT BELLAGIO	2	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY	0.0006	LB/MMBTU
NV-0050	MGM MIRAGE	11/30/2009 ACT	BOILERS - UNITS NY42, NY43, AND NY44 AT NEW YORK - NEW YORK	2	MMBTU/H	LIMITING THE FUEL TO NATURAL GAS ONLY	0.005	LB/MMBTU
SC-0113	PYRAMAX CERAMICS, LLC	02/08/2012 ACT	BOILERS	5	MMBTU/H	COMBUSTION OF NATURAL GAS AND PROPANE.	0	
WI-0228	WPS - WESTON PLANT	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	0.0001	LB/H
WI-0228	WPS - WESTON PLANT	10/19/2004 ACT	B63, S63; B64, S64 - NATURAL GAS STATION HEATER 1 AND 2	0.75	MMBTU/H	NATURAL GAS	0.0004	LB/H

RBLC Search for Heater – CO_2e Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
*CA-1212	PALMDALE HYBRID POWER PROJECT	LOS ANGELES	CA	10/18/2011	AUXILIARY HEATER	40	MMBTU/HR	ANNUAL BOILER TUNEUPS	0	
GA-0147	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	JEFFERSON	GA	1/27/2012	BOILERS	9.8	MMBTU/H	Good Combustion Practices, design, and thermal insulation.	5809	T/12-MO ROLLING AVG

GLYCOL DEHYDRATORS UNITS

RBLC Data for Glycol Dehydrators Units – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT	EMISSION UNIT AVERAGING TIME
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	GLYCOL STILL VENT, EPN14	N	NONE INDICATED	9.42	LB/H

STORAGE TANK

RBLC Data for Storage Tank – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AL-0191	HYUNDAI MOTOR MANUFACTURING OF ALABAMA, LLC	03/23/2004 ACT	STORAGE TANKS			SUBMERGED FILL PIPES, STAGE I ON LARGE GASOLINE TANKS.	0	
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	DENATURED ETHANOL STORAGE TANK	2000000	GALLON STORAGE	INTERNAL FLOATING ROOF	1.26	T/YR
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	30% CONDENSED DISTILLERS SOLUBLES (CDS) LOADOUT	30000	GALLON	OPERATE AND FILL TANKERS AT THE CDS LOADOUT IN A MANNER TO MINIMIZE VOC EMISSIONS.	0.0025	T/YR
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	DENATURANT STORAGE TANK	500000	GALLON STORAGE	INTERNAL FLOATING ROOF	0.51	T/YR
IA-0092	SOUTHWEST IOWA RENEWABLE ENERGY	04/19/2007 ACT	ETHANOL STORAGE TANKS	1500000	GAL	INTERNAL FLOATING ROOF	0	
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	ETHANOL STORAGE TANKS (2)			INTERNAL FLOATING ROOF	0	
LA-0208	IVANHOE CARBON BLACK PLANT	12/09/2004 ACT	TANK #3 (2.31 MM GALS)				0.14	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	TANKS - FOR BENZENE, XYLENE, SULFOLANE, PAREX, INTERMEDIATE			EQUIPPED WITH INTERNAL FLOATING ROOFS FOLLOWED BY THERMAL OXIDIZERS	0	
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	TANKS - FOR HEAVY MATERIALS			EQUIPPED WITH FIXED ROOF AND COMPLY WITH 40 CFR 63 SUBPART CC	0	
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	TANKS - FOR SPENT CAUSTIC			FIXED ROOF AND SUBMERGED FILL LINES (LAC 33:III.2103)	0	
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	TANKS - FOR LIGHT MATERIALS, SOUR WATER, NAPHTHA, RAFFINATE			EQUIP WITH FLOATING ROOFS (IFR OR EFR) & COMPLY WITH 40 CFR 60 SUBPART KB OR 40 CFR 63 SUBPART CC	0	
ND-0020	RICHARDTON PLANT	08/04/2004 ACT	ETHANOL STORAGE TANKS	68.3	MMGAL/YR	INTERNAL FLOATING ROOF	95	% REDUCTION
NM-0050	ARTESIA REFINERY	12/14/2007 ACT	STORAGE TANKS	100000	BBL	EXTERNAL FLOATING ROOF TANK EQUIPPED WITH DOUBLE SEALS .	0	
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	FIXED ROOF TANKS (8)	262500	GAL/D	SUBMERGED FILL	0.8	T/YR
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	INTERNAL FLOATING ROOF TANKS (4)	262500	GAL/D	FLOATING ROOF AND SUBMERGED FILL	0.88	T/YR
OK-0097	QUAD GRAPHICS OKC FAC	02/03/2004 ACT	STORAGE TANKS			TANKS DUCTED TO CARBON ADSORBER	1.94	T/YR
TX-0496	INEOS CHOCOLATE BAYOU FACILITY	08/29/2006 ACT	TANK CAP				11.06	LB/H
WI-0207	ACE ETHANOL - STANLEY	01/21/2004 ACT	STORAGE TANKS			FIXED ROOF TANKS WITH INTERNAL FLOATING ROOF (SUBJECT TO NSPS)	0	

TRUCK LOADING

RBLC Data for Truck Loading – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
IA-0088	ADM CORN PROCESSING - CEDAR RAPIDS	06/29/2007 ACT	ALCOHOL RAIL LOADOUT	12000	GAL/MIN	VAPOR RECOVERY SYSTEM WITH ENCLOSED FLARE	98	% REDUCTION
IA-0092	SOUTHWEST IOWA RENEWABLE ENERGY	04/19/2007 ACT	ETHANOL LOADOUT	125000000	GAL/YR	VAPOR RECOVERY SYSTEM AND FLARE	3.48	T/YR
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	ETHANOL TRUCK LOADOUT SYSTEM	800	GAL/MIN	ENCLOSED FLARE	98	% REDUCTION
IA-0095	TATE & LYLE INDGREDIENTS AMERICAS, INC.	09/19/2008 ACT	ETHANOL RAIL LOADOUT SYSTEM	2000	GAL/MIN	ENCLOSED FLARE	98	% REDUCTION

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	PETROLEUM PRODUCT LOADING DOCKS (94-9)			COMPLY WITH LAC 33:III.2108 FOR LOADING MATERIALS WITH VAPOR PRESSURE > 1.5 PSIA	687	LB/H
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	LOADINGS - REFINERY			TRUCK/RAILCAR LOADING: COMPLY WITH 40 CFR 63 SUBPART CC	0	
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	LOADINGS - AROMATIC RECOVERY UNIT			RAILCAR LOADING: COMPLY WITH 40 CFR 63 SUBPART G MARINE LOADING: COMPLY WITH 40 CFR 61 SUBPART BB	0	
ND-0020	RICHARDTON PLANT	08/04/2004 ACT	ETHANOL LOADOUT	68.3	MMGAL/YR	VAPOR COMBUSTION UNIT (ENCLOSED FLARE)	10	MG/L
NM-0050	ARTESIA REFINERY	12/14/2007 ACT	TRUCK LOADING RACK			CARBON ADSORPTION SYSTEM	10	MG/L
OH-0317	OHIO RIVER CLEAN FUELS, LLC	11/20/2008 ACT	LOADING RACK	172462496	GAL/YR	VAPOR RECOVERY SYSTEM. SUBMERGED FILL.	1.7	T/YR
OK-0097	AD GRAPHICS OKC FAC	02/03/2004 ACT	VOC LOADING			EMISSION AND THROUGHPUT LIMITS, BOTTOM FILL LOADING, AND WORK PRACTICE PROCEDURES TO MINIMIZE EMISSIONS	3.19	T/YR
VA-0313	TRANSMONTAIGNE NORFOLK TERMINAL	04/22/2010 ACT	Truck Loading Fugitive Emissions from Loading Rack LR-1	0			9.3	T/YR
WI-0207	ACE ETHANOL -STANLEY	01/21/2004 ACT	LOADING RACK, F01/S35			FLARE	0	

FUGITIVES

RBLC Data for Fugitives – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0197	ALLIANCE REFINERY	07/21/2009 ACT	UNIT FUGITIVES	LEAK DETECTION AND REPAIR PROGRAM - LOUISIANA REFINERY MACT DETERMINATION DATED JULY 26, 1994	13.22	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0211	GARYVILLE REFINERY	12/27/2006 ACT	FUGITIVE EMISSIONS	LDAR PROGRAM: COMPLY WITH OVERALL MOST STRINGENT PROGRAM APPLICABLE TO UNIT. APPLICABLE PROGRAMS INCLUDE 40 CFR 63 SUBPART CC, 40 CFR 60 SUBPART GGG, LAC 33:III.2121, & LAC 33:III.CHAPTER 51 (LA REFINERY MACT).	0	
LA-0211	GARYVILLE REFINERY	12/27/2006 ACT	HYDROGEN PLANT FUGITIVES (51-08)	LDAR PROGRAM: LAC 33:III.2121	0	
LA-0213	ST. CHARLES REFINERY	11/17/2009 ACT	FUGITIVE EMISSIONS	REFINERY (90-0): LA REFINERY MACT LDAR PROGRAM; ARU (2008-39): MONITORING ACCORDING TO 40 CFR 63 SUBPART H; ARU LOADING (2008-37): MONITORING ACCORDING TO 40 CFR 61 SUBPART V	0	
LA-0245	HYDROGEN PLANT	12/15/2010 ACT	Hydrogen Plant Fugitives (FUG0030)	LDAR PROGRAM THAT MEETS LA REFINERY MACT WITH CONSENT DECREE ENHANCEMENTS (JULY 26, 1994)	23.74	T/YR
OK-0102	PONCA CITY REFINERY	08/18/2004 ACT	EQUIPMENT LEAKS	REFINERY MACT II STANDARDS (LDAR): LEAK DETECTION, MONITORING	0	

RBLC Search Fugitives – CO_2e Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0257	SABINE PASS LNG TERMINAL	CAMERON	LA	12/6/2011	Acid Gas Vents (4)	0			39.29	LB/H
LA-0257	SABINE PASS LNG TERMINAL	CAMERON	LA	12/6/2011	Fugitive Emissions	0		conduct a leak detection and repair (LDAR) program	89629	TONS/YR
*LA-0266	EUNICE GAS EXTRACTION PLANT	ACADIA	A	5/1/2013	Process Fugitives (16) (FUG 0001)	0		LDAR programs: NSPS KKK and LAC 33:III.2121	0	

REFINERY FLARES

RBLC Data for Refinery Flares – NO_X Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
NM-0050	ARTESIA REFINERY	12/14/2007 ACT	EAST CRUDE EXPANSION FLARE	7.5	MMBTU/H		0.54	LB/H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) FLARES, EPN 9 & 29			NONE INDICATED	4.37	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE				1.14	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1067)				1.92	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1087)				1.45	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (8003B)				1.8	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	ACID GAS FLARE				0.6	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				8.5	LB/H
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	05/05/2005 ACT	ITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		0.19	LB/H
TX-0494	FLINT HILLS RESOURCES INSTALLATION OF BOILERS	01/24/2005 ACT	FLARES 5,6				1150.93	LB/H

RBLC Data for Refinery Flares – CO Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
NM-0050	ARTESIA REFINERY	12/14/2007 ACT	EAST CRUDE EXPANSION FLARE	7.5	MMBTU/H		0.2	LB/H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) FLARES, EPN 9 & 29			NONE INDICATED	37.2	LB/H
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	EAST PROPERTY FLARE				500	PPMV
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	COKER FLARE				500	PPMV
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	TWO FLARES				500	PPMV
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	NORTH PROPERTY FLARE				500	PPMV
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	CCU FLARE				500	PPMV
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	WEST PROPERTY FLARE				500	PPMV
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE				9.77	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1067)				13.84	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1087)				12.42	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (8003B)				3.6	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	ACID GAS FLARE				3.1	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				1.9	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				43.2	LB/H
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	05/05/2005 ACT	TY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		1.66	LB/H
TX-0494	FLINT HILLS RESOURCES INSTALLATION OF BOILERS	01/24/2005 ACT	FLARES 5,6				884.57	LB/H

RBLC Data for Refinery Flares – VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
NM-0050	ARTESIA REFINERY	12/14/2007 ACT	EAST CRUDE EXPANSION FLARE	7.5	MMBTU/H		0.03	LB/H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) FLARES, EPN 9 & 29			THE FLARE IS A VOC	42.82	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE				0.22	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1067)				7.55	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1087)				0.14	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (8003B)				1.21	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	ACID GAS FLARE				3.6	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				1.1	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				27.9	LB/H
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	05/05/2005 ACT	FACILITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		0.72	LB/H

RBLC Data for Refinery Flares – SO_2 Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION LIMIT
NM-0050	ARTESIA REFINERY	12/14/2007 ACT	EAST CRUDE EXPANSION FLARE	7.5	MMBTU/H		0.1	LB/H
TX-0364	SALT CREEK GAS PLANT	01/31/2003 ACT	(2) FLARES, EPN 9 & 29			NONE INDICATED	50.48	LB/H
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	EAST PROPERTY FLARE				300	PPM
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	COKER FLARE				300	PPM
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	CCU FLARE				300	PPM
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	WEST PROPERTY FLARE				300	PPM
TX-0442	SHELL OIL DEER PARK	07/30/2004 ACT	THREE FLARES				300	PPM
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE				0.02	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION LIMIT
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1067)				0.01	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (1087)				0.02	LB/H
TX-0475	FORMOSA POINT COMFORT PLANT	05/09/2005 ACT	FLARE (8003B)				0.01	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	ACID GAS FLARE				0.2	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	SOUR WATER STRIPPER FLARE				0.19	LB/H
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ACT	FLARE-COKE DRUM BLOWDOWN				1056	LB/H
TX-0492	VIRTEX PETROLEUM COMPANY DOERING RANCH GAS PLANT	05/05/2005 ACT	FACILITY FLARE-AMINE UNIT STILL VENT	0.75	LTPD		140.5	LB/H
TX-0494	FLINT HILLS RESOURCES INSTALLATION OF BOILERS	01/24/2005 ACT	FLARES 5,6				942.51	LB/H

RBLC Search Flares – GHGs Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AK-0076	POINT THOMSON PRODUCTION FACILITY	NORTH SLOPE	AK	8/20/2012	Combustion (Flares)	35	MMscf/yr	Good Combustion Practices	0	
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	SULLIVAN	IN	11/10/2011	COAL BED METHANE- FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	25	MMBTU/H	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.05	LB/MW-H
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	SULLIVAN	IN	11/10/2011	COAL BED METHANE- FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	25	MMBTU/H	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.06	LB/MW-H
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	SULLIVAN	IN	11/10/2011	COAL BED METHANE- FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	25	MMBTU/H	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	3235	LB/MW-H
LA-0257	SABINE PASS LNG TERMINAL	CAMERON	LA	12/6/2011	Marine Flare	1590	MMBTU/H	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	2909	TONS/YR

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
LA-0257	SABINE PASS LNG TERMINAL	CAMERON	LA	12/6/2011	Wet/Dry Gas Flares (4)	0.26	MMBTU/H	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	33	TONS/YR
*LA-0266	EUNICE GAS EXTRACTION PLANT	ACADIA	LA	5/1/2013	Smokeless Flare (14) (EQT 0028)	0		Good combustion practices	0	

HAUL ROADS

RBLC Data for Haul Roads – PM/PM_{10}/$PM_{2.5}$ Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNI	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
AR-0094	JOHN W. TURK JR. POWER PLANT	11/05/2008 ACT	ROADS			WATERING/DUST SUPPRESSION CHEMICALS	1.1	LB/H
KY-0095	RECMIX OF PA, INC.	08/06/2004 ACT	UNPAVED ROAD			WATERING	0.78	T/YR
LA-0202	RODEMACHER BROWNFIELD UNIT 3	02/23/2006 ACT	UNPAVED ROADS			WATERING OF AREAS USED BY HEAVY DUTY VEHICLES	3.82	LB/H
LA-0203	OAKDALE OSB PLANT	06/13/2005 ACT	PAVED ROADS			LIMITED ACCESS	2.6	LB/H
LA-0203	OAKDALE OSB PLANT	06/13/2005 ACT	UNPAVED ROADS			RESTRICTED ACCESS AND CHEMICAL DUST SUPPRESSANTS	0.29	LB/H
LA-0209	GRAVELITE DIVISION	06/28/2006 ACT	UNPAVED ROADS			WATERING AND REDUCED SPEED LIMIT	0.7	LB/H
LA-0239	NUCOR STEEL LOUISIANA	05/24/2010 ACT	FUG-101 - UNPAVED ROAD FUGITIVE DUST	0		BACT FOR ROAD DUST IS TO PAVE ROADWAYS WHERE PRACTICABLE INCLUDING AREAS WHERE THE EXTRA HEAVY VEHICLES (GREATER THAN 50 TONS IN WEIGHT) WILL NOT CAUSE DAMAGE TO PAVING. UNPAVED ROADS SHALL UTILIZE WATER SPRAY OR DUST SUPPRESSION CHEMICALS TO REDUCE EMISSIONS. ADDITIONALLY, REDUCED SPEED LIMITS OF LESS THAN OR EQUAL TO 15 MPH WILL BE ENFORCED ON ALL UNPAVED ROADWAYS.	18.69	LB/H

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNI	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT
LA-0240	FLOPAM INC.	06/14/2010 ACT	ROADWAY FUGITIVES	0		MAIN ROADWAY SHALL BE PAVED WHERE PRACTICAL. PRECAUTIONS SHALL BE TAKEN TO PREVENT DUST FROM BECOMING AIRBORNE	0.04	LB/H
NC-0112	NUCOR STEEL	11/23/2004 ACT	UNPAVED ROADS			PERIODIC APPLICATION OF WATER AND CHEMICAL DUST SUPPRESSANTS TO UNPAVED ROADWAYS AND POSTED SPEED LIMIT OF 10 MILES PER HOUR	0	
OH-0341	NUCOR STEEL MARION, INC.	12/23/2010 ACT	ROADWAYS	8375	MI/YR	BEST AVAILABLE CONTROL MEASURES TO INCLUDE WATERING, RESURFACING, CHEMICAL STABILIZATION, AND/OR SPEED REDUCTION AT SUFFICIENT FREQUENCY TO ENSURE COMPLIANCE.	30.64	T/YR

WATER TANKS

RBLC Data for Water Tanks– VOC Emissions

RBLCID	FACILITY NAME	PERMIT DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD	EMISSION LIMIT	EMISSION UNIT	EMISSION UNIT AVERAGING TIME
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/2005 ;ACT	TANK FARM THERMAL OXIDIZER				99.9	% DESTRUCTION	see notes
AZ-0046	ARIZONA CLEAN FUELS YUMA	04/14/2005 ;ACT	SOUR WATER TANK	2000000	GALLON STORAGE	FIXED ROOF TANK WITH INTERNAL FLOATING ROOF. HEAD SPACE ROUTED TO A CARBON ADSORPTION SYSTEM.			12-MONTH ROLLING TOTAL
IL-0103	CONOCOPHILLIPS WOOD RIVER REFINERY	08/05/2008 ;ACT	SOUR WATER STORAGE TANK (MODIFIED)	3360000	GALLON STORAGE	INTERNAL FLOATING ROOF WITH SECONDARY SEAL IN ACCORDANCE WITH 40 CFR 60, SUBPART KB AND 40 CFR 63, SUBPART CC.			12-MONTH ROLLING TOTAL
LA-0211	GARYVILLE REFINERY	12/27/2006 ;ACT	WASTEWATER COLLECTION/TREATMENT (TRAINS 1-5) (30-08)	7125	GALLON STORAGE	COMPLY WITH 40 CFR 63 SUBPART CC, 40 CFR 61 SUBPART FF, & 40 CFR 60 SUBPART QQQ			12-MONTH ROLLING TOTAL
LA-0211	GARYVILLE REFINERY	12/27/2006 ;ACT	THERMAL DRYING UNIT- WASTEWATER SUMP &p; FEED TANKS (124-9-91, 124-10-91, 124-11-91, 124-12-91)			124-10-91: SUBMERGED FILL PIPE 124-11-91: SUBMERGED FILL PIPE 124-12-91: SUBMERGED FILL PIPE			AVERAGE OF 3 TEST RUNS
LA-0213	ST. CHARLES REFINERY	1/17/2009 ;ACT	WASTEWATER COLLECTION & TREATMENT: REFINERY			WW (EQT0255): COMPLY WITH LA REFINERY MACT WWTU (EQT0359): COMPLY WITH 40 CFR 61 SUBPART FF CRUIDS (EQT369): COMPLY WITH 40 CFR 63 SUBPARTS F & G			SEE NOTE
LA-0213	ST. CHARLES REFINERY	11/17/2009 ;ACT	TANKS - FOR LIGHT MATERIALS, SOUR WATER, NAPHTHA, RAFFINATE			EQUIP WITH FLOATING ROOFS (IFR OR EFR) & COMPLY WITH 40 CFR 60 SUBPART KB OR 40 CFR 63 SUBPART CC			12-MONTH ROLLING TOTAL
NM-0050	ARTESIA REFINERY	12/14/2007 ;ACT	SOUR WATER TANK	20000	BBL	EXTERNAL FLOATING ROOF EQUIPPED WITH DOUBLE SEALS			SEE NOTE
NM-0050	ARTESIA REFINERY	12/14/2007 ;ACT	OIL WATER SEPARATOR			CARBON CANISTER			
TX-0478	CITGO CORPUS CHRISTI REFINERY - WEST PLANT	04/20/2005 ;ACT	SOUR WATER TANK				17.9	LB/H	SEE NOTE
TX-0575	SABINA PETROCHEMICALS LLC	08/20/2010 ;ACT	STORMWATER TANK	15	MGAL/YR	EXTERNAL FLOATING ROOF	0.31	tpy	SEE NOTE
TX-0439	TOYOTA MOTOR MANUFACTURING TEXAS	12/17/2003 ACT	BULK MATERIAL STORAGE TANKS				3.4	T/YR	

WET SURFACE AIR COOLER

RBLC Search Wet Surface Air Cooler– $PM/PM_{10}/PM_{2.5}$ Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
CO-0057	Comanche Station Public Service Company of Colorado		CO	---	Cooling Tower			RACT is Drift Eliminator to achieve 0.0005 % Drft or Less		
IA-0105	IOWA Fertilizer Company		IOWA		Cooling Tower			RACT is Drift Eliminator to achieve 0.0005 % Drft or Less		

SMALL ENGINE

RBLC Search Small Engine–Emissions

RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
AK-0082	Point Thomson Production Facility Exxon Mobil Corporation		AK	01/23/2015	Agitator Generator Engine (98 hp)			CO – Emission Limit	3.7	Grams/HP-hr
								NO_X – Emission Limit	5.6	Grams/HP-hr
								PM – Emission Limits	0.30	Grams/HP-hr
								VOC – Emission Limit	0.0025	Lb/HP-hr
								CO_2e – Emission Limit	356	Tons/year
					Incinerator Generator Engine (102 hp)			CO – Emission Limit	3.7	Grams/HP-hr
								NO_X – Emission Limit	4.9	Grams/HP-hr
								PM – Emission Limits	0.22	Grams/HP-hr
								VOC – Emission Limit	0.0025	Lb/HP-hr
								CO_2e – Emission Limit	516	Tons/year
MI-0412	Holland Board of Public Works	Ottawa	MI	12/04/2013	Emergency Engine – Diesel Fire Pump (165 hp)			CO – Emission Limit / Good Combustion Practice	3.7	Grams/HP-hr
								NO_X – Emission Limit / Good Combustion	3.0	Grams/HP-hr
								PM – Emission Limit / Good Combustion	0.22	Grams/HP-hr

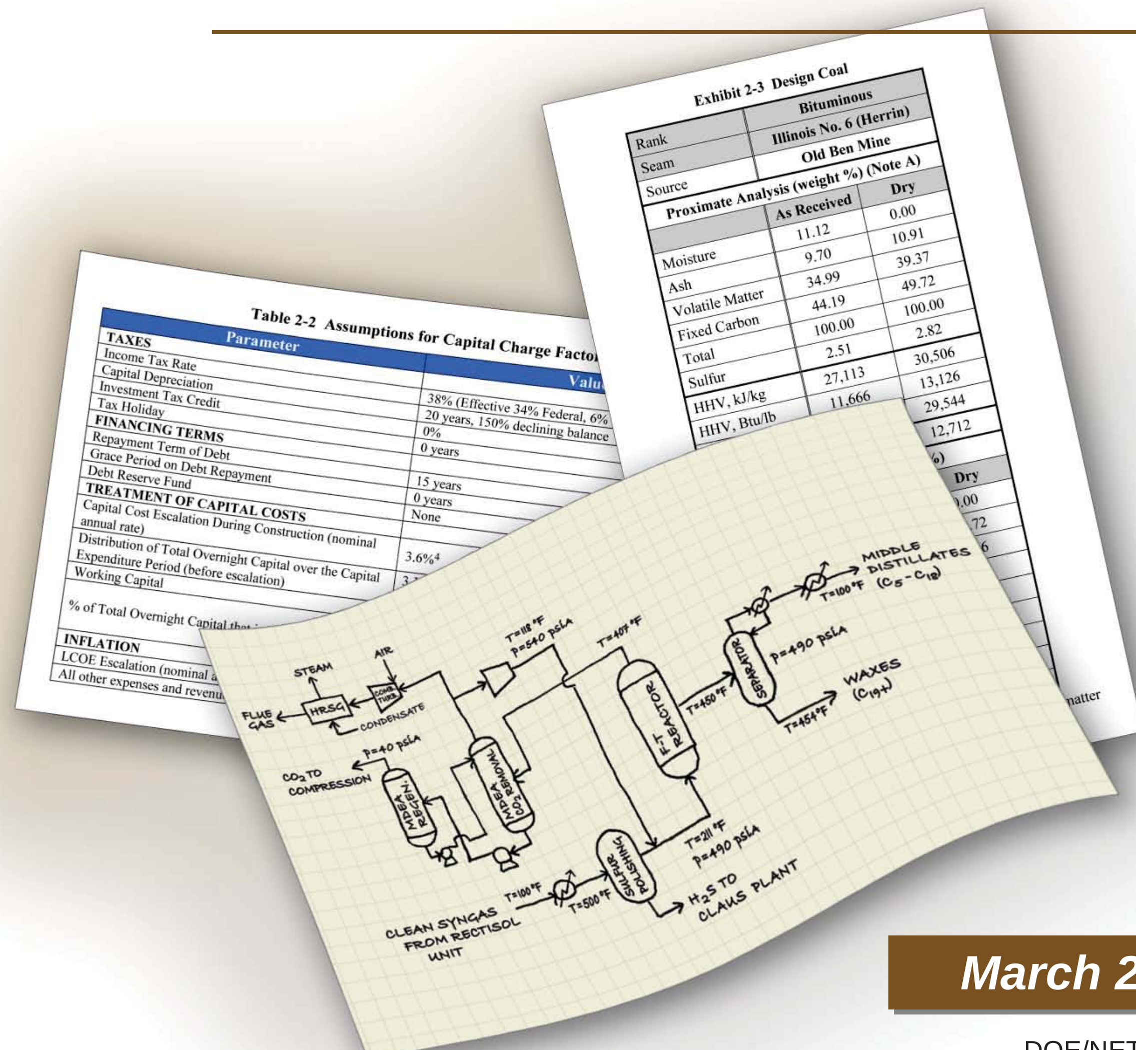
RBLCID	FACILITY NAME	FACILITY COUNTY	FACILITY STATE	PERMIT ISSUANCE DATE	PROCESS NAME	THROUGHPUT	THROUGHPUT UNIT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT	EMISSION LIMIT UNIT
								VOC – Emission Limit / Good Combustion	0.0010	Lb/HP-hr
								CO_2e – Emission Limit / Good Combustion	0.29	Tons/year

APPENDIX B. GREENHOUSE GAS BACT SUPPORTING INFORMATION

the ENERGY lab

QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Estimating Carbon Dioxide Transport and Storage Costs



March 2010

DOE/NETL-2010/1447

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

Quality Guidelines for Energy Systems Studies
Estimating CO_2 Transport, Storage & Monitoring Costs

Background

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

Approach

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

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

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

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

Table 1: Deep, Saline Formation Specification [4]

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

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

Cost Sources & Methodology

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

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

Cost Levelization and Sensitivity Cases

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

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

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

Transport Costs

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

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

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

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

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

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

Storage Costs

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

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

Liability Protection

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

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

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

Monitoring Costs

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

Cost Metrics

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

Transport Costs

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

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

Storage Costs

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

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

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

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

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

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

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

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

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

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

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

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

Monitoring Costs

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

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

Cost Escalation

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

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

Cost Comparisons

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

Table 4: Summary of Cost Escalation Methodology

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

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

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

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

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

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

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

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

Results

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

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

Figure 1: Capital Cost vs. Pipeline Length

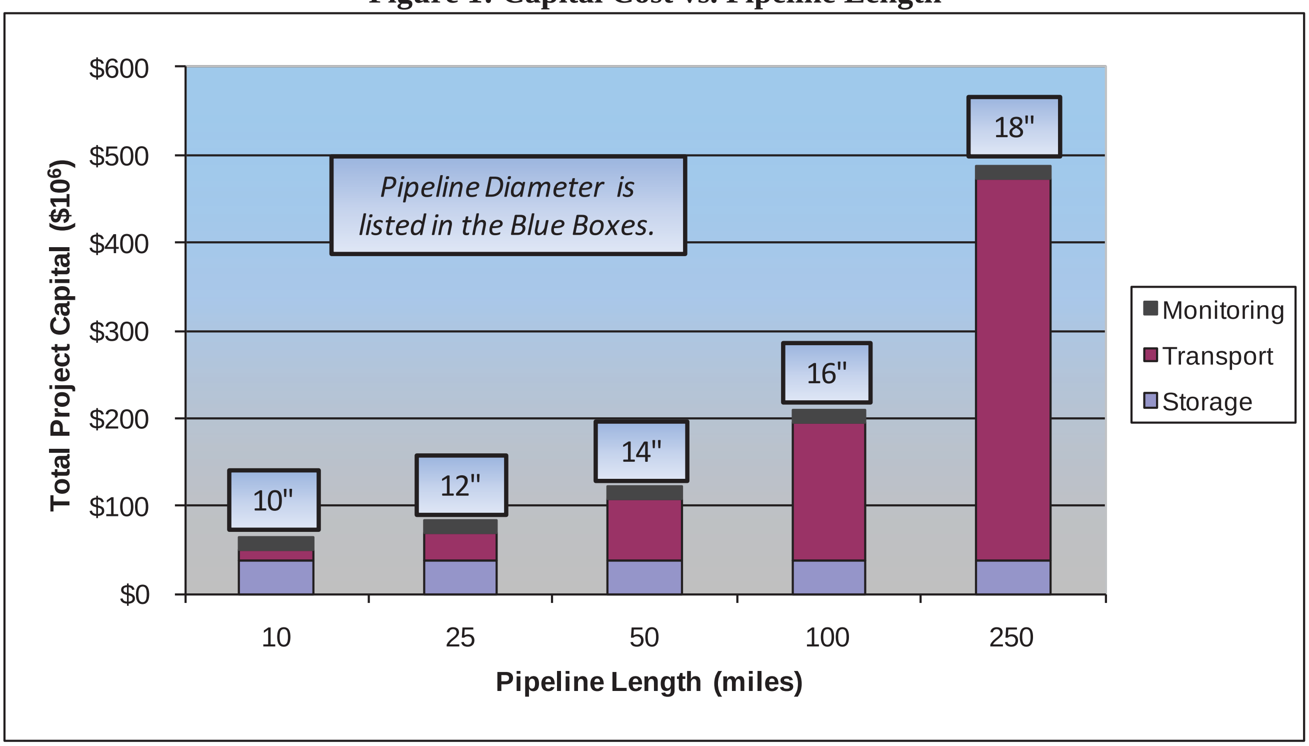
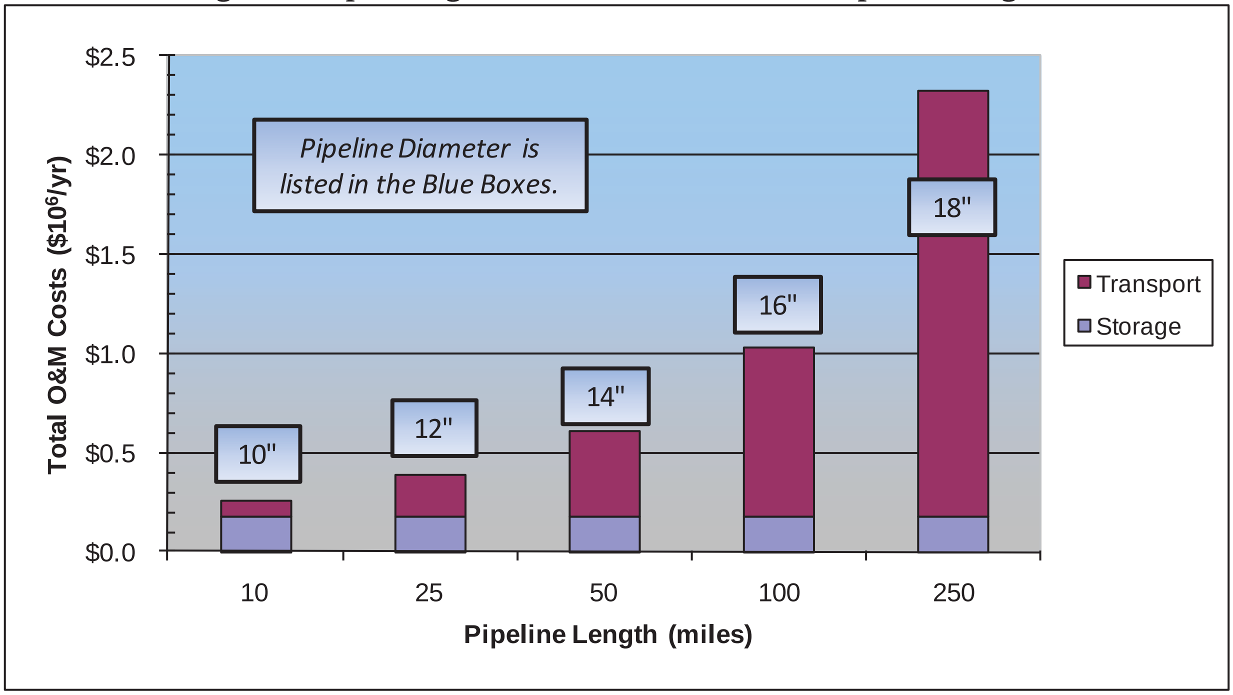


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



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

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

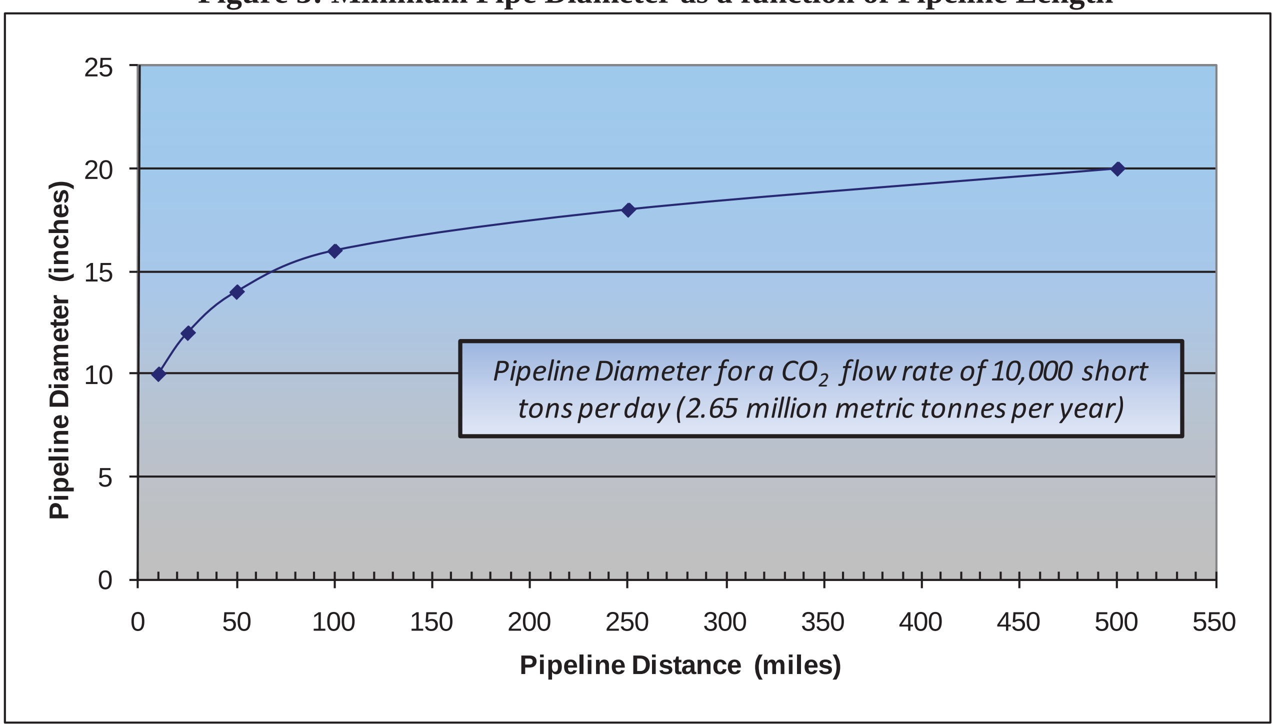
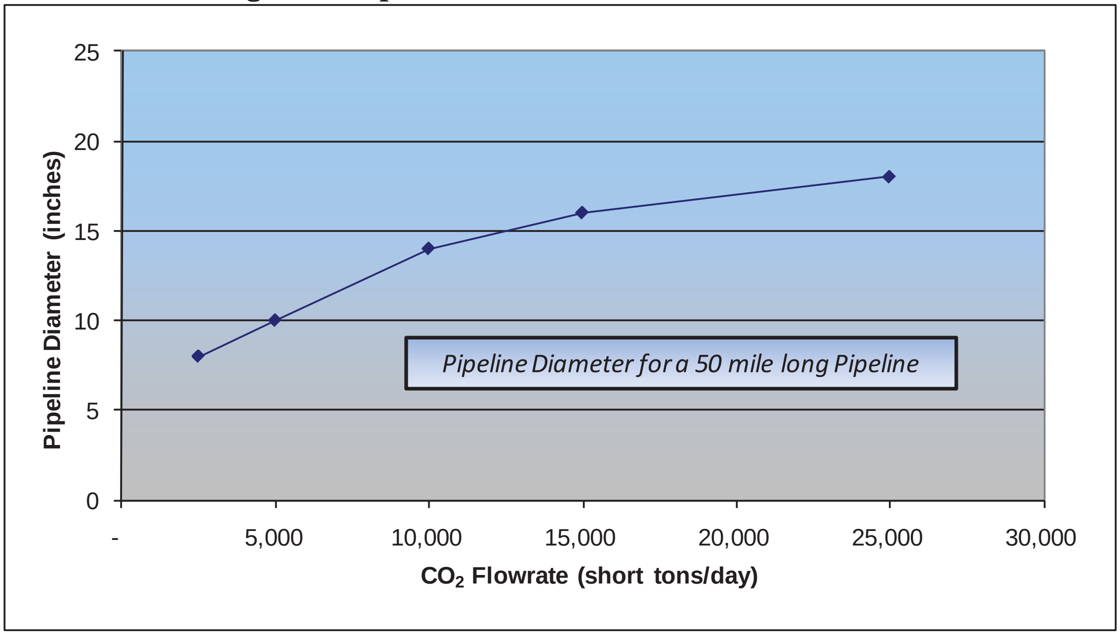


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



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

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

Figure 5: Capital Requirement vs. CO_2 Flow Rate

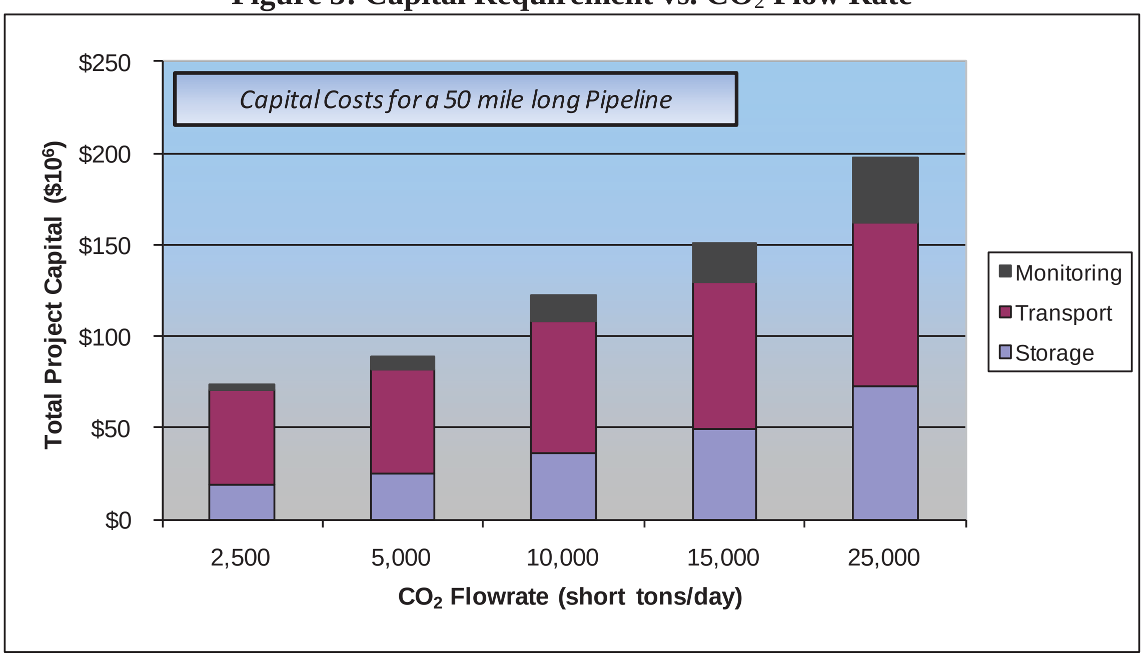
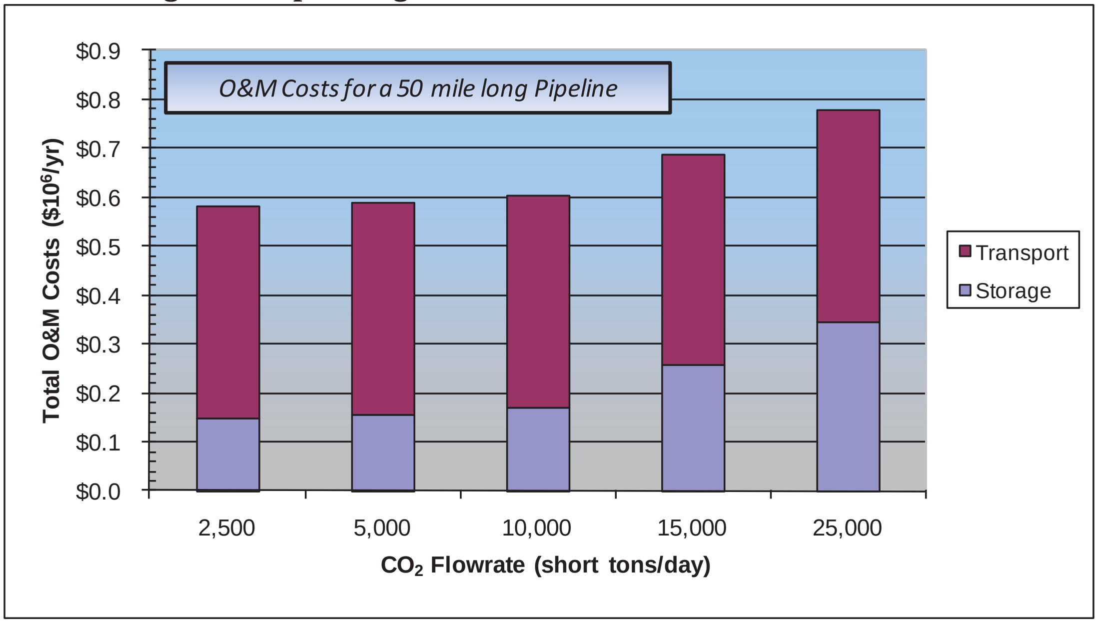
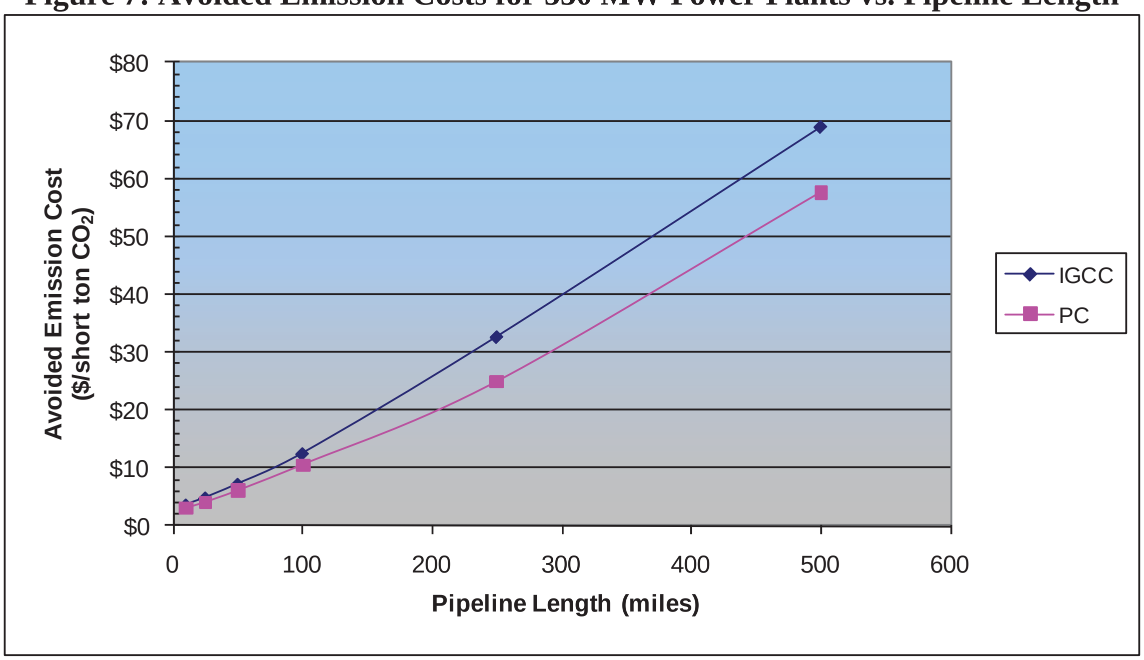


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



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

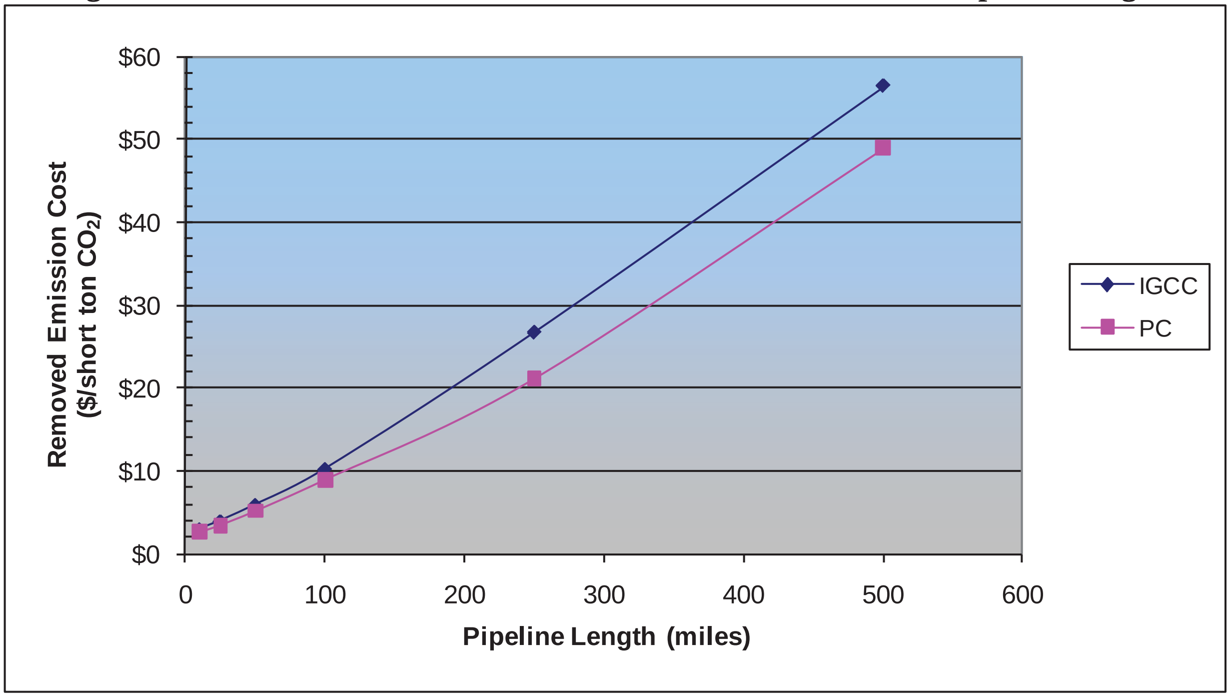
Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



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

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

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



Conclusions

- T&S avoided emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for our reference IGCC plant and the reference reservoir found in Table 1, or pipeline lengths of 50 to 95 miles for the PC plant.

- T&S removed emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.

- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.

- Transport capital requirements outweigh storage costs, independent of CO_2 flow rate, at a pipeline length of 50 miles and the reference reservoir.

- Operating expenses associated with storage approach transport operating costs for flow rates of 25,000 short tons of CO_2 per day at a 50 mile pipeline length.

Future Work

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

- Investigation into the apparent wide variability in site characterization and evaluation costs, including a sensitivity analysis to be performed to determine the sensitivity of overall project costs across the reported range of values.
- Continued research into liability costs and requirements.
- Further evaluation and sensitivity analysis into the number of land-owners pore space rights will have to be acquired from for a given sequestration project.

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Approved Ambient Air Monitoring Exemption Analysis

- Below is a timeline of the Ambient Air Monitoring Exemption Analysis

Timeline of Ambient Air Monitoring Exemption Analysis	
Date	Comment:
5/14/2013	Submitted original Ambient Air Monitoring Exemption Analysis
7/1/2013	Submitted second iteration of the Ambient Monitoring Exemption Analysis
7/22/2013	DCP and Trinity met with NMED to discuss Ambient Monitoring Exemption Analysis
7/26/2013	Submitted third iteration of the Ambient Monitoring Exemption Analysis.
7/31/2013	NMED approved Ambient Air Monitoring Exemption Analysis with all updated completed per NMED request.
3/15/2015	NMED approved a Pre-Construction Ambient Monitoring Report for the ZIA II Gas Plant (PSD-5217).

Refer to attached emails.

Milton Rosado

From: Heath, David, NMENV <david.heath@state.nm.us>
Sent: Tuesday, March 03, 2015 2:52 PM
To: Mustafa, Sufi A., NMENV; Adam Erenstein
Subject: RE: DCP Midstream's Zia II Gas Plant: Pre-Construction Ambient Monitoring Report
Attachments: Pre-Construction Ambient Monitoring_v0.8.pdf

Adam,

I have approved this Pre-Construction Ambient Monitoring Report for the Zia II Gas Plant (PSD-5217).

Dave

David Heath
Modeling Scientist
NMED / AQB

From: Mustafa, Sufi A., NMENV
Sent: Thursday, February 19, 2015 1:22 PM
To: Heath, David, NMENV
Subject: FW: DCP Midstream's Zia II Gas Plant: Pre-Construction Ambient Monitoring Report

Dave
Please review this report.
Thank you.

Sufi A. Mustafa, Ph.D.
Manager Air Dispersion Modeling and Emission Inventory Section
New Mexico Environment Department's Air Quality Bureau
Phone: 505 476 4318
525 Camino de los Marquez
Suite 1
Santa Fe, New Mexico, 87505

From: Adam Erenstein [mailto:AErenstein@trinityconsultants.com]
Sent: Thursday, February 19, 2015 11:22 AM
To: Mustafa, Sufi A., NMENV
Cc: JCorser@dcpmidstream.com; Andrew Glen
Subject: DCP Midstream's Zia II Gas Plant: Pre-Construction Ambient Monitoring Report

Sufi,
DCP Midstream will be submitting an application for the Zia II Gas Plant with minor updates to the proposed Zia II Gas Plant. Because this is a PSD application I am attaching to this e-mail is the Pre-Construction Ambient Monitoring Report for your review and approval. Please contact me if you have any questions regarding this Pre-Construction Ambient Monitoring Report. Thanks.

Regards,

Adam

……………………………………………………………………………………………………….
Adam Erenstein
Managing Consultant

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Section 12.2 – Updated Pre-Construction Monitoring Analysis

- Attached in this section is the updated pre-construction monitoring analysis.

Victoria Collis

From: Heath, David, NMENV <david.heath@state.nm.us>
Sent: Tuesday, March 03, 2015 2:52 PM
To: Mustafa, Sufi A., NMENV; Adam Erenstein
Subject: RE: DCP Midstream's Zia II Gas Plant: Pre-Construction Ambient Monitoring Report
Attachments: Pre-Construction Ambient Monitoring_v0.8.pdf

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NMED / AQB

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Thank you.

Sufi A. Mustafa, Ph.D.
Manager Air Dispersion Modeling and Emission Inventory Section
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To: Mustafa, Sufi A., NMENV
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Subject: DCP Midstream's Zia II Gas Plant: Pre-Construction Ambient Monitoring Report

Sufi,
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Regards,

Adam

....
Adam Erenstein
Managing Consultant

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PRE-CONSTRUCTION MONITORING
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February 19, 2015

Trinity Project Number: 143201.0195

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1. EXECUTIVE SUMMARY

DCP Midstream, LP (DCP) is proposing to make changes to the Zia II Gas Plant (Zia II) which is currently permitted under NSR Permit PSD-5217. The facility is currently under construction and will be a 230 MMscf/d Greenfield gas plant upon completion. The proposed gas plant is located on a parcel of land in Lea County New Mexico approximately 25 miles northwest of the city of Carlsbad, NM. The facility is classified as a major stationary source for NO_x and CO_2e. Also, the facility will trigger the Significant Emission Rates (SER) for $PM_{2.5}$, PM_{10}, and Ozone (VOC and NO_x). Per the monitoring requirements found in regulation 20.2.74.306.A NMAC:

"Any application for a permit under this part shall contain an analysis of ambient air quality. Air quality data can be that measured by the applicant or that available from a government agency in the area affected by the major stationary source or major modification. The analysis shall contain the following:

> *(1) for a major stationary source, each pollutant for which the potential to emit is equal to or greater than the significant emission rates as listed in Table 2 of this part (20.2.74.502 NMAC)"*

Preliminary calculations for the proposed Zia II project show NO_x, PM_{10}, $PM_{2.5}$, and Ozone emission rates are above the significant emission rates listed in 20.2.74.502 NMAC Table 2. Per 20.2.74.306.C NMAC:

"Continuous air quality monitoring data shall be required for all pollutants for which a national ambient air quality standard exists. Such data shall be submitted to the department for at least the one (1) year period prior to receipt of the permit application. The department has the discretion to:

> *(1) determine that a complete and adequate analysis can be accomplished with monitoring data gathered over a period shorter than one year but not less than four months; or*
> *(2) determine that existing air quality monitoring data is representative of air quality in the affected area and accept such data in lieu of additional monitoring by the applicant."*

DCP requests, based on the requirements of Ambient Monitoring Guidelines for PSD (5/87)[1], that the existing ambient monitoring program operated by the NMED is sufficient to meet the needs of any pre-construction monitoring requirements and thus may be used in lieu of such pre-construction monitoring requirements. Based on preliminary modeling runs, NO_x, PM_{10}, $PM_{2.5}$ and Ozone (NO_x and VOC) are expected to exceed the respective Significant Emission Rate (SER) and of these pollutants only NO_x and $PM_{2.5}$ exceed the Significant Monitoring Concentrations (SMC) (Refer to Table 1). DCP is proposing to use background data from the 5ZR Carlsbad monitor (AQS Site ID: 35-015-1005), Artesia (AQS Site ID: 35-015-1004) and 5ZS Hobbs Jefferson (AQS Site ID: 35-025-0008) listed in Table 2, in lieu of collecting site-specific ambient data for NO_x, PM_{10}, $PM_{2.5}$, and Ozone. This analysis is largely based on the submitted pre-construction analysis submitted on February 11, 2013 as part of the Zia II PSD application which was approved April 25, 2013. The analysis has been updated to reflect changes to emission rates for the following pollutants NO_x, CO, VOCs, SO_x, TSP, PM_{10}, $PM_{2.5}$, and H_2S.

[1] Ambient Monitoring Guidelines for Prevention of Significant Deterioration (PSD): EPA-450/4-87-007, May 1987.

Table 1. Zia II Gas Plant (GP) Comparison to 20.2.74.503 Table 3 – Significant Monitoring Concentrations (SMCs)

Pollutant	SMC Air Quality Concentration µg/m^3	Averaging Time	Modeled Zia II GP µg/m^3	Calculated[1] Zia II GP µg/m^3	Is Facility Above SMC?[3]
Nitrogen dioxide	14	24 hours	55.42	22.17	yes
Ozone	b	Annual	c	c	N/A
PM_{10}	10	24 hours	5.44	5.44	no
$PM_{2.5}$[2]	0	24 hours	3.28	3.28	yes

a - No acceptable monitoring techniques available at this time. Therefore, monitoring is not required until acceptable techniques are available.

b - No de minimis air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data.

c- A full ozone screening analysis will be conducted for this project, but as per the NMEDs instruction on June 14, 2013 (conversation between Dr. Sufi Mustafa, NMED and Mr. Adam Erenstein, Trinity Consultants) this analysis will be submitted with the dispersion modeling report.

[1] 40% ARM factor applied to modeled 24-hr NOx

[2] U.S. EPA promulgated $PM_{2.5}$ SILs, Significant Monitoring Concentrations (SMCs), and PSD Increments on October 20, 2010 (75 FR 64864, *Prevention of Significant Deterioration (PSD) for Particulate Matter Less Than 2.5 Micrometers Increments, Significant Impact Levels (SILs) and Significant Monitoring Concentration (SMC); Final Rule*). The SILs and SMCs became effective on December 20, 2010 (i.e., 60 days after the rule was published in the Federal Register) and the PSD Increments became effective on October 20, 2011 (i.e., one year after the date of promulgation). *On January 22, 2013, the United States Court of Appeals for the District of Columbia Circuit (Court) granted a request from the Environmental Protection Agency (EPA) to vacate the PSD rule establishing a PM $_{2.5}$ Significant Monitoring Concentration (SMC)*

[3] 20.2.74.306.A(1) "for a major stationary source, each pollutant for which the potential to emit is equal to or greater than the significant emission rates as listed in Table 2 of this part (20.2.74.502 NMAC) will require ambient monitoring

Table 2. Surrounding Ambient Monitors

Monitor Description	Distance From Zia II (km)	Currently Operational	Last Continuous Year	Pollutants	Details	Annual First Maximum Value				Units
						1 hr	3 hr	8 hr	24 hr	
5ZR Carlsbad (AQS Site ID: 35-015-1005)	51	Yes	2013	O_3		0.081		0.077		ppm
				NO		18				ppb
				NO_2		21				ppb
				NO_x		31				ppb
				$PM_{2.5}$	Acceptable $PM_{2.5}$ AQI & Speciation	166.4			28	μg/m^3
5ZS Hobbs Jefferson (AQS Site ID: 35-025-0008)	65	Yes	2013	PM_{10}	Local Conditions				100	μg/m^3
				PM_{10}	Total 0-10um STP				109	μg/m^3
				$PM_{2.5}$	Local Conditions				39.7	μg/m^3
				$PM_{2.5}$	Acceptable $PM_{2.5}$ AQI & Speciation	175.5			32.3	μg/m^3
				O_3		0.076		0.071		ppm
				NO_2		39				ppb
				NO		107				ppb
				NO_x		133				ppb
Artesia (AQS Site ID: 35-015-1004)	59	No	2008	NO		50				ppb
				NO_2		33				ppb
				NO_x		67				ppb
				SO_2		8	2.6		1	ppb

* Concentrations values provided in this table are maximum monitored values. DCP and Trinity will work with NMED to establish appropriate values to be used as background concentration levels for air dispersion modeling purposes.

2. DESCRIPTION OF FACILITY

DCP is constructing a 230 MMscf/d gas processing plant capable of producing an estimated 29,329 bbl/d of Natural Gas Liquids (NGLs).

Zia II Gas Plant (Zia II GP) will be located in Lea County, New Mexico, approximately 25 miles northwest of the city of Carlsbad, NM. The facility will be situated in Township 19S, Range 32E, and Section 19. The facility will operate year around and will restrict public access with a fence. Figure 1 shows the general regional location of the facility.

The proposed facility will consist of four inlet compressors (Caterpillar 3616), four residue compressors (Caterpillar 3616), and two additional compressors (Caterpillar 3608) to replace compression from the removal of the Lusk Booster Station. Table 3 shows the list of equipment and the changes to the equipment from the current permit. The gas that will be processed at this facility will be sour gas. The gas will be treated with an amine unit to remove CO_2 and H_2S. The amine unit (Amine) will have amine regeneration heaters associated with each unit. All CO_2 and H_2S removed will then be sent to one of two acid gas injection (AGI) wells. Associated with the AGIs is an emergency acid gas flare (FL2). After the inlet gas has been treated by the amine unit, it is then sent to the TEG glycol dehydrator where water is removed from the gas stream. Associated with this unit is a TEG regenerator heater. Liquid is further taken out of the gas stream with molecular sieves and is then sent to the cold plant for NGL processing. Table 4 references facility wide Zia II Gas Plant emissions compared to Significant Emission Rates (SER) of Table 2 of 20.2.74.502 NMAC. As the table shows NO_x, PM_{10}, $PM_{2.5}$ and Ozone all have emission rates above the SER.

Table 3. Proposed updates to Zia II Gas Plant

Equipment ID	Equipment Description	Current Permit PSD 5217	Proposed Changes
C1-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C2-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C3-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C4-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C5-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C6-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C7-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C8-E	4SLB RICE	X	change stack diameter to 3ft, currently permitted at 2ft
C9-E	4SLB RICE	X	N/A
C10-E	4SLB RICE	X	N/A
C11-E	4SLB RICE	X	remove from permit, electric driven
C12-E	4SLB RICE	X	remove from permit, electric driven
C13-E	4SLB RICE	X	remove from permit, electric driven
Dehy	TEG Dehydrator Still Vent/Flash Tank	X	N/A
FL1	Inlet Gas Flare	X	N/A
FL2	Acid Gas Flare	X	N/A
FUG	Facility-wide Fugitives	X	N/A
H1	Trim Reboiler Heater	X	change stack height to 20, currently permitted at 86
H2	Stabilizer Heater	X	remove from permit, not direct fired, uses HMO
H3	Regeneration Gas Heater	X	uprate to 10MMBTU, currently at 8MMBTU, stack height to 18 ft
H4	Hot Oil Heater	X	change from 114 MMBTU to 99MMBTU
H5	Hot Oil Heater	X	change from 114 MMBTU to 99MMBTU
H6	TEG Regeneration Heater	X	N/A
HAUL	Unpaved Haul Roads	X	Revise calculations to reflect new haul road length and paved control
L1	Truck Load-out	X	N/A
TK-1	Condensate Tank	X	N/A
TK-2	Condensate Tank	X	N/A
TK-C	Produced Water Tank	X	N/A
TK-G	Produced Water Tank	X	N/A
TK-H	Produced Water Tank	X	N/A
VCD1	Vapor Combustion Device	X	N/A
WSAC	Cooler	-	new unit being added
FL3	Lusk Flare	-	new unit being added
SSM (CB)	Blowdowns to atmosphere	-	new unit being added
GEN-1	Generator	-	new unit being added

Table 4. Zia II Gas Plant Comparison to Significant Emission Rates of Table 2 of 20.2.74.502 NMAC

Pollutant	Significant Emission Rate (tpy)	Zia II GP Proposed Emissions (tpy)	IS Facility below SER?
Carbon monoxide	100	86.9	Yes
Nitrogen oxides	40	326.9	No
Ozone (Volatile Organic Compounds or nitrogen oxides)	40 VOC	125.0	No
	40 NO_X	326.9	No
Particulate Matter			
Total Suspended Particulate (TSP)	25	20.0	Yes
PM_{10} emissions	15	19.7	No
Direct $PM_{2.5}$ emissions	10	19.7	No
Sulfur compounds			
Hydrogen sulfide (H_2S)	10	0.68	Yes
Sulfur dioxide	40	32.2	Yes
Sulfuric acid mist	7	1.5	Yes

Figure 1. Aerial Map of Zia II Facility, Surrounding Sources, Ambient Monitors and Meteorological Stations.

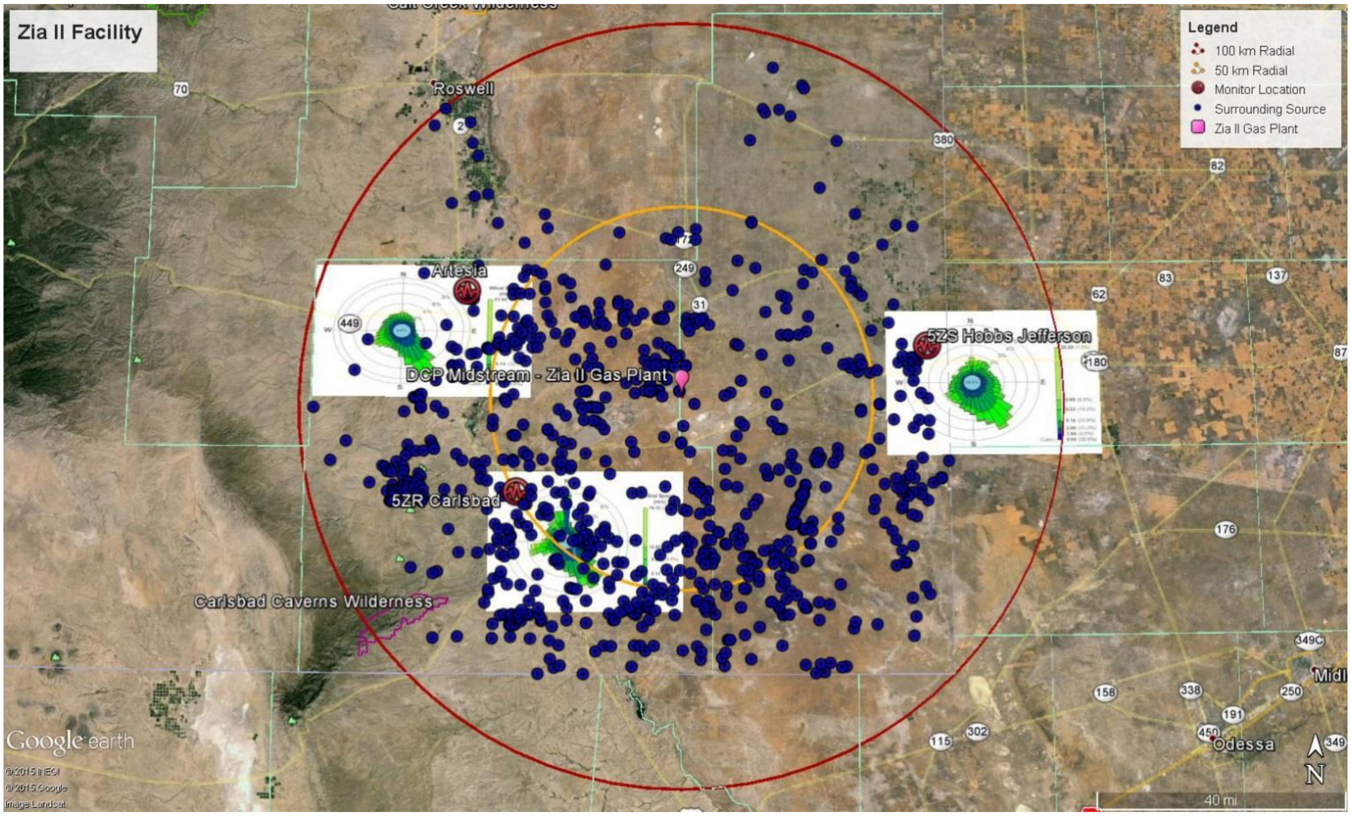


Figure 1. Map of the proposed Zia II facility and surrounding sources up to 100 km are also included. The three monitoring sites are shown with corresponding observed wind speed and direction for Carlsbad, NM and Hobbs, NM. The Empire Abo NMED meteorological model ready data set is centered near Artesia, NM and is included for consistency. Additionally, both 50 km and 100 km radials from the facility are shown for scale.

3. TOPOGRAPHY, ELEVATION, CLIMATE, AND VEGETATION

The proposed facility location is in the Pecos Valley Region of the Great Plains physiographic province. Lea County (including the city of Hobbs, New Mexico) and most of Eddy County (including the cities of Artesia and Carlsbad) are located within this region and physiographic province.

Terrain around the facility is moderately flat with an elevation ranging from 3,545 ft to 3,570 ft above sea level. The climate, as defined by the Koppen Geiger Climate Classification Method,[2] is an arid steppe region or semi-arid region. Semi-arid regions generally receive little rain and have low humidity. The monthly averaged temperature, relative humidity and precipitation as observed by three Automated Surface Observation Stations (ASOS) surrounding the proposed Zia II facility (Carlsbad, NM; Hobbs, NM; and Artesia, NM) are shown in Table 5 through Table 7 respectively. The location of these monitoring stations relative to the proposed Zia II facility is shown in Figure 1. The measured data for these three sites for 2013, show similar meteorological conditions at all three locations indicating no significant mesoscale variation in this region. The maximum average temperatures for this region are typically in the mid 80's °F, occurring in the summer months, well correlated with the Southwest monsoon season which typically starts in late May/Early June and lasts through September. The summer monsoon provides the majority of the annual precipitation for this region, typically ~ 10 in/year. The maximum summer temperature can be as high as 108 °F and the minimum winter temperature in the region can be as low as low as 14 °F. The wind roses for the three ASOS stations at Carlsbad, NM; Hobbs, NM and Artesia, NM, from January 1, 2013 through December 31, 2013 are included in Figure 2 through Figure 4 respectively. Additionally, a wind rose for the AERMOD ready NMED Empire Abo data set of 1993 – 1994, which is used in the dispersion modeling of this facility is shown in Figure 5 for comparison. It can be seen that the wind rose for the NMED Empire Abo data set is representative of the prevailing wind directions measured at the three other sites (main wind vector from the south east), however the magnitude of the prevailing wind speed of the Empire Abo data set (16 ms^{-1}) is less than that measured at the three ASOS sites (~ 25 ms^{-1}).

[2] Source: http://koeppen-geiger.vu-wien.ac.at/usa.htm

Table 5. Ambient Meteorological Conditions Measured at Carlsbad, NM for January 1, 2013 through December 31, 2013[3].

	Temperature (F)			Relative Humidity (%)	Total Precipitation (in)
Month	Maximum	Average	Minimum		
January	78.8	40.3	17.1	58.6	0.80
February	75.2	48.5	21.9	33.3	0.24
March	89.6	57.8	26.1	25.7	0.00
April	97.0	64.3	30.9	26.6	0.04
May	100.9	74.0	33.1	26.4	0.27
June	108.0	83.5	62.6	38.3	1.49
July	100.9	78.2	59.0	57.0	12.45
August	100.0	82.6	64.0	42.0	0.00
September	99.0	74.2	48.0	57.6	4.74
October	91.9	62.2	33.1	47.0	0.58
November	80.1	45.2	21.0	65.2	1.25
December	75.9	39.8	19.0	66.4	1.54

Table 6. Ambient Meteorological Conditions Measured at Hobbs, NM for January 1, 2013 through December 31, 2013[4].

	Temperature (F)			Relative Humidity (%)	Total Precipitation (in)
Month	Maximum	Average	Minimum		
January	73.4	38.8	17.6	61.1	2.49
February	73.4	42.9	23.0	46.0	0.67
March	86	51.9	23.0	37.1	0.05
April	93.2	57.9	28.4	37.4	0.00
May	98.6	68.1	28.4	36.5	0.30
June	104	78.4	57.2	48.1	1.78
July	96.8	75.6	57.2	57.5	3.67
August	98.6	77.2	62.6	50.7	0.04
September	95	71.2	44.6	54.3	0.08
October	91.4	58.6	32.0	54.6	0.03
November	77	45.3	24.8	64.4	1.73
December	73.4	37.0	14.0	65.7	0.38

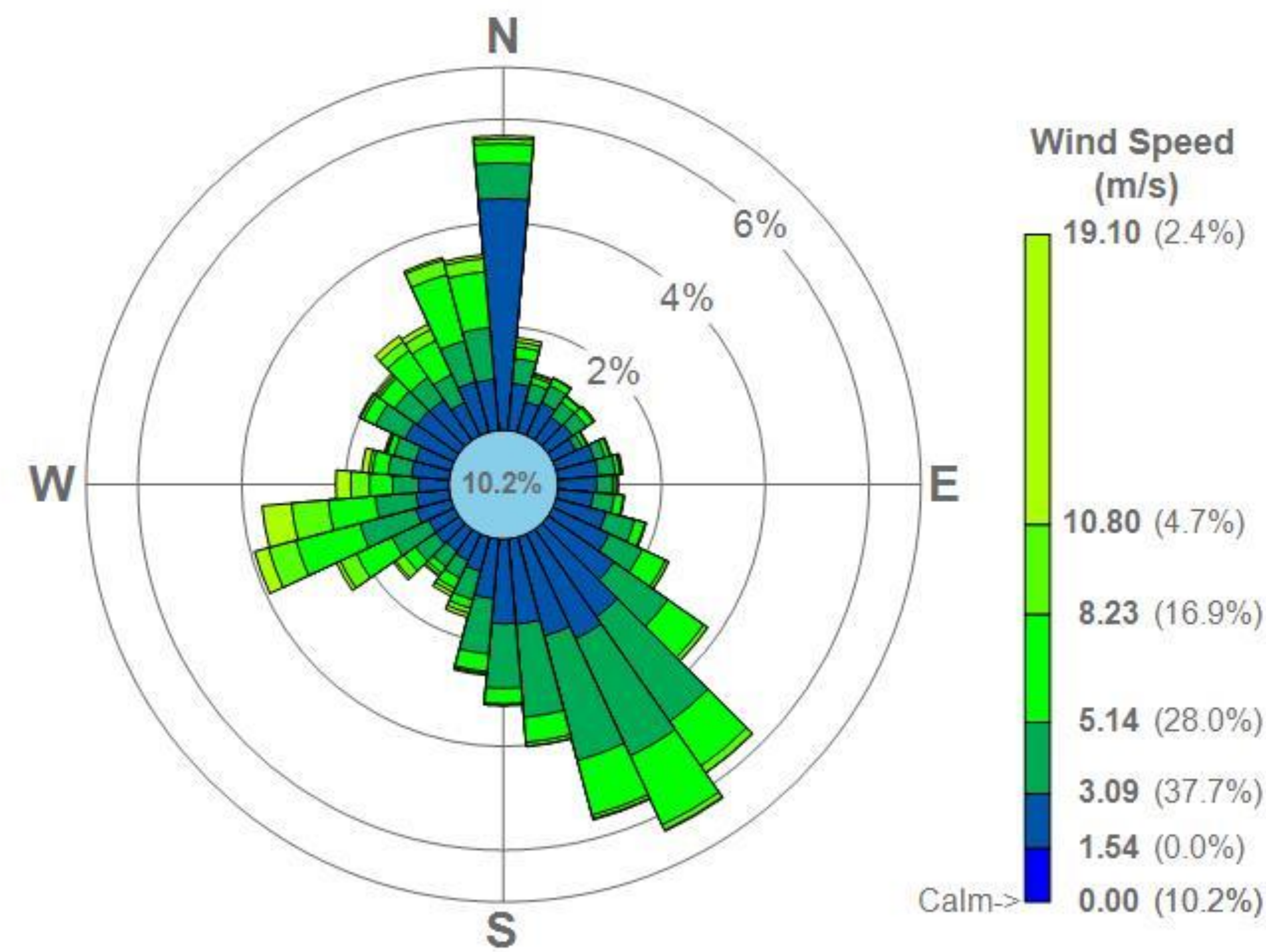
[3] Source: http://mesonet.agron.iastate.edu/request/download.phtml?network=NM_ASOS
[4] Source: http://mesonet.agron.iastate.edu/request/download.phtml?network=NM_ASOS

Table 7. Ambient Meteorological Conditions Measured at Artesia, NM for January 1, 2013 through December 31, 2013[5].

	Temperature (F)			Relative Humidity (%)	Total Precipitation (in)
Month	Maximum	Average	Minimum		
January	73.4	39.5	15.8	53.4	0.69
February	73.4	45.3	21.2	33.2	0.00
March	87.8	54.7	24.8	27.2	0.03
April	93.2	61.6	30.2	26.8	0.00
May	98.6	71.4	32.0	26.9	0.48
June	104.0	82.5	59.0	37.4	0.22
July	98.6	77.9	59.0	55.5	6.06
August	98.6	81.2	62.6	42.2	0.00
September	96.8	72.5	46.4	57.8	6.71
October	89.6	59.7	30.2	45.3	0.00
November	75.2	46.8	21.2	61.0	0.75
December	75.2	38.7	15.8	70.6	0.02

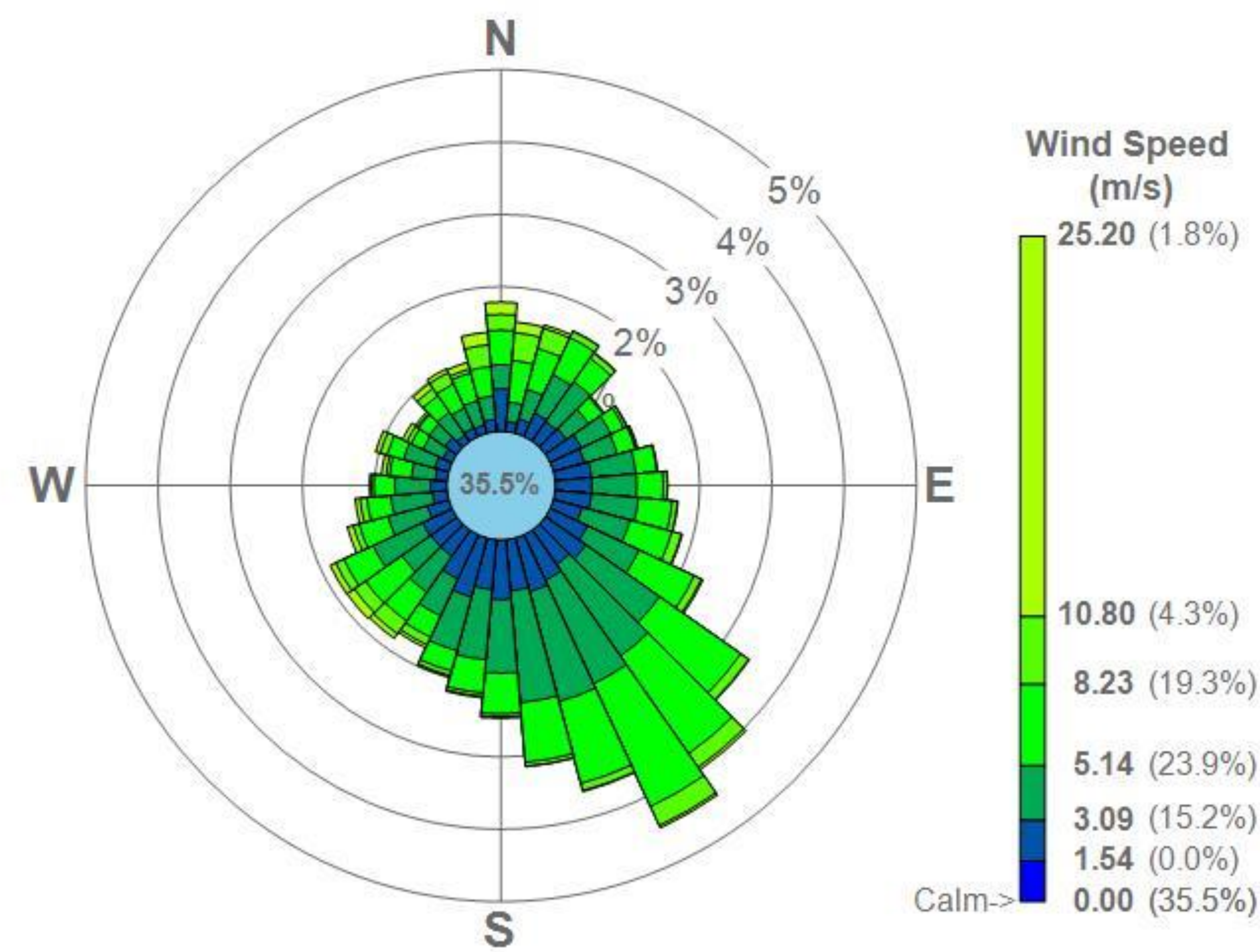
[5] Source: http://mesonet.agron.iastate.edu/request/download.phtml?network=NM_ASOS

Figure 2. Wind Rose for Carlsbad, NM based on data collected from January 1, 2013 through December 31, 2013[6].



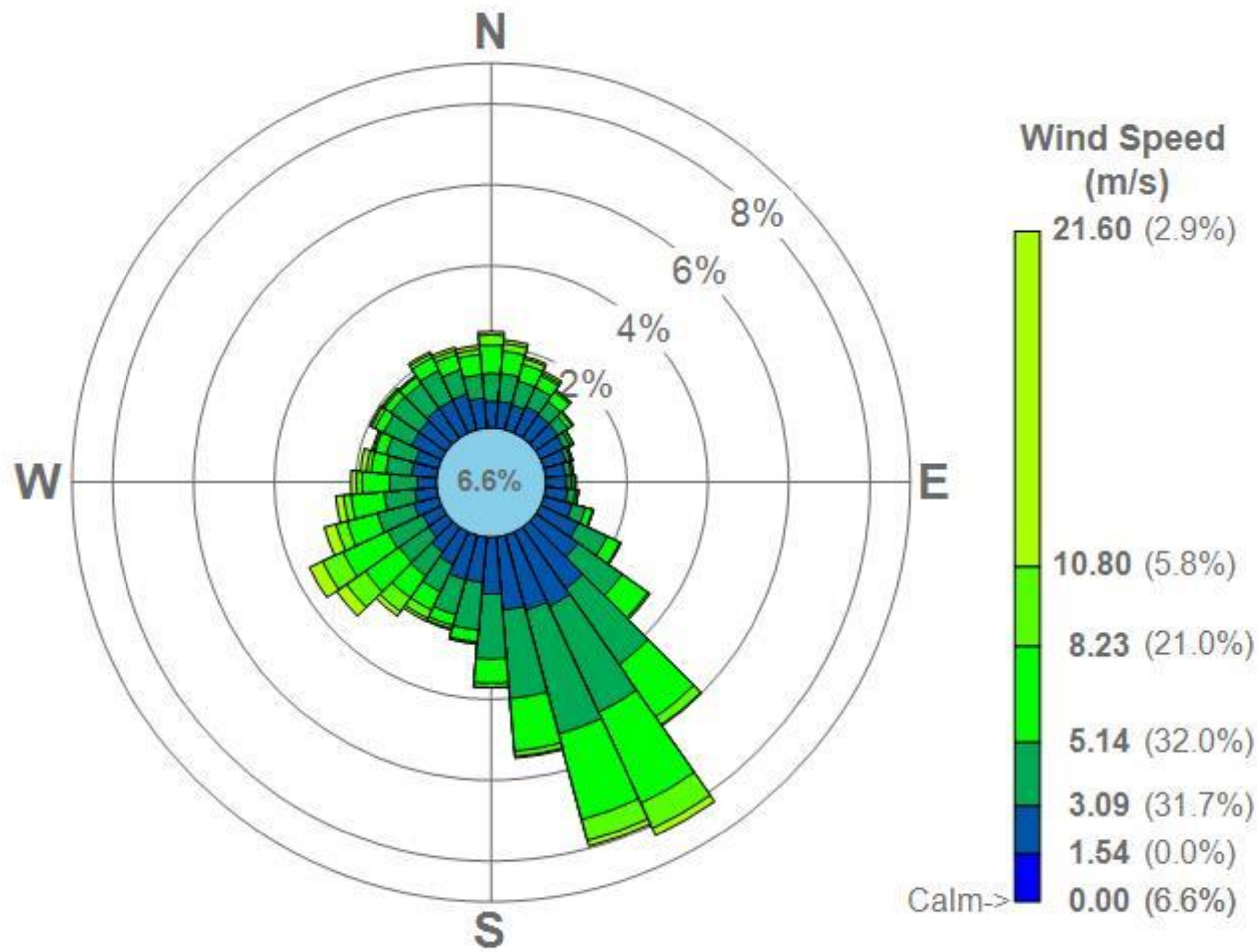
[6] Source: http://mesonet.agron.iastate.edu/request/download.phtml?network=NM_ASOS

Figure 3. Wind Rose for Hobbs, NM based on data collected from January 1, 2013 through December 31, 2013[7].



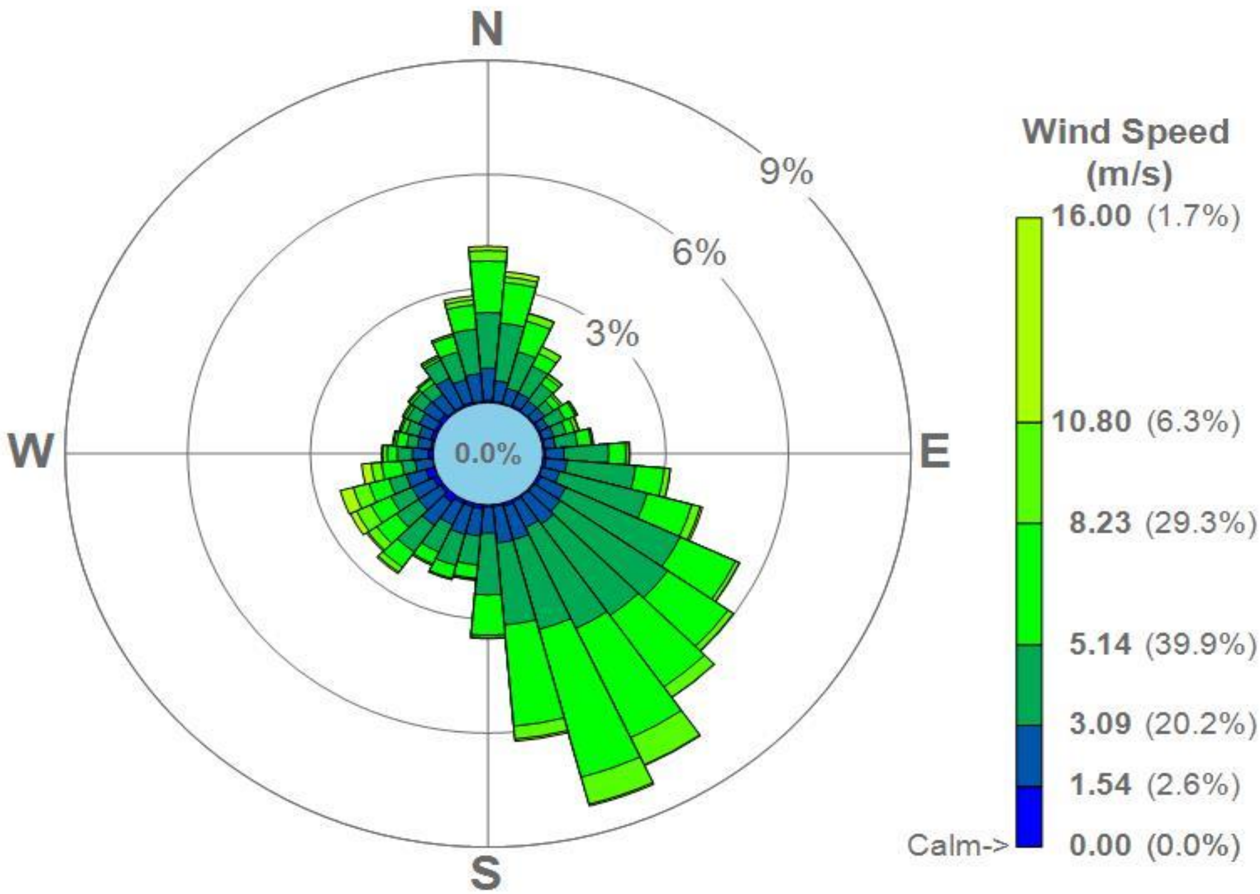
[7] Source: http://mesonet.agron.iastate.edu/request/download.phtml?network=NM_ASOS

Figure 4. Wind Rose for Artesia, NM based on data collected from January 1, 2013 through December 31, 2013[8].



[8] Source: http://mesonet.agron.iastate.edu/request/download.phtml?network=NM_ASOS

Figure 5. Wind Rose for NMED Empire Abo Model Ready Data Set, located at Artesia, NM.



The proposed facility is within the Environmental Protection Agency (EPA) ecoregion, Chihuahuan Desert Grasslands. Chihuahuan Desert Grasslands are found in areas of fine-textured soils, such as silts and clays, which have a higher water retention capacity than coarse-textured, rocky soil. These grasslands are present in areas of somewhat higher annual precipitation (10–15 inches) than the Chihuahuan Basins and Playas ecoregion, such as elevated basins between mountain ranges, low mountain benches and plateau tops, and north-facing mountain slopes. In grassland areas with lower rainfall, areal coverage of grasses may be sparse, 10% or less. Some areas are now mostly shrubs as grasslands continue to decline due to erosion, drought, and climatic change. Typical grasses are black grama (Bouteloua eriopoda), blue grama (B. gracilis), sideoats grama (B. curtipendula), dropseeds (Sporobolus spp.), bush muhly (Muhlenbergia porteri), and tobosagrass (Pleuraphis mutica), with scattered creosotebush (Larrea tridentata), prickly pear (Opuntia sp.), and cholla cacti (Cylindropuntia sp.)[9]. The proposed site is primarily Maljamar and palomas fine sands, 0 to 3% slopes (75%), with some pyote and Maljamar fine sands (approx. 25%).

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[9] Griffith, G.E., J.M. Omernik, M.M. McGraw, G.Z. Jacobi, C.M. Canavan, T.S. Schrader, D. Mercer, R. Hill, and B.C. Moran. 2006. Ecoregions of New Mexico (2 sided color poster with map, descriptive text, summary tables, and photographs). U.S. Geological Survey, Reston, VA.

4. DEMOGRAPHICS

The facility is located in Lea County, New Mexico but is also less than half a mile from Eddy County, New Mexico. Information provided by the United States Census Bureau shows more than half of the population in Lea County is centered around Hobbs, NM and about seventy percent of the population in Eddy County is accounted for in the cities of Artesia, NM and Carlsbad, NM. Table 8 shows the estimated population provided by the United States Census Bureau for each county and city mentioned above. The ambient impacts captured by the 5ZR Carlsbad monitor (AQS Site ID: 35-015-1005), Artesia monitor (AQS Site ID: 35-015-1004) and 5ZS Hobbs Jefferson monitor (AQS Site ID: 35-025-0008) provide representative background concentrations for NO_x, SO_2, PM_{10}, $PM_{2.5}$, and Ozone that meet the criteria found within the Ambient Monitoring Guidelines.

Table 8. Demographic Census

Monitor Name	Distance to Zia II Gas Plant (km)	Nearest Town	Population*	County	Population of County*
5ZS Hobbs Jefferson	64.8	Hobbs	34,122	Lea County	64,727
Artesia	60.9	Artesia	11,301	Eddy County	53,829
5ZR Carlsbad	51.8	Carlsbad	26,138		

* Information is based on a 2010 census by the United States Census Bureau

Based on preliminary modeling runs, NO_x, $PM_{2.5}$[10] and Ozone (Based on NOx and VOC Emissions) impacts are expected to exceed the respective Significant Monitoring Concentrations (SMC) (Refer to Table 1). DCP used the following background stations 5ZR Carlsbad monitor (AQS Site ID: 35-015-1005), Artesia (AQS Site ID: 35-015-1004) and 5ZS Hobbs Jefferson (AQS Site ID: 35-025-0008) listed in Table 1 for the initial application and proposes to use updated values for these same locations as part of this analysis in lieu of collecting site-specific ambient data for NO_x, $PM_{2.5}$, and Ozone.

Figure 1 is the map of the proposed facility and surrounding sources up to 100 km. The three monitoring sites are shown with corresponding observed wind speed and direction for Carlsbad, NM, Hobbs, NM, and Artesia, NM. Also, both 50 km and 100 km radials from the facility are shown for scale. As seen in Figure 1, a majority of the surrounding sources are located within the area enclosed by the three monitoring stations. Most of the surrounding sources are; oil and gas operations; and potash mining and processing. Additionally, the facility is centrally located between all three monitoring sites. Lusk Booster Station, also owned by DCP, was a PSD major source for NO_X located half a mile from the proposed Zia II site. With the construction and startup of the Zia II Gas Plant, all of the Lusk Booster equipment is being removed, with the exception of the flare, (Unit FL3) which is being included into the Zia II facility. Current calculations of the Zia II gas plant show NO_X and CO emissions to be less than the NO_X and CO emission emitted at Lusk Booster Station. This means with the construction update of the Zia Gas Plant, NO_X and CO emissions will not be increasing in the region (Table 9).

Table 9. Comparison of Emissions from Permitted Lusk Booster Station to Proposed Zia II Gas Plant

Pollutant	Lusk Booster Station Allowable Emissions[1] (tpy)	Lusk Booster Station Flare Emissions (tpy)	Zia II GP Proposed Emissions (tpy)	Net Change (tpy)
Nitrogen oxides	583.4	0.7	326.9	-255.8
Carbon monoxide	229.5	3.7	86.9	-138.9
VOC	61.1	0.054	125	64.0
SO_X	10.6	-	32.2	21.6
TSP	6.4	-	19.8	13.4
PM_{10}	6.4	-	19.7	13.3
$PM_{2.5}$	6.4	-	19.7	13.3

[1] NSR Permit No. 0355M5

If the maximum modeled impacts for a PSD triggering pollutant are greater than the Significant Impact Levels (SILs) in the Significance Analysis, a NAAQS analysis is required for that pollutant. In the NAAQS analysis, modeled impacts from the facility will be combined with background concentrations, which represent the air quality concentrations due to sources that are not explicitly modeled (e.g., mobile sources, small but local stationary sources, non-regulated fugitive sources, and large but distant sources). As mentioned, the selection of existing monitoring station data that is representative of the ambient air quality in the area surrounding the proposed facility is determined based on the following three criteria: 1) monitor location (Figure 1 and Table 10), 2) data

[10] Per NMED Memorandum issued April 25, 2013 for Applicants of Prevention of Significant Deterioration (PSD) Permits, "…Air Quality Bureau (AQB) will follow EPA's advice that "permitting authorities . . . consider [the $PM_{2.5}$ SMC provision] to be unlawful" and should "not be applied to individual PSD permits even if they remain in state law or states' approved SIPs." Therefore modeling against the SMC for $PM_{2.5}$ is not a viable option for this application.

quality (Table 2), and 3) data currentness (Table 2). Key considerations based on the monitor location criteria include proximity to the significant impact area of the facility and similarity (Table 10) of emission sources impacting the monitor to the emission sources impacting the air shed surrounding the facility (Refer to Figure 1).

Table 10. Zia II GP Modeled Significant Impact Levels and Radii of Impact, with Calculated Distances to Ambient Monitors

Pollutant	Period	Significance, µg/m³	Calculated[2] µg/m3	Radius of Impact[1] (km)	Distance from ROI to:		
			Max Impact		Carlsbad Monitor (km)	Artesia Monitor (km)	Hobbs Monitor (km)
NO_2	24-hr	5.0	22.17	1.2	59.9	62.9	51.0
$PM_{2.5}$	24-hr	1.2	3.28	1.0	60.1	63.1	51.1
PM_{10}	24-hr	5.0	5.44	0.2	60.9	63.9	51.9
Ozone	8-hr	a	b	b	b	b	b

Notes

[1] Radius of impact is defined as the greatest distance from the center of the facility to the most distant receptor where concentrations are greater than the significance levels. The facility center is located at 611,720 UTME, 3,612,340 UTMN.

[2] 40% ARM factor applied to modeled 24-hr NOx

[a] No de minimis air quality level is provided for ozone. However, any net increase of 100 tons per year or more of volatile organic compounds or nitrogen oxides subject to PSD would be required to perform an ambient impact analysis, including the gathering of ambient air quality data.

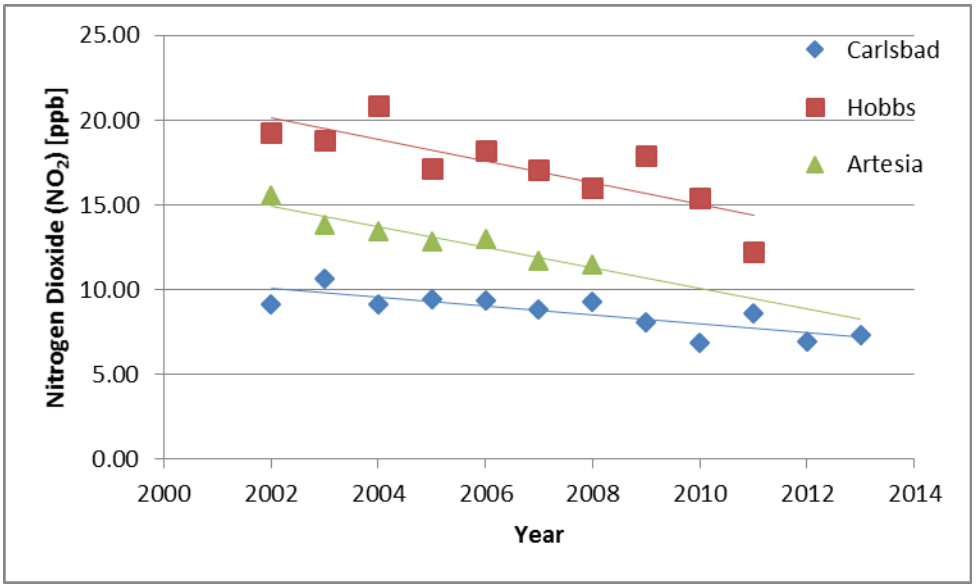
[b] A full ozone screening analysis will be conducted for this project, but as per the NMEDs instruction on June 14, 2013 (conversation between Dr. Sufi Mustafa, NMED and Mr. Adam Erenstein, Trinity Consultants) this analysis will be submitted with the dispersion modeling report.

The SLAMS monitors at Artesia, NM, Carlsbad, NM, and Hobbs, NM have a historical data set going back several years and the monitors are still currently operational, these monitors measure ozone, NO, NO_2, NO_X and particulates. The SLAMS monitor in Artesia measures SO_2. A decreasing trend was observed for NO_2, and NO_X (Figure 6 and Figure 7), over an eleven year period from 2002 to 2013 as observed at all three SLAMS stations. Figure 8 and Figure 9 show monitoring location specific time series data from 2002 through 2013 for ambient 1-hour and 8-hour ozone concentrations. The measured concentrations for the Carlsbad monitoring station show near constant ozone concentrations over the period from 2002 through 2013. The concentration time series for the Hobbs monitor shows a shallow decreasing trend over the 11 years of data since 2002. A full ozone screening analysis will be conducted for this project, but as per the NMEDs instruction this analysis will be submitted with the air dispersion modeling report. The screening analysis will consider NO_X as a precursor pollutant and the background concentration measured at Carlsbad and Hobbs monitoring stations in estimating the total ozone concentration.

The measured concentrations of $PM_{2.5}$ (Figure 10) at the Carlsbad monitor shows a constant concentration and then a decrease followed by an increase. The measured concentration of $PM_{2.5}$ at the Hobbs monitor shows an increase in the concentration followed by a decrease.

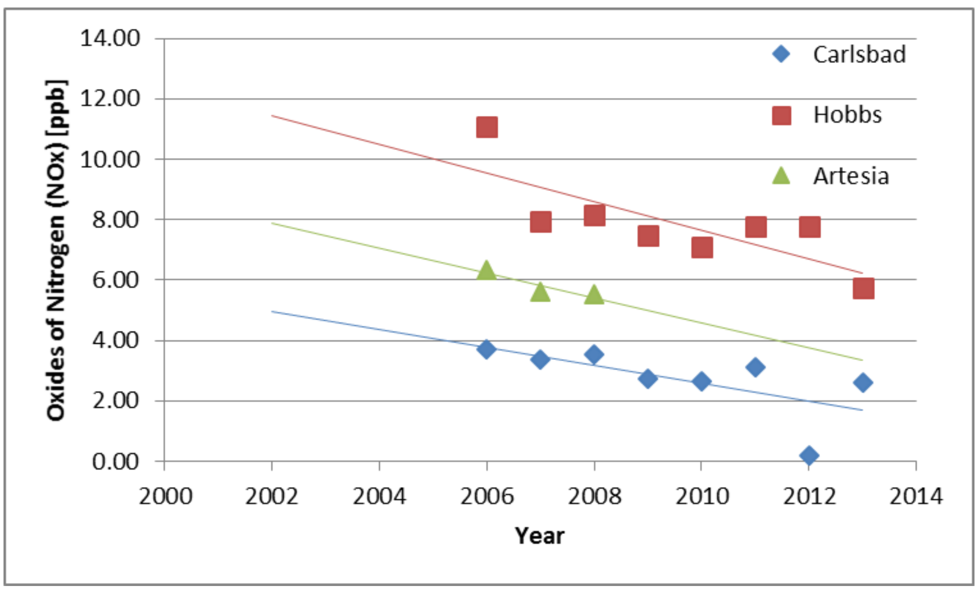
Based on the time series analysis it is concluded that the active surrounding ambient monitors are representative of the pollutant concentrations within the region that the facility will be located. Subsequently it is therefore satisfactory to use these data as the basis for ambient monitoring for the Zia II application.

Figure 6. Time Series Analysis of the 1-hr NO_2 Ambient Monitoring Measurements



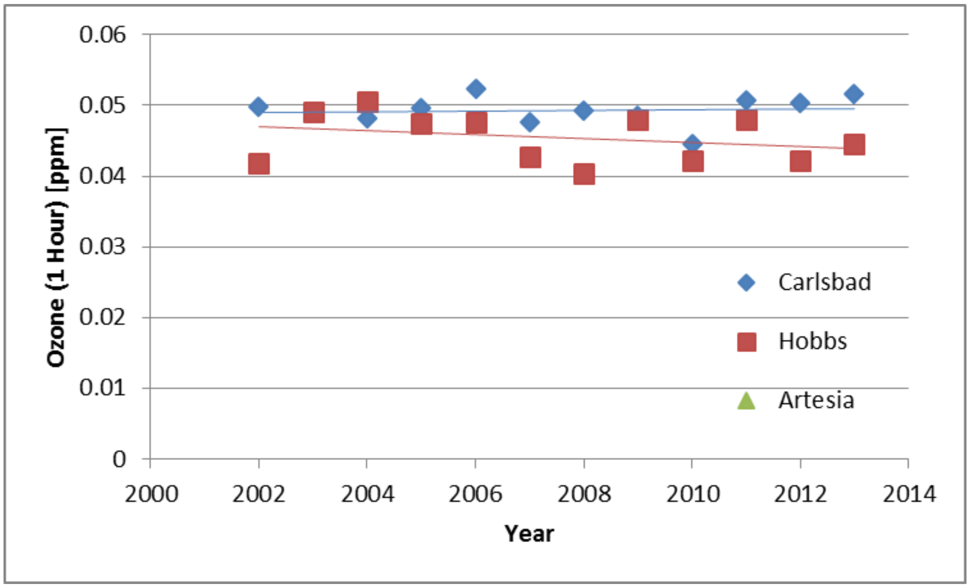
Data available from *http://www.epa.gov/airquality/airdata/ad_maps.html*. Analysis was conducted using the annual average concentration for specific pollutant and period.

Figure 7. Time Series Analysis of the 1-hr NO_X Ambient Monitoring Measurements



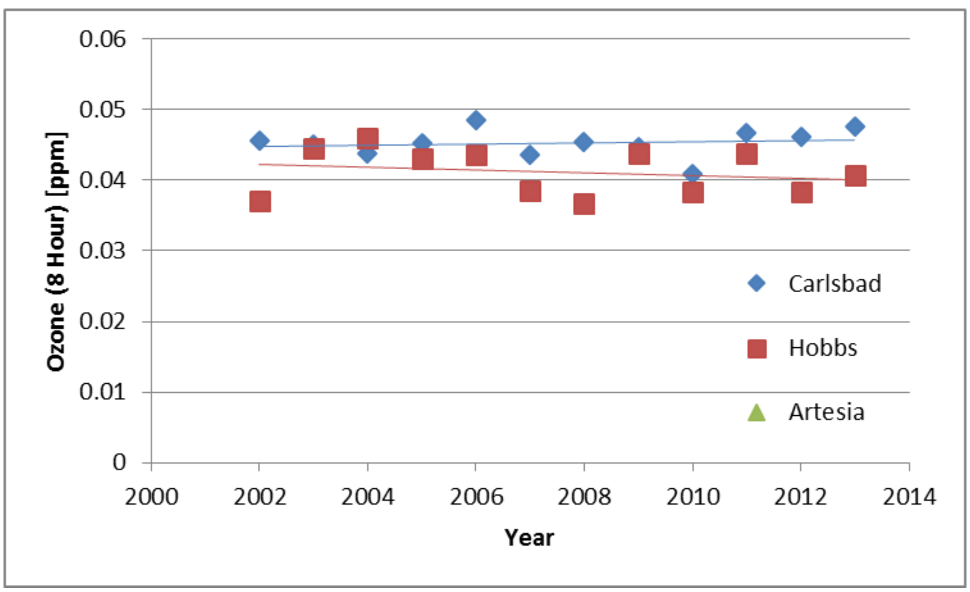
Data available from *http://www.epa.gov/airquality/airdata/ad_maps.html*. Analysis was conducted using the annual average concentration for specific pollutant and period.

Figure 8. Time Series Analysis of the 1-hr Ozone Ambient Monitoring Measurements



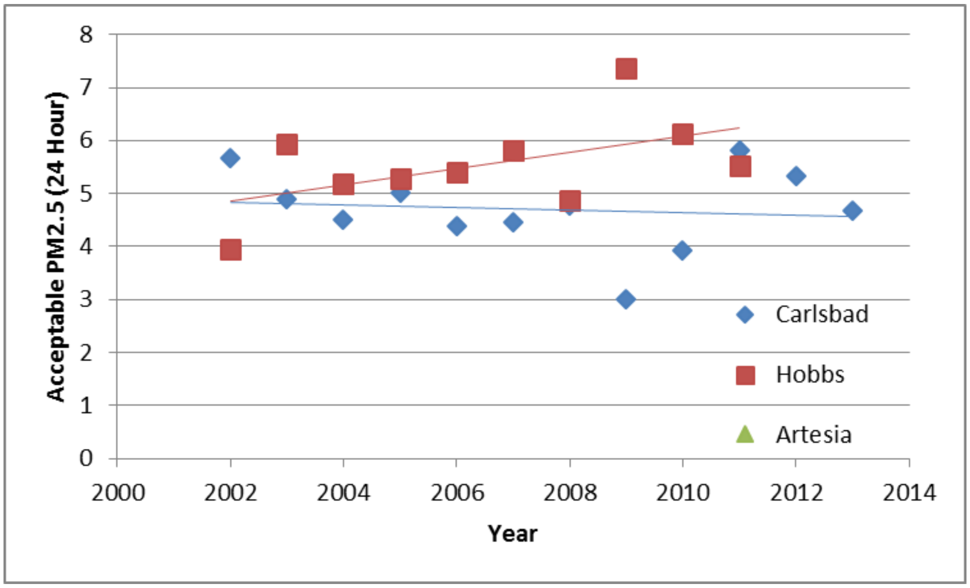
Data available from *http://www.epa.gov/airquality/airdata/ad_maps.html*. Analysis was conducted using the annual average concentration for specific pollutant and period.

Figure 9. Time Series Analysis of the 8-hr Ozone Ambient Monitoring Measurements



Data available from *http://www.epa.gov/airquality/airdata/ad_maps.html*. Analysis was conducted using the annual average concentration for specific pollutant and period.

Figure 10. Time Series Analysis of the 24-hr $PM_{2.5}$ Ambient Monitoring Measurements



Data available from *http://www.epa.gov/airquality/airdata/ad_maps.html*. Analysis was conducted using the annual average concentration for specific pollutant and period.

The ambient background data from the 5ZR Carlsbad monitor (AQS Site ID: 35-015-1005), Artesia (AQS Site ID: 35-015-1004) and 5ZS Hobbs Jefferson (AQS Site ID: 35-025-0008), listed in Table 1, are representative data as required by regulation 20.2.74.306.A NMAC. The selection of existing monitoring station data that are representative of the ambient air quality in the area surrounding the proposed facility was determined based on the following three criteria: 1) monitor location (Figure 1 and Table 10), 2) data quality (Table 2), and 3) data currentness (Table 2).

- The monitors are located in the same terrain, climate, and physiographic province as the facility. The climate is semi-arid and the terrain is relatively flat. The facility is centrally located between all three monitors with the majority of surrounding sources located in or around the monitoring sites. Most sites surrounding the facility and monitors are from oil and gas operations and potash mining and processing.
- The monitors depict the ambient air quality concentrations around the facility. The monitors are located around the majority of the population of each county and a majority of the surrounding sources are located around the monitors. The monitors are approved EPA certified stations, e.g. State & Local Air Monitoring Stations (SLAMS) or similar monitor type subject to the quality assurance requirements in 40 CFR Part 58 Appendix A.
- The most recent three complete years of quality assured data from the three monitors will be used.

With the available ambient pollutant monitor and meteorological data from the three locations, a representative background concentration for the pollutants above the SER and SMC thresholds were established. When comparing the Hobbs and Carlsbad ambient monitors the PM concentrations were typically higher at the Hobbs monitor. The background concentrations for PM were therefore found using Hobbs data to be conservative. In Table 11 the 24-hour averaging period for PM_{10}, $PM_{2.5}$ and TSP are shown for each month and are found by taking the average of the maximum values from the daily readings. Table 12 shows the annual averages found using the same methodology as the 24-hour averages. Both of these methodologies are consistent with NMED modeling guidance[11]. The maximum concentration for each pollutant shown in these tables will be used as the background concentrations for the future Cumulative Impact Analysis (CIA) modeling of this facility if applicable.

[11] New Mexico Air Quality Bureau Air Dispersion Modeling Guidelines, Revised February 18, 2014, Section 4.4 Background Concentrations.

Table 11. 24-hour PM background concentrations.

Month	PM_{10}[1] 24 Hour Average ($\mu g/m^3$)	$PM_{2.5}$[1] 24 Hour Average ($\mu g/m^3$)	TSP[1] 24 Hour Average ($\mu g/m^3$)
January	35.7	9.4	35.7
February	44.3	14.1	44.3
March	37.0	20.6	37.0
April	55.3	20.0	55.3
May	27.3	21.5	27.3
June	34.0	17.7	34.0
July	20.3	14.8	20.3
August	25.7	14.1	25.7
September	20.7	11.3	20.7
October	26.3	11.5	26.3
November	28.0	10.3	28.0
December	17.3	11.7	17.3
Average	**31.0**	**14.7**	**31.0**
Max	**55.3**	**21.5**	**55.3**

[1] PM2.5, PM10, and TSP Hobbs data available 2011-2013: http://www.epa.gov/airquality/airdata/ad_maps.html

Table 12. Annual PM background concentrations.

	PM_{10} Annual Average ($\mu g/m^3$)[b]	$PM_{2.5}$ Annual Average ($\mu g/m^3$)[a]	TSP Annual Average ($\mu g/m^3$)
2011	24.3	9.9	24.3
2012	15.7	7.9	15.7
2013	16.6	7.9	16.6
Average	**18.9**	**8.6**	**18.9**
Max	**24.3**	**9.9**	**24.3**

[a] Based on Annual Arithmetic Mean to be consistant with NMED Modeling Guidance Table 6c (annual average) for Averaging period)

[b] Not used for any modeling analysis, but shown for completition and calculation of TSP background

The only available NO_x data was from the Artesia monitor. The same methodology utilized above and described in the NMED modeling guidance[12] was used to find the NO_x 1-hour average concentration and the annual average concentration seen in Table 13 and Table 14 respectively. However, the NO_x concentrations will not be

[12] New Mexico Air Quality Bureau Air Dispersion Modeling Guidelines, Revised February 18, 2014, Section 4.4 Background Concentrations.

used in the CIA modeling of the facility as MergeMaster surrounding sources will be used to represent the background concentration of NO_x.

Table 13. 1-hr NO_x background concentrations.

Month	NOx[1] 1 hour Average (µg/m3)
January	41.0
February	28.1
March	27.3
April	17.0
May	15.4
June	13.1
July	13.9
August	13.2
September	16.1
October	20.9
November	27.7
December	35.8
Average	**41.0**
Max	**28.1**

[1] NO_x Artesia data available from July 2006 to April 2009: http://www.epa.gov/airquality/airdata/ad_maps.html

Table 14. Annual NO_x background concentrations.

	NOx Annual Average (µg/m3)
2006	11.9
2007	10.6
2008	10.4
2009	11.7
Average	**11.1**
Max	**11.9**

Based on the analysis of this report, DCP asserts the requirements of the Ambient Monitoring Guidelines for PSD (5/87) and 20.2.74.306.C.2 NMAC are being met. The existing ambient monitoring program operated by NMED is sufficient to meet the needs of any pre-construction monitoring requirements and thus may be used in lieu of such pre-construction monitoring requirements.

Section 12.σ – Additional Impact Analysis Waiver

- Attached is an email correspondence with David Heath of the NMED in which the additional impacts analysis is waived as previous impacts showed compliance at increased emission rates.

Victoria Collis

From:	Adam Erenstein
Sent:	Thursday, March 05, 2015 3:04 PM
To:	Heath, David, NMENV; Mustafa, Sufi A., NMENV
Cc:	JCorser@dcpmidstream.com
Subject:	RE: DCP Midstream's Zia II Gas Plant-Modeling Waiver and Additional Impacts Analysis

Dave,
That sounds great. We appreciate you waiving the additional impacts analysis for the Zia II Gas Plant. Thanks.

Regards,

Adam

Adam Erenstein
Managing Consultant

Trinity Consultants
9400 Holly Blvd NE, Building 3, Suite 300 | Albuquerque, NM 87122

Office: **505-266-6611** | Mobile: 480-760-3860 | Fax: 505-266-7738
Email: aerenstein@trinityconsultants.com

From: Heath, David, NMENV [mailto:david.heath@state.nm.us]
Sent: Thursday, March 05, 2015 2:01 PM
To: Adam Erenstein; Mustafa, Sufi A., NMENV
Cc: JCorser@dcpmidstream.com
Subject: RE: DCP Midstream's Zia II Gas Plant-Modeling Waiver and Additional Impacts Analysis

Adam,

I will also waive the recalculation of addition PSD impacts from the Zia II Gas Plant as previous impacts showed compliance at increased emission rates.

Dave

David Heath
Modeling Scientist

NMED / AQB

From: Adam Erenstein [mailto:AErenstein@trinityconsultants.com]
Sent: Wednesday, March 04, 2015 10:11 AM
To: Heath, David, NMENV; Mustafa, Sufi A., NMENV
Cc: JCorser@dcpmidstream.com
Subject: RE: DCP Midstream's Zia II Gas Plant-Modeling Waiver and Additional Impacts Analysis

Hi Dave,
Thanks again for the approval of the modeling waiver. I wanted to see if we would be able to receive a waiver for the additional impacts analysis for this application for the Zia II gas Plant? Since facility wide pollutant emission rates are decreasing with these modifications we believe that the additional impacts analysis would not change greatly and would definitely not increase impacts. Please let me know if this would be possible and if you would require any additional information. Thank you for your consideration. Please contact me if you have any questions.

Regards,

Adam

……………………………………………………………………………………………………

Adam Erenstein
Managing Consultant

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Office: **505-266-6611** | Mobile: 480-760-3860 | Fax: 505-266-7738
Email: aerenstein@trinityconsultants.com

From: Heath, David, NMENV [mailto:david.heath@state.nm.us]
Sent: Tuesday, March 03, 2015 2:54 PM
To: Mustafa, Sufi A., NMENV; Adam Erenstein
Subject: RE: DCP Midstream's Zia II Gas Plant- Modeling waiver

Adam,

I have approved this modeling waiver for the Zia II Gas Plant with the corrections noted in the first paragraph on the waiver form.

Dave

David Heath

Modeling Scientist
NMED / AQB

From: Mustafa, Sufi A., NMENV
Sent: Friday, February 20, 2015 3:43 PM
To: Heath, David, NMENV
Subject: FW: DCP Midstream's Zia II Gas Plant- Modeling waiver

Dave Please review this modeling waiver request.
Thank you.

Sufi A. Mustafa, Ph.D.
Manager Air Dispersion Modeling and Emission Inventory Section
New Mexico Environment Department's Air Quality Bureau
Phone: 505 476 4318
525 Camino de los Marquez
Suite 1
Santa Fe, New Mexico, 87505

From: Adam Erenstein [mailto:AErenstein@trinityconsultants.com]
Sent: Thursday, February 19, 2015 3:40 PM
To: Mustafa, Sufi A., NMENV
Cc: Victoria Collis; JCorser@dcpmidstream.com
Subject: DCP Midstream's Zia II Gas Plant- Modeling waiver

Sufi,
Attached to this e-mail is the modeling waiver for DCP Midstream's Zia II Gas Plant. The Zia II Gas Plant was modeled as part of the August 2013 initial permit application. We believe this modeling is still representative of the worst-case modeling scenario at Zia II. Although several new emission sources are being accounted for in this application, the emissions are very low and new NOX, CO, SO2, and particulate emissions are offset by reductions from other sources. Please contact me if you have any questions regarding this modeling waiver.

Regards,

Adam

…………………………………………………………………………………………………

Adam Erenstein
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Section 13

Discussion Demonstrating Compliance With Each Applicable State & Federal Regulation

Provide a discussion demonstrating compliance with applicable state & federal regulation. If there is a state or federal regulation (other than those listed here) for your facility's source category that does not apply to your facility, but seems on the surface that it should apply, add the regulation to the appropriate table below and provide the analysis. Examples of regulatory requirements that may or may not apply to your facility include 40 CFR 60 Subpart OOO (crushers), 40 CFR 63 Subpart HHH (HAPs), or 20.2.74 NMAC (PSD major sources). We don't want a discussion of every non-applicable regulation, but if there is questionable applicability, explain why it does not apply. All input cells should be filled in, even if the response is 'No' or 'N/A'.

In the "Justification" column, identify the criteria that are critical to the applicability determination, numbering each. For each unit listed in the "Applies to Unit No(s)" column, after each listed unit, include the number(s) of the criteria that made the regulation applicable. For example, TK-1 & TK-2 would be listed as: TK-1 (1, 3, 4), TK-2 (1, 2, 4). Doing so will provide the applicability criteria for each unit, while also minimizing the length of these tables.

As this table will become part of the SOB, please do not change the any formatting in the table, especially the width of the table.

If this application includes any proposed exemptions from otherwise applicable requirements, provide a narrative explanation of these proposed exemptions. These exemptions are from specific applicable requirements, which are spelled out in the requirements themselves, not exemptions from 20.2.70 NMAC or 20.2.72 NMAC.

Table for Applicable 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 m^3, 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.

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)
20.2.37 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 Facil.	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. The facility has not been constructed or started operation. Once the facility starts operating, DCP will submit the initial Title V application within 12 months 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.
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.
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.

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)
20.2.78 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 CFR60.40a, 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	Standards of Performance for **Industrial-commercial-institutional 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.

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 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.
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 IIII	Standards for 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.

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
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 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.
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.
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.

FEDERAL REGU-LATIONS CITATION	Title	Applies to Entire Facility	Applies to Unit No(s).	Federally Enforce-able	Does Not Apply	JUSTIFICATION:
MACT 40 CFR 63.760 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 requirements of MACT HH per 63.764(e)(1)(ii). 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 ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines	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).

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 DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and 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 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 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.
NESHAP 40 CFR 64	**Compliance Assurance Monitoring**	N/A	C1-E to C8-E, Dehy, L-1, Amine	N/A	N/A	This regulation defines compliance assurance monitoring. Emission from the amine unit, dehydrator (Unit Dehy), engines (Units C1 to C8), 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 tanks, dehydrator, and loading is the vapor combustion device (Unit VCD1). The engines are controlled by catalysts.
NESHAP 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 not

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						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.

This facility operates on a continuous basis with no alternative operating scenarios.

Section 16

Air Dispersion Modeling

NSR (20.2.72 NMAC) and PSD (20.2.74 NMAC) Modeling: Provide an air quality **dispersion modeling** demonstration (if applicable) as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines. If air dispersion modeling has been waived for this permit application, attach the AQB Modeling Section modeling waiver documentation.

SSM Modeling: Applicants must conduct dispersion modeling for the total short term emissions 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.nmenv.state.nm.us/aqb/permit/app_form.html) for more detailed instructions on SSM emissions modeling requirements.

Title V (20.2.70 NMAC) Modeling: Title V applications must specify the NSR Permit number for which air quality dispersion modeling was last submitted. Additionally, Title V facilities reporting new SSM emissions require modeling or a modeling waiver to demonstrate compliance with standards.

A modeling waiver was submitted to the NMED and approved on March 3, 2015. The approved modeling waiver is attached.

Victoria Collis

From: Heath, David, NMENV <david.heath@state.nm.us>
Sent: Tuesday, March 03, 2015 2:54 PM
To: Mustafa, Sufi A., NMENV; Adam Erenstein
Subject: RE: DCP Midstream's Zia II Gas Plant- Modeling waiver
Attachments: PSD-5217_Modeling Waiver_Zia II GP_2Mar2014.docx

Adam,

I have approved this modeling waiver for the Zia II Gas Plant with the corrections noted in the first paragraph on the waiver form.

Dave

David Heath
Modeling Scientist
NMED / AQB

From: Mustafa, Sufi A., NMENV
Sent: Friday, February 20, 2015 3:43 PM
To: Heath, David, NMENV
Subject: FW: DCP Midstream's Zia II Gas Plant- Modeling waiver

Dave Please review this modeling waiver request.
Thank you.

Sufi A. Mustafa, Ph.D.
Manager Air Dispersion Modeling and Emission Inventory Section
New Mexico Environment Department's Air Quality Bureau
Phone: 505 476 4318
525 Camino de los Marquez
Suite 1
Santa Fe, New Mexico, 87505

From: Adam Erenstein [mailto:AErenstein@trinityconsultants.com]
Sent: Thursday, February 19, 2015 3:40 PM
To: Mustafa, Sufi A., NMENV
Cc: Victoria Collis; JCorser@dcpmidstream.com
Subject: DCP Midstream's Zia II Gas Plant- Modeling waiver

Sufi,
Attached to this e-mail is the modeling waiver for DCP Midstream's Zia II Gas Plant. The Zia II Gas Plant was modeled as part of the August 2013 initial permit application. We believe this modeling is still representative of the worst-case modeling scenario at Zia II. Although several new emission sources are being accounted for in this application, the emissions are very low and new NOX, CO, SO2, and particulate emissions are offset by reductions from other sources. Please contact me if you have any questions regarding this modeling waiver.

Regards,

Adam

……………………………………………………………………………………………………

Adam Erenstein
Managing Consultant

Trinity Consultants
9400 Holly Blvd NE, Building 3, Suite 300 | Albuquerque, NM 87122

Office: **505-266-6611** | Mobile: 480-760-3860 | Fax: 505-266-7738
Email: aerenstein@trinityconsultants.com

New Mexico Environment Department
Air Quality Bureau
Modeling Section
525 Camino de Los Marquez - Suite 1
Santa Fe, NM 87505

Phone: (505) 476-4300
Fax: (505) 476-4375
www.nmenv.state.nm.us/aqb

For Department use only:

Approved**:** **Ξ Yes** **☐ No**

Date: 3-3-15

Approved by: David Heath

Air Dispersion Modeling Waiver Request Form

This form must be completed and submitted with all air dispersion modeling waiver requests.

If a permit is required, modeling is normally required for all pollutants, including state air toxics. In some cases, the demonstration that ambient air quality standards and PSD increments will not be violated can be satisfied with a discussion of previous modeling. The purpose of this form is to document and streamline requests to limit the new modeling that is submitted with an application. A waiver may be requested by e-mailing the completed form to the modeling manager, sufi.mustafa@state.nm.us. Permitting staff must approve the total emission rates during the permitting process for this waiver to be valid.

Contact and facility information:

Contact name	Adam Erenstein
E-mail Address:	aerenstein@trinityconsultants.com
Phone	(505) 266-6611
Facility Name	DCP Midstream, LP - Zia II Gas Plant
Air Quality Permit Number(s)	PSD-5217
AI Number (if known)	N/A

AQB Response:

I have approved this modeling waiver as all facility wide pollutant emission rates are decreasing with these modifications. The fact that the stack parameter changes will create a substantial decrease in plume buoyancy (thereby increasing ambient impacts) required a quick model run to determine that the impacts would not exceed NAAQS standards. The model results showed a decrease in NO2 impacts and only an increase of 2 to 3 ug/m3 for any of the SO2 impacts so neither would cause an ambient exceedance.

Also noted in this waiver is the discrepancy in the consultant's 1-hr NO2 and H2S impacts (values highlighted in red in this report). Neither exceeds the standards but it is unclear how the consultant's values were arrived at. The original AQB modeling report contains the values reported in red in this report.

%%

DCP Midstream, LP (DCP) is submitting an application for significant revision to PSD Permit PSD-5217 for the Zia II Gas Plant (Zia II). The facility is a new 230 MMscf/day greenfield gas plant in Lea County, New Mexico approximately 25 miles northeast of Carlsbad. The facility is currently under construction and has not yet begun operation. The facility is approximately 72 km from Carlsbad Caverns National Park.

DCP wishes to update the current permit to account for changes in equipment parameters, remove units which will no longer be installed at the site, and to add several sources with low emission rates. These changes are described in Table 1 below. Table 1 also includes a comparison of the proposed emissions to the previously modeled emissions. For NO_X, CO, SO_2, and particulates the proposed emissions are less than the previously modeled emissions.

Table 1. Summary of Proposed Changes									
Unit	Description	Proposed Update	Proposed Emissions Minus Previously Modeled Emission Rates (lb/hr)						
			NO_X	CO	SO_2	TSP	PM_{10}	$PM_{2.5}$	H_2S
C1-E through C8-E	4SLB RICE Caterpillar G3616	• Change stack diameter from 2 ft to 3 ft	**See appendix 3 table 1**						
C11-E through C13-E	4SLB RICE Caterpillar G3608LE	• Remove from the permit – units will be electric driven	-11.7	-3.0	-0.72	-0.51	-0.51	-0.51	
H1	Trim Reboiler Heater 26 MMBtu/hr	• Change stack height from 86 ft to 20 ft • Change exhaust temperature from 600 ˚F to 730 ˚F	No effect on emission rates.						
H2	Stabilizer Heater 7 MMBtu/hr	• Remove from the permit – unit no longer needed in process	-0.69	-0.58	-0.10	-0.052	-0.052	-0.052	
H3	Regeneration Gas Heater 8 MMBtu/hr	• Update capacity from 8 MMBtu/hr to 10 MMBtu/hr • Change exhaust temperature from 600 ˚F to 718 ˚F **and stack height from 40 to 18 ft**	-0.29	0.16	0.024	0.015	0.015	0.015	
H4 & H5	Hot Oil Heater 114 MMBtu/hr	• Update capacity from 114 MMBtu/hr to 99 MMBtu/hr	-1.7	-10.7	-0.35	-0.22	-0.22	-0.22	
HAUL	Unpaved Haul Roads	• Revise road length and add paved control				-0.05	-0.0042	0.007	
WSAC	Cooling Tower	• Add this cooling tower to the permit				0.020	0.0092	0.000043	
FL3	Lusk Flare	• Add pilot and purge emissions from this nearby flare, previously permitted at DCP's Lusk Booster Station, to Zia II.	0.16	0.84	0.012				
SSM (CB)	Compressor Blowdowns to Atmosphere	• Account for emissions from compressor blowdowns to the atmosphere							0.050
GEN-1	Cummins Diesel Generator	• Add 67 hp diesel generator limited to 500 hrs/yr to permit	0.49	0.39	0.20	0.022	0.022	0.022	
		Total Emission Difference	**-13.7**	**-12.9**	**-0.93**	**-0.67**	**-0.68**	**-0.64**	**0.050**

Section 1: Toxic air pollutants
The facility has no toxic air pollutants.

Section 2: Pollutants with very low emission rates
This facility has no pollutants with very low emission rates.

Section 3: Pollutants that have previously been modeled at equal or higher emission rates
The Zia II Gas Plant was modeled as part of the August 2013 initial permit application. We believe this modeling is still representative of the worst-case modeling scenario at Zia II. Although several new emission sources are being accounted for in this application, the emissions are very low and new NO_X, CO, SO_2, and particulate emissions are offset by reductions from other sources.

Table 2 shows that for the gaseous pollutants, the operating scenario which produced the maximum impacts was SSM flaring from Flare 1 or Flare 2. SSM flaring is not changing as part of this application. The updates proposed in this application will not result in the steady-state source group producing greater impacts than the SSM flaring source groups.

Table 2. Summary of Previously Modeled Emissions/Operating Scenarios

Pollutant	Modeled Operating Scenario	Previously modeled emission rate (lb/hr)	Proposed emission rate (lb/hr)	Modeled minus proposed emissions (lb/hr)	High Source Group for Applicable Averaging Periods
NO_X	Steady-State	92.2	75.1	17.1	FL2NAAQS FL1NAAQS
	SSM	796.4	796.4	0	FL1NAAQS
CO	Steady-State	34.9	20.2	14.7	FL1NAAQS
	SSM	4,333.6	4,333.6	0	FL1NAAQS
SO_2	Steady-State	8.5	7.5	1.0	FL1NAAQS FL2NAAQS
	SSM	18,451.0	18,451.0	0	FL2NAAQS FL2NAAQS
TSP	Steady-State	5.7	5.0	0.70	NAAQS NAAQS
PM_{10}	Steady-State	5.4	4.7	0.70	NAAQS NAAQS
$PM_{2.5}$	Steady-State	5.3	4.6	0.70	NAAQS NAAQS
H_2S	Steady-State	0.16	0.16	0	FL2NAAQS
	SSM (Flaring)	200.6	200.6	0	
	SSM (Compressor Blowdown)	-	0.05	-0.05	-

H_2S SSM emissions are increasing from 200.6 lb/hr to 200.7 lb/hr. The previously model showed an H_2S impact of ~~1.5~~ 71% of the NMAAQS during the worst-case operating scenario, ~~SSM flaring from Flare 2 (AGI flare)~~ **Steady-State operations**. The addition of 0.05 lb/hr of H_2S from compressor blowdowns (0.0082 lb/hr/source) is unlikely to cause or contribute to an exceedance of the NMAAQS.
For particulates, 3D analyst output from previous modeling indicates that haul road emissions are the major contributor to the high impacts. Hourly haul road emissions of $PM_{2.5}$ are increasing by 0.007 lb/hr as a result of the road length changing. However, the road length is increasing and is being paved so the lb/hr/source is decreasing greatly. Modeled impacts were 66.3% of the 24-hour NAAQS and 63.6% of the annual NAAQS. Based on the lb/hr/source decrease for haul road emissions and the relatively low percent of the standards, it is unlikely that haul road emissions would cause or contribute to an exceedance of the NAAQS.

Table 3A: List of previously modeled pollutants (facility-wide PTE)

Pollutant	Averaging period	Previously modeled emission rate (lb/hr)	Proposed emission rate (lb/hr)	Modeled minus proposed emissions (lb/hr)	Avg. Period	Modeled % of standard		High Source Group
						NAAQS	NMAAQS	
NO_X (SS)	1 hr, 24 hr, annual	92.2	75.1	17.1	1 hr: 24 hr: Ann:	~~.0026~~ 62% N/A 11.8%	N/A 15.9% 14.0%	FL2NAAQS FL1NAAQS FL1NAAQS
NO_X (SSM)		796.4	796.4	0				
CO (SS)	1 hr, 8 hr	34.9	20.2	14.7	1 hr: 8 hr:	0.1% 0.3%	0.3% 0.3%	FL1NAAQS FL1NAAQS
CO (SSM)		4,333.6	4,333.6	0				
SO_2 (SS)	1 hr, 3 hr, 24 hr, annual	8.5	7.5	1.0	1 hr: 3 hr: 24 hr: Ann:	92.0% 11.0% N/A N/A	N/A N/A 26.5% 20.9%	FL1NAAQS FL2NAAQS FL2NAAQS FL2NAAQS
SO_2 (SSM)		18,451.0	18,451.0	0				
TSP	24-hr, annual	5.7	5.0	0.70	24 hr: Ann:	N/A N/A	66.3% 63.6%	NAAQS NAAQS
PM_{10}	24-hr, annual	5.4	4.7	0.70	24 hr: Ann:	42.6% N/A	N/A N/A	NAAQS NAAQS
$PM_{2.5}$	24-hr, annual	5.3	4.6	0.70	24 hr: Ann:	64.1% 89.7%	N/A N/A	NAAQS NAAQS
H_2S (SS)	1-hr	0.16	0.16	0	1 hr:	N/A	~~1.5~~ 71%	FL2NAAQS
H_2S (SSM)		200.6	200.7	-0.1				

Note: "SS" denotes "Steady-State" emissions

Table 3B: List of previously modeled pollutants (facility-wide PTE) compared to PSD Increment, for reference

Pollutant	Period	Modeled % of Standard
NO_2	Annual	45.8%
$PM_{2.5}$	Annual	21.5%
$PM_{2.5}$	24-hr	37.1%
PM_{10}	Annual	12.5%
PM_{10}	24-hr	19.8%
SO_2	Annual	45.4%
SO_2	24-hr	67.8%
SO_2	3-hr	28.1%

Question			Yes	No
Was modeling performed within the past four years?	Date of modeling report	8/1/2013	X	
Was AERMOD used to model the facility?			X	
Did previous modeling predict concentrations less than 95% of each air quality standard and PSD increment?			X	
Were all averaging periods modeled that apply to the pollutants listed above?			X	
Were all applicable startup/shutdown/maintenance scenarios modeled?				X
Did modeling include all sources within 1,000 meters of the facility fence line that now exist?			X	
Did modeling include background concentrations at least as high as current background concentrations?			X	
If a source is changing or being replaced, is the following equation true for all pollutants for which the waiver is requested? EXISTING SOURCE REPLACMENT SOURCE $\frac{[(g) \times (h1)] + [(v1)^2/2] + [(c) \times (T1)]}{q1} <= \frac{[(g) \times (h2)] + [(v2)^2/2] + [(c) \times (T2)]}{q2}$ Where g = gravitational constant = 32.2 ft/sec^2 h1 = existing stack height, feet v1 = exhaust velocity, existing source, feet per second c = specific heat of exhaust, 0.28 BTU/lb-degree F T1 = absolute temperature of exhaust, existing source = degree F + 460 q1 = emission rate, existing source, lbs/hour h2 = replacement stack height, feet v2 = exhaust velocity, replacement source, feet per second T2 = absolute temperature of exhaust, replacement source = degree F + 460 q2 = emission rate, replacement source, lbs/hour				X
Are all replacement stacks either the same direction as the replaced stack or vertical?			X	

If you checked "no" for any of the questions, provide an explanation for why you think the previous modeling may still be valid anyway.

Were all applicable startup/shutdown/maintenance scenarios modeled?
With this application, compressor blowdown emissions are being accounted for. Emissions of H_2S from compressor blowdowns are 0.05 lb/hr total, 0.0083 lb/hr per compressor. These emissions are unlikely to produce greater impacts than the AGI flaring scenario. AGI flaring at a rate of 200.6 lb/hr H_2S produced the highest impacts in previous modeling (~~1.5~~ 71% of the NMAAQS).

Buoyancy Equation
Results of the buoyancy equation for units C1-E through C8-E, H1, and H3 are included in Appendix 3. Although the revised equipment stacks will be less buoyant than previously modeled, these units are not key contributors to the high impacts for the gaseous and particulate pollutants.

For the gaseous pollutants, the operating scenario which produced the maximum impacts was SSM flaring from Flare 1 or Flare 2. SSM flaring is not changing as part of this application. The updates proposed in this application will not result in the steady-state source group producing greater impacts than the SSM flaring source groups.

For particulates, 3D analyst output from previous modeling indicates that haul road emissions are the major contributor to the high impacts. It is our belief that the changes in plume buoyancy from combustion sources are unlikely to cause or contribute to an exceedance of the standards. Although the lb/hr/source for haul roads is decreasing, the haul roads will likely still be the major contributor to the high impacts due to the proximity of the road to the facility fenceline.

Section 4: Discussions of scaled emission rates and scaled concentrations
We are not scaling previous results.

Appendix 1: Stack Height Release Correction Factor (adapted from 20.2.72.502 NMAC)

Release Height in Meters	Correction Factor
0 to 9.9	1
10 to 19.9	5
20 to 29.9	19
30 to 39.9	41
40 to 49.9	71
50 to 59.9	108
60 to 69.9	152
70 to 79.9	202
80 to 89.9	255
90 to 99.9	317
100 to 109.9	378
110 to 119.9	451
120 to 129.9	533
130 to 139.9	617
140 to 149.9	690
150 to 159.9	781
160 to 169.9	837
170 to 179.9	902
180 to 189.9	1002
190 to 199.9	1066
200 or greater	1161

Appendix 2. Very small emission rate modeling waiver requirements

Type of emissions	Modeling is waived if emissions of a pollutant for the entire facility (including haul roads) are below the amount:
Point source	0.1 lb/hr of H_2S or reduced sulfur, 1.0 lb/hr for other pollutants
Fugitive sources	0.01 lb/hr of H_2S or reduced sulfur, 0.1 lb/hr for other pollutants

Appendix 3. Buoyancy Equation Calculations

EXISTING SOURCE REPLACMENT SOURCE

$$\frac{[(g) \times (h1)] + [(v1)^2/2] + [(c) \times (T1)]}{q1} <= \frac{[(g) \times (h2)] + [(v2)^2/2] + [(c) \times (T2)]}{q2}$$

Where

g = gravitational constant = 32.2 ft/sec2

h1 = existing stack height, feet

v1 = exhaust velocity, existing source, feet per second

c = specific heat of exhaust, 0.28 BTU/lb-degree F

T1 = absolute temperature of exhaust, existing source = degree F + 460

q1 = emission rate, existing source, lbs/hour

h2 = replacement stack height, feet

v2 = exhaust velocity, replacement source, feet per second

T2 = absolute temperature of exhaust, replacement source = degree F + 460

q2 = emission rate, replacement source, lbs/hour

Unit	Pollutant	h1	v1	T1	q1	h2	v2	T2	q2	Existing	Replacement
C1-E through C8-E	NOx	50	155	1298	6.9	50	75.7	1298	5.2	2,027	927
	CO				0.49				0.54	28,543	8,964
	SO_2				0.43				0.45	32,525	10,733
	PM				0.3				0.31	46,620	15,488
H1	NOx	86	25.2	1060	1.3	20	28.3	1190	1.3	2,603	1,081
	CO				2.1				2.1	1,611	643
	SO_2				0.37				0.37	9,145	3,675
	PM				0.19				0.19	17,808	7,109
H3	NOx	40	11.2	1060	0.78	18	15.5	1178	0.49	2,112	2,100
	CO				0.66				0.82	2,496	1,250
	SO_2				0.12				0.14	13,729	7,144
	PM				0.060				0.075	27,459	13,819

Section 17

Compliance Test History

(submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

The facility is not yet constructed and therefore has no compliance test history.

Section 20

Other Relevant Information

Other relevant information. 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

Green House Gas Applicability

(submitting under 20.2.70, 20.2.72, 20.2.73, 20.2.74 NMAC)

Title V (20.2.70 NMAC), NSR (20.2.72 NMAC), NOI (20.2.73 NMAC) and PSD (20.2.74 NMAC) applicants must determine if they are subject to Title V permitting and/or PSD permitting for green house gas (GHG) emissions. GHG emissions are the sum of the aggregate group of six green house gases that include carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). There are two thresholds that must be computed to determine applicability. The first threshold is the sum of GHG mass emissions in TPY. GHG mass emissions are the sum of the total annual tons of green house gases without adjusting with the GWPs. The second threshold is the sum of CO_2 equivalent (CO_2e) emissions in TPY GHG. CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its global warming potential (GWP) found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Green House Gas TV and PSD Applicability Determination:

☐ **Notice of Intent Sources** (20.2.73 NMAC): By checking this box and certifying this application the applicant certifies that the facility, based upon the quantity of stack emissions, including start up, shut down, and maintenance emissions, is not subject to 20.2.70 NMAC or 20.2.74 NMAC for Green House Gas (GHG) Emissions. The Department may request the emissions calculations and other documents supporting this determination.

Minor NSR (20.2.72 NMAC), PSD Major (20.2.74 NMAC), and Title V (20.2.70 NMAC) sources must complete the steps outlined below to determine GHG TV and/or PSD applicability.

1. Calculate existing mass GHG and CO_2e emissions from your source. For PSD purposes, if this is a modification to an existing source, you must also calculate the increase in mass GHG and CO_2e emissions due to the modification. Start up, shut down, and maintenance emissions must be included.
2. See Tables 1 and 2 below and compare your mass GHG and CO_2e emissions to the appropriate category for your source.
3. If your source meets all of the criteria within a category, then you must obtain a PSD permit and/or a Title V permit for green house gas emissions.
4. If this is a GHG Major source with an existing BACT or if this is a permit application for a PSD or Title V permit with GHG above the thresholds in Tables 1 or 2, include the emissions calculations and supporting documents in the appropriate sections of this application unless instructed otherwise in Tables 1 or 2. Report GHG mass and CO_2e emissions in Table 2-P of this application unless instructed otherwise in Tables 1 or 2. Emissions are reported in **<u>short</u>** tons per year and represent each emission unit's Potential to Emit (PTE).

NSR (20.2.72 NMAC), PSD Major (20.2.74 NMAC), and Title V (20.2.70 NMAC): Based upon the GHG applicability criteria in this section the applicant certifies that the source is (check all that apply):

☐ Title V Minor and PSD Minor for GHG Emissions [The Department may request the emissions calculations and other documents supporting this determination.]
☑ Title V Major for GHG Emissions
☑ PSD Major for GHG Emissions

Table 1 - Title V Applicability Criteria		
On or after July 1, 2011, newly constructed source, or existing source that does not have a Title V permit	**On or after July 1, 2011, modification or Renewal to Existing Title V Source**	**Requirement**
Source emits or has potential to emit (PTE) ≥ 100,000 TPY CO_2e **and** 100 TPY GHG mass basis	Source emits or has PTE of ≥100,000 TPY CO_2e **and** 100 TPY GHG mass basis	**<u>For new sources:</u>** For a source that meets the criteria on July 1, 2011, submit a Title V permit application no later than June 30, 2012.

Table 1 - Title V Applicability Criteria		
		For a source that meets the criteria after July 1, 2011, submit a Title V application within 12 months of becoming subject to the GHG operating permit program (12 months from commencement of operation of the new unit or modification that caused the source to be subject to Title V). **For existing sources:** Include GHG with the next Title V application for a renewal or modification. **For both new and existing sources:** Include in the TV application, GHG emissions calculations and supporting documents, report CO_2e and GHG emissions in Table 2-P, and address any applicable CAA requirements (e.g. PSD BACT, NSPS). If there are no applicable requirements and if GHG emissions have been reported to the Department under 20.2.73 NMAC, the requirements of the previous sentence do not apply, but changes in GHG emissions resulting in GHG emission limits must be calculated and reported in Table 2-P for Title V permit modifications. Typically GHG emission limits would be established only when there is an applicable requirement, such as a PSD GHG BACT or limits taken to be GHG synthetic minor.

Table 2 - PSD Applicability Criteria			
On or After July 1, 2011, New Source	**On or After July 1, 2011, Major Modification to Existing PSD Major Source**	**On or After July 1, 2011, Modification to Existing PSD Minor Source**	**Requirement**
Source is subject to PSD for another pollutant **and** GHG PTE is ≥ than 75,000 tpy CO_2e **or** GHG PTE is ≥ 100,000 TPY CO_2e **and** ≥ 100/250 TPY mass basis	Source is subject to PSD for another regulated pollutant **and** net GHG emissions increase is ≥ 75,000 tpy CO_2e and greater than zero TPY mass basis **or** existing source has GHG PTE ≥ 100,000 TPY CO_2e **and** ≥ 100/250 TPY mass basis **and** net emissions GHG increase is ≥ 75,000 TPY	Actual or potential emissions of GHGs from the modification is ≥ 100,000 TPY CO_2e **and** ≥ 100/250 TPY mass basis. Minor PSD sources cannot net out of PSD review.	The source is subject to PSD permitting for GHG emissions and other regulated pollutants that are significant. In the application include GHG emissions calculations and supporting documents, report CO_2e and GHG emissions in Table 2-P, complete a GHG BACT determination, and include the TPY CO_2e and GHG mass emissions in the public notice. **Note:** If a minor source permit is issued after January 2, 2011, but before July 1, 2011, and construction has not commenced by July 1, 2011, the permit must be

Table 2 - PSD Applicability Criteria

	CO_2e and greater than zero TPY mass basis		cancelled, reopened, or an additional PSD permitting action taken, if the approved change/construction would trigger GHG PSD after July 1, 2011.

Additional Information:

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/
- Subparts C through UU of 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 and TV 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/ghgresources.html:
  - ENERGY STAR Industrial Sector Energy Guides and Plant Energy Performance Indicators (benchmarks) http://www.energystar.gov;
  - US EPA National Greenhouse Gas Inventory, http://epa.gov/climatechange/emissions/usinventoryreport.html;
  - EPA's Climate Leaders, http://www.epa.gov/climateleaders/index.html
  - EPA Voluntary Partnerships of GHG Reductions that include the landfill methane outreach program, the CHP partnership program, the Green Power Partnership, the Coalbed Methane Outreach program, the Natural Gas STAR program, and the Voluntary Aluminum Industrial Partnership.
  - SF Emission Reduction Partnership for the Magensium Industry http://www.epa.gov/highgwp/magnesium-sf6/index.html
  - PFC Reduction/Climate Partnership for the Semiconductor Industry http://www.epa.gov/highgwp/semiconductor-pfc/index.html

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. Please note that sources not subject to 40 CFR 98 and/or 20.2.300 NMAC may still be subject to the GHG PSD and/or TV permitting. 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 this part 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.O NMAC, 20.2.74.7.Y NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Short Tons:

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)

EPA's GHG Tailoring Rule:

To review EPA's final GHG Tailoring rule and pre-amble, See "Final GHG Tailoring Rule dated May 13, 2010 located on EPA's NSR Regulations Webpage or Federal Register June 3, 2010 Volume 75, No. 106
http://www.epa.gov/nsr/actions.html

EPA Permitting Guidance:

EPA's Permitting Guidance for GHG and other GHG information can be found on EPA's NSR Clear Air Act Permitting for Greenhouse Gases webpage.
http://www.epa.gov/nsr/ghgpermitting.html

Section 23: Certification

Company Name: DCP Midstream

I, Jackie Strickland, 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 13th day of April, 2015, upon my oath or affirmation, before a notary of the State of

Texas.

JW Strickland
*Signature

JWS
4-13-2015
Date

Jackie W. Strickland
Printed Name

General Manager
Title

Scribed and sworn before me on this 13th day of April, 2015.

My authorization as a notary of the State of Texas expires on the

10th day of November, 2016.

Yolanda DeLaO
Notary's Signature

4-13-2015
Date

Yolanda DelaO
Notary's Printed Name

NOTARY PUBLIC STATE OF TEXAS
YOLANDA DELAO
My Commission Expires
November 10, 2016

*For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC.