Trinity Consultants
9737 Great Hills Trl, Ste 340, Austin, TX 78759 / P 512.349.5800 / F 512.233.0803 / trinityconsultants.com

October 12, 2023

Mr. James Nellessen
Title V Permitting
New Mexico Environmental Department
Air Quality Bureau - Permitting Section
525 Camino de los Marquez, Suite 1
Santa Fe, NM 87505-1816

Submitted via Federal Express

RE: OXY USA WTP, LP
Indian Basin Gas Plant
Title V Renewal for Permit No. P103-R3
Ai No. 197
Eddy County

Dear Mr. Nellessen:

On behalf of OXY USA WTP, LP, I am submitting the attached Title V Renewal for Permit No. P1-3-R3. All necessary attachments are included.

If you have any questions, please get in touch with me at (512) 255-9999 or email jmechell@waid.com or Ms. Femi Serrano at (713) 215-7000 or femi_serrano@oxy.com.

Sincerely,

TRINITY CONSULTANTS

Justin K. Mechell

Justin K. Mechell, P.E.
Managing Consultant

JKM/tvp

Attachment

cc: Ms. Femi Serrano, P.E., OXY USA WTP, LP, Houston, w/attachment

TITLE V RENEWAL FOR PERMIT NO. P103-R3

OXY USA WTP LP \ Indian Basin Gas Plant

Prepared By:

JUSTIN K. MECHELL
NEW MEXICO
22144
LICENSED PROFESSIONAL ENGINEER

Justin K. Mechell
10/12/2023

Justin K. Mechell, P.E. – Managing Consultant

TRINITY CONSULTANTS
9737 Great Hills Trail
Suite 340
Austin, TX 78759
(512) 238-2324
trinityconsultants.com

October 2023

Project OPL16092

Air Permit Application
Compliance History Disclosure Form

Pursuant to Subsection 74-2-7(S) of the New Mexico Air Quality Control Act ("AQCA"), NMSA §§ 74-2-1 to -17, the New Mexico Environment Department ("Department") may deny any permit application or revoke any permit issued pursuant to the AQCA if, within ten years immediately preceding the date of submission of the permit application, the applicant met any one of the criteria outlined below. In order for the Department to deem an air permit application administratively complete, or issue an air permit for those permits without an administrative completeness determination process, the applicant must complete this Compliance History Disclosure Form as specified in Subsection 74-2-7(P). An existing permit holder (permit issued prior to June 18, 2021) shall provide this Compliance History Disclosure Form to the Department upon request.

Permittee/Applicant Company Name		**Expected Application Submittal Date**
OXY USA WTP, LP		October 15, 2023
Permittee/Company Contact	**Phone**	**Email**
Femi Serrano	713-366-5331	Femi_serrano@oxy.com

Within the 10 years preceding the expected date of submittal of the application, has the permittee or applicant:		
1	Knowingly misrepresented a material fact in an application for a permit?	☐ Yes ☒ No
2	Refused to disclose information required by the provisions of the New Mexico Air Quality Control Act?	☐ Yes ☒ No
3	Been convicted of a felony related to environmental crime in any court of any state or the United States?	☐ Yes ☒ No
4	Been convicted of a crime defined by state or federal statute as involving or being in restraint of trade, price fixing, bribery, or fraud in any court of any state or the United States?	☐ Yes ☒ No
5a	Constructed or operated any facility for which a permit was sought, including the current facility, without the required air quality permit(s) under 20.2.70 NMAC, 20.2.72 NMAC, 20.2.74 NMAC, 20.2.79 NMAC, or 20.2.84 NMAC?	☐ Yes ☒ No
5b	If "No" to question 5a, go to question 6. If "Yes" to question 5a, state whether each facility that was constructed or operated without the required air quality permit met at least one of the following exceptions: a. The unpermitted facility was discovered after acquisition during a timely environmental audit that was authorized by the Department; or b. The operator of the facility estimated that the facility's emissions would not require an air permit, **and** the operator applied for an air permit within 30 calendar days of discovering that an air permit was required for the facility.	☐ Yes ☐ No
6	Had any permit revoked or permanently suspended for cause under the environmental laws of any state or the United States?	☐ Yes ☒ No
7	For each "yes" answer, please provide an explanation and documentation.	

Mail Application To:		For Department use only:
New Mexico Environment Department Air Quality Bureau Permits Section 525 Camino de los Marquez, Suite 1 Santa Fe, New Mexico, 87505 Phone: (505) 476-4300 Fax: (505) 476-4375 www.env.nm.gov/aqb		

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 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: ☐ NOI 20.2.73 NMAC ☐ 20.2.72 NMAC application or revision ☐ 20.2.72.300 NMAC StreaN/Amline application
Title V Source: ☐ Title V (new) ☒ Title V renewal ☐ TV minor mod. ☐ TV significant mod. ☐ TV Acid Rain: ☐ New ☐ Renewal
PSD Major Source: ☐ PSD major source (new) ☐ Minor Modification to a PSD source ☐ a PSD major modification

Acknowledgements:

☒ I acknowledge that a pre-application meeting is available to me upon request. ☒ Title V Operating, Title IV Acid Rain, and NPR applications have no fees.

☐ $500 NSR application Filing Fee enclosed OR ☐ The full permit fee associated with 10 fee points (required w/ streamline applications).

☐ Check No.: N/A in the amount of N/A

☒ I acknowledge the required submittal format for the hard copy application is printed double sided 'head-to-toe', 2-hole punched (except the Sect. 2 landscape tables is printed 'head-to-head'), numbered tab separators. Incl. a copy of the check on a separate page.

☒ I acknowledge there is an annual fee for permits in addition to the permit review fee: www.env.nm.gov/air-quality/permit-fees-2/.

☐ This facility qualifies for the small business fee reduction per 20.2.75.11.C. NMAC. The full $500.00 filing fee is included with this application and I understand the fee reduction will be calculated in the balance due invoice. The Small Business Certification Form has been previously submitted or is included with this application. (Small Business Environmental Assistance Program Information: www.env.nm.gov/air-quality/small-biz-eap-2/.)

Citation: Please provide the **low level citation** under which this application is being submitted: **20.2.70.404.C.(1)(a) NMAC**
(e.g. application for a new minor source would be 20.2.72.200.A NMAC, one example for a Technical Permit Revision is 20.2.72.219.B.1.b NMAC, a Title V acid rain application would be: 20.2.70.200.C NMAC)

Section 1 – Facility Information

Section 1-A: Company Information

		AI # if known: 197	Updating Permit/NOI #: P103-R3
1	Facility Name: Indian Basin Gas Plant	Plant primary SIC Code (4 digits): 1321	
		Plant NAIC code (6 digits): 211112	
a	Facility Street Address (If no facility street address, provide directions from a prominent landmark): From Carlsbad, Take US 285 North for approximately 12 miles and turn left on State Highway 137. Go 9 miles on SH-137 and turn right on Country Road 401 (Marathon Road) and go 2 miles. Stay right and continue onto CR 404 and go approximately 2 miles. The facility is on the left (south) side of the road.		

b	Proposed	Hourly: 12.50 MMscfh (residue gas); 520.83 bbl/hr [natural gas liquids (NGL)]; 0.15 MMscfh (acid gas)	Daily: 300 MMscfd (residue gas); 12,500 bbl/day (NGL); 3.6 MMscfd (acid gas)	Annually: 109,500 MMscfy (residue gas); 4,562,500 bbl/yr (NGL) 1,314 MMscfy (acid gas)

Section 1-D: Facility Location Information

1	Latitude (decimal degrees): 32.4638972	Longitude (decimal degrees): -104.5741167	County: Eddy	Elevation (ft): 3821
2	UTM Zone: ☐ 12 or ☒ 13	Datum: ☐ NAD 83 ☒ WGS 84		
a	UTM E (in meters, to nearest 10 meters): 540,023	UTM N (in meters, to nearest 10 meters): 3,591,937		
3	Name and zip code of nearest New Mexico town: Carlsbad, NM			
4	Detailed Driving Instructions from nearest NM town (attach a road map if necessary): From Carlsbad, Take US 285 North for approximately 12 miles and turn left on State Highway 137. Go 9 miles on SH-137 and turn right on Country Road 401 (Marathon Road) and go 2 miles. Stay right and continue onto CR 404 and go approximately 2 miles. Facility is on the left (south) side of the road.			
5	The facility is 14.5 (distance) miles west (direction) of Carlsbad, NM (nearest town).			
6	Land Status of facility (check one): ☒ Private ☐ Indian/Pueblo ☐ Government ☐ BLM ☐ Forest Service ☐ Military			
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: Municipalities: None; Indian Tribes: Non; Counties: Eddy County			
8	**20.2.72** NMAC applications **only**: Will the property on which the facility is proposed to be constructed or operated be closer than 50 km (31 miles) to other states, Bernalillo County, or a Class I area (see www.env.nm.gov/air-quality/modeling-publications/)? ☒ Yes ☐ No (20.2.72.206.A.7 NMAC) If yes, list all with corresponding distances in kilometers: Carlsbad Caverns National Park (Class I Area) - approximately 34 km (21 miles)			
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): 34.1 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: 2253.08 m E (Residence)			
12	Method(s) used to delineate the Restricted Area: Fencing "**Restricted Area**" is an area to which public entry is effectively precluded. Effective barriers include continuous fencing, continuous walls, or other continuous barriers approved by the Department, such as rugged physical terrain with steep grade that would require special equipment to traverse. If a large property is completely enclosed by fencing, a restricted area within the property may be identified with signage only. Public roads cannot be part of a Restricted Area.			
13	Does the owner/operator intend to operate this source as a portable stationary source as defined in 20.2.72.7.X NMAC? ☐ Yes ☒ No A portable stationary source is not a mobile source, such as an automobile, but a source that can be installed permanently at one location or that can be re-installed at various locations, such as a hot mix asphalt plant that is moved to different job sites.			
14	Will this facility operate in conjunction with other air regulated parties on the same property? ☒ No ☐ Yes If yes, what is the name and permit number (if known) of the other facility? **N/A**			

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

1	Facility **maximum** operating ($\frac{hours}{day}$): 24	($\frac{days}{week}$): 7	($\frac{weeks}{year}$): 52	($\frac{hours}{year}$): 8760	
2	Facility's maximum daily operating schedule (if less than 24 $\frac{hours}{day}$)? Start: N/A	☐AM ☐PM	End: N/A	☐AM ☐PM	
3	Month and year of anticipated start of construction: N/A				
4	Month and year of anticipated construction completion: N/A				

2	Plant Operator Company Name: OXY USA WTP Limited Partnership	Phone/Fax: 713-366-5331
a	Plant Operator Address: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	
b	Plant Operator's New Mexico Corporate ID or Tax ID: CRS 02-459740-006	
3	Plant Owner(s) name(s): OXY USA WTP Limited Partnership	Phone/Fax: 713-366-5331
a	Plant Owner(s) Mailing Address(s): 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	
4	Bill To (Company): OXY USA WTP Limited Partnership	Phone/Fax: 713-366-5331
a	Mailing Address: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	E-mail: femi_serrano@oxy.com
5	☒ Preparer: Trinity Consultants ☒ Consultant: Justin Mechell, P.E.	Phone/Fax: 512-255-9999
a	Mailing Address: 9737 Great Hills Trl, Ste 340, Austin, TX 78759	E-mail: jmechell@waid.com
6	Plant Operator Contact: Mario Guerrero	Phone/Fax: (432) 758-8640
a	Address: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	E-mail: mario_guerrero@oxy.com
7	Air Permit Contact: Femi Serrano	Title: Manager Air Quality, EOR
a	E-mail: femi_serrano@oxy.com	Phone/Fax: 713-366-5331
b	Mailing Address: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	
c	The designated Air permit Contact will receive all official correspondence (i.e. letters, permits) from the Air Quality Bureau.	

Section 1-B: Current Facility Status

1.a	Has this facility already been constructed? ☒ Yes ☐ No	1.b If yes to question 1.a, is it currently operating in New Mexico? ☐ Yes ☒ No
2	If yes to question 1.a, was the existing facility subject to a Notice of Intent (NOI) (20.2.73 NMAC) before submittal of this application? ☐ Yes ☒ No	If yes to question 1.a, was the existing facility subject to a construction permit (20.2.72 NMAC) before submittal of this application? ☒ Yes ☐ No
3	Is the facility currently shut down? ☒ Yes ☐ No	If yes, give month and year of shut down (MM/YY): 06/20
4	Was this facility constructed before 8/31/1972 and continuously operated since 1972? ☐ Yes ☒ No	
5	If Yes to question 3, has this facility been modified (see 20.2.72.7.P NMAC) or the capacity increased since 8/31/1972? ☐ Yes ☐ No ☐ N/A	
6	Does this facility have a Title V operating permit (20.2.70 NMAC)? ☒ Yes ☐ No	If yes, the permit No. is: P-103-R3
7	Has this facility been issued a No Permit Required (NPR)? ☐ Yes ☒ No	If yes, the NPR No. is:
8	Has this facility been issued a Notice of Intent (NOI)? ☐ Yes ☒ No	If yes, the NOI No. is:
9	Does this facility have a construction permit (20.2.72/20.2.74 NMAC)? ☒ Yes ☐ No	If yes, the permit No. is: PSD-0295-M10-R3
10	Is this facility registered under a General permit (GCP-1, GCP-2, etc.)? ☐ Yes ☒ No	If yes, the register No. is:

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: 13.33 MMscfh (field gas); 9.73 bbl/hr (field condensate)	Daily: 320 MMscfd (field gas); 233.60 bbl/day (field condensate)	Annually: 116,800 MMscfy (field gas); 85,265 bbl/yr (field condensate)
b	Proposed	Hourly: 13.33 MMscfh (field gas); 9.73 bbl/hr (field condensate)	Daily: 320 MMscfd (field gas); 233.60 bbl/day (field condensate)	Annually: 116,800 MMscfy (field gas); 85,265 bbl/yr (field condensate)
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: 12.50 MMscfh (residue gas); 520.83 bbl/hr [natural gas liquids (NGL)]; 0.15 MMscfh (acid gas)	Daily: 300 MMscfd (residue gas); 12,500 bbl/day (NGL); 3.6 MMscfd (acid gas)	Annually: 109,500 MMscfy (residue gas); 4,562,500 bbl/yr (NGL) 1,314 MMscfy (acid gas)

5	Month and year of anticipated startup of new or modified facility: N/A
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:		
a	If yes, NOV date or description of issue:		NOV Tracking No:
b	Is this application in response to any issue listed in 1-F, 1 or 1a above? ☐ Yes ☐ No If Yes, provide the 1c & 1d info below:		
c	Document Title:	Date:	Requirement # (or page # and paragraph #):
d	Provide the required text to be inserted in this permit:		
2	Is air quality dispersion modeling or modeling waiver being submitted with this application? ☐ Yes ☒ No		
3	Does this facility require an “Air Toxics” permit under 20.2.72.400 NMAC & 20.2.72.502, Tables A and/or B? ☐ Yes ☒ No		
4	Will this facility be a source of federal Hazardous Air Pollutants (HAP)? ☒ Yes ☐ No		
a	If Yes, what type of source? ☐ **Major** (☐ ≥10 tpy of any single HAP **OR** ☐ ≥25 tpy of any combination of HAPS) **OR** ☒ **Minor** (☐ <10 tpy of any single HAP **AND** ☒ <25 tpy of any combination of HAPS)		
5	Is any unit exempt under 20.2.72.202.B.3 NMAC? ☐ Yes ☒ No		
a	If yes, include the name of company providing commercial electric power to the facility: ___________________________ Commercial power is purchased from a commercial utility company, which specifically does not include power generated on site for the sole purpose of the user.		

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

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

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

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

1	Responsible Official (R.O.) (20.2.70.300.D.2 NMAC): Jim Richardson	Phone: 713-215-7235
a	R.O. Title: President and General Manager	R.O. e-mail: Jim_Richardson@oxy.com
b	R. O. Address: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	
2	Alternate Responsible Official (20.2.70.300.D.2 NMAC): Kevin Sevin	Phone: 713-366-5979
a	A. R.O. Title: Manager of Operations	A. R.O. e-mail: Jim_Richardson@oxy.com
b	A. R. O. Address: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	
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): Occidental Permian Ltd – South Hobbs Unit Reinjection Compression Facility	
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.): OXY USA Inc.	
a	Address of Parent Company: 5 Greenway Plaza, Suite 110, Houston, TX 77046-0521	
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.): NGL Ventures LLC	

6	Telephone numbers & names of the owners' agents and site contacts familiar with plant operations: Clinton W. Kirkes (575) 628-4113 and Rodney Campbell (575) 628-4167
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: Texas – 53 km south (33 miles)

Section 1-I – Submittal Requirements

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

Hard Copy Submittal Requirements:

1) One hard copy **original signed and notarized application package** **printed double sided** **'head-to-toe'** **2-hole punched** as we bind the document on top, not on the side; except Section 2 (landscape tables), which should be head-to-head. Please use **numbered tab separators** in the hard copy submittal(s) as this facilitates the review process. For NOI submittals only, hard copies of UA1, Tables 2A, 2D & 2F, Section 3 and the signed Certification Page are required. Please include a copy of the check on a separate page.
2) If the application is for a minor NSR, PSD, NNSR, or Title V application, include one working hard **copy** for Department use. This copy should be printed in book form, 3-hole punched, and **must be double sided**. Note that this is in addition to the head-to-to 2-hole punched copy required in 1) above. Minor NSR Technical Permit revisions (20.2.72.219.B NMAC) only need to fill out Sections 1-A, 1-B, 3, and should fill out those portions of other Section(s) relevant to the technical permit revision. TV Minor Modifications need only fill out Sections 1-A, 1-B, 1-H, 3, and those portions of other Section(s) relevant to the minor modification. NMED may require additional portions of the application to be submitted, as needed.
3) The entire NOI or Permit application package, including the full modeling study, should be submitted electronically. Electronic files for applications for NOIs, any type of General Construction Permit (GCP), or technical revisions to NSRs must be submitted with compact disk (CD) or digital versatile disc (DVD). For these permit application submittals, **two** CD copies are required (in sleeves, not crystal cases, please), with additional CD copies as specified below. NOI applications require only a single CD submittal. Electronic files for other New Source Review (construction) permits/permit modifications or Title V permits/permit modifications can be submitted on CD/DVD or sent through AQB's secure file transfer service.

Electronic files sent by (check one):

☐ CD/DVD attached to paper application

☐ Secure electronic transfer. Air Permit Contact Name________________, Email______________ Phone number _________.

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

4) Optionally, the applicant may submit the files with the application on compact disk (CD) or digital versatile disc (DVD) following the instructions above and the instructions in 5 for applications subject to PSD review.
5) If **air dispersion modeling** is required by the application type, include the **NMED Modeling Waiver** and/or electronic air dispersion modeling report, input, and output files. The dispersion modeling ***summary report only*** should be submitted as hard copy(ies) unless otherwise indicated by the Bureau.
6) If the applicant submits the electronic files on CD and the application is subject to PSD review under 20.2.74 NMAC (PSD) or NNSR under 20.2.79 NMC include,
   a. one additional CD copy for US EPA,
   b. one additional CD copy for each federal land manager affected (NPS, USFS, FWS, USDI) and,
   c. one additional CD copy for each affected regulatory agency other than the Air Quality Bureau.

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

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

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

2) The documents should also be submitted in Microsoft Office compatible file format (Word, Excel, etc.) allowing us to access the text and formulas in the documents (copy & paste). Any documents that cannot be submitted in a Microsoft Office compatible format shall be saved as a PDF file from within the electronic document that created the file. If you are unable to provide Microsoft office compatible electronic files or internally generated PDF files of files (items that were not created electronically: i.e. brochures, maps, graphics, etc,), submit these items in hard copy format. We must be able to review the formulas and inputs that calculated the emissions.

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

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

Table of Contents

Table 2-A: Regulated Emission Sources

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

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2]	Date of Construction/ Reconstruction[2]	Controlled by Unit #	Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
ES-02	Regeneration Gas Heater #1	John Zink	HEVD 15	N/A	15 Mmbtu/hr	15 Mmbtu/hr	-	1980	-	ES-02	10200602	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-03	Glycol Dehydrator Reboiler	McIver and Smith Fab.	Type 30 Z Burner	N7703	2.0 Mmbtu/hr	2.0 Mmbtu/hr	-	1965	-	ES-03	10200602	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-04 [9,10]	Turbine Generator #1	Solar	Saturn 10-T1021	S400946; OHF11-S7153	1073 hp	1073 hp	1965	Oct-11	-	ES-04	20100201	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-05 [8, 10]	Turbine Generator #2	Solar	Saturn 10-T1021	S400945; OHC17-S9573	1073 hp	1073 hp	1965	Apr-17	-	ES-05	20100201	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-06/07[6,8,10]	Turbine Recompressor #1	Solar	Centaur 40-4002	CC80580; OHC09-C1194	4000 hp	4000 hp	1980	Aug-15	-	ES-06/07	20200201	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-08/09[7,8,10]	Turbine Recompressor #2	Solar	Centaur 40-4002	CC80578; OHJ14-C3032	4000 hp	4000 hp	1980	Jan-15	-	ES-08/09	20200201	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-10/11 [8, 10]	Turbine Recompressor #3	Solar	Centaur 40-4002	CC80579; OHK11-C8665	4000 hp	4000 hp	1980	Dec-11	-	ES-10/11	20200201	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-12	Auxiliary Boiler	York- Shipley	SPHC-500-N	83-15354	16.73 Mmbtu/hr	16.73 Mmbtu/hr	-	2000	-	ES-12	10200602	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-14 [5,7]	Utility Flare Pilot and Purge	Flare Industries	N/A	-	135 MMscfd	135 MMscfd	-	1989	-	ES-14	30600903	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A
ES-17 [8,10]	Turbine Inlet Compressor	Solar	Centaur 50-5702S	OH108-H0771	5700 hp	5700 hp	2017	2017	-	ES-17	20200201	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified ☐ To be Removed ☐ Replacement Unit ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] Date of Construction/ Reconstruction[2]	Controlled by Unit # Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
ES-21[8,10]	Turbine Generator #3	Solar	Saturn 10-T 1021	S423381; OHI16-S7720	1146 hp	1146 hp	1970 Nov-16	- ES-21	20100201	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-22 [8,10]	Turbine Recompressor #4	Solar	Centaur 40-470S	CC79420; OHG11-C2099	4700 hp	4700 hp	1979 Aug-11	- ES-22	20100201	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-40	Glycol Dehydrator Regenerator	McIver and Smith Fab.	N/A	N/A	260 MMscfd	260 MMscfd	- 1965	-5 VRU-ES-40-SB 5	N/A	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-42 [7]	Residue Gas Flare Pilot and Purge	Flare Industries	N/A	N/A	300 MMscfd	300 MMscfd	- 2000	- ES-42	3060090	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-46[7]	Condensate Gunbarrel	Palmer Barnett	-	4536	31500 gal	31500 gal	Dec-02 -	ES-50 [6] ES-50 [6]	40400311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-47	Condensate Tank 1	Permian Tank	-	33100	42000 gal	42000 gal	Sep-02 -	ES-50 [6] ES-50 [6]	40400311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-48	Condensate Tank 2	Palmer	-	ST-26230	42000 gal	42000 gal	2011 -	ES-50 [6] ES-50 [6]	40400311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-50 [7]	SSM Flare Pilot/Purge and combustino of vapors collected by VCS-COND; ES-46, ES-47, ES-48, ES-56	Tornado Combustion Technologies Inc.	SL8-26-10-.375-10-316L	10674	3.5 MMscfd	3.5 MMscfd	7/28/2010 11/15/2010	- ES-50 [6]	30600903	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-52 [8]	Skimmer Basin Oil/Condensate Tank	Palmer	12F	27611	210 bbl	210 bbl	1996 1996	-9 VRU-ES-40-SB -	40400311	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-56 [5]	Condensate Truck Loading	N/A	N/A	N/A	N/A	N/A	N/A 2003	ES-50 ES-50	40600199	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-60	Natural Gas Liquids Truck Loading	N/A	N/A	N/A	N/A	N/A	2015 2015	- -	40600199	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

Unit Number[1]	Source Description	Make	Model #	Serial #	Manufact-urer's Rated Capacity[3] (Specify Units)	Requested Permitted Capacity[3] (Specify Units)	Date of Manufacture[2] / Date of Construction/ Reconstruction[2]	Controlled by Unit # / Emissions vented to Stack #	Source Classi-fication Code (SCC)	For Each Piece of Equipment, Check One	RICE Ignition Type (CI, SI, 4SLB, 4SRB, 2SLB)[4]	Replacing Unit No.
ES-61	Natural Gas Liquids Truck Loading	N/A	N/A	N/A	N/A	N/A	2015 2015	- -	40600199	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
GC-1	Inlet and Sales Gas Chromatograph	ABB	PGC-1000	T153335377	N/A	N/A	2016 2016	- -	-	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
GC-2	NGL Gas Chromatograph	ABB	NGC-8206	T153335380	N/A	N/A	2016 2016	- -	-	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-62	Cooling Tower	Accu-Pac	CF150M Ax	CTB 24.100	5000 gpm	5000 gpm	2015 2015	- -	38500110	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
FUG	Fugitive Emissions	N/A	N/A	N/A	N/A	N/A	N/A N/A	- -	N/A	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-14-SSM	Utility Flare- SSM Emissions	Flare Industries	-	-	135 MMscfd	135 MMscfd	- 1989	- ES-14-SSM	30600903	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-42-SSM	Residue Gas Flare- SSM Emissions	-	-	-	300 MMscfd	300 MMscfd	- 1989	- ES-42-SSM	30600903	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
ES-50-SSM	SSM Flare- SSM Emissions	Tornado Combustion Technologies Inc.	SL8-26-10-.375-10-316L	10674	3.5 MMscfd	3.5 MMscfd	7/28/2010 11/15/2010	- ES-50-SSM	30600903	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A
AMINE-1	Amine Sweeting Unit 1	Field Erection and Welding Co. (Olfen Engineering)	-	-	-	-	1965 1966	ES-50 ES-50	31000305	☑ Existing (unchanged) ☐ To be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To be Replaced	N/A	N/A

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

5 The vapor recovery unit (VRU-ES-40-SB) for the glycol dehydrator and skimmer basin tanks is not considered a control device but is integral to the process. Potential emissions from VRU-ES-40-SB are classified as fugitive emissions since there is no stack. There is also a back-up VRU for the glycol dehydrator/skimmer basin tanks to be designated VRU-ES-40-SB-BU.
6 Emissions from the gunbarrel (ES-46), condensate tanks (ES-47, ES-58), and condensate truck loading operation (ES-56) will be collected in a closed vent vapor collection system (VCS-COND, which was previously called VRU-COND) and vented to the flare control device ES-50.
7 Flares ES-42 and ES-50 listed above include pilot and purge gas emissions. In addition, flare ES-50 includes emissions from combusting vapors from the closed vent vapor collection system (VCS-COND). The VCS-COND system collects vapors from condensate tanks (ES-46, ES-47, ES-48), and condensate truck loading (ES-56). Emissions resulting from flare SSM events are broken out separately and designated by unit nos. ES-42-SSM / ES-50-SSM. SSM emissions for tanks, when the VCS-COND is down, are listed with the individual tanks unit IDs (ES-46, ES-47, ES-48).
8 Skimmer basin Tank ES-52 contains oil, which has been separated in the gunbarrel, from the field water tanks. Emissions include only working and standing losses; there are no flashing losses.
9 Potential emissions are classified as fugitive since there is no VRU stack.(2) The vapor recovery unit (VRU-ES-40-SB) is connected to the glycol dehydrator & skimmer basin tanks and is considered integral to the process. VRU-ES-40-SB-BU is a back-up VRU only.

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

All 20.2.70 NMAC (Title V) applications must list all Insignificant Activities in this table. All 20.2.72 NMAC applications must list Exempted Equipment in this table. If equipment listed on this table is exempt under 20.2.72.202.B.5, include emissions calculations and emissions totals for 202.B.5 "similar functions" units, operations, and activities in Section 6, Calculations. Equipment and activities exempted under 20.2.72.202 NMAC may not necessarily be Insignificant under 20.2.70 NMAC (and vice versa). Unit & stack numbering must be consistent throughout the application package. Per Exemptions Policy 02-012.00 (see http://www.env.nm.gov/aqb/permit/aqb_pol.html), 20.2.72.202.B NMAC Exemptions do not apply, but 20.2.72.202.A NMAC exemptions do apply to NOI facilities under 20.2.73 NMAC. List 20.2.72.301.D.4 NMAC Auxiliary Equipment for Streamline applications in Table 2-A. The List of Insignificant Activities (for TV) can be found online at https://www.env.nm.gov/wp-content/uploads/sites/2/2017/10/InsignificantListTitleV.pdf. TV sources may elect to enter both TV Insignificant Activities and Part 72 Exemptions on this form.

Unit Number	Source Description	Manufacturer	Model No.	Max Capacity	List Specific 20.2.72.202 NMAC Exemption (e.g. 20.2.72.202.B.5)	Date of Manufacture /Reconstruction[2]	For Each Piece of Equipment, Check Onc
			Serial No.	Capacity Units	Insignificant Activity citation (e.g. IA List Item #1.a)	Date of Installation /Construction[2]	
ES-23	Methanol Tank #1	-	1200	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #1.a	1989/90 est.	
ES-24	Methanol Tank #2	-	760	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #1.a	1989/90 est.	
ES-30	Clycol Tank #1	-	8812	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1965	
ES-31	Glycol Tank #2	-	752	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1986	
ES-32	Glycol Tank #3	-	940	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1986	
ES-33	Glycol Tank #4	-	940	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1965	
ES-34	Amine Slop Tank #1	-	12117	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1965	
ES-35	Amine Slop Tank #2	-	3008	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1965	
ES-36	Amine Tank #1	-	4223	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1965	
ES-37	Amine Tank #2	-	3008	-	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ To Be Removed ☐ New/Additional ☐ Replacement Unit ☐ To Be Modified ☐ To Be Replaced
			gal	-	IA List Item #5	1965	

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]		
ES-38	Turbine Oil Storage Tank 1	-	-	2022	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			-	gal	IA List Item #5	1980		
ES-39	Turbine Oil Storage Tank 2	-	-	8812	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			-	gal	IA List Item #5	1988		
Es-49 [3]	Produced Water Tank (with up to 5% condensate)	-	-	21000	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			AP-13991	gal	IA List Item #1.a	2015		
ES-51	Skimmer Basin-Gunbarrel Water Tank	-	-	500	20.2.72.202.B(5)	2014	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			14-315-500	bbl	IA List Item #1.a	-		
ES-53	Simmer Basin Oil/Condensate Tank	-	-	500	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			-	bbl	IA List Item #1.a	-		
ES-54	Skimmer Basin Water Tank 2	-	-	500	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			-	bbl	IA List Item #1.a	-		
ES-55	Skimmer Basin Water Tank 3	-	-	500	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			-	bbl	IA List Item #1.a	-		
ES-57	Skimmer Basin Water Tank 4	-	-	500	20.2.72.202.B(5)	-	☑ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced
			-	bbl	IA List Item #1.a	-		
							☐ Existing (unchanged) ☐ New/Additional ☐ To Be Modified	☐ To Be Removed ☐ Replacement Unit ☐ To Be Replaced

[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
VRU-ES-40-SB or VRU-ES-40-SB-BU	Vapor recovery unit connected to glycol dehydrator and skimmer basin tanks. Standby unit (VRU-ES-40-SB-BU) is used if primary unit is down. The VRU is integral to process vs. a control, but is listed here to be consistent with previous permit applications.	VRU-ES-40-SB 2005 -------------- VRU-ES-40-SB-BU Prior to January 20, 1984	VOC	ES-40 (& skimmer basin tanks below)	95%	Engineering Estimate
				Skimmer Basin Tanks: ES-51, ES-52, ES-53, ES-54, ES-55 (& ES-40 above)	95%	Engineering Estimate
VCS-COND/ ES-50	VCS-COND (previously named VRU-COND) is a closed vent vapor collection system for emissions from condensate tanks, gunbarrel, condensate truck loading operations, and gas chromatographs. The collected vapors are controlled by combustion in Flare ES-50	November 15, 2010	VOC	ES-46, ES-47, ES-48, ES-56, GC-1, GC-2	95%	Engineering Estimate
ES-14-SSM	Utility flare -controls emissions during startup, shutdown and maintenance (SSM) events as described in application		VOC, H2S, Mercaptans	Inlet gas; Gas Filters; Residue gas production; ES-4 (pneumatic pump); ES-5 (pneumatic pump); ES-06/07; ES-08/09; ES-10/11; ES-22; & ES-17	98%	TCEQ Flares & Vapor Oxidizers, RG-109 (Draft), October 2000 & Previous NMED Guidance
ES-42-SSM	Residue gas flare -controls emissions during startup, shutdown and maintenance (SSM) events as described in application		VOC, H2S, Mercaptans	Inlet gas & Gas Filters & Residue gas production;	98%	TCEQ Flares & Vapor Oxidizers, RG-109 (Draft), October 2000 & Previous NMED Guidance
ES-50-SSM	SSM flare -controls emissions during startup, shutdown and maintenance (SSM) events as described in application	11/15/2010	VOC, H2S, Mercaptans	NGL vapors (including NGL sales meter, pipeline pumps, & pipeline maintenance); Condensate Stabilizer Compressor (CONDSTAB-COM); Off-site Acid Gas Compressor (AG-COM); Inlet Gas; & Gas Filters in Plant	98%	TCEQ Flares & Vapor Oxidizers, RG-109 (Draft), October 2000 & Previous NMED Guidance

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

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

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

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

Unit No.	NOx		CO		VOC		SOx		PM[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
ES-02	1.47	6.43	1.23	5.41	0.081	0.35	0.0088	0.039	0.11	0.49	0.11	0.49	0.11	0.49	-	-	-	-
ES-03	0.2	0.86	0.16	0.72	0.011	0.047	0.0012	0.0051	0.015	0.065	0.015	0.065	0.015	0.065	-	-	-	-
ES-04	4.32	18.9	6.8	29.8	0.73	3.21	0.0079	0.035	0.1	0.45	0.1	0.45	0.1	0.45	-	-	-	-
ES-05	4.32	18.9	6.8	29.8	0.73	3.21	0.0079	0.035	0.1	0.45	0.1	0.45	0.1	0.45	-	-	-	-
ES-06/07	15.4	67.43	3.88	17.02	1.32	5.8	0.025	0.11	0.33	1.43	0.33	1.43	0.3	1.43	-	-	-	-
ES-08/09	15.4	67.43	3.88	17.02	1.32	5.8	0.025	0.11	0.33	1.43	0.33	1.43	0.3	1.43	-	-	-	-
ES-10/11	11.1	48.62	3.88	17.02	1.32	5.8	0.025	0.11	0.33	1.43	0.33	1.43	0.3	1.43	-	-	-	-
ES-12	1.64	7.18	1.38	6.03	0.09	0.39	0.0098	0.043	0.12	0.55	0.12	0.55	0.12	0.55	-	-	-	-
ES-14	0.1	0.44	0.27	1.19	0.021	0.094	-	-	-	-	-	-	-	-	-	-	-	-
ES-17	5.76	25.23	7.01	30.7	2	8.78	0.032	0.14	0.39	1.69	0.39	1.69	0.39	1.69	-	-	-	-
ES-21	3	12.9	2.8	12	0.09	0.39	0.0079	0.035	0.1	0.45	0.1	0.45	0.1	0.45	-	-	-	-
ES-22	6.17	27.04	5.11	22.39	1.35	5.93	0.028	0.12	0.37	1.61	0.37	1.61	0.37	1.61	-	-	-	-
ES-40	-	-	-	-	3	13.1	-	-	-	-	-	-	-	-	-	-	-	-
ES-42	0.15	0.64	0.39	1.72	0.031	0.14	-	-	-	-	-	-	-	-	-	-	-	-
ES-46 (W&S) [3]	-	-	-	-	1.05	4.6	-	-	-	-	-	-	-	-	-	-	-	-
ES-46 (Flash) [3]	-	-	-	-	12.09	52.94	-	-	-	-	-	-	-	-	-	-	-	-
ES-46- Subtotal	-	-	-	-	13.14	57.54	-	-	-	-	-	-	-	-	-	-	-	-
ES-47 (W&S) [3]	-	-	-	-	1.72	7.55	-	-	-	-	-	-	-	-	-	-	-	-
ES-47 (Flash) [3]	-	-	-	-	4.49	19.67	-	-	-	-	-	-	-	-	-	-	-	-
ES-47- Subtotal	-	-	-	-	6.21	27.22	-	-	-	-	-	-	-	-	-	-	-	-
ES-48 (W&S) [3]	-	-	-	-	1.86	8.17	-	-	-	-	-	-	-	-	-	-	-	-
ES-48 (Flash) [3]	-	-	-	-	6.74	29.51	-	-	-	-	-	-	-	-	-	-	-	-
ES-48- Subtotal	-	-	-	-	8.6	37.67	-	-	-	-	-	-	-	-	-	-	-	-
ES-50 [4]	0.049	0.21	0.13	0.57	0.01	0.045	-	-	-	-	-	-	-	-	-	-	-	-
ES-52	-	-	-	-	0.015	0.066	-	-	-	-	-	-	-	-	-	-	-	-
ES-56[3]	-	-	-	-	40	9.47	-	-	-	-	-	-	-	-	-	-	-	-
ES-60	-	-	-	-	0.24	0.13	-	-	-	-	-	-	-	-	-	-	-	-
ES-61	-	-	-	-	0.24		-	-	-	-	-	-	-	-	-	-	-	-
ES-62	-	-	-	-	-	-	-	-	0.42	1.84	0.01	0.05	0.00011	0.0005	-	-	-	-
GC-1	-	-	-	-	0.0039	0.017	-	-	-	-	-	-	-	-	-	-	-	-
GC-2	-	-	-	-	0.0003	0.001	-	-	-	-	-	-	-	-	3.6E-06	0.0047	-	-
FUG	-	-	-	-	6.35	27.8	-	-	-	-	-	-	-	-	0.062	0.28	-	-
Totals	69.01	302.27	43.7	191.42	86.91	212.96	0.18	0.78	2.71	11.89	2.3	10.1	2.29	10.05	0.062	0.28	-	-

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but PM is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

2 Condensables: Include condensable particulate matter emissions in particulate matter calculations.

3 ES-46, ES-47, ES-48, and ES-56 are units with flare control that are reported as uncontrolled in the above table. Tanks' working/standing (W&S) losses and Flashing losses are broken out.

4 ES-50 includes pilot and purge gas emissions only. Combustion emissions resulting from its being a control device are not included as this table is for "uncontrolled emissions".

Table 2-E: Requested Allowable Emissions

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

Unit No.	NOx		CO		VOC		SOx		PM[1]		PM10[1]		PM2.5[1]		H_2S		Lead	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
ES-02	1.47	6.43	1.23	5.41	0.081	0.35	0.0088	0.039	0.11	0.49	0.11	0.49	0.11	0.49	-	-	-	-
ES-03	0.2	0.86	0.16	0.72	0.011	0.047	0.0012	0.0051	0.015	0.065	0.015	0.065	0.015	0.065	-	-	-	-
ES-04	4.32	18.9	6.8	29.8	0.73	3.21	0.0079	0.035	0.1	0.45	0.1	0.45	0.1	0.45	-	-	-	-
ES-05	4.32	18.9	6.8	29.8	0.73	3.21	0.0079	0.035	0.1	0.45	0.1	0.45	0.1	0.45	-	-	-	-
ES-06/07	15.4	67.43	3.88	17.02	1.32	5.8	0.025	0.11	0.33	1.43	0.33	1.43	0.3	1.43	-	-	-	-
ES-08/09	15.4	67.43	3.88	17.02	1.32	5.8	0.025	0.11	0.33	1.43	0.33	1.43	0.3	1.43	-	-	-	-
ES-10/11	11.1	48.62	3.88	17.02	1.32	5.8	0.025	0.11	0.33	1.43	0.33	1.43	0.3	1.43	-	-	-	-
ES-12	1.64	7.18	1.38	6.03	0.09	0.39	0.0098	0.043	0.12	0.55	0.12	0.55	0.12	0.55	-	-	-	-
ES-14	0.1	0.44	0.27	1.19	0.021	0.094	-	-	-	-	-	-	-	-	-	-	-	-
ES-17	5.76	25.23	7.01	30.7	2	8.78	0.032	0.14	0.39	1.69	0.39	1.69	0.39	1.69	-	-	-	-
ES-21	2.96	12.94	2.75	12.05	0.09	0.39	0.0079	0.035	0.1	0.45	0.1	0.45	0.1	0.45	-	-	-	-
ES-22	6.17	27.04	5.11	22.39	1.35	5.93	0.028	0.12	0.37	1.61	0.37	1.61	0.37	1.61	-	-	-	-
ES-40 [4]	-	-	-	-	3	13.1	-	-	-	-	-	-	-	-	-	-	-	-
ES-42	0.15	0.64	0.39	1.72	0.031	0.14	-	-	-	-	-	-	-	-	-	-	-	-
ES-50 (pilot/purge) [5]	0.049	0.21	0.13	0.57	0.01	0.045	-	-	-	-	-	-	-	-	-	-	-	-
ES-50 (control) [5]	0.13	0.24	0.68	1.32	1.36	2.64	-	-	-	-	-	-	-	-	-	-	-	-
ES-50 - (GC's) [5]	0.0002	0.0007	0.001	0.0029	0.0001	0.0004	8.1E-06	0.01	-	-	-	-	-	-	8.7E-08	0.00011	-	-
ES-50- Subtotal	0.17	0.46	0.81	1.9	1.37	2.68	8.1E-06	0.01	-	-	-	-	-	-	-	-	-	-
ES-46 (2)	-	-	-	-	0.657	2.88	-	-	-	-	-	-	-	-	-	-	-	-
ES-47(2)					0.31	1.36	-	-	-	-	-	-	-	-	-	-	-	-
ES-48(2)					0.43	1.88	-	-	-	-	-	-	-	-	-	-	-	-
ES-52 [4]	-	-	-	-	0.015	0.066	-	-	-	-	-	-	-	-	-	-	-	-
ES-56 [4]	-	-	-	-	0.8	0.19	-	-	-	-	-	-	-	-	-	-	-	-
ES-60	-	-	-	-	0.24	-	-	-	-	-	-	-	-	-	-	-	-	
ES-61	-	-	-	-	0.24	-	-	-	-	-	-	-	-	-	-	-	-	
ES-62	-	-	-	-	-	-	-	-	0.51	2.21	0.01	0.06	0.00011	0.0006	-	-	-	-
GC-1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
GC-2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FUG	-	-	-	-	6.35	27.8	-	-	-	-	-	-	-	-	0.062	0.28	-	-
Totals	69.14	302.52	44.39	192.75	22.51	89.98	0.18	0.79	2.8	12.26	2.3	10.11	2.29	10.05	0.062	0.28	-	-

[1] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but it is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

2 Condensables: Include condensable particulate matter emissions in particulate matter calculations.

3 Flare SSM emissions and exempt emissions are not included in this table.

4 Certain SSM events related to vapor collection system (VCS-COND) or VRU (VRU-ES-40-SB) downtime are included in the table above to be consistent with historical representations.

5 ES-50 flare emissions above are broken out for: (i) Pilot and purge gas; (ii) Combustion control-related for gunbarrel/condensate tanks (ES-46, ES-47, ES-48) & truck loading vapors (ES-56), which are collected in the closed vent vapor collection system (VCS-COND) and sent to flare ES-50; and (iii) Combustion control related to the Gas Chromatographs (GC-1 & GC-2). Total ES-50 emissions are listed separately in the table above.

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

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

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

Unit No.	NOx		CO		VOC		SOx		PM[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
ES-14-SSM	281.69	0.28	755.26	0.76	1.09	0.0011	1583.11	1.58	-	-	-	-	-	-	118.42	0.12	-	-
ES-42-SM	563.39	5.07	1510.53	13.59	237.98	2.14	3167.26	28.51	-	-	-	-	-	-	33.64	0.30	-	-
ES-50-SSM	29.65	0.4	90.48	1.23	57.91	0.61	4147.33	82.95	-	-	-	-	-	-	44.07	0.36	-	-
Total Flares*	573.68	5.1	1543.33	13.71	262.07	2.19	7042.8	82.95	-	-	-	-	-	-	74.82	0.67	-	-
***Totals**	573.68	5.1	1543.33	13.71	262.07	2.19	7042.8	82.95	-	-	-	-	-	-	74.82	0.67	-	-

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

[2] **Condensable Particulate Matter:** Include condensable particulate matter emissions for PM10 and PM2.5 if the source is a combustion source. Do not include condensable particulate matter for PM unless PM is set equal to PM10 and PM2.5. Particulate matter (PM) is not subject to an ambient air quality standard, but it is a regulated air pollutant under PSD (20.2.74 NMAC) and Title V (20.2.70 NMAC).

* The total values for flares in the table above and included in the total values below, are not the sum of the maximum value for each flare represented in the table.
The total flare values includes the highest emissions scenario for all flares that can occur simultaneously. See flare emissions calculations for details.

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		PM		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
VRU-ES-40-SB [1]		-	-	-	-	2.98	13.06	-	-	-	-	-	-	-	-	-	-
and	ES-40	-	-	-	-	0.015	0.066	-	-	-	-	-	-	-	-	-	-
VRU-ES-40-SB-BU																	
Subtotal		**-**	**-**	**-**	**-**	**3.00**	**13.12**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
ES-50 [2]	ES-46	-	-	-	-	0.26	1.2	-	-	-	-	-	-	-	-	-	-
	ES-47	-	-	-	-	0.12	0.54	-	-	-	-	-	-	-	-	-	-
ES-50 [2]	ES-48	-	-	-	-	0.17	0.75	-	-	-	-	-	-	-	-	-	-
	ES-56	-	-	-	-	0.8	0.19	-	-	-	-	-	-	-	-	-	-
	ES-50 (GS-1 and GC-2)	0.0002	0.0006	0.0018	0.0053	0.001	0.0029	1.9E-06	5.5E-06								
	ES-50 combustion [3]	0.13	0.24	0.68	1.32	1.36	2.64	-	-	-	-	-	-	-	-	-	-
Subtotal		**0.13**	**0.24**	**0.68**	**1.33**	**2.72**	**5.28**	**1.9E-06**	**5.5E-06**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
FUG	FUG	-	-	-	-	6.3	27.7	-	-	-	-	-	-	-	-	0.062	0.28
Totals:		0.13	0.24	0.68	1.33	12.02	46.1	1.9E-06	5.5E-06	-	-	-	-	-	-	0.062	0.28

1 VRU-ES-40-SB and VRU-ES-40-SB-BU are the VRU and VRU backup system for the glycol dehydrator and the skimmer basin tanks.

2 A closed vent vapor collection system (VCS-COND) collects vapors from condensate gunbarrel/storage tanks (ES-46, ES-47, ES-48), and condensate truck loading (ES-56), and vents them to the flare control device ES-50. The flare has a minimum VOC contro

3 Vented emissions from GC-1 & GC-2 are sent to the flare (ES-50). The flare has a minimum VOC control efficiency of 98%. Combustion emissions are listed in the table above. The 2% uncombusted emissions are listed under GC-1 & GC-2.

Table 2-H: Stack Exit Conditions

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

Stack Number	Serving Unit Number(s) from Table 2-A	Orientation (H-Horizontal V=Vertical)	Rain Caps (Yes or No)	Height Above Ground (ft)	Temp. (F)	Flow Rate		Moisture by Volume (%)	Velocity (ft/sec)	Inside Diameter (ft)
						(acfs)	(dscfs)			
ES-02	ES-02	V	N	77	400	84	-	N/A	11.9	3.00
ES-03	ES-03	V	N	30	670	15	-	N/A	45.8	0.64
ES-04	ES-04	V	N	12	822	488	-	N/A	249.1	1.58
ES-05	ES-05	V	N	10	822	488	-	N/A	249.1	1.58
ES-06	ES-06/07	V	N	28	751	1284	-	N/A	154.9	3.25
ES-07	ES-06/07	V	N	28	350	859.27	-	N/A	92.50	3.44
ES-08	ES-08/09	V	N	28	751	1284.36	-	N/A	154.9	3.25
ES-09	ES-08/09	V	N	28	350	859.27	-	N/A	92.5	3.44
ES-10	ES-10/11	V	N	28	751	1284.36	-	N/A	154.9	3.25
ES-11	ES-10/11	V	N	28	350	859.27	-	N/A	92.5	3.44
ES-12	ES-12	V	N	19	420	95.92	-	N/A	22.9	2.31
ES-14	ES-14	V	N	174	1832 [1]	4.63 [1]	-	N/A	65.6 [1]	1.9 (physical)
ES-17	ES-17	V	N	20	918	1485.85	-	N/A	179.2	3.25
ES-21	ES-21	V	N	10	822	488.15	-	N/A	249.1	1.58
ES-22A	ES-22	V	N	28	781	1446.05	-	N/A	174.4	3.25
ES-22B	ES-22	V	N	50	440	1048.76	-	N/A	83.5	4
ES-42	ES-42	V	N	195	1832 [1]	4.63 [1]	-	N/A	65.6 [1]	3.4 (physical)
ES-43	ES-43	V	N	20	600	58.88	-	N/A	75	1
ES-50	ES-50	V	N	120	1832 [1]	4.63 [1]	-	N/A	65.6 [1]	0.67

1 Flare temperatures, velocities, and flow rates are from NMED AQB Modeling Guidelines (1000C=1832 F; 20 m/s=65.6 ft/s; acfm is calculated using effective diameter).

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		Benzene ☑HAP or ☐ TAP		Ethylbenzene ☑HAP or ☐ TAP		Toluene ☑HAP or ☐ TAP		Xylenes ☑HAP or ☐ TAP		n-hexanes ☑HAP or ☐ TAP		Formaldehyde ☑HAP or ☐ TAP		2-2-4-Trimethylpentane ☑HAP or ☐ TAP		Other (see Calc. section) ☑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
ES-02	ES-02	0.22	0.95	0.011	0.049	0.032	0.14	0.015	0.067	0.02	0.087	0.021	0.092	0.013	0.056	0.043	0.19	0.062	0.27
ES-03	ES-03	0.029	0.13	0.0015	0.007	0.0042	0.019	0.002	0.0089	0.0026	0.012	0.0028	0.012	0.0017	0.007	0.0057	0.025	0.0082	0.036
ES-04	ES-04	0.14	0.63	0.0026	0.011	0.029	0.13	0.0039	0.017	0.015	0.066	0.0036	0.016	0.04	0.18	0.0038	0.017	0.045	0.2
ES-05	ES-05	0.14	0.63	0.0026	0.011	0.029	0.13	0.0039	0.017	0.015	0.066	0.0036	0.016	0.04	0.18	0.0038	0.017	0.045	0.2
ES-06/07	ES-06/07	0.47	2.07	0.0084	0.037	0.1	0.42	0.013	0.057	0.049	0.22	0.012	0.052	0.13	0.58	0.013	0.055	0.15	0.66
ES-08/09	ES-08/09	0.47	2.07	0.0084	0.037	0.1	0.42	0.013	0.057	0.049	0.22	0.012	0.052	0.13	0.58	0.013	0.055	0.15	0.66
ES-10/11	ES-10/11	0.47	2.07	0.0084	0.037	0.096	0.42	0.013	0.057	0.049	0.22	0.012	0.052	0.13	0.58	0.013	0.055	0.15	0.66
ES-12	ES-12	0.024	0.11	0.00011	0.0005	-	-	9.1E-05	0.0004	2.3E-05	0.0001	0.0054	0.024	0.0059	0.026	0.00055	0.0024	0.012	0.053
ES-14	ES-14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ES-17	ES-17	0.6	2.64	0.0068	0.03	0.0018	0.008	0.0052	0.023	0.016	0.068	0.019	0.083	0.19	0.84	0.02	0.088	0.34	1.5
ES-21	ES-21	0.14	0.63	0.0026	0.011	0.029	0.13	0.0039	0.017	0.015	0.066	0.0036	0.016	0.04	0.18	0.0038	0.017	0.045	0.2
ES-22	ES-22	0.54	2.35	0.01	0.042	0.11	0.47	0.015	0.065	0.056	0.25	0.013	0.058	0.15	0.66	0.014	0.062	0.17	0.74
VRU-ES-40-SB [1]	ES-40, ES-52	1.38	6.03	0.24	1.04	0.11	0.5	0.54	2.39	0.21	0.93	0.27	1.17	-	-	0.0001	0.00045	-	-
ES-42	ES-42	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ES-43	ES-43	0.022	0.095	0.0011	0.0049	0.0032	0.014	0.0015	0.0067	0.002	0.0087	0.0021	0.0092	0.0013	0.0055	0.0043	0.019	0.0062	0.027
ES-50 [2]	ES-46, 47,48,56	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]	[2]
	ES-50	0.28	0.55	0.039	0.075	0.0021	0.004	0.038	0.074	0.016	0.032	0.19	0.36	-	-	-	-	-	-
FUG	FUG	0.037	0.16	0.029	0.13	0.00023	0.001	0.0076	0.033	0.001	0.0042	-	-	-	-	-	-	-	-
ES-46*	ES-46	0.14	0.6	0.019	0.082	0.001	0.0044	0.018	0.08	0.008	0.035	0.09	0.4	-	-	-	-	-	-
ES-47*	ES-47	0.064	0.28	0.0088	0.039	0.00048	0.0021	0.0087	0.038	0.0038	0.017	0.043	0.19	-	-	-	-	-	-
ES-48*	ES-48	0.089	0.39	0.012	0.053	0.00066	0.0029	0.012	0.053	0.005	0.023	0.059	0.26	-	-	-	-	-	-
ES-56*	ES-56	0.41	0.1	0.057	0.013	0.0031	0.00072	0.056	0.013	0.024	0.0057	0.275	0.065	-	-	-	-	-	-

Stack No.	Unit No.(s)	Total HAPs		Benzene ☑HAP or ☐ TAP		Ethylbenzene ☑HAP or ☐ TAP		Toluene ☑HAP or ☐ TAP		Xylenes ☑HAP or ☐ TAP		n-hexanes ☑HAP or ☐ TAP		Formaldehyde ☑HAP or ☐ TAP		2-2-4-Trimethylpentane ☑HAP or ☐ TAP		Other (see Calc. section) ☑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
ES-14-SSM	ES-14-SSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ES-42-SSM	ES-42-SSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
ES-50-SSM	ES-50-SSM	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Totals:		5.68	22.46	0.46	1.71	0.64	2.8	0.77	3.07	0.56	2.31	1.03	2.92	0.88	3.85	0.14	0.6	1.19	5.19

Table 2-J: Fuel

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

Unit No.	Fuel Type (low sulfur Diesel, ultra low sulfur diesel, Natural Gas, Coal, …)	Fuel Source: purchased commercial, pipeline quality natural gas, residue gas, raw/field natural gas, process gas (e.g. SRU tail gas) or other	Specify Units				
			Lower Heating Value	Hourly Usage	Annual Usage	% Sulfur	% Ash
ES-02	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	14.6 Mscf	127.8MMscf	2 gr S/1000 scf	N/A
ES-03	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	2 Mscf	17.2 MMscf	2 gr S/1000 scf	N/A
ES-04	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	12 Mscf	105.5 MMscf	4 ppmv H2S	N/A
ES-05	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	12 Mscf	105.5 MMscf	4 ppmv H2S	N/A
ES-06/07	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	32.5 Mscf	284.5 MMscf	4 ppmv H2S	N/A
ES-08/09	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	32.5 Mscf	284.5 MMscf	4 ppmv H2S	N/A
ES-10/11	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	32.5 Mscf	284.5 MMscf	4 ppmv H2S	N/A
ES-12	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	32.5 Mscf	284.5 MMscf	2 gr S/1000 scf	N/A
ES-14	Pipeline Quality Natural Gas- Pilot and Purge	Pipeline Quality Natural Gas- Pilot and Purge	1012	726 scfh	6.4 MMscf	-	N/A
ES-17	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	46.6 Mscf	408.2 MMscf	4 ppmv H2S	N/A
ES-21	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	12 Mscf	105.5 MMscf	4 ppmv H2S	N/A
ES-22	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	36.9Mscf	323.3 MMscf	4 ppmv H2S	N/A
ES-42	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	1050 scfh	9.2 MMscf	-	N/A
ES-43	Pipeline Quality Natural Gas	Pipeline Quality Natural Gas	1012	10.3Mscf	90.1 MMscf	2 gr S/1000 scf	N/A
ES-50	Pipeline Quality Natural Gas- Pilot and Purge	Pipeline Quality Natural Gas- Pilot and Purge	1012	350 scfh	3.1 MMscf	-	N/A

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)*
ES-46	40400311	Oil/Condensate	Mixed Hydrocarbons	6.7	50	317	4.52	325	5.84
ES-47	40400311	Oil/Condensate	Mixed Hydrocarbons	6.7	50	317	4.52	325	5.84
ES-48	40400311	Oil/Condensate	Mixed Hydrocarbons	6.7	50	317	4.52	325	5.84
ES-52	40400311	Oil/Condensate	Mixed Hydrocarbons	6.7	50	317	4.52	325	5.84

* Oil/condensate temperatures & vapor pressures listed above are conservatively high based on analysis of liquid coming out of the stabilizer at 325F.
Temperatures & vapor pressures based on ambient conditions are as follows: Average : 72.26 F/3.64 psia ; Maximum: 86.25 F /4.7 psia. Calculations use higher values listed in the table

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			
ES-46	2003	Oil/Condensate	N/A	FX	500	79	3.66	3.85	MG	MG	Good	3,570,000	169
ES-47	2003	Oil/Condensate	N/A	FX	1,000	159	6.55	2.51	MG	MG	Good	1,428,000	33
EW-48	2003	Oil/Condensate	N/A	FX	1,000	159	6.55	2.51	MG	MG	Good	2,142,000	49
ES-52	Unknown	Oil/Condensate (Skimmer Basin)	N/A	FX	210	33	4.57	1.57	MG	MG	Good	306,600	23

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

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

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

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

Material Processed				Material Produced			
Description	Chemical Composition	Phase (Gas, Liquid, or Solid)	Quantity (specify units)	Description	Chemical Composition	Phase	Quantity (specify units)
Field Gas	Hydrocarbons	G	320 MMscfd	Residue Gas	Hydrocarbons	G	300 MMscfd
Field Condensate	Water and Hydrocarbons	L	234 bbl/day	Natural Gas Liquids	Hydrocarbons	L	12500 bbl/dayu
				Acid Gas	45-60 % H2S; CO	G	3.6 MMscfd
				Water	Water	L	2200 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									

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								

Table 2-P: Greenhouse Gas Emissions

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

☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

		CO_2 ton/yr	N_2O ton/yr	CH_4 ton/yr	SF_6 ton/yr	PFC/HFC ton/yr[2]									Total GHG Mass Basis ton/yr[4]	Total CO_2e ton/yr[5]
Unit No.	**GWPs [1]**	1	298	25	22,800	footnote 3										
ES-02	mass GHG	7679.6	0.014	0.14											7679.8	
	CO_2e	7679.6	4.32	3.62												7687.6
ES-03	mass GHG	1023.9	0.0019	0.02											1024	
	CO_2e	1023.9	0.58	0.48												1025
ES-04	mass GHG	6298	0.012	0.12											6298.1	
	CO_2e	6298	3.54	2.97												6304.5
ES-05	mass GHG	6298	0.012	0.12											6298.1	
	CO_2e	6298	3.54	2.97												6304.5
ES-06/07	mass GHG	19969.9	0.038	0.38											19970.3	
	CO_2e	19969.9	11.22	9.42												19990.5
ES-08/09	mass GHG	19969.9	0.038	0.38											19970.3	
	CO_2e	19969.9	11.22	9.42												19990.5
ES-10/11	mass GHG	19969.9	0.038	0.38											19970.3	
	CO_2e	19969.9	11.22	9.42												19990.5
ES-12	mass GHG	8565.3	0.016	0.16											8565.5	
	CO_2e	8565.3	4.81	4.04												8574.2
ES-14	mass GHG	590.7	0.0012	4.12											594.8	
	CO_2e	590.7	0.35	102.89												693.9
ES-17	mass GHG	24616.5	0.05	0.46											24617	
	CO_2e	24616.5	13.8	11.6												24641.9
ES-21	mass GHG	6298	0.012	0.12											6298.1	
	CO_2e	6298	3.54	2.97												6304.5
ES-22	mass GHG	22449.6	0.042	0.42											22450.1	
	CO_2e	22449.6	12.62	10.59												22472.8
ES-40	mass GHG	0.017	NA	0.805											0.82	
	CO_2e	0.017	N/A	20.14												20.2
ES-42	mass GHG	4662.7	0.0091	30.3											4693	
	CO_2e	4662.7	2.72	757.5												5422.9

ES-43	mass GHG	5375.7	0.01	0.1014											5375.8	
	CO2e	5375.7	3.02	2.5348												5381.3
ES-46	mass GHG	0	N/A	0.0044											0.0044	
	CO_2e	0	N/A	0.1108												0.11
ES-47	mass GHG	0	N/A	0.0004											0.0004	
	CO2e	0	N/A	0.0101												0.01
ES-48	mass GHG	0	N/A	0.002											0.002	
	CO_2e	0	N/A	0.0504												0.05
ES-49	mass GHG	0	N/A	0.00053											0.00053	
	CO2e	0	N/A	0.0133												0.013
Es-50	mass GHG	412	0	1.61											413.6	
	CO_2e	412	0.12	40.25												452.3
ES-52	mass GHG	0	N/A	0.00025											0.00025	
	CO2e	0	N/A	0.0062												0.0062
Es-56	mass GHG	N/A	N/A	0.42											0.42	
	CO_2e	N/A	N/A	10.51												10.5
FUG	mass GHG	1.6	N/A	78.51											80.1	
	CO2e	1.6	N/A	1962.85												1964.5
Total	mass GHG														154300.2	
	CO_2e															157232.2

[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.

Section 3

Application Summary

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

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

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

The Indian Basin Gas Plant, owned and operated by OXY USA WTP LP is located in Eddy County, New Mexico. The function of the facility is to remove hydrogen sulfide, carbon dioxide and water from raw natural gas to make commercial natural gas. The facility also extracts natural gas liquids (propane and butane) from natural gas. The facility is currently authorized to operate under NSR Permit No. PSD-0295-M10-R3and Title V Permit No. P103-R3.

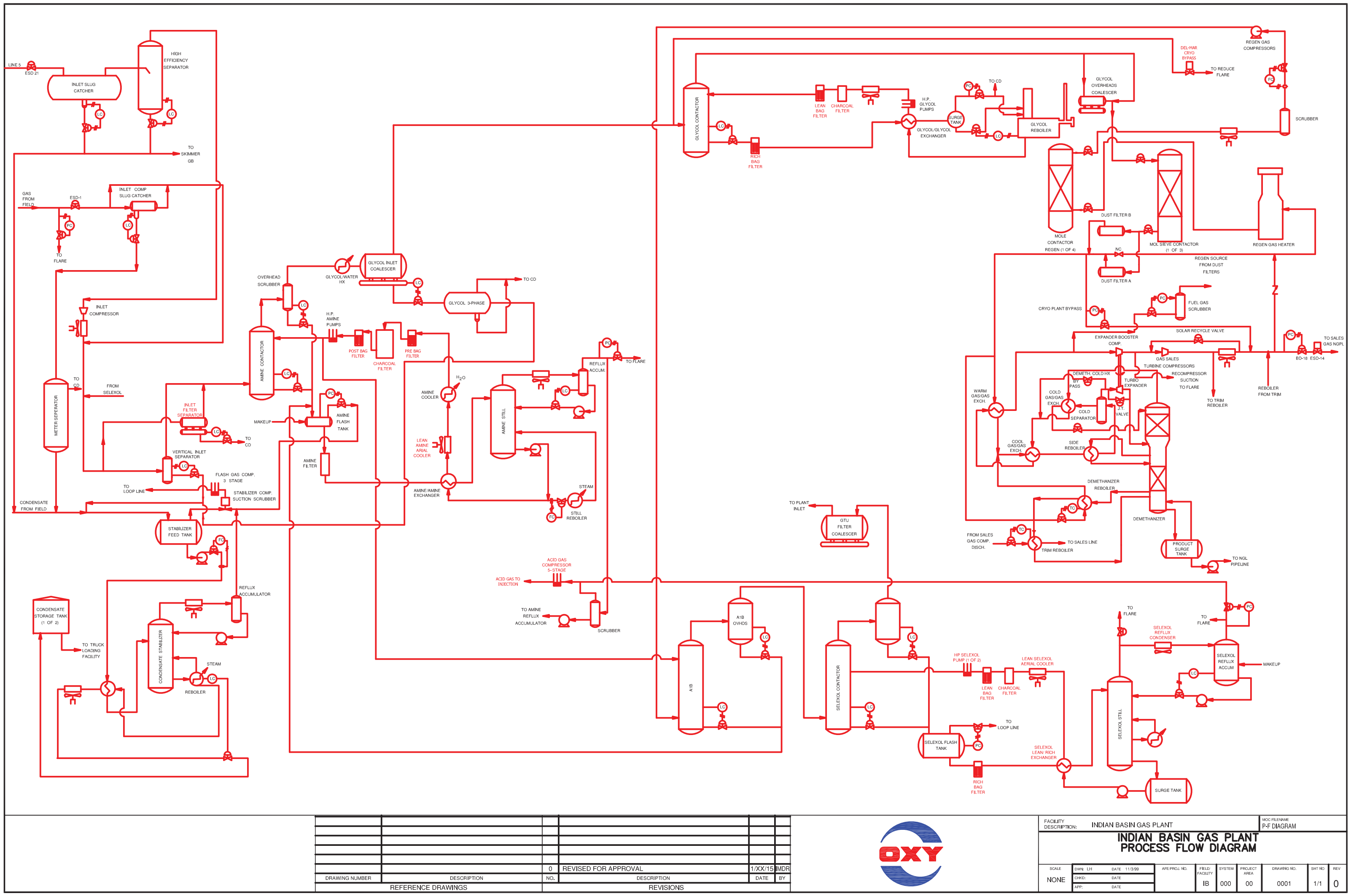
This application to meet the requirements of a Title V renewal application pursuant to 20.2.70.300.B.(2) NMAC which requires a Title V Permit renewal application to be submitted at least twelve (12) months prior to the expiration of the current Title V Operating Permit (the current permit expires November 1, 2024).

Section 4

Process Flow Sheet

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

A process flow sheet is attached.

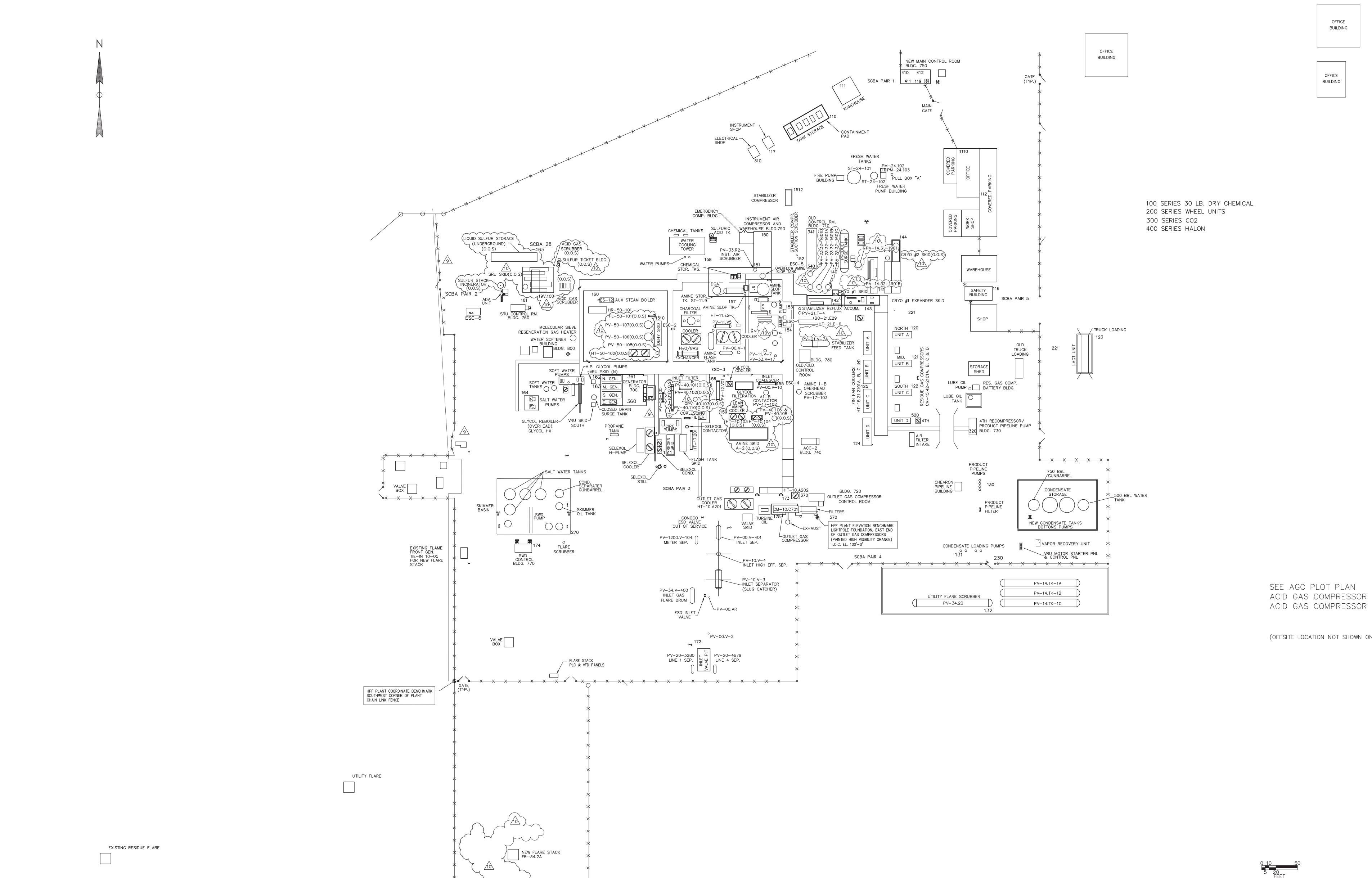

INLET SLUG CATCHER
HIGH EFFICIENCY SEPARATOR
TO SKIMMER GB
GAS FROM FIELD
INLET COMP. SLUG CATCHER
TO FLARE
INLET COMPRESSOR
METER SEPERATOR
FROM SELEXOL
INLET FILTER SEPARATOR
VERTICAL INLET SEPARATOR
FLASH GAS COMP. 3 STAGE
STABILIZER COMP. SUCTION SCRUBBER
TO LOOP LINE
CONDENSATE FROM FIELD
STABILIZER FEED TANK
REFLUX ACCUMULATOR
CONDENSATE STORAGE TANK (1 OF 2)
TO TRUCK LOADING FACILITY
CONDENSATE STABILIZER
STEAM
REBOILER
OVERHEAD SCRUBBER
GLYCOL/WATER HX
GLYCOL INLET COALESCER
GLYCOL 3-PHASE
TO CD
AMINE CONTACTOR
H.P. AMINE PUMPS
POST BAG FILTER
CHARCOAL FILTER
PRE BAG FILTER
MAKEUP
AMINE FLASH TANK
AMINE FILTER
AMINE COOLER
LEAN AMINE ARIAL COOLER
AMINE/AMINE EXCHANGER
AMINE STILL
REFLUX ACCUM
TO FLARE
STILL REBOILER
ACID GAS TO INJECTION
ACID GAS COMPRESSOR 5-STAGE
TO AMINE REFLUX ACCUMULATOR
SCRUBBER
GLYCOL CONTACTOR
RICH BAG FILTER
LEAN BAG FILTER
CHARCOAL FILTER
H.P. GLYCOL PUMPS
GLYCOL/GLYCOL EXCHANGER
SURGE TANK
GLYCOL REBOILER
GLYCOL OVERHEADS COALESCER
DEL-HAR CRYO BYPASS
TO REDUCE FLARE
REGEN GAS COMPRESSORS
SCRUBBER
MOLE CONTACTOR REGEN (1 OF 4)
DUST FILTER B
DUST FILTER A
MOL SIEVE CONTACTOR (1 OF 3)
REGEN SOURCE FROM DUST FILTERS
REGEN GAS HEATER
CRYO PLANT BYPASS
FUEL GAS SCRUBBER
SOLAR RECYCLE VALVE
EXPANDER BOOSTER COMP.
GAS SALES TURBINE COMPRESSORS
RECOMPRESSOR SUCTION TO FLARE
TO SALES GAS NGPL
WARM GAS/GAS EXCH.
COLD GAS/GAS EXCH.
COLD SEPARATOR
TURBO EXPANDER
TO TRIM REBOILER
REBOILER FROM TRIM
COOL GAS/GAS EXCH.
SIDE REBOILER
DEMETHANIZER REBOILER
DEMETHANIZER
FROM SALES GAS COMP. DISCH.
TO SALES LINE
TRIM REBOILER
PRODUCT SURGE TANK
TO NGL PIPELINE
TO PLANT INLET
GTU FILTER COALESCER
A/B OVHDS
A/B
SELEXOL CONTACTOR
HP SELEXOL PUMP (1 OF 2)
LEAN BAG FILTER
CHARCOAL FILTER
LEAN SELEXOL AERIAL COOLER
TO LOOP LINE
SELEXOL FLASH TANK
RICH BAG FILTER
SELEXOL LEAN/ RICH EXCHANGER
SELEXOL STILL
SELEXOL REFLUX CONDENSER
SELEXOL REFLUX ACCUM
MAKEUP
SURGE TANK
0 REVISED FOR APPROVAL 1/XX/15 MDR
DRAWING NUMBER
DESCRIPTION
NO.
DESCRIPTION
DATE
BY
REFERENCE DRAWINGS
REVISIONS
OXY
FACILITY DESCRIPTION: INDIAN BASIN GAS PLANT
MOC FILENAME
P-F DIAGRAM
INDIAN BASIN GAS PLANT
PROCESS FLOW DIAGRAM
SCALE
NONE
DWN: LH
DATE 11/3/99
CHKD:
DATE
APP:
DATE
AFE/PROJ. NO.
FIELD/ FACILITY
IB
SYSTEM
000
PROJECT AREA
00
DRAWING NO.
0001
SHT NO
1/1
REV
0

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.

Please find the plot plan attached.



100 SERIES 30 LB. DRY CHEMICAL
200 SERIES WHEEL UNITS
300 SERIES CO2
400 SERIES HALON

SEE AGC PLOT PLAN
ACID GAS COMPRESSOR = ZONE 1600
ACID GAS COMPRESSOR PLC – AGC-1600

(OFFSITE LOCATION NOT SHOWN ON THIS DWG.)

REVISED DESTROY ALL PREVIOUS ISSUES

ISSUED FOR 04/01/2015 AS BUILT

HPF CONSULTANTS, INC. TBPE FIRM REG. # 4098

NO:	DATE:	DESCRIPTION:	DRAWN:	CHECKED:	APPD:
6	9/24/13	REV. PER OXY MOC, OPM-10376	PVL		
5	5/22/12	REVISED AS BUILT PER HPF #12053	PVL		
11	04/01/15	UPDATED OXY LOGO, HPF #15015	LPD	SAY	
10	3/3/15	REVISED PER OXY, HPF #15015	IMDR	SAY	SAY
9	5/8/14	REVISED PER OXY, HPF #14027	PVL		
8	3/24/14	REVISED ES-12 LOC. PER HPF #13076	PVL	JW	
7	3/6/14	REV. PER OXY OPM #10561, HPF #14002	PVL		

REVISIONS:

	NAME:	DATE:
DESIGNED:		
DRAWN:	EC	3/4/10
CHECKED:		
APPD. DESIGN:		
APPD. DESIGN:		
APPD. DESIGN:		
APPD. PROCESS:		
APPD. PROJ. ENGR:		

ISSUED FOR CONSTRUCTION:
OXY APPROVAL: DATE:
OTHER APPROVAL: DATE:
OTHER APPROVAL: DATE:

HPF CONSULTANTS, INC.
ENGINEERING, DESIGN & INSPECTION
MIDLAND, TEXAS

INDIAN BASIN GAS PLANT
PLOT PLAN

SCALE: 1" = 60'-0" | FILENAME: D-C03-101C | DRAWING NO: D-C03-101C | 11

Section 6

All Calculations

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

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

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

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

Road Calculations: Calculate fugitive particulate emissions and enter haul road fugitives in Tables 2-A, 2-D and 2-E for:

1. If you transport raw material, process material and/or product into or out of or within the facility and have PER emissions greater than 0.5 tpy.
2. If you transport raw material, process material and/or product into or out of the facility more frequently than one round trip per day.

Significant Figures:

A. All emissions standards are deemed to have at least two significant figures, but not more than three significant figures.
B. At least 5 significant figures shall be retained in all intermediate calculations.
C. In calculating emissions to determine compliance with an emission standard, the following rounding off procedures shall be used:

- **(1)** If the first digit to be discarded is less than the number 5, the last digit retained shall not be changed;
- **(2)** If the first digit discarded is greater than the number 5, or if it is the number 5 followed by at least one digit other than the number zero, the last figure retained shall be increased by one unit; **and**
- **(3)** If the first digit discarded is exactly the number 5, followed only by zeros, the last digit retained shall be rounded upward if it is an odd number, but no adjustment shall be made if it is an even number.
- **(4)** The final result of the calculation shall be expressed in the units of the standard.

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

Emission calculations have not changed or been updated since the last Title V Renewal. Calculations being presented have not been reviewed or by Waid Environmental and were provided by OXY USA WTP LP.

Turbine Compressor

ES-17 – this emission source was replaced and updated in permit PSD0295-M10. The most recent calculation from PSD0295-M10 is included in this application.

Turbine Generator

ES-04 – this emission source was replaced as part of a like-kind replacement in PSD0295-M10R2. The previously permitted unit was replaced with the exact same unit and so calculations for the previously permitted unit are included and are representative of the replacement unit.

ES-05 – this emission source was replaced as part of a like-kind replacement in PSD0295-M9R2. The previously permitted unit was replaced with the exact same unit and so calculations for the previously permitted unit are included and are representative of the replacement unit.

Turbines

ES-06/07 – This emission source was updated with permit PSD0295-M8R3. The most recent calculation from permit PSD0295-M8R3 is included in this application.

ES-08/09 – This emission source was updated with permit PSD0295-M8. The most recent calculation from permit PSD0295-M8 is included in this application.

ES-10/11 – This emission source was updated with permit PSD0295-M8. The most recent calculation from permit PSD0295-M8 is included in this application.

ES-21 – This emission source was updated with permit PSD0295-M8. The most recent calculation from permit PSD0295-M8 is included in this application.

ES-22 – This emission source was updated with permit PSD0295-M8. The most recent calculation from permit PSD0295-M8 is included in this application.

Cooling Towers

ES-62 – This emission source was added with permit PSD0295-M8R1. The calculation from permit PSD0295-M8R4 is included in this application.

Gas Chromatographs

GC-1 & GC-2 – These two emission sources were originally permitted in PSD0295-M8R1, but the type of gas chromatographs were updated in permit PSD0295-M8R4. The emissions are the same as permitted in PSD0295-M8R1

NGL Truck Load Out

ES-60 & ES-61 – These two emission sources were added with permit PSD0295-M8R1. The calculation from permit PSD0295-M8R1 is included in this application.

Fugitives

FUG – This emission source was updated with permit PSD0295-M8R1. As well as in PSD0295-M9. The most recent calculation from PSD0295-M9 is attached in this application.

Tanks

ES-46 & ES-47 – This emission source was updated with permit PSD0295-M8. The calculation from permit PSD0295-M8 is included in this application.

ES-48 – This emission source was changed in PSD0295-M8. The calculations from that permit application is included in this section.
E**S-49 –** This emission source was updated with permit PSD0295-M8R1. The calculation from permit PSD0295-M8R1 is included in this application.

Truck Loading Operations

ES-56 – This emission source was updated with permit PSD0295-M8. The calculation from permit PSD0295-M8 is included in this application.

Flare

ES-50 Combustion/VOC emissions from Condensate Tanks and Truck Loading

ES-50 – This emission source was updated with permit PSD0295-M8. The calculation from permit PSD0295-M8 is included in this application. Emissions for this unit also changed in PSD0295-M8-R1 with Gas Chromatograph calculations.

Heaters

ES-02 – Regenerator Gas Heater: emissions are based on AP-42 Table 1.4-1 and 1.4-2 for NOx, CO, VOC, SO2 and PM as well as GRI HAPCalc for HAPs.

ES-03 – Glycol Regenerator Heater: emissions are based on AP-42 Table 1.4-1 and 1.4-2 for NOx, CO, VOC, SO2 and PM as well as GRI HAPCalc for HAPs.
Boilers

ES-12 – Auxiliary Boiler: emissions are based on AP-42 Table 1.4-1 and 1.4-2 for NOx, CO, VOC, SO2 and PM as well as GRI HAPCalc for HAPs.

Flare Maintenance Emissions Summary: Steady State and SSM Emissions

ES-14 Steady State/SSM Emissions – emissions based on SSM event as shown in calculations

ES-42 Steady State/SSM Emissions – emissions based on SSM event as shown in calculations

ES-50 Steady State/SSM Emissions – emissions based on SSM event as shown in calculations

Regenerators

ES-40 – Glycol Dehydrator Regenerator: emissions based on GRI-GLYCalc 4.0

Tanks

ES-52 – Skimmer Basin Oil/Condensate Tank: there are no flash emissions associated with this unit as the oil in this tank has been separated in a gunbarrel – only working and breathing emissions are included.

Greenhouse Gas Emissions

GHG totals in Table 2-P – This emission source was updated with permit PSD0295-M8. The calculation from permit PSD0295-M8 is included in this application.

Turbine			
Horsepower	5700	hp	CENTAUR 50-6100S Emissions Performance SolaNOx
Fuel HHV	1031	Btu/scf	
Heat Rate	8429	BTU/hp-hr	CENTAUR 50-6100S Emissions Performance SolaNOx
Heat Input	48.0	MMBtu/hr	Heat Rate (Btu/hp-hr) * hp * (MMBtu/10^6 BTU)
Fuel Usage	0.047	MMscf/hr	
Exhaust Flow	142369.0	lb/hr	CENTAUR 50-6100S Emissions Performance SolaNOx
Operating Hours	8760.0	hours	

NO_X	CO	Hydrocarbons (VOC)	SO_2[1]	TSP	PM_{10}	$PM_{2.5}$	HCOH[2]	Total HAP[3]		
25	50	25							ppm	Manufacturer's data
			4						ppm H2S	
				0.0067	0.0067	0.0067			lb/MMBtu	AP-42 Table 3.12a
4.8	5.8	1.67	0.032	0.32	0.32	0.32	0.16	0.50	lb/hr	
20%	20%	20%	0%	20%	20%	20%	20%	20%	Safety Factor	
5.8	7.0	2.0	0.032	0.39	0.39	0.39	0.19	0.60	lb/hr	
25.2	30.7	8.8	0.14	1.7	1.7	1.7	0.84	2.64	tpy	

1 SO2 emissions are based on the conversion of H2S to SO2 during the combustion process and a 1:1 molar ratio conversion of H2S to SO2. The fuel gas concentration is based on 4 ppm of H2S.
2 HCOH from Table 2 of Solar Turbines PIL 168 Product Information Letter
3 Total HAP calculated from GRI-HAPCalc 3.01 using manufacturer's HCOH

CO_2	CH_4	N_2O	CO_2e		
53.06	0.001	0.0001		kg/MMBtu	40 CFR 98 Subpart C
24616.5	11.6	13.8	24641.9	tpy	

GRI-HAPCalc ® 3.01
Turbine Report

Facility ID:	**IBGP**	**Notes:**
Operation Type:	**GAS PLANT**	
Facility Name:	**OXY INDIAN BASIN 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".

Turbine Unit

Unit Name: ES-17

Hours of Operation:	8,760	Yearly
Rate Power:	5700	hp
Fuel Type:	NATURAL GAS	
Emission Factor Set:	FIELD > EPA > LITERATURE	
Additional EF Set:	-NONE-	

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor	Emission Factor Set
HAPs			
PAHs	0.0005	0.00000970 g/bhp-hr	EPA
Formaldehyde	0.9314	0.01693680 g/bhp-hr	GRI Field
Acetaldehyde	0.9533	0.01733570 g/bhp-hr	GRI Field
1,3-Butadiene	0.0034	0.00006160 g/bhp-hr	GRI Field
Acrolein	0.0143	0.00026000 g/bhp-hr	GRI Field
Propional	0.0476	0.00086500 g/bhp-hr	GRI Field
Propylene Oxide	0.0070	0.00012730 g/bhp-hr	EPA
Benzene	0.0296	0.00053840 g/bhp-hr	GRI Field
Toluene	0.0226	0.00041100 g/bhp-hr	GRI Field
Ethylbenzene	0.0077	0.00014050 g/bhp-hr	EPA
Xylenes(m,p,o)	0.0684	0.00124410 g/bhp-hr	GRI Field
2,2,4-Trimethylpentane	0.0883	0.00160530 g/bhp-hr	GRI Field
n-Hexane	0.0828	0.00150580 g/bhp-hr	GRI Field
Phenol	0.0061	0.00011010 g/bhp-hr	GRI Field
Naphthalene	0.0004	0.00000760 g/bhp-hr	GRI Field
2-Methylnaphthalene	0.0001	0.00000130 g/bhp-hr	GRI Field
Biphenyl	0.0182	0.00033050 g/bhp-hr	GRI Field
Phenanthrene	0.0000	0.00000050 g/bhp-hr	GRI Field
Chrysene	0.0001	0.00000100 g/bhp-hr	GRI Field
Beryllium	0.0000	0.00000010 g/bhp-hr	GRI Field
Phosphorus	0.0036	0.00006520 g/bhp-hr	GRI Field
Chromium	0.0005	0.00000820 g/bhp-hr	GRI Field
Manganese	0.0010	0.00001750 g/bhp-hr	GRI Field
Nickel	0.0003	0.00000610 g/bhp-hr	GRI Field
Cobalt	0.0001	0.00000160 g/bhp-hr	GRI Field

Arsenic	0.0000	0.00000060	g/bhp-hr	GRI Field
Selenium	0.0000	0.00000030	g/bhp-hr	GRI Field
Cadmium	0.0000	0.00000020	g/bhp-hr	GRI Field
Mercury	0.0001	0.00000270	g/bhp-hr	GRI Field
Lead	0.0002	0.00000340	g/bhp-hr	GRI Field
Total	2.2876			

Criteria Pollutants

PM	1.5932	0.02897200	g/bhp-hr	EPA
CO	115.9371	2.10828420	g/bhp-hr	GRI Field
NMHC	10.6616	0.19387800	g/bhp-hr	GRI Field
NMEHC	0.5069	0.00921840	g/bhp-hr	EPA
NOx	68.8579	1.25216290	g/bhp-hr	GRI Field
SO2	0.0565	0.00102720	g/bhp-hr	GRI Field

Other Pollutants

Methane	54.2869	0.98719230	g/bhp-hr	GRI Field
Acetylene	0.3940	0.00716540	g/bhp-hr	GRI Field
Ethylene	0.7674	0.01395450	g/bhp-hr	GRI Field
Ethane	8.2533	0.15008370	g/bhp-hr	GRI Field
Propane	0.8799	0.01600000	g/bhp-hr	GRI Field
Isobutane	0.2640	0.00480000	g/bhp-hr	GRI Field
Butane	0.2860	0.00520000	g/bhp-hr	GRI Field
Cyclopentane	0.0908	0.00165110	g/bhp-hr	GRI Field
Butyrald/Isobutyraldehyde	0.0737	0.00134000	g/bhp-hr	GRI Field
n-Pentane	4.4625	0.08115000	g/bhp-hr	GRI Field
Cyclohexane	0.3368	0.00612400	g/bhp-hr	GRI Field
Methylcyclohexane	0.4856	0.00883120	g/bhp-hr	GRI Field
n-Octane	0.1754	0.00318890	g/bhp-hr	GRI Field
1,3,5-Trimethylbenzene	0.1650	0.00300000	g/bhp-hr	GRI Field
n-Nonane	0.0293	0.00053260	g/bhp-hr	GRI Field
CO2	26,553.3800	482.86607780	g/bhp-hr	EPA
Vanadium	0.0000	0.00000070	g/bhp-hr	GRI Field
Copper	0.0011	0.00002050	g/bhp-hr	GRI Field
Molybdenum	0.0011	0.00002030	g/bhp-hr	GRI Field
Barium	0.0013	0.00002290	g/bhp-hr	GRI Field

Indian Basin Gas Plant

Unit ID - Description	**ES-04 Solar Saturn 10-T1200 Turbine**			
Fuel	Natural Gas			
Annual Use	7009	MW-hrs		
Hourly Load Rate	0.80	MW		
HHV of Fuel	1031	Btu/scf		
Engine Rating	1073	BHP		
Load Percent	100%	percent		
Annual Operating Hours	8760	hrs/yr		
Heat Rate	15374	Btu/KW-hr		
Efficiency	22.2%	percent		
Heat Rate	11530	BTU/hp-hr		
Heat Input	12.30	MMBTU/hr	107,760	MMBtu/year
Dry Fd	9190	dscf/MMBTU		
Exhaust Flow	0.40	MMdscf/hr		

Constituent	ppm	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	**lb/hr**	**tons/yr**
Nitrogen Oxides (as NO_2)	82	0.32	lb/MMBtu	17.24	3.94	10%	4.3	**18.9**
Carbon Monoxide (CO)	124	1.52	g/hp/hr	15.75	3.60	89%	6.8	**29.8**
Hydrocarbons (VOC) as CH_4	5	0.09	lb/hr	0.39	0.09	714%	0.7	**3.2**
Sulfur Dioxide (SO_2)	0.1	-	-	0.035	0.0079	0%	0.0079	**0.0347**
Particulate matter (as PM_{10})	0.0014	0.0067	lb/MMBtu	0.361	0.082	25%	0.103	**0.5**

<u>* Emission Factors</u>

NOx = 0.32 lb/MMBtu (AP-42, Table 3.1-1, 4/00)
CO = 1.52 g/hp-hr (Source Test)
VOC = 0.09 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/22.2% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.
Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx					
	AP-42	3.98	1.69	**0.32**	For loads >80%
CO	**Src Test**	3.60	**1.52**	0.29	
VOC					
	Mfr	**0.09**	0.038	0.007	
PM					
	AP-42	0.082	0.035	**0.0067**	For loads >80%

Indian Basin Gas Plant

Unit ID - Description	**ES-05 Solar Saturn 10-T1200 Turbine**	
Fuel	Natural Gas	
Annual Use	7009	MW-hrs
Hourly Load Rate	0.80	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	1073	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	15374	Btu/KW-hr
Efficiency	22.2%	percent
Heat Rate	11530	BTU/hp-hr
Heat Input	12.30	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	0.40	MMdscf/hr

Constituent	ppm	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	**lb/hr**	**tons/yr**
Nitrogen Oxides (as NO_2)	82	0.32	lb/MMBtu	17.24	3.936	10%	4.3	**18.9**
Carbon Monoxide (CO)	96	2.79	lb/hr	12.22	2.79	144%	6.8	**29.8**
Hydrocarbons (VOC) as CH_4	5	0.09	lb/hr	0.39	0.09	714%	0.7	**3.2**
Sulfur Dioxide (SO_2)	0.1	-	-	0.035	0.0079	0%	0.0079	**0.0347**
Particulate matter (as PM_{10})	0.0014	0.0067	lb/MMBtu	0.361	0.082	25%	0.103	**0.5**

* Emission Factors

NOx = 0.32 lb/MMBtu (AP-42, Table 3.1-1, 4/00)
CO = 2.79 g/hp-hr (Manufacturer's Test Data)
VOC = 0.09 lb/hr (Manufacturer's Test Data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/22.2% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.
Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx	**AP-42**	3.98	1.69	**0.32**	For loads >80%
CO	**Mfr**	**2.79**	1.18	0.23	
VOC	**Mfr**	**0.09**	0.038	0.007	
PM	**AP-42**	0.082	0.035	**0.0067**	For loads >80%

Indian Basin Gas Plant

ES-06/07

Revised 12-9-14

Unit ID - Description	**ES-06/07 Solar Centaur 40-4000 Turbine**	
Fuel	Natural Gas	
Annual Use	26130	MW-hrs
Hourly Load Rate	2.98	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	4000	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	13077	Btu/KW-hr
Efficiency	26.1%	percent
Heat Rate	9807	BTU/hp-hr
Heat Input	39.01	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	1.27	MMdscf/hr

Constituent	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	lb/hr	tons/yr
Nitrogen Oxides (as NO_2)	10.57	lb/hr	46.30	10.57	46%	15.4	**67.4**
Carbon Monoxide (CO)	0.083	lb/MMBtu	14.18	3.24	20%	3.9	**17.0**
Hydrocarbons (VOC) as CH_4	0.12	lb/hr	0.53	0.12	1004%	1.3	**5.8**
Sulfur Dioxide (SO_2)	4.0	ppm	0.110	0.025	0%	0.025	**0.11**
Particulate matter (as PM_{10})	0.0067	lb/MMBtu	1.145	0.261	25%	0.327	**1.4**

* Emission Factors

NOx = 10.57 lb/hr (TRC Stack Test Data, September 2014)
CO = 0.082 lb/MMBtu (AP-42, Table 3.1-1, 4/00) x 1031/1020 (adjustment per footnote b) =0.083 lb/MMBtu.
VOC = 0.12 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/26.1% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.

Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx					
	Test Data	**10.57**	1.20	0.27	
CO	**AP-42**	3.23	0.37	**0.083**	For loads >80%
VOC					
	Mfr	**0.12**	0.014	0.0031	
PM	**AP-42**	0.260	0.030	**0.0067**	For loads >80%

OXY USA WTP LP

Indian Basin Gas Plant

ES-08/09

Revised 12-9-14

Unit ID - Description	**ES-08/09 Solar Centaur 40-4000 Turbine**	
Fuel	Natural Gas	
Annual Use	26130	MW-hrs
Hourly Load Rate	2.98	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	4000	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	13077	Btu/KW-hr
Efficiency	26.1%	percent
Heat Rate	9807	BTU/hp-hr
Heat Input	39.01	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	1.27	MMdscf/hr

Constituent	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	**lb/hr**	**tons/yr**
Nitrogen Oxides (as NO_2)	13.09	lb/hr	57.33	13.09	18%	15.4	**67.4**
Carbon Monoxide (CO)	0.083	lb/MMBtu	14.18	3.24	20%	3.9	**17.0**
Hydrocarbons (VOC) as CH_4	0.12	lb/hr	0.53	0.12	1004%	1.3	**5.8**
Sulfur Dioxide (SO_2)	4.0	ppm	0.110	0.025	0%	0.0251	**0.11**
Particulate matter (as PM_{10})	0.0067	lb/MMBtu	1.145	0.261	25%	0.327	**1.4**

* Emission Factors

NOx = 13.09 lb/hr (TRC Stack Test Data, September 2014)
CO = 0.082 lb/MMBtu (AP-42, Table 3.1-1, 4/00) x 1031/1020 (adjustment per footnote b) =0.083 lb/MMBtu.
VOC = 0.12 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/26.12% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.

Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx					
	Test Data	**13.09**	1.48	0.34	
CO	AP-42	3.23	0.37	**0.083**	For loads >80%
VOC					
	Mfr	**0.12**	0.014	0.0031	
PM	AP-42	0.260	0.030	**0.0067**	For loads >80%

Indian Basin Gas Plant

ES-10/11

Revised 12-9-14

Unit ID - Description	**ES-10/11 Solar Centaur 40-4000 Turbine**	
Fuel	Natural Gas	
Annual Use	26130	MW-hrs
Hourly Load Rate	2.98	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	4000	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	13077	Btu/KW-hr
Efficiency	26.1%	percent
Heat Rate	9807	BTU/hp-hr
Heat Input	39.01	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	1.27	MMdscf/hr

Constituent	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	**lb/hr**	**tons/yr**
Nitrogen Oxides (as NO_2)	10.95	lb/hr	47.96	10.95	1.37%	11.1	**48.6**
Carbon Monoxide (CO)	0.083	lb/MMBtu	14.18	3.24	20%	3.9	**17.0**
Hydrocarbons (VOC) as CH_4	0.12	lb/hr	0.53	0.12	1004%	1.3	**5.8**
Sulfur Dioxide (SO_2)	-	-	0.110	0.025	0%	0.025	**0.11**
Particulate matter (as PM_{10})	0.0067	lb/MMBtu	1.145	0.261	25%	0.33	**1.4**

* Emission Factors

NOx = 10.95 lb/hr (Oxy data)
CO = 0.082 lb/MMBtu (AP-42, Table 3.1-1, 4/00) x 1031/1020 (adjustment per footnote b) =0.083 lb/MMBtu.
VOC = 0.12 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/26.1% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.
Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx					
	Test Data	**10.95**	1.24	0.28	
CO	**AP-42**	3.23	0.37	**0.083**	For loads >80%
VOC					
	Mfr	**0.12**	0.014	0.0031	
PM	**AP-42**	0.260	0.030	**0.0067**	For loads >80%

Indian Basin Gas Plant

Unit ID - Description	**ES-21 Solar Saturn 10-T1021 Turbine**	
Fuel	Natural Gas	
Annual Use	7009	MW-hrs
Hourly Load Rate	0.80	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	1073	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	15374	Btu/KW-hr
Efficiency	22.2%	percent
Heat Rate	11530	BTU/hp-hr
Heat Input	12.30	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	0.40	MMdscf/hr

Constituent	ppm	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	lb/hr	tons/yr
Nitrogen Oxides (as NO_2)	53	2.55	lb/hr	11.17	2.55	15.9%	3.0	**12.9**
Carbon Monoxide (CO)	54	1.56	lb/hr	6.83	1.56	76.3%	2.8	**12.0**
Hydrocarbons (VOC) as CH_4	5	0.09	lb/hr	0.39	0.09	0%	0.1	**0.4**
Sulfur Dioxide (SO_2)	0.1	-	-	0.035	0.008	0%	0.0079	**0.03**
Particulate matter (as PM_{10})	0.0014	0.0067	lb/MMBtu	0.36	0.082	25%	0.103	**0.5**

* Emission Factors

NOx = 2.55 lb/hr (Manufacturer's Test data)
CO = 1.56 lb/hr (Source Test)
VOC = 0.09 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/22.2% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.

Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx	**Mfr**	**2.55**	1.08	0.21	
CO	**Src Test**	**1.56**	0.66	0.13	
VOC	**Mfr**	**0.09**	0.038	0.0073	
PM	**AP-42**	0.082	0.035	**0.0067**	For loads >80% -Adjusted

Indian Basin Gas Plant

Unit ID - Description	**ES-22 Solar Centaur 40-4700S Turbine**	
Fuel	Natural Gas	
Annual Use	30702	MW-hrs
Hourly Load Rate	3.50	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	4700	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	12511	Btu/KW-hr
Efficiency	27.3%	percent
Heat Rate	9383	BTU/hp-hr
Heat Input	43.85	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	1.43	MMdscf/hr

Constituent	ppm	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	**lb/hr**	**tons/yr**
Nitrogen Oxides (as NO_2)	35	5.88	lb/hr	25.75	5.88	5%	6.2	**27.0**
Carbon Monoxide (CO)	41	4.26	lb/hr	18.66	4.26	20%	5.1	**22.4**
Hydrocarbons (VOC) as CH_4	21	1.22	lb/hr	5.34	1.22	10.9%	1.4	**5.9**
Sulfur Dioxide (SO_2)	0.1	-	-	0.124	0.028	0%	0.028	**0.12**
Particulate matter (as PM_{10})	0.0014	0.0067	lb/MMBtu	1.29	0.294	25%	0.37	**1.6**

* Emission Factors

NOx = 5.88 lb/hr (Manufacturer's Test Data)
CO = 4.26 lb/MMBtu (Manufacturer's Test Data)
VOC = 1.22 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/27.3% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.
Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx	Src Test	2.39	0.23	0.05	
	AP-42	14.18	1.38	0.32	For loads >80% -Adjusted
	Mfr	**5.88**	0.57	0.13	
CO	Src Test	1.35	0.13	0.03	
	AP-42	3.63	0.35	0.083	For loads >80% -Adjusted
	Mfr	**4.26**	0.411	0.097	
VOC	Src Test	-	-	-	
	AP-42	0.09	0.0090	0.0021	For loads >80% -Adjusted
	Mfr	**1.22**	0.118	0.0278	
PM	Src Test	-	-	-	
	AP-42	0.293	0.028	**0.0067**	For loads >80% -Adjusted
	Mfr	-	-	-	

Red font = units of EF source
Blue font - Units converted from EF source units

Cooling Tower (ES-62)

Estimation of the emission rate of TSP, PM_{10} and $PM_{2.5}$ from a new cooling tower at the Indian Basin Gas Plant. The emission estimates were based on Total Dissolved Solids (TDS) concentrations derived from conductivity measurements taken from the recirculation flow of the cooling tower.

CALCULATION METHODOLOGY

The methodology to calculate the emission rates from the cooling towers is split into three steps:

1) TDS calculation of the cooling tower liquids based on conductivity measurements.
2) Estimation of the dry particle distribution from wet liquid droplets.
3) Calculating the emission rates for TSP, PM_{10} and $PM_{2.5}$.

These steps are explained in more detail below.

TDS Calculation

A conductivity analysis of the cooling tower water was conducted by Smart Chemical Services on December 1, 2014. A copy of the Field Service Report is included in Attachment 1 for reference. The results of the conductivity analysis show that the cooling tower conductivity is 2900 µmhos/cm (or 2900 µS/cm). This measurement was made using a Myron L model EP-10 conductivity meter.

The conductivity of a liquid sample is directly proportional to the TDS content of the sample[1]. A study conducted by Atekwana et al, in collaboration with the US Environmental Protection Agency (EPA) has derived the following relationship for conductivity and TDS (Equation 1):

$$TDS\left(\frac{mg}{L}\right) = k \times Conductivity\left(\frac{\mu S}{cm}\right) \qquad \text{Equation 1.}$$

Where: $k \sim 0.64$ $(0.55 \leq k \leq 0.8)$
The conductivity of a liquid is proportional to the temperature of the liquid and composition of the TDS within the liquid. The Myron L EP-10 instrument compensates for temperature and corrects the measured data to a standard 25 °C. For this analysis it is assumed that the TDS has a typical composition of $CaCO_3$, $CaSO_4$, $CaCl_2$ NaCl, Na_2SO_4, and Na_2CO_3 and an average density (ρ_{TDS})[2] of 2.5 g/cm^3. Using Equation 1, the conductivity measurement of 2900 µS/cm and assuming a value of k = 0.64, the TDS concentration was calculated and is shown in Table 1. Additionally, a safety factor of 20% was also added to the calculated TDS concentration and used for all future calculations.

Table 1. Estimation of TDS from conductivity measurements.

Location	Conductivity (µmhos/cm)	Conductivity (µS/cm)	TDS (mg/L) (Equation 1)	TDS (mg/L) x Safety Factor (20%)
Cooling Tower	2900	2900	1856	2227

1 Atekwana, E. A., Atekwana, E. A., Rowe, R. S., Werkema Jr, D. D., Legall, F. D., The relationship of total dissolved solids measurements to bulk electrical conductivity in an aquifer contaminated with hydrocarbon. *Journal of Applied Geophysics*, Volume 56, Issue 4, November 2004, Pages 281-294, (2004).

2 Calculating TSP, PM-10 and PM2.5 from Cooling Towers - Technical Memorandum, New Mexico Environment Department, Daren Zigich, September 9, 2013.

Wet Droplet to Dry Particle Calculation

To accurately reflect the PM emissions from a cooling tower the process of evaporating liquid droplets containing TDS to form dry particles must be evaluated. The method used for this analysis is consistent with NMED guidance[2] and that of Reisman and Frisbie[3]. Table 2 shows the calculations for the dry particle diameter based on the initial droplet diameter emitted from the cooling tower and the TDS content. The cumulative particle mass fraction across all particle sizes is also calculated and used to derive the total mass percentage for TSP, PM_{10} and $PM_{2.5}$ through interpolation, the results of which are shown in Table 3.

The equations used in the derivation of the dry particle diameter are shown below and referenced in Table 2.

$$Droplet\ Volume = \left(\frac{4}{3}\right)\pi\left(\frac{D_d}{2}\right)^3 \qquad \text{Equation 2.}$$

$$Droplet\ Mass = Droplet\ Volume \times \rho_{Water} \qquad \text{Equation 3.}$$

$$Particle\ Mass = TDS \times \rho_{water} \times \left(\frac{4}{3}\right)\pi\left(\frac{D_d}{2}\right)^3 \qquad \text{Equation 4.}$$

$$Particle\ Volume = \frac{Particle\ Mass}{\rho_{TDS}} \qquad \text{Equation 5.}$$

$$Particle\ Diameter = 2 \times \sqrt[3]{Particle\ Volume \times \left(\frac{1}{\pi}\right) \times \left(\frac{3}{4}\right)} \qquad \text{Equation 6.}$$

[3] Calculating Realistic PM10 Emissions from Cooling Towers, Abstract No. 216 Session No. AS-1b, J. Reisman and G. Frisbie, Greyston Environmental Consultants, Inc.

Cooling Tower (ES-62)

Table 2. Droplet to Particle Distribution calculations.

Droplet Diameter	Droplet Volume (Equation 2)	Droplet Mass (Equation 3)	Particle Mass (Equation 4)	Solid Particle Volume (Equation 5)	Particle Diameter (Equation 6)	Particle % Mass
(μm)	(μm^3)	(μg)	(μg)	(μm^3)	(μm)	Smaller
10	524	5.24E-04	1.17E-06	4.66E-01	0.96	0.000
20	4189	4.19E-03	9.33E-06	3.73E+00	1.92	0.00
30	14137	1.41E-02	3.15E-05	1.26E+01	2.89	0.01
40	33510	3.35E-02	7.46E-05	2.99E+01	3.85	0.016
50	65450	6.54E-02	1.46E-04	5.83E+01	4.81	0.036
60	113097	1.13E-01	2.52E-04	1.01E+02	5.77	0.071
70	179594	1.80E-01	4.00E-04	1.60E+02	6.74	0.126
90	381704	3.82E-01	8.50E-04	3.40E+02	8.66	0.243
110	696910	6.97E-01	1.55E-03	6.21E+02	10.58	0.456
130	1150347	1.15E+00	2.56E-03	1.02E+03	12.51	0.809
150	1767146	1.77E+00	3.94E-03	1.57E+03	14.43	1.351
180	3053628	3.05E+00	6.80E-03	2.72E+03	17.32	2.287
210	4849048	4.85E+00	1.08E-02	4.32E+03	20.21	3.773
240	7238229	7.24E+00	1.61E-02	6.45E+03	23.09	5.992
270	10305995	1.03E+01	2.30E-02	9.18E+03	25.98	9.152
300	14137167	1.41E+01	3.15E-02	1.26E+04	28.87	13.49
350	22449298	2.24E+01	5.00E-02	2.00E+04	33.68	20.37
400	33510322	3.35E+01	7.46E-02	2.99E+04	38.49	30.640
450	47712938	4.77E+01	1.06E-01	4.25E+04	43.30	45.266
500	65449847	6.54E+01	1.46E-01	5.83E+04	48.11	65.330
600	113097336	1.13E+02	2.52E-01	1.01E+05	57.73	100.000

Table 3. Total PM Mass Percentage as a function of TSP, PM_{10} and $PM_{2.5}$.

	PM Diameter (μm)	Total PM Mass %
$PM_{2.5}$	2.5	0.004
PM_{10}	10	0.392
TSP	30	15.107

Cooling Tower Emissions Calculation

Using the estimated TDS content derived from the conductivity measurements, cooling tower parameters and the total mass percentage of TSP, PM_{10} and $PM_{2.5}$, the emissions of TSP, PM_{10} and $PM_{2.5}$ from the cooling tower can be calculated. Table 4 shows the cooling tower operational parameters such as the recirculation rate, drift rate fraction and TDS concentrations.

Cooling Tower (ES-62)

Table 4. Cooling tower operational parameters.

	Cooling Water Recirculation Rate (gpm)	Drift Rate fraction of Circulating Flow (Q_{drift}) %	Total Drift Mass lb/min	Circulating Water Total Dissolved Solids (mg/l)	Circulating Water Total Dissolved Solids (ppm_w)
Note	1	2	3	4	
Cooling Tower	5,000	0.050%	20.9	2,227	2,227

The total drift mass and the TDS concentration are used to calculate the hourly uncontrolled particulate emissions shown in Table 5. This emission rate is for particles of all diameter within the particle size distribution (0 μm ≤ Dp ≤ 600 μm) and must be scaled to find the mass contribution of PM for TSP, PM_{10} and $PM_{2.5}$ using the total mass percentage values for each size shown in Table 3 to produce the final emission rates. The total annual and hourly emission rates for the TSP, PM_{10} and $PM_{2.5}$ are shown in Table 5. A safety factor of 20% has been added to the emission rates and included in Table 6.

Table 5. Calculation of TSP, PM_{10} and $PM_{2.5}$ emission rate from cooling tower.

	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	5	5	6	6	6	6	6	6
Cooling Tower	2.79	12.20	0.42	1.84	0.01	0.05	0.00011	0.0005

Notes

1 Cooling Tower Water Recirculation rate based on email from Aditya Singh (Oxy) to Rob Liles (Trinity) 02/25/2015 = 5,000 gpm

2 Uncontrolled circulating water flow percent drift estimated based on manufacturer specifications for Accu-Pac CF150MAx drift eliminators and email from Aditya Singh (Oxy) to Rob Liles (Trinity) 02/25/2012.

3 Total Drift Mass = Recirculation rate * Drift Rate Fraction * Drift Density (Water = 8.34 lb/gal)

4 TDS estimated by conversion of conductivity of cooling tower liquids.

5 Total particulate emission calculated using procedure described in "Calculating TSP, PM10 and PM2.5 from Cooling Towers - Technical Memorandum", Daren Zigich, September 9, 2013.

PM = Water Circulation Rate * Drift Rate* Percent drift mass escape * TDS

Particulate Hourly Emissions:

$$\frac{5{,}000\text{ gal}}{\text{min}} \cdot \frac{60\text{ min}}{\text{hr}} \cdot \frac{0.0005\text{ gal drift}}{\text{gal recirculation}} \cdot 15.1\,\% \cdot \frac{8.34\text{ lb drift}}{\text{gal drift}} \cdot \frac{2227\text{ lb PM}}{10^6\text{ lb drift}} = \frac{2.79\text{ lb}}{\text{hr}}$$

Particulate annual emissions = Hourly emissions (lb/hr) * 8760 (hrs/yr) / 2000 (lb/ton)

6 Particle size distribution based on the following distribution (based on Droplet/Particle Distribution Table)

Cooling Tower (ES-62)

Table 6. Calculation of TSP, PM_{10} and $PM_{2.5}$ emission rate from cooling tower with safety factor.

	Hourly Uncontrolled Particulate Emissions w/ SF (lb/hr)	Annual Uncontrolled Particulate Emissions w/SF (tpy)	Hourly Uncontrolled TSP Emissions w/SF (lb/hr)	Annual Uncontrolled TSP Emissions w/SF (tpy)	Hourly Uncontrolled PM10 Emissions w/SF (lb/hr)	Annual Uncontrolled PM10 Emissions w/SF (tpy)	Hourly Uncontrolled PM2.5 Emissions w/SF (lb/hr)	Annual Uncontrolled PM2.5 Emissions w/SF (tpy)
Note	1	1	1	1	1	1	1	1
Cooling Tower	3.34	14.64	0.51	2.21	0.01	0.06	0.00013	0.0006

Notes

1 Safety Factor of 20% added to calculations

Gas Chromatographs (GC-1 GC-2)

Emissions from the gas chromatographs (GC-1 & GC-2) are sent to the flare (ES-50). A 98% destruction efficiency of H2S and VOC and a 1:1 molar ratio conversion of H2S to SO2 was assumed.

INLET GC (4,380 hrs/yr)

	MW	Mol%	Weighted MW (lb/lbmole)	mass (lb/yr)
Methane	16.04246	81.99%	13.153	6.84
Ethane	30.06904	8.49%	2.553	1.33
Propane	44.09562	3.88%	1.710	0.89
I-Butane	58.1222	0.52%	0.301	0.16
N-Butane	58.1222	1.13%	0.657	0.34
I-Pentane	72.14878	0.27%	0.195	0.10
N-Pentane	72.14878	0.27%	0.198	0.10
Hexane +	86.17536	0.44%	0.378	0.20
H2S	34.08	0.15%	0.051	0.03
CO2	44.01	0.49%	0.215	0.11
		97.63%	19.412	9.86
			VOC Total (lb/yr):	1.79
			H2S Total (lb/yr):	0.03

Stream	**Hours of Operation**	**Inlet Flow**	**Flare Efficiency**	**Un-combusted Flow**	**Un-combusted Flow**
	hrs/yr	**cm^3/min**	**%**	**m^3/yr**	**ft^3/yr**
GC1 (sales):	4380	400	98	2.10	74.25
GC1 (inlet):	4380	400	98	2.10	74.25
GC2 (NGL):	8760	400	98	4.20	148.49

PV=nRT		
n=PV/RT		
m(lb)=PV(MW)/RT		
P=39.7 psia	(15 psig+14.7)	39.7 <-- gas is 15 psig
T= 528R	(460+68)	528 <-- assumed standard ambient 68 deg F
V= defined above ft3		
R=10.732 ft3-psi/R lb-mol		10.732

Gas Chromatographs (GC-1 GC-2)

SALES GC (4,380 hrs/yr)

	Mol%	Weighted MW lb/lbmole	mass (lb/yr)
Methane	92.93%	14.909	7.76
Ethane	3.24%	0.973	0.51
Propane	0.13%	0.057	0.03
I-Butane	0.00%	0.003	0.00
N-Butane	0.01%	0.003	0.00
I-Pentane	0.00%	0.000	0.00
N-Pentane	0.00%	0.000	0.00
Hexane +	0.00%	0.000	0.00
H2S	0.00%	0.000	0.00
CO2	0.00%	0.000	0.00
	96.31%	15.944	7.99
		VOC Total (lb/yr):	0.03
		H2S Total (lb/yr):	0.00

NGL GC (8,760 hrs/yr)

	Mol%	Weighted MW lb/lbmole	mass (lb/yr)
Methane	0.75%	0.120	0.13
Ethane	46.34%	13.934	14.50
Propane	32.86%	14.490	15.07
I-Butane	4.18%	2.430	2.53
N-Butane	9.15%	5.318	5.53
I-Pentane	2.14%	1.544	1.61
N-Pentane	2.09%	1.508	1.57
Hexane +	2.48%	2.137	2.22
H2S	0.00%	0.000	0.00
CO2	0.00%	0.000	0.00
	99.99%	41.481	8.29
		VOC Total (lb/yr):	28.53
		H2S Total (lb/yr):	0.00

GC-1 & GC-2 Emissions Summary

Unit No.	VOC (lb/hr)	H2S (lb/hr)	Safety Factor (%)	VOC w/SF (lb/hr)	H2S w/SF (lb/hr)	VOC w/SF (tpy)	H2S w/SF (tpy)
GC-1	3.3E-03	0.00	20	3.9E-03	0.00	0.017	0.00
GC-2	2.0E-04	3.0E-06	20	2.5E-04	3.6E-06	0.001	4.7E-03

NGL Truck Load Out (ES-60)

NGL Unloading Throughput Data

Truck capacity	8,000	gal/truck
	190	bbl/truck
Number of trucks per hour	2	trucks/hr
Number of trucks per day	6	trucks/day
Hourly Throughput	381	bbl/hr
Daily Throughput	1,143	bbl/day
Annual Throughput	417,143	bbl/yr
Loading Rack Control Device	Vapor balance	

Materials Transferred at Truck Rack

Material Transferred	Material Type	Loading or Unloading	Control Device
Natural Gas	Liquid	Loading	Vapor Balance

Liquid Loading Losses (Hose Disconnect Fugitive Emissions)

Source ID	Material Transferred	Loading or Unloading	Loading Arm Diameter[2] (in)	Soft Hose Length[2] (ft)	Gas Molecular Weight[1] (lb/lb-mole)	Loading Arm Pipe Length (ft)	Loading Arm Overpressure (psig)	Depressurized Volume[2] (ft^3/truck)	Annual Throughput (bbl/yr)	Fugitive Emissions (lb/truck)
ES-60	Natural Gas Liquids	Loading	2	40	42	0	1	0.93	417,143	1.02E-01

Hourly VOC Emissions[3] (lb/hr)	Annual VOC Emissions[4] (tpy)	Safety Factor (%)	Hourly VOC Emissions[3] (lb/hr)	Annual VOC Emissions[4] (tpy)
0.20	0.11	20.00	0.24	0.13
Total Fugitive Emissions from Trucks				

[1] Vapor Molecular Weight and hose parameters from Gas Analysis received via email from Aditya Singh (Oxy) to Rob Liles (Trinity) 04/21/2015

[2] The hose will be capped as soon as it is disconnected from the truck. It is assumed, all of the vapor from the soft hose is released (worst case emissions)

[3] For hourly emissions, it is assumed that the truck rack can unload 2 trucks per hour.

[4] Annual emissions are based on the maximum of 6 trucks per day at a truck capacity of 8,000 gallons per truck

Sample Calculation

Depressurized Volume: $\dfrac{2.18\text{E-}02 \text{ sq ft}}{} \Big| \dfrac{40 \text{ ft}}{} = \dfrac{0.93 \text{ cubic ft}}{\text{truck}}$

Unloading Emissions: $\dfrac{0.93 \text{ cubic ft}}{\text{truck}} \Big| \dfrac{\text{lb-mol}}{385.4 \text{ cubic ft}} \Big| \dfrac{42 \text{ lb}}{\text{lb-mol}} = \dfrac{1.02\text{E-}01 \text{ lb}}{\text{truck}}$

Annual Emission: $\dfrac{1.02\text{E-}01 \text{ lb}}{\text{truck}} \Big| \dfrac{417{,}143 \text{ bbl}}{\text{yr}} \Big| \dfrac{\text{truck}}{190 \text{ bbl}} \Big| \dfrac{\text{ton}}{2000 \text{ lb}} = \dfrac{1.12\text{E-}01 \text{ ton}}{\text{yr}}$

VOC and H2 S Emissions (no safety factor)

Stream	VOC (lb/day)	VOC (tpy)	H2S (lb/day)	H2S (tpy)
Table 2-4 NGL Gas Stream	59.44	10.85	0.00	0.00
Table 2-4 Stabilizer	33.46	6.11	0.54	0.10
Table 2-4 Fuel Residue	4.01	0.73	0.00	0.00
Table 2-4 Inlet	23.85	4.35	0.75	0.14
Table 2-4 Amine	9.59	1.75	0.00	0.00
TOTAL:	**130.36**	**23.79**	**1.29**	**0.24**

VOC and H2 S Emissions (10% safety factor)

Stream	VOC (lb/day)	VOC (tpy)	H2S (lb/day)	H2S (tpy)
Table 2-4 NGL Gas Stream	65.38	11.93	0.00	0.00
Table 2-4 Stabilizer	36.80	6.72	0.60	0.11
Table 2-4 Fuel Residue	4.41	0.81	0.00	0.00
Table 2-4 Inlet	26.24	4.79	0.82	0.15
Table 2-4 Amine	10.55	1.93	0.00	0.00
TOTAL:	**143.39**	**26.17**	**1.42**	**0.26**

Current Permit Limit = 26.1 tpy VOC

Occidental Petroleum
Indian Basin Gas Plant Carlsbad, NM
NGL Gas Stream

EPA Protocol for Equipment Leak Emission Estimate

Table 2-4. *Oil and Gas Production Operations*

Average Emission Factors

Weight percentage of VOC in the total organic compounds in gas?	64.55	%*
Weight percentage of VOC in the total organic compounds in oil?	100	%

Equipment Type	Service	Screening Value EF - TOC (kg/hr/source)	(lb/day/source)	Component Count	VOC emissions (lb/day)
Valves	Gas	4.5E-03	2.381E-01	62	9.529
	Heavy Oil	8.4E-06	4.445E-04		0.00
	Light Oil	2.5E-03	1.323E-01	137	18.12
	Water/Oil	9.8E-05	5.185E-03		0.00
Pump Seals	Gas	2.4E-03	1.270E-01	0	0.000
	Heavy Oil	N/A	N/A		N/A
	Light Oil	1.3E-02	6.878E-01	12	8.25
	Water/Oil	2.4E-05	1.270E-03		0.00
Others	Gas	8.8E-03	4.656E-01	18	5.410
	Heavy Oil	3.2E-05	1.693E-03		0.00
	Light Oil	7.5E-03	3.968E-01	24	9.52
	Water/Oil	1.4E-02	7.408E-01		0.00
Connectors	Gas	2.0E-04	1.058E-02	179	1.223
	Heavy Oil	7.5E-06	3.968E-04		0.00
	Light Oil	2.1E-04	1.111E-02	368	4.09
	Water/Oil	1.1E-04	5.820E-03		0.00
Flanges	Gas	3.9E-04	2.064E-02	131	1.745
	Heavy Oil	3.9E-07	2.064E-05		0.00
	Light Oil	1.1E-04	5.820E-03	265	1.54
	Water/Oil	2.9E-06	1.534E-04		0.00
Open-ended Lines	Gas	2.0E-03	1.058E-01	0	0.000
	Heavy Oil	1.4E-04	7.408E-03		0.00
	Light Oil	1.4E-03	7.408E-02	0	0.00
	Water/Oil	2.5E-04	1.323E-02		0.00

Total VOC Emissions =	**59.4**	**lb/day**
	21,695.2	**lb/yr**
Weight % H2S:	0	
Total H2S Emissions =	**0**	**lb/day**
	0	**lb/yr**

*Note: VOC weight percentage calculated using the average mol % from gas analyses.

Occidental Petroleum
Indian Basin Gas Plant Carlsbad, NM
Stabilizer Gas Stream

EPA Protocol for Equipment Leak Emission Estimate

Table 2-4. *Oil and Gas Production Operations*

Average Emission Factors

Weight percentage of VOC in the total organic compounds in gas? 12.50 %

Weight percentage of VOC in the total organic compounds in oil? 100 %

Equipment Type	Service	Screening Value EF - TOC (kg/hr/source)	(lb/day/source)	Component Count	VOC emissions (lb/day)
Valves	Gas	4.5E-03	2.381E-01	100	2.975
	Heavy Oil	8.4E-06	4.445E-04		0.00
	Light Oil	2.5E-03	1.323E-01	81	10.71
	Water/Oil	9.8E-05	5.185E-03		0.00
Pump Seals	Gas	2.4E-03	1.270E-01	4	0.063
	Heavy Oil	N/A	N/A		N/A
	Light Oil	1.3E-02	6.878E-01	8	5.50
	Water/Oil	2.4E-05	1.270E-03		0.00
Others	Gas	8.8E-03	4.656E-01	39	2.269
	Heavy Oil	3.2E-05	1.693E-03		0.00
	Light Oil	7.5E-03	3.968E-01	11	4.37
	Water/Oil	1.4E-02	7.408E-01		0.00
Connectors	Gas	2.0E-04	1.058E-02	621	0.821
	Heavy Oil	7.5E-06	3.968E-04		0.00
	Light Oil	2.1E-04	1.111E-02	436	4.84
	Water/Oil	1.1E-04	5.820E-03		0.00
Flanges	Gas	3.9E-04	2.064E-02	281	0.725
	Heavy Oil	3.9E-07	2.064E-05		0.00
	Light Oil	1.1E-04	5.820E-03	193	1.12
	Water/Oil	2.9E-06	1.534E-04		0.00
Open-ended Lines	Gas	2.0E-03	1.058E-01	4	0.053
	Heavy Oil	1.4E-04	7.408E-03		0.00
	Light Oil	1.4E-03	7.408E-02	0	0.00
	Water/Oil	2.5E-04	1.323E-02		0.00

Total VOC Emissions = 33.5 lb/day

12,211.8 lb/yr

H2S wt%: 0.202688331

Total H2S Emissions = 0.54 lb/day

198.07 lb/yr

*Note: VOC weight percentage calculated using the average mol % from gas analyses.

Occidental Petroleum
Indian Basin Gas Plant Carlsbad, NM
Fuel-Residue Gas Stream

EPA Protocol for Equipment Leak Emission Estimate

Table 2-4. *Oil and Gas Production Operations*

Average Emission Factors

Weight percentage of VOC in the total organic compounds in gas?	0.32	%*
Weight percentage of VOC in the total organic compounds in oil?	100	%

Equipment Type	Service	Screening Value EF - TOC (kg/hr/source)	(lb/day/source)	Component Count	VOC emissions (lb/day)
Valves	Gas	4.5E-03	2.381E-01	296	0.224
	Heavy Oil	8.4E-06	4.445E-04		0.00
	Light Oil	2.5E-03	1.323E-01	12	1.59
	Water/Oil	9.8E-05	5.185E-03		0.00
Pump Seals	Gas	2.4E-03	1.270E-01	10	0.004
	Heavy Oil	N/A	N/A		N/A
	Light Oil	1.3E-02	6.878E-01	1	0.69
	Water/Oil	2.4E-05	1.270E-03		0.00
Others	Gas	8.8E-03	4.656E-01	76	0.112
	Heavy Oil	3.2E-05	1.693E-03		0.00
	Light Oil	7.5E-03	3.968E-01	2	0.79
	Water/Oil	1.4E-02	7.408E-01		0.00
Connectors	Gas	2.0E-04	1.058E-02	3,513	0.118
	Heavy Oil	7.5E-06	3.968E-04		0.00
	Light Oil	2.1E-04	1.111E-02	29	0.32
	Water/Oil	1.1E-04	5.820E-03		0.00
Flanges	Gas	3.9E-04	2.064E-02	626	0.041
	Heavy Oil	3.9E-07	2.064E-05		0.00
	Light Oil	1.1E-04	5.820E-03	21	0.12
	Water/Oil	2.9E-06	1.534E-04		0.00
Open-ended Lines	Gas	2.0E-03	1.058E-01	0	0.000
	Heavy Oil	1.4E-04	7.408E-03		0.00
	Light Oil	1.4E-03	7.408E-02	0	0.00
	Water/Oil	2.5E-04	1.323E-02		0.00

Total VOC Emissions =	**4.0**	**lb/day**
	1,464.6	**lb/yr**
Weight % H2S:	0	
Total H2S Emissions =	**0**	**lb/day**
	0	**lb/yr**

*Note: VOC weight percentage calculated using the average mol % from gas analyses.

Occidental Petroleum
Indian Basin Gas Plant Carlsbad, NM
Inlet Gas Stream

EPA Protocol for Equipment Leak Emission Estimate

Table 2-4. *Oil and Gas Production Operations*

Average Emission Factors

Weight percentage of VOC in the total organic compounds in gas?	15.63	%*
Weight percentage of VOC in the total organic compounds in oil?	100	%

Equipment Type	Service	Screening Value EF - TOC (kg/hr/source)	Screening Value EF - TOC (lb/day/source)	Component Count	VOC emissions (lb/day)
Valves	Gas	4.5E-03	2.381E-01	172	6.403
	Heavy Oil	8.4E-06	4.445E-04		0.00
	Light Oil	2.5E-03	1.323E-01	37	4.89
	Water/Oil	9.8E-05	5.185E-03		0.00
Pump Seals	Gas	2.4E-03	1.270E-01	2	0.040
	Heavy Oil	N/A	N/A		N/A
	Light Oil	1.3E-02	6.878E-01	0	0.00
	Water/Oil	2.4E-05	1.270E-03		0.00
Others	Gas	8.8E-03	4.656E-01	34	2.475
	Heavy Oil	3.2E-05	1.693E-03		0.00
	Light Oil	7.5E-03	3.968E-01	12	4.76
	Water/Oil	1.4E-02	7.408E-01		0.00
Connectors	Gas	2.0E-04	1.058E-02	1,165	1.927
	Heavy Oil	7.5E-06	3.968E-04		0.00
	Light Oil	2.1E-04	1.111E-02	148	1.64
	Water/Oil	1.1E-04	5.820E-03		0.00
Flanges	Gas	3.9E-04	2.064E-02	398	1.284
	Heavy Oil	3.9E-07	2.064E-05		0.00
	Light Oil	1.1E-04	5.820E-03	73	0.42
	Water/Oil	2.9E-06	1.534E-04		0.00
Open-ended Lines	Gas	2.0E-03	1.058E-01	0	0.000
	Heavy Oil	1.4E-04	7.408E-03		0.00
	Light Oil	1.4E-03	7.408E-02	0	0.00
	Water/Oil	2.5E-04	1.323E-02		0.00

Total VOC Emissions =	**23.9**	**lb/day**
	8,706.8	**lb/yr**
H2S wt%:	0.488440967	
Total H2S Emissions =	**0.75**	**lb/day**
	272.02	**lb/yr**

*Note: VOC weight percentage calculated using the average mol % from gas analyses.

Occidental Petroleum
Indian Basin Gas Plant Carlsbad, NM
Amine Gas Stream

EPA Protocol for Equipment Leak Emission Estimate

Table 2-4. *Oil and Gas Production Operations*

Average Emission Factors

Weight percentage of VOC in the total organic compounds in gas?	13.30	%*
Weight percentage of VOC in the total organic compounds in oil?	100	%

Equipment Type	Service	Screening Value EF - TOC (kg/hr/source)	(lb/day/source)	Component Count	VOC emissions (lb/day)
Valves	Gas	4.5E-03	2.381E-01	172	5.448
	Heavy Oil	8.4E-06	4.445E-04		0.00
	Light Oil	2.5E-03	1.323E-01	0	0.00
	Water/Oil	9.8E-05	5.185E-03		0.00
Pump Seals	Gas	2.4E-03	1.270E-01	2	0.034
	Heavy Oil	N/A	N/A		N/A
	Light Oil	1.3E-02	6.878E-01	0	0.00
	Water/Oil	2.4E-05	1.270E-03		0.00
Others	Gas	8.8E-03	4.656E-01	42	2.601
	Heavy Oil	3.2E-05	1.693E-03		0.00
	Light Oil	7.5E-03	3.968E-01	0	0.00
	Water/Oil	1.4E-02	7.408E-01		0.00
Connectors	Gas	2.0E-04	1.058E-02	385	0.542
	Heavy Oil	7.5E-06	3.968E-04		0.00
	Light Oil	2.1E-04	1.111E-02	0	0.00
	Water/Oil	1.1E-04	5.820E-03		0.00
Flanges	Gas	3.9E-04	2.064E-02	353	0.969
	Heavy Oil	3.9E-07	2.064E-05		0.00
	Light Oil	1.1E-04	5.820E-03	0	0.00
	Water/Oil	2.9E-06	1.534E-04		0.00
Open-ended Lines	Gas	2.0E-03	1.058E-01	0	0.000
	Heavy Oil	1.4E-04	7.408E-03		0.00
	Light Oil	1.4E-03	7.408E-02	0	0.00
	Water/Oil	2.5E-04	1.323E-02		0.00

Total VOC Emissions =	**9.6**	**lb/day**
	3,501.9	**lb/yr**
Weight % H2S:	0	
Total H2S Emissions =	**0**	**lb/day**
	0	**lb/yr**

*Note: VOC weight percentage calculated using the average mol % from gas analyses.

Tank Calculations – Information / Discussion

Working and Standing Losses

The tank calculations include working and standing losses, calculated using US EPA AP-42 equations, which are consistent with EPA's TANKS 4.09 Program.

Flashing Losses

There are essentially no flashing losses from the oil/condensate and water storage tanks; however, to be conservative and consistent with previous application representations, some flashing losses are included for permitting purposes.

The oil/condensate and water are stabilized in a stabilization process vessel prior to being sent to the storage tanks and thus any flashing of light gasses that may occur is upstream of the tanks in this stabilization process. The vapors from the stabilizer tank are recycled back to the plant inlet via a closed loop line. The true vapor pressure of the condensate stream is in the range of 4-6 psia, and only working and standing losses will occur at the tanks.

No flashing losses are predicted by the E&P Tanks program, which was run with known process parameters; however, to be conservative as mentioned above, Vasquez Beggs equations were used to predict some flashing losses to be conservative for permitting purposes.

Control of Tanks Emissions

During normal operations tank vapors are collected in a vapor collection system (VCS-COND) and sent to the Flare (ES-50), which has 98% VOC destruction efficiency. Additional tank emissions are represented to account for vapor collection system maintenance-related downtime (SSM).

Indian Basin Gas Plant

Tanks Emissions Summary *

Oil/Condensate Tanks - VOC Emissions Summary

	ES-46 -Gunbarrel				ES-47 Condensate				ES-48 Condensate				Total ES-46, 47 & 48				
Normal Operations	VOC		HAPs		VOC		HAPs		VOC		HAPs		VOC		HAPs		
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	
Emissions from Flare (ES-50):																	Unit ID : ES-46, ES-47, ES-48
Working & Standing Losses	0.021	0.09	0.0044	0.019	0.034	0.15	0.0071	0.031	0.037	0.16	0.0077	0.034	**0.09**	**0.41**	**0.019**	**0.084**	Stack ID: ES-50 - Flare
Flashing Losses	0.24	1.06	0.0501	0.219	0.090	0.39	0.0186	0.082	0.13	0.59	0.0279	0.122	**0.47**	**2.0**	**0.097**	**0.42**	Control ID: ES-50 - Flare
Total - ES-50 (Flare)	0.26	1.15	0.054	0.239	0.124	0.54	0.0258	0.113	0.17	0.75	0.036	0.156	**0.56**	**2.4**	**0.116**	**0.51**	
Maintenance/SSM																	
Emissions from Tanks (SSM):																	Unit ID : ES-46, ES-47, ES-48
																	Stack ID: ES-46, ES-47, ES-48
Working & Standing Losses	0.053	0.23	0.011	0.048	0.086	0.38	0.018	0.078	0.093	0.41	0.019	0.085	**0.23**	**1.02**	**0.048**	**0.21**	Control ID: -
Flashing Losses	0.60	2.6	0.125	0.55	0.22	0.98	0.047	0.20	0.34	1.5	0.070	0.306	**1.17**	**5.1**	**0.24**	**1.06**	
Total - Tanks (SSM)	0.66	2.9	0.14	0.60	0.31	1.36	0.064	0.282	0.43	1.9	0.089	0.390	**1.4**	**6.1**	**0.29**	**1.27**	

Water Tank - Emissions Summary

(Water tank is uncontrolled)

	ES-49 Water				
	VOC		HAPs		
	lb/hr	tpy	lb/hr	tpy	
Normal Operations					
Working & Standing Losses	**0.027**	**0.12**	**0.0057**	**0.025**	**Unit ID :** ES-49
Flashing Losses	**0.035**	**0.15**	**0.0073**	**0.032**	**Stack ID:** ES-49
					Control ID: -
TOTAL	**0.062**	**0.27**	**0.013**	**0.057**	

SUMMARY - CONDENSATE TANKS AND WATER TANK

	Total Cond+ Water			
	VOC		HAPs	
	lb/hr	tpy	lb/hr	tpy
Flare - ES-50				
Working & Standing Losses	**0.09**	**0.41**	**0.019**	**0.084**
Flashing Losses	**0.47**	**2.0**	**0.097**	**0.423**
Total	**0.56**	**2.4**	**0.116**	**0.507**
Tanks -ES-46, ES-47, ES-48, ES-49				
Working & Standing Losses	**0.26**	**1.14**	**0.054**	**0.24**
Flashing Losses	**1.2**	**5.3**	**0.249**	**1.09**
Total	**1.5**	**6.4**	**0.303**	**1.33**

See separate tables provided for emissions from truck loading during VCS-COND maintenance, i.e, 5% VCS downtime, and for flare NOx/CO combustion emissions.

* Vapors from condensate tanks are collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), which has 98% VOC destruction efficiency (DE).
Emissions from the condensate tanks themselves during SSM/maintenance, which includes 5% downtime for VCS-COND, are depicted separately as are the flare's NOx and CO combustion emissions.

10/24/20144:02 PM

Liaise

Indian Basin Gas Plant
Oil/Condensate and Water Tanks - Emissions Summary Without Control

Used to complete NMED Table 2D (Uncontrolled Emissions) and to calculate the worst case NOx and CO combustion emissions from Flare ES-50 from the tanks' VOC stream.

	ES-46 -Gunbarrel		ES-47 Condensate		ES-48 Condensate		ES-49 Water (normally uncontrolled)		WITHOUT CONTROL Total - All	
	VOC		VOC		VOC		VOC		VOC	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
Working & Standing Losses	1.05	4.60	1.72	7.55	1.86	8.17	0.027	0.12	4.67	20.44
Flashing Losses	12.09	52.94	4.49	19.67	6.74	29.51	0.035	0.15	23.35	102.27
TOTAL	13.14	57.54	6.21	27.22	8.60	37.67	0.062	0.27	**28.02**	**122.71**

Total ES-46, ES-47, ES-48	
VOC	
lb/hr	tpy
4.64	20.32
23.31	102.12
27.95	**122.44**

10/24/20144:02 PM

Liaise

Section 6.a

Green House Gas Emissions

(Submitting under 20.2.70, 20.2.72 20.2.74 NMAC)

Title V (20.2.70 NMAC), Minor NSR (20.2.72 NMAC), and PSD (20.2.74 NMAC) applicants must estimate and report greenhouse gas (GHG) emissions to verify the emission rates reported in the public notice, determine applicability to 40 CFR 60 Subparts, and to evaluate Prevention of Significant Deterioration (PSD) applicability. GHG emissions that are subject to air permit regulations consist of the sum of an aggregate group of these six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Calculating GHG Emissions:

1. Calculate the ton per year (tpy) GHG mass emissions and GHG CO_2e emissions from your facility.
2. GHG mass emissions are the sum of the total annual tons of greenhouse gases without adjusting with the global warming potentials (GWPs). GHG CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its GWP found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. Emissions from routine or predictable start up, shut down, and maintenance must be included.
4. Report GHG mass and GHG CO_2e emissions in Table 2-P of this application. Emissions are reported in **short** tons per year and represent each emission unit's Potential to Emit (PTE).
5. All Title V major sources, PSD major sources, and all power plants, whether major or not, must calculate and report GHG mass and CO2e emissions for each unit in Table 2-P.
6. For minor source facilities that are not power plants, are not Title V, and are not PSD there are three options for reporting GHGs in Table 2-P: 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHGs as a second separate unit; 3) or check the following ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

Sources for Calculating GHG Emissions:

- Manufacturer's Data
- AP-42 Compilation of Air Pollutant Emission Factors at http://www.epa.gov/ttn/chief/ap42/index.html
- EPA's Internet emission factor database WebFIRE at http://cfpub.epa.gov/webfire/
- 40 CFR 98 Mandatory Green House Gas Reporting except that tons should be reported in short tons rather than in metric tons for the purpose of PSD applicability.
- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009 or most recent version.
- Sources listed on EPA's NSR Resources for Estimating GHG Emissions at http://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases:

Global Warming Potentials (GWP):
Applicants must use the Global Warming Potentials codified in Table A-1 of the most recent version of 40 CFR 98 Mandatory Greenhouse Gas Reporting. The GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specified time period.

"Greenhouse gas" for the purpose of air permit regulations is defined as the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. **(20.2.70.7 NMAC, 20.2.74.7 NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Metric to Short Ton Conversion:
Short tons for GHGs and other regulated pollutants are the standard unit of measure for PSD and title V permitting programs. 40 CFR 98 Mandatory Greenhouse Reporting requires metric tons.
1 metric ton = 1.10231 short tons (per Table A-2 to Subpart A of Part 98 – Units of Measure Conversions)

Unit IDs:	ES-46, ES-47, ES-48
Stack ID:	ES-50 * -Flare
Control ID:	ES-50 * -Flare
Unit ID:	ES-49
Stack ID:	ES-49
Control ID:	-

Indian Basin Gas Plant

Condensate and Water Tanks - VOC Working and Standing Losses (Normal Operations)

Material	References :	(Gunbarrel) Condensate	Condensate	Condensate	Water	
Tank ID	Fixed roof vertical (cone-type) storage tanks	**ES-46**	**ES-47**	**ES-48**	**ES-49**	
Atmospheric pressure (Pa, psia)	Avg. Atmospheric Pressure, EPA Tanks 4.0; Roswell	12.73	12.73	12.73	12.73	
Max Ambient Temp (Tax, F)	EPA AP-42 Table 7.1-7 or Tanks 4.09; Roswell	75.73	75.73	75.73	75.73	
Min Ambient Temp (Tan, F)	EPA AP-42 Table 7.1-7 or Tanks 4.09;-Roswell	45.90	45.90	45.90	45.90	
Daily Average Amb. Temp (Taa, R)	EPA AP-42, Fifth Edition, Chapter 7	520.49	520.49	520.49	520.49	
Daily Ambient Temp Range (dTa)	EPA AP-42, Fifth Edition, Chapter 7	29.83	29.83	29.83	29.83	
Solar Paint Absorptance Factor (alpha, α)	AP-42 Table 7.1-6 (Grey, Med.)	0.68	0.68	0.68	0.68	
Solar Insolation Factor (I, Btu/ft^2*day)	AP-42 Table 7.1-7, Roswell	1810	1810	1810	1810	
Daily vapor temp. range (dTv, R)	*Delta Tv = 0.72 x Delta Ta + 0.028 x alpha x I*	55.94	55.94	55.94	55.94	
Liquid Bulk Temp (Tb, R)	*Tb = Taa + 6 x alpha - 1*	523.57	523.57	523.57	523.57	
Daily Avg Liq surf temp (Tla, R)	*Tla = (0.44 x Taa) + (0.56 x Tb) + (0.0079 x alpha x I)*	531.93	531.93	531.93	531.93	
Daily Max Liq surf temp (Tlx, R)	*Tlx = Tla + (0.25 x Delta Tv)*	545.92	545.92	545.92	545.92	
Daily Min Liq surf temp (Tln, R)	*Tln = Tla - (0.25 x Delta Tv)*	517.95	517.95	517.95	517.95	
ANNUAL EMISSION RATE						
Vapor Molecular Weight, (Mv)	Representative analysis	66.19	66.19	66.19	66.19	
Annual net throughput (Q, bbl/yr)		85000	34000	51000	5300	
Tank Maximum Liquid Volume, (V_{lx},ft^3)	V_{LX} = (3.14 / 4) x (D^2) x Hs	2826.00	5805.86	5805.86	2826.00	
Turnover per year (N)	N = (5.614 x Q) / V_{LX}	168.86	32.88	49.31	10.53	
Turnover factor (Kn)	AP-42 Fig. 7.1-18, Kn = (180 + N) / (6 x N) if N>36 **or 1**	0.34	1.00	0.78	1.00	
Working loss product factor (Kp)	AP-42 Page 7.1-18 [0.75 for crude oils / all other, 1]	0.75	0.75	0.75	0.75	
Tank Shell Height (Hs, ft)		25.00	16.00	16.00	16.00	
Liquid Height (Hl, ft)		12.50	8.00	8.00	8.00	
Diameter (ft)		12.00	21.50	21.50	15.00	
Roof Outage (Hro, ft)	cone-1/3 x Hr & Hr =tank radius x .0625	0.13	0.22	0.22	0.16	
Vapor Space Outage (Hvo, ft)	Hvo = Hs - Hl + Hro	12.63	8.22	8.22	8.16	
Vapor Space Volume (Vv, ft^3)	Vv = (3.14 / 4) x (D^2) x Hvo	1427.85	2985.71	2985.71	1441.33	
Vapor Density (Wv, lb/ft^3)	Wv = (Mv x Pva) / (R x Tla); [R = 10.731 (psia x ft^3) / (lb-mole°R)]	0.0524	0.0524	0.0524	0.0524	
VP @daily max liq surf temp (Pvx, psia)	= 4.7011 (Tanks 4.09); Raised per max. VP @ 325F (conserv.)	5.837	5.837	5.837	5.837	
VP @daily min liq surf temp (Pvn, psia)	= 2.7818 (Tanks 4.09); Adjusted per max. analysis VP (conserv.)	3.453	3.453	3.453	3.453	
Daily Vapor Pressure Range (dPv,psia)	Delta Pv = Pvx - Pvn	2.3840	2.3840	2.3840	2.3840	Total
VP @ daily avg liq surf temp (Pva, psia)	= 3.6413 (Tanks 4.09); Adjsuted per max. analysis VP (conserv.)	4.520	4.520	4.520	4.520	
Vapor Space Expansion Factor (Ke)	Ke = (Delta Tv / Tla) + (Delta Pv - 0.06) / (Pa - Pva); AP42 7.1-17	0.39	0.39	0.39	0.39	
Vented Vapor Saturation factor (Ks)	Ks = 1 / (1 + (0.053 x Pva x Hvo))	0.25	0.34	0.34	0.34	
Standing Storage Loss (Ls, lb/yr)	Ls = 365 x Vv x Wv x Ke x Ks	2634.94	7465.61	7465.61	3623.76	**21189.93**
Working Loss (Lw, lb/yr)	Lw = 0.0010 x Mv x Pva x Q x Kn x Kp	6567.52	7629.29	8869.11	1189.27	**24255.19**
Total Losses (Lt, lb/yr)	Lt = Ls + Lw	9202.46	15094.90	16334.72	4813.03	45445.11
Total Losses (Lt", tpy)	*Lt" = Lt / 2000*	4.6012	7.5475	8.1674	2.4065	22.7226
VOC weight fraction	Note: water tank (ES-49) ~ 5% VOC & not controlled	1.00	1.00	1.00	0.05	

CALCULATED EMISSION RATES - SUMMARY

					Water w/ 5%max VOC	
VOC Annual Emission Rate - TPY		4.60	7.55	8.17	0.120	20.44
Hourly VOC Emission Rate - Lb/hr		1.05	1.72	1.86	0.027	4.67
	Flare ES-50 control efficiency *	**98%**	**98%**	**98%**	**0%**	
VOC Annual Emission Rate - TPY	**[With flare ES-50 control, except ES-49]**	**0.092**	**0.15**	**0.16**	**0.12**	**0.53**
Hourly VOC Emission Rate - Lb/hr	**[With flare ES-50 control, Except ES-49]**	**0.021**	**0.034**	**0.037**	**0.027**	**0.12**
					-No Control-	

* Vapors are collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), which has 98% VOC destruction efficiency (DE).

Emissions from the tanks themselves during maintenance of the vapor collection system (VCS), which includes 5% downtime, are depicted in a separate table as are the flare NOx and CO combustion emissions.

Indian Basin Gas Plant
Condensate and Water Tanks - Working & Standing Losses (Normal Operations)

Speciated Emissions of Hazardous Air Pollutants (HAPs)

Unit ID:	ES-46, ES-47& ES-48	
Stack ID:	ES-50 (2)	**-Flare**
Control ID:	ES-50 (2)	**-Flare**
Unit ID:	ES-49	
Stack ID:	ES-49	
Control ID:	-	

	(Gunbarrel) Condensate ES-46	Condensate ES-47	Condensate ES-48	Water ES-49
VOC - TPY	0.092	0.151	0.16	0.120
VOC - Lb/hr	0.021	0.034	0.037	0.027

		ES-46		**ES-47**		**ES-48**		**ES-49**		**Total**	
HAPs	**Wt. Frac. (1)**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
n-Hexane	0.137359	0.0029	0.013	0.005	0.021	0.0051	0.022	3.8E-03	0.0165	0.017	0.072
Benzene	0.028351	5.96E-04	0.0026	0.0010	0.0043	0.0011	0.0046	7.8E-04	3.4E-03	0.0034	0.015
Toluene	0.027887	5.86E-04	0.0026	0.0010	0.0042	0.0010	0.0046	7.7E-04	3.4E-03	0.0034	0.015
Ethylbenzene	0.001529	3.21E-05	1.41E-04	5.27E-05	2.3E-04	5.70E-05	2.50E-04	4.2E-05	1.8E-04	1.8E-04	8.1E-04
Xylene	0.012124	2.55E-04	0.0011	0.0004	0.0018	4.5E-04	0.0020	3.33E-04	1.46E-03	0.0015	0.0064
TOTAL HAPs		**0.0044**	**0.019**	**0.0071**	**0.031**	**0.0077**	**0.0339**	**0.0057**	**0.025**	**0.025**	**0.11**

Water tank is uncontrolled

Example Calculation, ES-46:

0.092	tpy VOC x	0.1374	wt. frac. hexane =	**0.013**	tpy n-Hexane
0.021	lb/hr VOC x	0.1374	wt. frac. hexane =	**0.0029**	lb/hr n-Hexane

(1) Condensate Analysis, Mobile Analystical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions assuming condensate =100% VOC.

(2) Vapors are collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), which has 98% VOC destruction efficiency (DE).
Emissions vented from tanks during maintenance of the vapor collection system (VCS), i.e, 5% VCS downtime, are in a separate table as are flare NOx/CO combustion emissions.

Unit IDs:	ES-46, ES-47, ES-48
Stack ID:	ES-46, ES-47, ES-49
Control ID:	NA [1]

Indian Basin Gas Plant
Condensate Tanks - VOC Working and Standing Losses (SSM)

Material	References :	(Gunbarrel) Condensate	Condensate	Condensate	
Tank ID	Fixed roof vertical (cone-type) storage tanks	**ES-46**	**ES-47**	**ES-48**	
Atmospheric pressure (Pa, psia)	Avg. Atmospheric Pressure, EPA Tanks 4.0; Roswell	12.73	12.73	12.73	
Max Ambient Temp (Tax, F)	EPA AP-42 Table 7.1-7 or Tanks 4.09; Roswell	75.73	75.73	75.73	
Min Ambient Temp (Tan, F)	EPA AP-42 Table 7.1-7 or Tanks 4.09;-Roswell	45.90	45.90	45.90	
Daily Average Amb. Temp (Taa, R)	EPA AP-42, Fifth Edition, Chapter 7	520.49	520.49	520.49	
Daily Ambient Temp Range (dTa)	EPA AP-42, Fifth Edition, Chapter 7	29.83	29.83	29.83	
Solar Paint Absorptance Factor (alpha, α)	AP-42 Table 7.1-6 (Grey, Med.)	0.68	0.68	0.68	
Solar Insolation Factor (I, Btu/ft^2*day)	AP-42 Table 7.1-7, Roswell	1810	1810	1810	
Daily vapor temp. range (dTv, R)	*Delta Tv = 0.72 x Delta Ta + 0.028 x alpha x I*	55.94	55.94	55.94	
Liquid Bulk Temp (Tb, R)	*Tb = Taa + 6 x alpha - 1*	523.57	523.57	523.57	
Daily Avg Liq surf temp (Tla, R)	*Tla = (0.44 x Taa) + (0.56 x Tb) + (0.0079 x alpha x I)*	531.93	531.93	531.93	
Daily Max Liq surf temp (Tlx, R)	*Tlx = Tla + (0.25 x Delta Tv)*	545.92	545.92	545.92	
Daily Min Liq surf temp (Tln, R)	*Tln = Tla - (0.25 x Delta Tv)*	517.95	517.95	517.95	
ANNUAL EMISSION RATE					
Vapor Molecular Weight, (Mv)	Representative analysis	66.19	66.19	66.19	
Annual net throughput (Q, bbl/yr)		85000	34000	51000	
Tank Maximum Liquid Volume, (V_{lx},ft^3)	V_{LX} = (3.14 / 4) x (D^2) x Hs	2826.00	5805.86	5805.86	
Turnover per year (N)	N = (5.614 x Q) / V_{LX}	168.86	32.88	49.31	
Turnover factor (Kn)	AP-42 Fig. 7.1-18, Kn = (180 + N) / (6 x N) if N>36 **or 1**	0.34	1.00	0.78	
Working loss product factor (Kp)	AP-42 Page 7.1-18 [0.75 for crude oils / all other, 1]	**0.75**	**0.75**	**0.75**	
Tank Shell Height (Hs, ft)		25.00	16.00	16.00	
Liquid Height (Hl, ft)		12.50	8.00	8.00	
Diameter (ft)		12.00	21.50	21.50	
Roof Outage (Hro, ft)	cone-1/3 x Hr & Hr =tank radius x .0625	0.13	0.22	0.22	
Vapor Space Outage (Hvo, ft)	Hvo = Hs - Hl + Hro	12.63	8.22	8.22	
Vapor Space Volume (Vv, ft^3)	Vv = (3.14 / 4) x (D^2) x Hvo	1427.85	2985.71	2985.71	
Vapor Density (Wv, lb/ft^3)	Wv = (Mv x Pva) / (R x Tla); [R = 10.731 (psia x ft^3) / (lb-molex^{o}R)]	0.0524	0.0524	0.0524	
VP @daily max liq surf temp (Pvx, psia)	= 4.7011 (Tanks 4.09); Raised per max. VP @ 325F (conserv.)	5.837	5.837	5.837	
VP @daily min liq surf temp (Pvn, psia)	= 2.7818 (Tanks 4.09); Adjusted per max. analysis VP (conserv.)	3.453	3.453	3.453	
Daily Vapor Pressure Range (dPv,psia)	Delta Pv = Pvx - Pvn	2.3840	2.3840	2.3840	<u>Total</u>
VP @ daily avg liq surf temp (Pva, psia)	= 3.6413 (Tanks 4.09); Adjsuted per max. analysis VP (conserv.)	4.520	4.520	4.520	
Vapor Space Expansion Factor (Ke)	Ke = (Delta Tv / Tla) + (Delta Pv - 0.06) / (Pa - Pva); AP42 7.1-17	0.39	0.39	0.39	
Vented Vapor Saturation factor (Ks)	Ks = 1 / (1 + (0.053 x Pva x Hvo))	0.25	0.34	0.34	
Standing Storage Loss (Ls, lb/yr)	Ls = 365 x Vv x Wv x Ke x Ks	2634.94	7465.61	7465.61	**17566.17**
Working Loss (Lw, lb/yr)	Lw = 0.0010 x Mv x Pva x Q x Kn x Kp	<u>6567.52</u>	<u>7629.29</u>	<u>8869.11</u>	**<u>23065.91</u>**
Total Losses (Lt, lb/yr)	Lt = Ls + Lw	9202.46	15094.90	16334.72	40632.09
Total Losses (Lt", tpy)	*Lt" = Lt / 2000*	4.6012	7.5475	8.1674	20.3160
VOC weight fraction		1.00	1.00	1.00	
CALCULATED EMISSION RATES - SUMMARY					
VOC <u>Annual</u> Emission Rate - TPY		4.60	7.55	8.17	20.32
<u>Hourly</u> VOC Emission Rate - Lb/hr		1.05	1.72	1.86	4.64
	Emissions during vapor collection system (VCS-COND) - 5% downtime [1]	**95%**	**95%**	**95%**	
VOC <u>Annual</u> Emission Rate - TPY	**[With VCS-COND downtime]**	**0.23**	**0.38**	**0.41**	**1.02**
<u>Hourly</u> VOC Emission Rate - Lb/hr	**[With VCS-COND downtime]**	**0.053**	**0.086**	**0.093**	**0.23**

(1) Emissions from the condensate tanks themselves during maintenance (SSM) of the vapor collection system (VCS), which includes 5% downtime, are depicted.

10/24/20142:16 PM

Liaise

Indian Basin Gas Plant
Condensate Tanks - Working & Standing Losses (SSM)

Speciated Emissions of Hazardous Air Pollutants (HAPs)

Unit IDs:	ES-46, ES-47, ES-48
Stack ID:	ES-46, ES-47, ES-49
Control ID:	NA [2]

	(Gunbarrel) Condensate ES-46	Condensate ES-47	Condensate ES-48
VOC - TPY	0.230	0.377	0.41
VOC - Lb/hr	0.053	0.086	0.093

HAPs	Wt. Frac. [1]	ES-46 lb/hr	ES-46 tpy	ES-47 lb/hr	ES-47 tpy	ES-48 lb/hr	ES-48 tpy	Total lb/hr	Total tpy
n-Hexane	0.137359	0.007	0.032	0.012	0.052	0.013	0.056	0.032	0.140
Benzene	0.028351	0.0015	0.0065	0.0024	0.0107	0.0026	0.012	0.0066	0.029
Toluene	0.027887	0.0015	0.0064	0.0024	0.0105	0.0026	0.011	0.0065	0.028
Ethylbenzene	0.001529	8.03E-05	3.52E-04	1.32E-04	5.8E-04	1.43E-04	6.24E-04	3.55E-04	0.0016
Xylene	0.012124	6.37E-04	0.0028	0.0010	0.0046	0.0011	0.0050	0.0028	0.012
TOTAL HAPs		**0.011**	**0.048**	**0.0179**	**0.078**	**0.0193**	**0.085**	**0.048**	**0.211**

Example Calculation, ES-46:

0.230	tpy VOC x	0.1374	wt. frac. hexane =	**0.032**	tpy n-Hexane
0.053	lb/hr VOC x	0.1374	wt. frac. hexane =	**0.0072**	lb/hr n-Hexane

(1) Condensate Analysis, Mobile Analystical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions assuming condensate =100% VOC.

(2) Emissions from the condensate tanks themselves during maintenance (SSM) of the vapor collection system (VCS), which includes 5% downtime, are depicted.

Indian Basin Gas Plant **OXY USA, Inc.**

Condensate Tanks and Water Tank - VOC Flashing Losses (Normal Operations)

Unit ID:	ES-46, ES-47& ES-48
Stack ID:	ES-50 (2) **-Flare**
Control ID:	ES-50 (2) **-Flare**
Unit ID:	ES-49
Stack ID:	ES-49
Control ID:	-

Vasquez Beggs Method for Estimating Flashing Losses (1)	ES-46	ES-47	ES-48	[Water /GB] ES-49	TOTAL	
Production in barrels per day (bbl/day)	250.7	93.2	139.7	14.5	498.1	
Annual throughput **(Q)**, bbl	91500	34000	51000	5300	181800.0	
API Gravity, **APIG**	69.2	69.2	69.2	69.2		
Vasquez Beggs Constants	API> or =30	API> or =30	API> or =30	API> or =30		
C1	0.0178	0.0178	0.0178	0.0178		
C2	1.187	1.187	1.187	1.187		
C3	23.931	23.931	23.931	23.931		
Mole fraction of Total Hydrocarbon (THC) in vent Gas (1 for Vasquez Beggs as the equations and parameters deal only with total hydrocarbons)	1.00	1.00	1.00	1.00		
MW of THC in Tank Vapor, **Mc**	66.19	66.19	66.19	66.19		
SG of gas in separator - Air = 1	0.70	0.70	0.70	0.70		
Gas density **(GD)** , lb/ft^3 = C x Mc / 379.... (For NMED use 385)	0.172	0.172	0.172	0.172		
Upstream vessel pressure **(UVP)**, psig	40	40	40	40		
Upsteam Pressure **(UP)**, psia	54.7	54.7	54.7	54.7		
T = Fluid Temp. in upsteam vessel, ^{0}F	325	325	325	325		
Corrected SG of Gas **(CSG)** = SG x (1+0.00005912 x APIG x T x Log(UP/114.7))	0.40	0.40	0.40	0.40		
Gas to Oil Ratio **(GOR)**, scf/bbl = C1 x CSG x UP^C2x EXP((C3xAPIG)/(T+460))	6.80	6.80	6.80	6.80		
% Reduction - water tank assumed to have up to 5% VOC	0	0	0	95		
Correlated Flashing Loss, **Lf (tpy)** = GOR x Q x GD x (100-E)/(2000 x 100)	53.47	19.87	29.81	0.15		
VOC vapor weight fraction	1.0	1.0	1.0	1.0	**TOTAL ES-46, 47 & 48**	**TOTAL ES-49**
Emissions - Uncontrolled						
VOC Flashing Loss (tpy)	**52.94**	**19.67**	**29.51**	**0.15**	**102.12**	**0.15**
VOC Flashing Loss (lb/hr)	12.09	4.49	6.74	0.035	**23.31**	0.035
Emissions with vapor collection system to Flare ES-50 (except water tank ES-49) **98%** -->Flare ES-50 Control Efficiency. No control for ES-49						
VOC Flashing Loss (tpy)	**1.06**	**0.39**	**0.59**	**0.15**	**2.04**	**0.15**
VOC Flashing Loss (lb/hr)	0.24	0.090	0.13	0.035 no control	**0.47**	0.035

(1) Vasquez Beggs Equation, API - Exploration and Production Emission Calculator (EPEC) Guide, pp. 3-14,15,16.
Rollins, J.B., McCain Jr. W.D., and Creeger J.T., "Estimation of Solution GOR of Black Oils," JPT, January 1990, pp. 92-92.

(2) Vapors are collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), which has 98% VOC destruction efficiency (DE).
Emissions vented from tanks during maintenance of the vapor collection system (VCS), i.e, 5% VCS downtime, are in a separate table as are flare NOx/CO combustion emissions.

* EPA Program E&P Tanks was run to estimate flashing losses & calculated zero flashing losses. Vasquez Beggs equations were used to estimate flashing losses to be conservative.
Minimal to zero flashing losses are expected and any flashing that occurs is in the upstream stabilizer vessel from where the gases are recycled back to the plant inlet.

8/27/20142:18 PM

Liaise

Indian Basin Gas Plant
Condensate and Water Tanks - Flashing Losses - Speciated Emissions of Hazardous Air Pollutants (HAPs) - (Normal Operations)

Unit ID:	ES-46, ES-47& ES-48	
Stack ID:	ES-50 [2]	**-Flare**
Control ID:	ES-50 [2]	**-Flare**
Unit ID:	ES-49	
Stack ID:	ES-49	
Control ID:	-	

	ES-46	ES-47	ES-48	ES-49
VOC (tpy)	1.06	0.39	0.59	0.15
VOC (max. lb/hr)	0.24	0.090	0.13	0.035

		ES-46		**ES-47**		**ES-48**		**ES-49**		**TOTAL**	
HAPs	Wt. Fraction [1]	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
n-Hexane	0.137359	3.3E-02	1.5E-01	1.2E-02	5.4E-02	1.9E-02	8.1E-02	4.8E-03	2.1E-02	6.9E-02	3.0E-01
Benzene	0.028351	6.9E-03	3.0E-02	2.5E-03	1.1E-02	3.8E-03	1.7E-02	9.9E-04	4.3E-03	1.4E-02	6.2E-02
Toluene	0.027887	6.7E-03	3.0E-02	2.5E-03	1.1E-02	3.8E-03	1.6E-02	9.8E-04	4.3E-03	1.4E-02	6.2E-02
Ethylbenzene	0.001529	3.7E-04	1.6E-03	1.4E-04	6.0E-04	2.1E-04	9.0E-04	5.4E-05	2.3E-04	1.4E-02	6.1E-02
Xylene	0.012124	2.9E-03	1.3E-02	1.1E-03	4.8E-03	1.6E-03	7.2E-03	4.2E-04	1.9E-03	6.1E-03	2.7E-02
TOTAL HAPs		**0.050**	**0.22**	**0.019**	**0.082**	**0.028**	**0.12**	**0.0073**	**0.032**	**0.12**	**0.51**

(1) Condensate Analysis, Mobile Analystical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions assuming condensate is 100% VOC.

(2) Vapors are collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), which has 98% VOC destruction efficiency (DE).
Emissions vented from tanks during maintenance of the vapor collection system, i.e, 5% VCS downtime, are in a separate table as are flare NOx/CO comb. emissions.

Unit ID:	ES-46, ES-47& ES-48
Stack ID:	ES-46, ES-47& ES-49
Control ID:	NA [(2)]

Vasquez Beggs Method for Estimating Flashing Losses [(1)]	ES-46	ES-47	ES-48	TOTAL
Production in barrels per day (bbl/day)	250.7	93.2	139.7	483.6
Annual throughput **(Q)**, bbl	91500	34000	51000	176500.0
API Gravity, **APIG**	69.2	69.2	69.2	
Vasquez Beggs Constants	API> or =30	API> or =30	API> or =30	
C1	0.0178	0.0178	0.0178	
C2	1.187	1.187	1.187	
C3	23.931	23.931	23.931	
Mole fraction of Total Hydrocarbon (THC) in vent Gas (1 for Vasquez Beggs as the equations and parameters deal only with total hydrocarbons)	1.00	1.00	1.00	
MW of THC in Tank Vapor, **Mc**	66.19	66.19	66.19	
SG of gas in separator - Air = 1	0.70	0.70	0.70	
Gas density **(GD)** , lb/ft^3 = C x Mc / 379.... (For NMED use 385)	0.172	0.172	0.172	
Upstream vessel pressure **(UVP)**, psig	40	40	40	
Upsteam Pressure **(UP)**, psia	54.7	54.7	54.7	
T = Fluid Temp. in upsteam vessel, ^{0}F	325	325	325	
Corrected SG of Gas **(CSG)** = SG x (1+0.00005912 x APIG x T x Log(UP/114.7))	0.40	0.40	0.40	
Gas to Oil Ratio **(GOR)**, scf/bbl = C1 x CSG x UP^C2x EXP((C3xAPIG)/(T+460))	6.80	6.80	6.80	
% Reduction	0	0	0	
Correlated Flashing Loss, **Lf (tpy)** = GOR x Q x GD x (100-E)/(2000 x 100)	53.47	19.87	29.81	
VOC vapor weight fraction	1.0	1.0	1.0	**TOTAL ES-46, 47 & 48**
Emissions - Uncontrolled				
VOC Flashing Loss (tpy)	**52.94**	**19.67**	**29.51**	**102.1**
VOC Flashing Loss (lb/hr)	12.09	4.49	6.74	**23.3**
Emissions during vapor collection system (VCS-COND) - 5% downtime [(2)] **95%**				
VOC Flashing Loss (tpy)	**2.65**	**0.98**	**1.48**	**5.1**
VOC Flashing Loss (lb/hr)	0.60	0.22	0.34	**1.17**

[(1)] Vasquez Beggs Equation, API - Exploration and Production Emission Calculator (EPEC) Guide, pp. 3-14,15,16.
Rollins, J.B., McCain Jr. W.D., and Creeger J.T., "Estimation of Solution GOR of Black Oils," JPT, January 1990, pp. 92-92.

(2) Emissions from the condensate tanks themselves during maintenance (SSM) of the vapor collection system (VCS), which includes 5% downtime, are depicted.

Indian Basin Gas Plant
Condensate - Flashing Losses - Speciated Emissions of Hazardous Air Pollutants (HAPs) - (SSM)

Unit ID:	ES-46, ES-47& ES-48
Stack ID:	ES-46, ES-47& ES-48
Control ID:	NA (2)

	ES-46	ES-47	ES-48
VOC (tpy)	2.65	0.98	1.48
VOC (max. lb/hr)	0.60	0.225	0.34

		ES-46		ES-47		ES-48		TOTAL	
HAPs	Wt. Fraction (1)	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
n-Hexane	0.137359	8.3E-02	3.6E-01	3.1E-02	1.4E-01	4.6E-02	2.0E-01	1.6E-01	7.0E-01
Benzene	0.028351	1.7E-02	7.5E-02	6.4E-03	2.8E-02	9.5E-03	4.2E-02	3.3E-02	1.4E-01
Toluene	0.027887	1.7E-02	7.4E-02	6.3E-03	2.7E-02	9.4E-03	4.1E-02	3.3E-02	1.4E-01
Ethylbenzene	0.001529	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Xylene	0.012124	7.3E-03	3.2E-02	2.7E-03	1.2E-02	4.1E-03	1.8E-02	1.4E-02	6.2E-02
TOTAL HAPs		**0.125**	**0.549**	**0.0465**	**0.204**	**0.0698**	**0.306**	**0.242**	**1.06**

(1) Condensate Analysis, Mobile Analystical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions (assuming worst case, I.e., condensate =100% VOC)

(2) Emissions from the condensate tanks themselves during maintenance (SSM) of the vapor collection system (VCS), which includes 5% downtime, are depicted.

Indian Basin Gas Plant Unit ID: ES-52
Oil/Condensate Tank - Skimmer Basin - Working and Standing Losses (only) Stack ID: VRU-ES-40-SB*

SSM - Emissions when VRU-ES-40-SB is not operating.

Material	References :	**Skimmer Basin -Oil Condensate**	**TOTAL**
Tank ID	Fixed roof vertical (cone-type) storage tanks	**T-52**	
Atmospheric pressure (Pa, psia)	Avg. Atmospheric Pressure, EPA Tanks 4.0; Roswell	12.73	
Max Ambient Temp (Tax, F)	EPA AP-42 Table 7.1-7 or Tanks 4.09; Roswell	75.73	
Min Ambient Temp (Tan, F)	EPA AP-42 Table 7.1-7 or Tanks 4.09;-Roswell	45.90	
Daily Average Amb. Temp (Taa, R)	EPA AP-42, Fifth Edition, Chapter 7	520.49	
Daily Ambient Temp Range (dTa)	EPA AP-42, Fifth Edition, Chapter 7	29.83	
Solar Paint Absorptance Factor (alpha, α)	AP-42 Table 7.1-6 (Grey, Med.)	0.68	
Solar Insolation Factor (I, Btu/ft^2*day)	AP-42 Table 7.1-7, Roswell	1810	
Daily vapor temp. range (dTv, R)	*Delta Tv = 0.72 x Delta Ta + 0.028 x alpha x I*	55.94	
Liquid Bulk Temp (Tb, R)	*Tb = Taa + 6 x alpha - 1*	523.57	
Daily Avg Liq surf temp (Tla, R)	*Tla = (0.44 x Taa) + (0.56 x Tb) + (0.0079 x alpha x I)*	531.93	
Daily Max Liq surf temp (Tlx, R)	*Tlx = Tla + (0.25 x Delta Tv)*	545.92	
Daily Min Liq surf temp (Tln, R)	*Tln = Tla - (0.25 x Delta Tv)*	517.95	
ANNUAL EMISSION RATE			
Vapor Molecular Weight, (Mv)	EPA AP-42 and Tanks 4.0 Program	50.00	
Annual net throughput (Q, bbl/yr)	20 bbl/day	7300	20 bbl/day
Tank Maximum Liquid Volume, (V_{lx}, ft^3)	V_{LX} = (3.14 / 4) x (D^2) x Hs	1766.25	
Turnover per year (N)	N = (5.614 x Q) / V_{LX}	23.20	
Turnover factor (Kn)	AP-42 Fig. 7.1-18, Kn = (180 + N) / (6 x N) if N>36 **or 1**	1.00	
Working loss product factor (Kp)	AP-42 Page 7.1-18 [0.75 for crude oils / all other, 1]	0.75	
Tank Shell Height (Hs, ft)		10.00	
Liquid Height (Hl, ft)		5.00	
Diameter (ft)		15.00	
Roof Outage (Hro, ft)	cone-1/3 x Hr & Hr =tank radius x .0625	0.16	
Vapor Space Outage (Hvo, ft)	Hvo = Hs - Hl + Hro	5.16	
Vapor Space Volume (Vv, ft^3)	Vv = (3.14 / 4) x (D^2) x Hvo	911.18	.
Vapor Density (Wv, lb/ft^3)	Wv = (Mv x Pva) / (R x Tla); [R = 10.731 (psia x ft^3) / (lb-molex^{0}R)]	0.0319	
VP @daily max liq surf temp (Pvx, psia)	EPA Tanks 4 Chem. Data Base, Crude Oil (RVP 5)	4.7011	
VP @daily min liq surf temp (Pvn, psia)	EPA Tanks 4 Chem. Data Base, Crude Oil (RVP 5)	2.7818	
Daily Vapor Pressure Range (dPv,psia)	Delta Pv = Pvx - Pvn	1.9193	
VP @ daily avg liq surf temp (Pva, psia)	EPA Tanks 4 Chemical Data Base, Crude Oil (RVP 5)	3.6413	
Vapor Space Expansion Factor (Ke)	Ke = (Delta Tv / Tla) + (Delta Pv - 0.06) / (Pa - Pva); AP42 7.1-17	0.31	
Vented Vapor Saturation factor (Ks)	Ks = 1 / (1 + (0.053 x Pva x Hvo))	0.50	
Standing Storage Loss (Ls, lb/yr)	Ls = 365 x Vv x Wv x Ke x Ks	1646.74	
Working Loss (Lw, lb/yr)	Lw = 0.0010 x Mv x Pva x Q x Kn x Kp	996.81	
Total Losses (Lt, lb/yr)	Lt = Ls + Lw	2643.54	
Total Losses (Lt", tpy)	*Lt" = Lt / 2000*	1.3218	
VOC weight fraction		1.00	
CALCULATED EMISSION RATES - SUMMARY			
VOC Annual Emission Rate - TPY		1.32	
Hourly VOC Emission Rate - Lb/hr		0.30	
	VRU recovery rate (5% downtime)	**95%**	
VOC Annual Emission Rate - TPY	*| Lt" x VOC wt. frac.* **With vapor recovery unit (VRU)**	**0.066**	
Hourly VOC Emission Rate - Lb/hr	**With vapor recovery unit (VRU)**	**0.015**	

* VRU-ES-40-SB recovers vapors from this tank; the emissions are vented from process control valves associated with the skimmer basin and/or the ES-40 dehy system. Emissions will occur when the VRU is down up to 5% of the time.

Indian Basin Gas Plant
Oil/Condensate Tank - Skimmer Basin - Emissions of Hazardous Air Pollutants (HAPs) from Working & Standing Losses (only)

Unit ID: ES-52
Stack ID: VRU-ES-40-SB

	ES-52
VOC - TPY	0.066
VOC - Lb/hr	0.015

HAPs	Wt. Frac. *	ES-52 lb/hr	ES-52 tpy
n-Hexane	0.137359	0.0021	0.0091
Benzene	0.028351	4.3E-04	0.0019
Toluene	0.027887	4.2E-04	0.0018
Ethylbenzene	0.001529	2.3E-05	1.0E-04
Xylene	0.012124	1.8E-04	8.0E-04
TOTAL HAPs		**0.0031**	**0.014**

Example Calculation:

0.066	tpy VOC x	0.1374	wt. frac. hexane =	**0.0091**	tpy n-Hexane
0.015	lb/hr VOC x	0.1374	wt. frac. hexane =	**0.0021**	lb/hr n-Hexane

* Condensate Analysis, Mobile Analystical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions (assuming worst case, I.e., condensate =100% VOC)

- **CONDENSATE /WATER TRUCK LOADING**

- **FLARE (ES-50) COMBUSTION /VOC EMISSIONS FROM CONDENSATE TANK AND TRUCK LOADING VAPORS**

Truck Loading Calculations

Similar to oil/condensate tanks, emissions from truck loading operations are collected by the vapor collection system (VCS-COND) and sent to the flare (ES-50) during normal operations. Truck loading emissions are represented separately to account for any vapor collection system maintenance downtime.

Indian Basin Gas Plant
VOC /HAP Emissions from Condensate & Water Truck Loading (Normal Operations)

Unit ID: ES-56
Stack ID: ES-50 [5] - Flare
Control ID: ES-50 [5] - Flare

Loading Loss Equation Terms

Saturation factor (S)	0.6	AP-42, Table 5.2-1, Submerged Loading
True Vapor Pres. (psia)- (P)	5.837	(1)
Molecular Wt. of Vapor (MW)	66.19	(2)
Temperature R (T)	545.92	(3) Max. Liq. Surface Temp. ~ 86.25 F
% VOC	100%	
Max. Gallons Loaded per hour (Gal/hr)	7560	

Loading Rate Information:	
85265.0	bbls/yr
3581130	gal/yr
180	bbls/hr/truck
7560	gal/hr/truck
474	hours/year

VOC Loading Losses

VOC Loading Losses (lbs/1000gal) $= 12.46 \times \frac{S \times P \times MW}{T} \times \%VOC$

$= 5.29$

VOC Emissions converted to maximum pounds per hour (lbs/hr) and tons per year (tpy)

Including Flare Combustion Efficiency

7560	gal/hr x	5.29	lb/1000 gal =	**40.00**	**lbs/hr**	98%	= **0.80**	**lbs/hr**
85265	bbls/yr x 42 gal/bbl x	5.29	lbs/1000 gal x1 ton/2000 lbs =	**9.47**	**tpy**	98%	= **0.19**	**tpy**

Hazardous Air Pollutant (HAP) Emissions

	Wt. Fraction [4] (Frac. of VOC only)	Emissions without Control [without VCS-COND or ES-50 (flare)] lb/hr	tpy	**Controlled Emissions to VCS-COND and ES-50** lb/hr	tpy
n-Hexane	0.137359	5.49	1.30	0.11	0.026
Benzene	0.028351	1.13	0.27	0.023	0.0054
Toluene	0.027887	1.12	0.26	0.022	0.0053
Ethylbenzene	0.001529	0.061	0.014	0.0012	2.9E-04
Xylene	0.012124	0.48	0.115	0.0097	0.0023
Total HAPs		**8.29**	**1.96**	**0.17**	**0.039**

Example Calculations:

9.47	tpy VOC x	0.137	wt. frac. hexane x (1-0.98) D.E.=	0.026	tpy n-hexane
40.0	lb/hr VOC x	0.137	wt. frac. hexane x (1-0.98) D.E.=	0.11	lb/hr n-hexane

(1) Conservative vapor pressure of liquids out of the upstream stabillizer vessel at maximum temperature of 325F. [Mobile Analystical Labs, Inc. 2/9/2010, Lab# 5147].
(2) Vapor molecular weight from the upstream stabilizer vessel reflux analysis. [Mobile Analystical Labs, Inc. 2/9/2010, Lab# 5148].
(3) The max. liquid temp. of the upstream stabilizer vessel is 325F (784.67 R); however a lower max liq. surface temp. from TANKS 4.09/AP-42 was used to derive more conservative (higher) emission rates per the above EPA loading loss equation.
(4) Mobile Analytical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions assuming condensate is 100% VOC.
(5) Vapors are collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), which has 98% VOC destruction efficiency (DE).
See separate tables provided for emissions from truck loading during VCS-COND maintenance, i.e, 5% VCS downtime, and for flare NOx/CO combustion emissions.

Indian Basin Gas Plant
VOC /HAP Emissions from Condensate & Water Truck Loading (SSM)

Unit ID: ES-56
Stack ID: ES-56 (5) - Flare
Control ID: -

Loading Loss Equation Terms

Saturation factor (S)	0.6	AP-42, Table 5.2-1, Submerged Loading
True Vapor Pres. (psia)- (P)	5.837	(1)
Molecular Wt. of Vapor (MW)	66.19	(2)
Temperature R (T)	545.92	(3) Max. Liq. Surface Temp. ~ 86.25 F
% VOC	100%	
Max. Gallons Loaded per hour (Gal/hr)	7560	

Loading Rate Information:
85265.0 bbls/yr
3581130 gal/yr
180 bbls/hr/truck
7560 gal/hr/truck
474 hours/year

VOC Loading Losses

VOC Loading Losses (lbs/1000gal) $= 12.46 \times \frac{S \times P \times MW}{T} \times \%VOC$

$= 5.29$

VOC Emissions converted to maximum pounds per hour (lbs/hr) and tons per year (tpy)

Vapor Collection System - Maintenance Downtime (5%)

7560	gal/hr	x	5.29	lb/1000 gal =	40.00	lbs/hr	→	95%	=	2.00	lbs/hr
85265	bbls/yr x 42 gal/bbl x		5.29	lbs/1000 gal x1 ton/2000 lbs =	9.47	tpy	→	95%	=	0.47	tpy

Hazardous Air Pollutant (HAP) Emissions

	Wt. Fraction (4)	Emissions without Control [without VCS-COND or ES-50 (flare)]		VCS-COND - Maintenance Downtime (5%) SSM HAP Emissions from Truck Loading	
	(Frac. of VOC only)	lb/hr	tpy	lb/hr	tpy
n-Hexane	0.137359	5.49	1.30	0.275	0.065
Benzene	0.028351	1.13	0.27	0.057	0.013
Toluene	0.027887	1.12	0.26	0.056	0.013
Ethylbenzene	0.001529	0.061	0.014	0.0031	7.2E-04
Xylene	0.012124	0.48	0.115	0.024	0.0057
Total HAPs		**8.29**	**1.96**	**0.41**	**0.098**

Example Calculation:

9.47 tpy VOC x	0.137	wt. frac. hexane x (1-0.98) D.E.=	0.065	tpy n-hexane
40.0 lb/hr VOC x	0.137	wt. frac. hexane x (1-0.98) D.E.=	0.27	lb/hr n-hexane

(1) Conservative vapor pressure of liquids out of the upstream stabillizer vessel at maximum temperature of 325F. [Mobile Analytical Labs, Inc. 2/9/2010, Lab# 5147].
(2) Vapor molecular weight from the upstream stabilizer vessel reflux analysis. [Mobile Analytical Labs, Inc. 2/9/2010, Lab# 5148].
(3) The max. liquid temp. of the upstream stabilizer vessel is 325F (784.67 R); however a lower max liq. surface temp. from TANKS 4.09/AP-42 was used to derive more conservative (higher) emission rates per the above EPA loading loss equation.
(4) Mobile Analytical Labs, Inc. 2/9/2010, Lab # 5147. Constituent wt. fractions assuming condensate is 100% VOC.
(5) Vapors are normally collected by an enclosed vapor collection system (VCS-COND) and sent to the flare (ES-50), however, the emissions depicted in the above table are SSM emissions from truck loading during maintenance of the vapor collection system, i.e, 5% VCS downtime.

Flare (ES-50) Combustion / VOC Emissions - from Condensate Tank and Truck Loading Vapors [1]

Stream		VOC -Uncontrolled [2] lb/hr	VOC -Uncontrolled [2] tpy	VOC - ES-50 [3] lb/hr	VOC - ES-50 [3] tpy	Vapor MW	Btu/scf
Vapors from Condensate Tanks (normal operations)		27.95	122.44	0.56	2.4	66.19	**4500**
Vapors from Truck Loading (normal operations)		40.00	9.47	0.80	0.19		
	Total	67.95	131.91	1.36	2.64		

Using PV=nRT
mRT/MW*P=V
[m=lb/hr or tpy; MW ~63.5; P=14.696 psia; R=10.73; T=545.92 °R]

V, scfh = 67.95 lb/hr * 10.73*545.92/(MW*14.696)
V, scfm = 409.20

4500.00 Btu/scf x 409 scf/hr = 1841391 Btu/hr

V, scfy = 131.91 tpy * 10.73*545.92/(MW*14.696)
V, scfy = 794.33

4500.00 Btu/scf x 794 scf/yr = 3574468 Btu/yr

Emissions Calculations — **Combustion Emissions - ES-50**

NOx	0.068 lb/MMBtu [4]	x 1.841391	MM Btu/hr	=	**0.13**	**lb/hr NOx**
CO	0.37 lb/MMBtu [4]	x 1.841391	MM Btu/hr	=	**0.68**	**lb/hr CO**
NOx	0.068 lb/MMBtu [4]	x 3.574468	MM Btu/yr	=	**0.24**	**tpy NOx**
CO	0.37 lb/MMBtu [4]	x 3.574468	MM Btu/yr	=	**1.32**	**tpy CO**

(1) Vapors are collected by the vapor collection system (VCS-COND) and sent to Flare ES-50 during normal operations.
(2) The "VOC uncontrolled" values represents worst case VOC streams to the flare (ES-50). If the vapor collection system (VCS-COND) is down for SSM, up to 5% of the time, vapors may be emitted from individual tanks or loading operations. See separate tank and truck loading emissions calculations.
(3) VOC from the ES-50 flare is calculated in separate tables for tanks and truck loading.
(4) NOx and CO Emissions Factors are from EPA AP-42 Emission Factors for Flare Combustion, Fifth Edition, Table 13.5-1, 9/91 (reformatted 1/95).

Indian Basin Gas Plant
Calculation of Btu/scf for Condensate Tanks [ES-46, ES-47, ES-48) and Truck Loading (ES-56) Vapor streams
For use in Flare ES-50 Combustion Calculations

Stream [1]	MW	Mole %	Net Heating Value Btu/lb	Net Heating Value Btu/scf	Net Heat Release Btu/1scf		Calculated MW	
N2	28	0.0000					0	
CO2	44	0.0000					0	
H_2S	34	0.0000		596	0.000		0	
Methane	16	0.0000	-	1000	0.000		0.0010	
Ethane	30	0.0033	-	1587	0.052		0.0029	
Propane	44	0.0065	-	2272	0.148		0.0032	
Butane/Isobutane	58	0.0055	-	2956	0.163		11.69	
Pentanes	72	16.2399	19300	3591	583.212		1.717	
Cyclopentane	70	2.4476	-	4000	97.904		30.94	
Hexanes or n-hexane	86	35.9717	19246	4278	1538.697		6.37	
Cyclohexane	84	7.5633	-	4481	338.911		14.75	
Heptanes	100	14.7516	19170	4954	730.827		6.89	
Methylcyclohexane	98	7.0349	-	5215	366.870		2.53	
Benzene	78	3.2443	17460	3520	114.186		2.49	
Toluene	92	2.7054	17430	4144	112.117		0.14	
Ethylbenzene	106	0.1287	17600	4821	6.205		1.08	
Xylene	106	1.0208	17559	4810	49.102		10.12	
C8 + Heavies	114	8.8767	-	6248	554.616		0	
2,2,4 Trimethylpentane	44	0.0000		116	0.000		0	
Total		100.000			4,493.0	~	88.7	Liquid MW
				* ~	**4,500**	**Btu/scf**	**66.19**	Vapor MW [2]

*** 4500 Btu/scf and 66.19 vapor MW used in Flare (ES-50) Combustion Calculations**

(1) Ref: Mobile Analytical Labs, Inc. 2/9/2010, Liquid out of stabilizer, Lab# 5147, Cylinder 3983.
(2) Ref: Mobile Analytical Labs, Inc. 2/9/2010, Stabilizer Reflux , Lab # 5148, Cylinder 5060.

7/23/2014 2:22 PM

Flare (ES-50)

Stream	Hours of Operation	Inlet Flow	Inlet Flow	Inlet Flow
	hrs/yr	cm^3/min	m^3/yr	ft^3/yr
GC1 (sales):	4380	400	105.12	3712.28
GC1 (inlet):	4380	400	105.12	3712.28
GC2 (NGL):	8760	400	210.24	7424.56

	GC1 (Sales)	GC1 (Inlet)	GC2 (NGL)
V (scf/hr)	0.85	0.85	0.85
V (scf/yr)	3712.3	3712.3	7424.6
Avg. MW (lb/lb-mol)	17.0	20.1	41.6
HHV (Btu/scf)	1023.9	1205	1020
Control Device	ES-50	ES-50	ES-50
Flare Efficiency	98	98	98

Emission Factors

NOX (lb/MMBtu)	0.068
CO (lb/MMBtu)	0.31

[1] NO_X and CO factors taken from AP-42 Table 13.5 -1 & 2 (4/15)

Emission Summary

Chromatograph	NO_X		VOC		CO		SO_2		H_2S	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
GC1	1.3E-04	2.8E-04	7.8E-05	3.4E-04	5.9E-04	1.3E-03	-	-	-	-
GC2	5.9E-05	2.6E-04	4.9E-06	2.1E-05	2.7E-04	1.2E-03	6.7E-06	8.7E-03	7.3E-08	9.4E-05

Emission Summary with Safety Factor

Chromatograph	NO_X		VOC		CO		SO_2		H_2S	
	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy	lb/hr	tpy
GC1	1.5E-04	3.4E-04	9.4E-05	4.1E-04	7.0E-04	1.5E-03	-	-	-	-
GC2	7.1E-05	3.1E-04	5.9E-06	2.6E-05	3.2E-04	1.4E-03	8.1E-06	1.0E-02	8.7E-08	1.1E-04
Total	2.2E-04	6.5E-04	1.0E-04	4.4E-04	1.0E-03	2.9E-03	8.1E-06	1.0E-02	8.7E-08	1.1E-04

[1] Safety Factor of 20% added to emission rates

GREENHOUSE GAS EMISSIONS

[CALCULATIONS BU FOR UA2 TABLE 2P, UA3 SECTION 22]

Indian Basin Gas Plant

ES-02: Regeneration Gas Heater

Manufacturer:	John Zink
Model:	HEVD15
Serial #:	Not Specified
Fuel:	Natural gas

Fuel Consumption

15	MMBtu/hr	Input heat rate	Nameplate
1021	Btu/scf	Fuel heat value	Nominal for natural gas
14691	scf/hr	Fuel rate	Input heat rate / Fuel heat value
128.70	MMscf/yr	Annual fuel usage	Fuel rate * 8760 / 1,000,000

Emission Rates

Uncontrolled emissions

NOx	CO	VOC	SO2	PM_{10}	Units	
100	84	5.5	0.6	7.6	lb/MMscf	Unit emission from AP-42 Table 1.4-1 & 2
1.47	1.23	0.08	0.01	0.11	lb/hr	Unit emissions * Input heat rate
6.4	5.4	0.4	0.0	0.5	tpy	lb/hr * 8760 hrs/yr / 2000lb/ton

Exhaust Parameters

400	°F	Exhaust temp (Tstk)	Measured
3820	ft MSL	Site Elevation	
25.99	in. Hg	Ambient pressure (Pstk)	Calculated based on elevation
10610	wscf/MMBtu	F factor	40 CFR 60 Appx A Method 19
2652.5	scfm	Exhaust flow	Calculated from F factor and heat rate
5050.5	acfm	Exhaust flow	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
3	ft	Stack diameter	Measured
77	ft	Stack height	Measured
11.9	ft/sec	Exhaust velocity	Exhaust flow ÷ stack area

Source: February 2003 - Air Permit Application prepared by Environmental Services Inc. (ESI) for Marathon Oil Company

GRI-HAPCalc® 3.0
External Combustion Devices Report

Facility ID:	**INDIAN BASIN GP**	**Notes:**
Operation Type:	**GAS PLANT**	
Facility Name:	**INDIAN BASIN 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".

External Combustion Devices

Unit Name: ES-02

Hours of Operation:	8,760	Yearly
Heat Input:	15.00	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-Methylchloranthrene	0.0000	0.0000000018 lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157 lb/MMBtu	EPA
Formaldehyde	0.0555	0.0008440090 lb/MMBtu	GRI Field
Methanol	0.0633	0.0009636360 lb/MMBtu	GRI Field
Acetaldehyde	0.0485	0.0007375920 lb/MMBtu	GRI Field
1,3-Butadiene	0.0225	0.0003423350 lb/MMBtu	GRI Field
Benzene	0.0491	0.0007480470 lb/MMBtu	GRI Field
Toluene	0.0668	0.0010163310 lb/MMBtu	GRI Field
Ethylbenzene	0.1388	0.0021128220 lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.0868	0.0013205140 lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	0.1867	0.0028417580 lb/MMBtu	GRI Field
n-Hexane	0.0924	0.0014070660 lb/MMBtu	GRI Field
Phenol	0.0000	0.0000001070 lb/MMBtu	GRI Field
Styrene	0.1366	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	0.9470			

Criteria Pollutants

VOC	0.3543	0.0053921569	lb/MMBtu	EPA
PM	0.4895	0.0074509804	lb/MMBtu	EPA
PM, Condensible	0.3671	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.1224	0.0018627451	lb/MMBtu	EPA
CO	2.1263	0.0323636360	lb/MMBtu	GRI Field
NMHC	0.5604	0.0085294118	lb/MMBtu	EPA
NOx	6.3740	0.0970167730	lb/MMBtu	GRI Field
SO2	0.0386	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0001	0.0000011765	lb/MMBtu	EPA
Methane	0.6912	0.0105212610	lb/MMBtu	GRI Field
Acetylene	0.9198	0.0140000000	lb/MMBtu	GRI Field
Ethylene	0.0623	0.0009476310	lb/MMBtu	GRI Field
Ethane	0.1729	0.0026312210	lb/MMBtu	GRI Field
Propylene	0.1541	0.0023454550	lb/MMBtu	GRI Field
Propane	0.0702	0.0010686280	lb/MMBtu	GRI Field
Isobutane	0.0962	0.0014640770	lb/MMBtu	GRI Field
Butane	0.0904	0.0013766990	lb/MMBtu	GRI Field
Cyclopentane	0.0743	0.0011304940	lb/MMBtu	GRI Field
Pentane	0.2278	0.0034671850	lb/MMBtu	GRI Field
n-Pentane	0.0934	0.0014221310	lb/MMBtu	GRI Field
Cyclohexane	0.0603	0.0009183830	lb/MMBtu	GRI Field
Methylcyclohexane	0.1446	0.0022011420	lb/MMBtu	GRI Field
n-Octane	0.1875	0.0028538830	lb/MMBtu	GRI Field
1,2,3-Trimethylbenzene	0.2249	0.0034224540	lb/MMBtu	GRI Field
1,2,4-Trimethylbenzene	0.2249	0.0034224540	lb/MMBtu	GRI Field
1,3,5-Trimethylbenzene	0.2249	0.0034224540	lb/MMBtu	GRI Field
n-Nonane	0.2405	0.0036604170	lb/MMBtu	GRI Field
CO2	7,729.4118	117.6470588235	lb/MMBtu	EPA

Indian Basin Gas Plant

ES-03: Glycol Regeneration Heater

Manufacturer:	McIver & Smith
Model:	30Z
Serial #:	N7703
Fuel:	Natural gas

Fuel Consumption

2	MMBtu/hr	Input heat rate	Nameplate
1021	Btu/scf	Fuel heat value	Nominal for natural gas
1959	scf/hr	Fuel rate	Input heat rate / Fuel heat value
17.16	MMscf/yr	Annual fuel usage	Fuel rate * 8760 / 1,000,000

Emission Rates

Uncontrolled emissions

NOx	CO	VOC	SO2	PM_{10}	Units	
100	84	5.5	0.6	7.6	lb/MMscf	Unit emission from AP-42 Table 1.4-1 & 2
0.20	0.16	1.08E-02	1.18E-03	1.49E-02	lb/hr	Unit emissions * Input heat rate
0.9	0.7	4.72E-02	5.15E-03	6.52E-02	tpy	lb/hr * 8760 hrs/yr / 2000lb/ton

Exhaust Parameters

670	°F	Exhaust temp (Tstk)	Measured
3820	ft MSL	Site Elevation	
25.99	in. Hg	Ambient pressure (Pstk)	Calculated based on elevation
10610	wscf/MMBtu	F factor	40 CFR 60 Appx A Method 19
353.7	scfm	Exhaust flow	Calculated from F factor and heat rate
884.8	acfm	Exhaust flow	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
0.64	ft	Stack diameter	Measured
30	ft	Stack height	Measured
45.8	ft/sec	Exhaust velocity	Exhaust flow ÷ stack area

Source: February 2003 - Air Permit Application prepared by Environmental Services Inc. (ESI) for Marathon Oil Company

GRI-HAPCalc® 3.0
External Combustion Devices Report

Facility ID:	**INDIAN BASIN GP**	**Notes:**
Operation Type:	**GAS PLANT**	
Facility Name:	**INDIAN BASIN 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".

External Combustion Devices

Unit Name: ES-03

Hours of Operation:	8,760	Yearly
Heat Input:	2.00	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-Methylchloranthrene	0.0000	0.0000000018 lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157 lb/MMBtu	EPA
Formaldehyde	0.0074	0.0008440090 lb/MMBtu	GRI Field
Methanol	0.0084	0.0009636360 lb/MMBtu	GRI Field
Acetaldehyde	0.0065	0.0007375920 lb/MMBtu	GRI Field
1,3-Butadiene	0.0030	0.0003423350 lb/MMBtu	GRI Field
Benzene	0.0066	0.0007480470 lb/MMBtu	GRI Field
Toluene	0.0089	0.0010163310 lb/MMBtu	GRI Field
Ethylbenzene	0.0185	0.0021128220 lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.0116	0.0013205140 lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	0.0249	0.0028417580 lb/MMBtu	GRI Field
n-Hexane	0.0123	0.0014070660 lb/MMBtu	GRI Field
Phenol	0.0000	0.0000001070 lb/MMBtu	GRI Field
Styrene	0.0182	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	0.1263			

Criteria Pollutants

VOC	0.0472	0.0053921569	lb/MMBtu	EPA
PM	0.0653	0.0074509804	lb/MMBtu	EPA
PM, Condensible	0.0490	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.0163	0.0018627451	lb/MMBtu	EPA
CO	0.2835	0.0323636360	lb/MMBtu	GRI Field
NMHC	0.0747	0.0085294118	lb/MMBtu	EPA
NOx	0.8499	0.0970167730	lb/MMBtu	GRI Field
SO2	0.0052	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0000	0.0000011765	lb/MMBtu	EPA
Methane	0.0922	0.0105212610	lb/MMBtu	GRI Field
Acetylene	0.1226	0.0140000000	lb/MMBtu	GRI Field
Ethylene	0.0083	0.0009476310	lb/MMBtu	GRI Field
Ethane	0.0230	0.0026312210	lb/MMBtu	GRI Field
Propylene	0.0205	0.0023454550	lb/MMBtu	GRI Field
Propane	0.0094	0.0010686280	lb/MMBtu	GRI Field
Isobutane	0.0128	0.0014640770	lb/MMBtu	GRI Field
Butane	0.0121	0.0013766990	lb/MMBtu	GRI Field
Cyclopentane	0.0099	0.0011304940	lb/MMBtu	GRI Field
Pentane	0.0304	0.0034671850	lb/MMBtu	GRI Field
n-Pentane	0.0125	0.0014221310	lb/MMBtu	GRI Field
Cyclohexane	0.0080	0.0009183830	lb/MMBtu	GRI Field
Methylcyclohexane	0.0193	0.0022011420	lb/MMBtu	GRI Field
n-Octane	0.0250	0.0028538830	lb/MMBtu	GRI Field
1,2,3-Trimethylbenzene	0.0300	0.0034224540	lb/MMBtu	GRI Field
1,2,4-Trimethylbenzene	0.0300	0.0034224540	lb/MMBtu	GRI Field
1,3,5-Trimethylbenzene	0.0300	0.0034224540	lb/MMBtu	GRI Field
n-Nonane	0.0321	0.0036604170	lb/MMBtu	GRI Field
CO2	1,030.5882	117.6470588235	lb/MMBtu	EPA

Indian Basin Gas Plant

ES-12: Auxiliary Boiler

Manufacturer:	York Shipley
Model:	SPHC-500-N
Serial #:	83-15354
Fuel:	Natural gas

Fuel Consumption

16.73	MMBtu/hr	Input heat rate	Nameplate
1021	Btu/scf	Fuel heat value	Nominal for natural gas
16386	scf/hr	Fuel rate	Input heat rate / Fuel heat value
143.54	MMscf/yr	Annual fuel usage	Fuel rate * 8760 / 1,000,000

Emission Rates

Uncontrolled emissions

NOx	CO	VOC	SO2	PM_{10}	Units	
100	84	5.5	0.6	7.6	lb/MMscf	Unit emission from AP-42 Table 1.4-1 & 2
1.64	1.38	0.09	9.83E-03	0.12	lb/hr	Unit emissions * Input heat rate
7.2	6.0	0.4	4.31E-02	0.5	tpy	lb/hr * 8760 hrs/yr / 2000lb/ton

Exhaust Parameters

420	°F	Exhaust temp (Tstk)	Measured
3820	ft MSL	Site Elevation	
25.99	in. Hg	Ambient pressure (Pstk)	Calculated based on elevation
10610	wscf/MMBtu	F factor	40 CFR 60 Appx A Method 19
2958.4	scfm	Exhaust flow	Calculated from F factor and heat rate
5764.0	acfm	Exhaust flow	scfm * (Pstd/Pstk)*(Tstk/Tstd), Pstd = 29.92 "Hg, Tstd = 520 °R
2.31	ft	Stack diameter	Measured
19	ft	Stack height	Measured
22.9	ft/sec	Exhaust velocity	Exhaust flow ÷ stack area

Source: February 2003 - Air Permit Application prepared by Environmental Services Inc. (ESI) for Marathon Oil Company

GRI-HAPCalc® 3.0
External Combustion Devices Report

Facility ID:	**INDIAN BASIN GP**	**Notes:**
Operation Type:	**GAS PLANT**	
Facility Name:	**INDIAN BASIN 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".

External Combustion Devices

Unit Name: ES-12

Hours of Operation:	8,760	Yearly
Heat Input:	16.73	MMBtu/hr
Fuel Type:	NATURAL GAS	
Device Type:	BOILER	
Emission Factor Set:	FIELD > EPA > LITERATURE	
Additional EF Set:	-NONE-	

Calculated Emissions (ton/yr)

Chemical Name	Emissions	Emission Factor	Emission Factor Set
HAPs			
3-Methylchloranthrene	0.0000	0.0000000018 lb/MMBtu	EPA
7,12-Dimethylbenz(a)anthracene	0.0000	0.0000000157 lb/MMBtu	EPA
Formaldehyde	0.0258	0.0003522500 lb/MMBtu	GRI Field
Methanol	0.0318	0.0004333330 lb/MMBtu	GRI Field
Acetaldehyde	0.0213	0.0002909000 lb/MMBtu	GRI Field
1,3-Butadiene	0.0000	0.0000001830 lb/MMBtu	GRI Field
Benzene	0.0005	0.0000062550 lb/MMBtu	GRI Field
Toluene	0.0004	0.0000053870 lb/MMBtu	GRI Field
Ethylbenzene	0.0000	0.0000000720 lb/MMBtu	GRI Field
Xylenes(m,p,o)	0.0001	0.0000010610 lb/MMBtu	GRI Field
2,2,4-Trimethylpentane	0.0024	0.0000323000 lb/MMBtu	GRI Field
n-Hexane	0.0236	0.0003214790 lb/MMBtu	GRI Field
Phenol	0.0000	0.0000000950 lb/MMBtu	GRI Field
Naphthalene	0.0000	0.0000002950 lb/MMBtu	GRI Field
2-Methylnaphthalene	0.0000	0.0000000700 lb/MMBtu	GRI Field
Acenaphthylene	0.0000	0.0000000550 lb/MMBtu	GRI Field
Biphenyl	0.0001	0.0000011500 lb/MMBtu	GRI Field
Acenaphthene	0.0000	0.0000000800 lb/MMBtu	GRI Field
Fluorene	0.0000	0.0000000700 lb/MMBtu	GRI Field
Anthracene	0.0000	0.0000000750 lb/MMBtu	GRI Field
Phenanthrene	0.0000	0.0000000550 lb/MMBtu	GRI Field
Fluoranthene	0.0000	0.0000000800 lb/MMBtu	GRI Field
Pyrene	0.0000	0.0000000750 lb/MMBtu	GRI Field
Benz(a)anthracene	0.0000	0.0000000750 lb/MMBtu	GRI Field

Chrysene	0.0000	0.0000001000	lb/MMBtu	GRI Field
Benzo(a)pyrene	0.0000	0.0000000600	lb/MMBtu	GRI Field
Benzo(b)fluoranthene	0.0000	0.0000001350	lb/MMBtu	GRI Field
Benzo(k)fluoranthene	0.0000	0.0000004400	lb/MMBtu	GRI Field
Benzo(g,h,i)perylene	0.0000	0.0000001500	lb/MMBtu	GRI Field
Indeno(1,2,3-c,d)pyrene	0.0000	0.0000001000	lb/MMBtu	GRI Field
Dibenz(a,h)anthracene	0.0000	0.0000000950	lb/MMBtu	GRI Field
Lead	0.0000	0.0000004902	lb/MMBtu	EPA
Total	0.1060			

Criteria Pollutants

VOC	0.3951	0.0053921569	lb/MMBtu	EPA
PM	0.5460	0.0074509804	lb/MMBtu	EPA
PM, Condensible	0.4095	0.0055882353	lb/MMBtu	EPA
PM, Filterable	0.1365	0.0018627451	lb/MMBtu	EPA
CO	2.2516	0.0307275000	lb/MMBtu	GRI Field
NMHC	0.6250	0.0085294118	lb/MMBtu	EPA
NOx	6.4671	0.0882553330	lb/MMBtu	GRI Field
SO2	0.0431	0.0005880000	lb/MMBtu	EPA

Other Pollutants

Dichlorobenzene	0.0001	0.0000011765	lb/MMBtu	EPA
Methane	0.4308	0.0058790650	lb/MMBtu	GRI Field
Acetylene	0.3907	0.0053314000	lb/MMBtu	GRI Field
Ethylene	0.0386	0.0005264000	lb/MMBtu	GRI Field
Ethane	0.1231	0.0016804650	lb/MMBtu	GRI Field
Propylene	0.0684	0.0009333330	lb/MMBtu	GRI Field
Propane	0.0881	0.0012019050	lb/MMBtu	GRI Field
Butane	0.1016	0.0013866350	lb/MMBtu	GRI Field
Cyclopentane	0.0030	0.0000405000	lb/MMBtu	GRI Field
Pentane	0.1514	0.0020656400	lb/MMBtu	GRI Field
n-Pentane	0.1466	0.0020000000	lb/MMBtu	GRI Field
Cyclohexane	0.0033	0.0000451000	lb/MMBtu	GRI Field
Methylcyclohexane	0.0124	0.0001691000	lb/MMBtu	GRI Field
n-Octane	0.0037	0.0000506000	lb/MMBtu	GRI Field
n-Nonane	0.0004	0.0000050000	lb/MMBtu	GRI Field
CO2	8,620.8706	117.6470588235	lb/MMBtu	EPA

Indian Basin Gas Plant - Flare Maintenance Emissions Summary

ES-14 (Utiility Flare); ES-42 (Residue Gas Flare) and ES-50 (SSM Flare) / Startup, Shutdown, Maintenance (SSM)

Indian Basin Gas Plant - Flare Maintenance Emissions Summary
ES-14 (Utiility Flare); ES-42 (Residue Gas Flare) and ES-50 (SSM Flare) / Startup, Shutdown, Maintenance (SSM)

Event	Equipment/Process	Maintenance Event (1)	Flare Unit ID	Stream Code	NOx lb/hr	NOx tpy	CO lb/hr	CO tpy	SO_2 lb/hr	SO_2 tpy	VOC lb/hr	VOC tpy	H_2S lb/hr	H_2S tpy	Other S Compds. lb/hr	Other S Compds. tpy
1	NGL Sales Meter	NGL Sales Meter Proving	ES-50-SSM	s1a-NGL-Vap(1)	4.61	0.0046	12.37	0.012	-	-	7.71	0.0077	-	-	-	-
2	Pipeline pumps	Start-up/shutdown of pipeline pumps for maintenance	ES-50-SSM	s1b-NGL-Vap(2)	20.18	0.020	54.11	0.054	-	-	33.74	0.034	-	-	-	-
3	NGL Pipeline	Maintenance performed by pipeline company	ES-50-SSM	s1c-NGL-Vap(3)	15.18	0.36	40.69	0.98	-	-	25.37	0.61	-	-	-	-
4	Cond. Stabilizer Compressor	Startup/Shutdown for Maintenance on Instrumentation	ES-50-SSM	s2a-Cond-Stab(1)	7.44	0.0019	19.94	0.0050	80.24	0.020	19.20	0.0048	0.85	2.1E-04	-	-
5	Cond. Stabilizer Compressor	Annual Overhaul of Stabilizer Compressor	ES-50-SSM	s2b-Cond-Stab(2)	9.33	0.22	25.02	0.60	100.69	2.42	24.09	0.58	1.07	0.026	-	-
6	Cond. Stabilizer Compressor	Oil Change to Stabilizer Compressor	ES-50-SSM	s2c-Cond-Stab(3)	9.33	0.028	25.02	0.08	100.69	0.30	24.09	0.072	1.07	0.0032	-	-
7	Cond. Stabilizer Compressor	Shutdown for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s2d1-Cond-Stab(4)	9.33	0.009	25.02	0.03	100.69	0.10	24.09	0.024	1.07	0.0011	-	-
8	Cond. Stabilizer Compressor	Startup for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s2d2-Cond-Stab(5)	9.33	0.019	25.02	0.05	100.69	0.20	24.09	0.048	1.07	0.0021	-	-
9	Acid Gas Compressor	Annual Overhaul - Start-up/Shutdown	ES-50-SSM	s3a-Selexol AG(1)	0.86	0.031	6.96	0.25	484.50	17.44	0.071	0.0026	5.15	0.19	31.62	1.14
									1656.29	59.63						
									2140.79	77.07						
10	Acid Gas Compressor	Quarterly Oil Change	ES-50-SSM	s3b-Selexol AG(2)	0.88	0.0070	7.08	0.057	492.87	3.94	0.073	5.8E-04	5.24	0.042	32.17	0.26
									1684.94	13.48						
									2177.81	17.42						
11	Acid Gas Compressor	Shutdown for Instrumentation Maintenance	ES-50-SSM	s3c-Selexol AG(3)	1.00	0.015	8.09	0.12	563.27	8.45	0.083	0.0012	5.98	0.090	36.76	0.55
									1925.58	28.88						
									2488.85	37.33						
12	Acid Gas Compressor	Shutdown for Instrumentation Maintenance	ES-50-SSM	s4a-Acid Gas(1)	1.03	0.015	8.35	0.13	4046.64	60.70	-	-	43.00	0.64	-	-
13	Acid Gas Compressor	Shutdown for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s4b1-Acid Gas(2)	0.98	0.0010	7.93	0.0079	3842.79	3.84	-	-	40.83	0.041	-	-
14	Acid Gas Compressor	Start-up for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s4b2-Acid Gas(3)	0.96	0.0087	7.79	0.070	3774.85	33.97	-	-	40.11	0.36	-	-
15	Acid Gas Compressor	Maintenance on Acid Gas Compressor - Shutdown	ES-50-SSM	s4c1-Acid Gas(4)	1.00	0.0015	8.07	0.012	3910.74	5.87	-	-	41.55	0.062	-	-
16	Acid Gas Compressor	Maintenance on Acid Gas Compressor - Startup	ES-50-SSM	s4c2-Acid Gas(5)	1.00	0.0015	8.07	0.012	3910.74	5.87	-	-	41.55	0.062	-	-
17	Acid Gas Compressor	Oil Change to AG Compressor	ES-50-SSM	s4d-Acid Gas(6)	1.00	0.0020	8.07	0.016	3910.74	7.82	-	-	41.55	0.083	-	-
18	Gas Filters	Maintenance on Gas Filters in Plant	ES-14-SSM	s8a-Plant Inlet(1)	12.06	0.0060	32.34	0.016	115.50	0.058	8.64	0.0043	1.23	6.1E-04	2.44	0.0012
									0.038	1.9E-05						
									115.54	0.058						
19	Inlet Gas & Gas Filters bldwn	Shutdown for Plant Turnaround (Every 4 yrs)	ES-14-SSM	s8b1-Plant Inlet(2)	165.31	0.17	443.23	0.44	1583.11	1.58	0.52	5.2E-04	118.42	0.12	16.82	0.017
20	Inlet Gas & Gas Filters bldwn	Shutdown for Plant Turnaround (Every 4 yrs)	ES-42-SSM	s8b1-Plant Inlet(2)	165.31	0.17	443.23	0.44	1583.11	1.58	0.52	5.2E-04	118.42	0.12	16.82	0.017
		Subtotal		s8b1-Plant Inlet(2)	330.63	0.33	886.46	0.89	3167.26	3.17	236.84	0.24	33.64	0.03	0.022	2.17E-05
21	Inlet Gas	Start-up for Plant Turnaround (Every 4 yrs)	ES-42-SSM	s8b2-Plant Inlet(3)	330.63	2.98	886.46	7.98	3167.26	28.51	236.84	2.13	33.64	0.30	0	0.30
22	Residue Gas Production	Shutdown for Plant Turnaround (Every 4 yrs)	ES-14-SSM	s9a1-Residue Gas(1)	116.38	0.12	312.03	0.31	-	-	0.57	5.7E-04	-	-	-	-
23	Residue Gas Production	Shutdown for Plant Turnaround (Every 4 yrs)	ES-42-SSM	s9a1-Residue Gas(1)	116.38	0.12	312.03	0.31	-	-	0.57	5.7E-04	-	-	-	-
		Subtotal		s9a1-Residue Gas(1)	232.76	0.23	624.07	0.62	-	-	1.14	0.0011	-	-	-	-
24	Residue Gas Production	Start-up after Plant Turnaround (Every 4 yrs)	ES-42-SSM	s9a2-Residue Gas(2)	232.76	2.09	624.07	5.62	-	-	1.14	0.010	-	-	-	-
25	ES-4 Turbine Pump	ES-4 pneumatic pump gas to Flare after maint./SD	ES-14-SSM	s9b-Residue Gas(3)	2.24	0.0056	6.01	0.015	-	-	0.011	2.8E-05	-	-	-	-
26	ES-5 Turbine Pump	ES-5 pneumatic pump gas to Flare after maint./SD	ES-14-SSM	s9c-Residue Gas(4)	2.24	0.0056	6.01	0.015	-	-	0.011	2.8E-05	-	-	-	-
27	ES-06/07 Turbine	ES-06/07 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9d-Residue Gas(5)	52.37	0.0044	140.42	0.012	-	-	0.26	2.1E-05	-	-	-	-
28	ES-08/09 Turbine	ES-08/09 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9e-Residue Gas(6)	52.37	0.0044	140.42	0.012	-	-	0.26	2.1E-05	-	-	-	-
29	ES-10/11 Turbine	ES-10/11 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9f-Residue Gas(7)	52.37	0.0044	140.42	0.012	-	-	0.26	2.1E-05	-	-	-	-
30	ES-22 Turbine	ES-22 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9g-Residue Gas(8)	52.37	0.0044	140.42	0.012	-	-	0.26	2.1E-05	-	-	-	-
31	ES-17 Turbine	ES-17 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9h-Residue Gas(9)	59.49	0.0099	159.51	0.027	-	-	0.29	4.9E-05	-	-	-	-
32	ES-14	ES-14 Pilot and Purge Gas (2)	ES-14-SSM	Pilot&Purge-ES-14	0.10	0.44	0.27	1.19	-	-	0.021	0.094	-	-	-	-
33	ES-42	ES-42 Pilot and Purge Gas (2)	ES-42-SSM	Pilot&Purge-ES-42	0.15	0.64	0.39	1.72	-	-	0.031	0.14	-	-	-	-
34	ES-50	ES-50 Pilot and Purge Gas (2)	ES-50-SSM	Pilot&Purge-ES-50	0.049	0.21	0.13	0.57	-	-	0.010	0.045	-	-	-	-

Notes
(1) Each maintenance event is explained in more detail in the individual calculation sheets following this summary table. Events numbers are listed in the first column, and stream numbers in the fifth column of this table.
(2) Pilot and Purge emissions are listed in the table but are not considered SSM emissions and are not included in the SSM event totals. GHG's are reported in separate table
(3) The events numbers are listed in the left column of the table above. The highest emissions, both lb/hr and tpy, for each pollutant that may occur simultaneously is included in each total.

See Page 2 - Total Emissions Scenarios

Indian Basin Gas Plant - Flare Maintenance Emissions Summary
ES-14 (Utiility Flare); ES-42 (Residue Gas Flare) and ES-50 (SSM Flare) / Startup, Shutdown, Maintenance (SSM)

Total Emissions Scenarios

I. Worst Case for Plant Turnaround Every Four Years		**NOx**		**CO**		**SO2**		**VOC**		**H2S**		**Other S Compds.**	
		lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
	Events occuring simultaneously as worst case*												
ES-50	8, 14	10.29	0.027	32.80	0.12	3875.54	34.18	24.09	0.05	41.18	0.36	-	-
ES-14	19, 22	281.69	0.28	755.26	0.76	1583.11	1.58	1.09	0.0011	118.42	0.12	16.82	0.017
ES-42	21, 24	563.39	5.07	1510.53	13.59	3167.26	28.51	237.98	2.14	33.64	0.30	0.00	0.30
Total (I) - All Flares	**Worst case:** ES-50 & ES-42 simultaneously	573.68	5.10	1543.33	13.71	7042.80	62.68	262.07	2.19	74.82	0.67	0.000	0.32

II. Worst Case - Years when (4-yr) Plant Turnaround Does Not Occur			**NOx**		**CO**		**SO2**		**VOC**		**H2S**		**Other S Compds.**	
			lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
	Events occuring simultaneously as worst case*													
ES-50	NOx - max lb/hr: Event #s 2,4,11,12	tpy: Event #s 3,4,11,12	29.65	0.40	90.48	1.23	4147.33	82.95	57.91	0.61	44.07	0.25	36.76	1.14
	CO - max lb/hr: Event #s 2,4,11,12	tpy: Event #s 3,4,11,13												
	SO2 - max lb/hr: Event #s 5 & 12	tpy: Event #s 4,9,16												
	VOC - max lb/hr: Event #s 2,5,11	tpy: Event #s 2,5,11												
	H2S - max lb/hr: Event #s 5 & 12	tpy: Event #s 4,9,16												
	Other S - max lb/hr: Event # 11	tpy: Event # 9												
ES-14	NOx - max lb/hr: Event #s 25, 31	tpy: Event #s 25, 31	61.73	0.016	165.52	0.042	-	-	0.30	7.6E-05	-	-	-	-
	CO - max lb/hr: Event #s 25, 31	tpy: Event #s 25, 31												
	SO_2 - max lb/hr: --	tpy: --												
	VOC - max lb/hr: Event #s 25, 31	tpy: Event #s 25, 31												
	H2S - max lb/hr: --	tpy: --												
	Other S - max lb/hr: --	tpy: --												
ES-42	None		-	-	-	-	-	-	-	-	-	-	-	-
Total (II) - All Flares (worst case)			91.38	0.41	255.99	1.27	4147.33	82.95	58.22	0.61	44.07	0.25	36.76	1.14

III. Worst Case from Each Individual Flare		**NOx**		**CO**		**SO2**		**VOC**		**H2S**		**Other S Compds.**	
		lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
	Events occuring simultaneously as worst case*												
ES-50	Same as Scenario II above (4-yr turnaround) except H2S tpy - Event # 8 & #14	29.65	0.40	90.48	1.23	4147.33	82.95	57.91	0.61	44.07	0.36	36.76	1.14
ES-14	Same as Scenario II above (4-yr turnaround)	281.69	0.28	755.26	0.76	1583.11	1.58	1.09	0.0011	118.42	0.12	16.82	0.017
ES-42	Same as Scenario II above (4-yr turnaround)	563.39	5.07	1510.53	13.59	3167.26	28.51	237.98	2.14	33.64	0.30	0.000	0.30

IV. Worst Case Total [All flares] - The largest of Scenario I or Scenario II totals, above	**NOx**		**CO**		**SO2**		**VOC**		**H2S**		**Other S Compds.**	
	lb/hr	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
	573.68	**5.10**	**1543.33**	**13.71**	**7042.80**	**82.95**	**262.07**	**2.19**	**74.82**	**0.67**	**36.76**	**1.14**

* The events numbers are listed in the first column of the table on page 1. The highest emissions, both lb/hr and tpy, for each pollutant that may occur simultaneously are included in each total.

Indian Basin Gas Plant - Flare Maintenance Emissions Summary

ES-14 (Utiility Flare); ES-42 (Residue Gas Flare) and ES-50 (SSM Flare) / Startup, Shutdown, Maintenance (SSM)

Event	Equipment/Process	Maintenance Event (1)	Flare Unit ID	Stream Code	Greenhouse Gases (GHGs) CH_4 ton/yr mass GHG	CH_4 ton/yr CO_2e	CO_2 ton/yr mass GHG	N_2O ton/yr mass GHG	N_2O ton/yr CO_2e	Total CO_2e
1	NGL Sales Meter	NGL Sales Meter Proving	ES-50-SSM	s1a-NGL-Vap(1)	0.0003	0.0081	4.75	7.37E-06	0.0023	4.8
2	Pipeline pumps	Start-up/shutdown of pipeline pumps for maintenance	ES-50-SSM	s1b-NGL-Vap(2)	0.0014	0.0352	20.77	3.22E-05	0.0100	20.8
3	NGL Pipeline	Maintenance performed by pipeline company	ES-50-SSM	s1c-NGL-Vap(3)	0.03	0.64	374.92	5.82E-04	0.18	375.7
4	Cond. Stabilizer Compressor	Startup/Shutdown for Maintenance on Instrumentation	ES-50-SSM	s2a-Cond-Stab(1)	0.01	0.19	1.78	2.97E-06	0.00	2.0
5	Cond. Stabilizer Compressor	Annual Overhaul of Stabilizer Compressor	ES-50-SSM	s2b-Cond-Stab(2)	0.90	22.44	214.82	3.58E-04	0.11	237.4
6	Cond. Stabilizer Compressor	Oil Change to Stabilizer Compressor	ES-50-SSM	s2c-Cond-Stab(3)	0.11	2.80	26.85	4.47E-05	0.01	29.7
7	Cond. Stabilizer Compressor	Shutdown for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s2d1-Cond-Stab(4)	0.037	0.93	8.95	1.49E-05	0.0046	9.9
8	Cond. Stabilizer Compressor	Startup for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s2d2-Cond-Stab(5)	0.075	1.87	17.90	2.98E-05	0.0092	19.8
9	Acid Gas Compressor	Annual Overhaul - Start-up/Shutdown	ES-50-SSM	s3a-Selexol AG(1)	0.12	2.98	18.78	2.28E-06	0.0007	21.8
10	Acid Gas Compressor	Quarterly Oil Change	ES-50-SSM	s3b-Selexol AG(2)	0.027	0.67	4.25	5.15E-07	0.0002	4.9
11	Acid Gas Compressor	Shutdown for Instrumentation Maintenance	ES-50-SSM	s3c-Selexol AG(3)	0.058	1.44	9.10	1.10E-06	0.0003	10.5
12	Acid Gas Compressor	Shutdown for Instrumentation Maintenance	ES-50-SSM	s4a-Acid Gas(1)	0.0041	0.1016	29.82	5.02E-05	0.0156	29.9
13	Acid Gas Compressor	Shutdown for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s4b1-Acid Gas(2)	0.0003	0.0064	1.89	3.18E-06	0.0010	1.9
14	Acid Gas Compressor	Start-up for Plant Turnaround (Every 4 yrs)	ES-50-SSM	s4b2-Acid Gas(3)	0.0023	0.0569	16.69	2.81E-05	0.0087	16.8
15	Acid Gas Compressor	Maintenance on Acid Gas Compressor - Shutdown	ES-50-SSM	s4c1-Acid Gas(4)	0.00039	0.0098	2.88	4.85E-06	0.0015	2.9
16	Acid Gas Compressor	Maintenance on Acid Gas Compressor - Startup	ES-50-SSM	s4c2-Acid Gas(5)	0.00039	0.0098	2.88	4.85E-06	0.0015	2.9
17	Acid Gas Compressor	Oil Change to AG Compressor	ES-50-SSM	s4d-Acid Gas(6)	0.00052	0.0131	3.84	6.47E-06	0.0020	3.9
18	Gas Filters	Maintenance on Gas Filters in Plant	ES-14-SSM	s8a-Plant Inlet(1)	0.028	0.7091	4.94	9.63E-06	0.0030	5.7
19	Inlet Gas & Gas Filters bldwn	Shutdown for Plant Turnaround (Every 4 yrs)	ES-14-SSM	s8b1-Plant Inlet(2)	0.78	19.44	135.55	2.64E-04	0.08	155.1
20	Inlet Gas & Gas Filters bldwn	Shutdown for Plant Turnaround (Every 4 yrs)	ES-42-SSM	s8b1-Plant Inlet(2)	0.78	19.44	135.55	2.64E-04	0.08	155.1
		Subtotal		s8b1-Plant Inlet(2)	1.56	38.88	271.10	5.28E-04	0.16	310.1
21	Inlet Gas	Start-up for Plant Turnaround (Every 4 yrs)	ES-42-SSM	s8b2-Plant Inlet(3)	14.00	349.89	2,439.94	4.75E-03	1.47	2,791.3
22	Residue Gas Production	Shutdown for Plant Turnaround (Every 4 yrs)	ES-14-SSM	s9a1-Residue Gas(1)	0.69	17.33	94.51	1.86E-04	0.06	111.9
23	Residue Gas Production	Shutdown for Plant Turnaround (Every 4 yrs)	ES-42-SSM	s9a1-Residue Gas(1)	0.69	17.33	94.51	1.86E-04	0.06	111.9
		Subtotal		s9a1-Residue Gas(1)	1.39	34.66	189.02	3.72E-04	0.12	223.8
24	Residue Gas Production	Start-up after Plant Turnaround (Every 4 yrs)	ES-42-SSM	s9a2-Residue Gas(2)	12.48	311.9	1,701.2	0.0033	1.0375	2,014.1
25	ES-4 Turbine Pump	ES-4 pneumatic pump gas to Flare after maint./SD	ES-14-SSM	s9b-Residue Gas(3)	0.033	0.8340	4.55	8.95E-06	0.0028	5.4
26	ES-5 Turbine Pump	ES-5 pneumatic pump gas to Flare after maint./SD	ES-14-SSM	s9c-Residue Gas(4)	0.033	0.8340	4.55	8.95E-06	0.0028	5.4
27	ES-06/07 Turbine	ES-06/07 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9d-Residue Gas(5)	0.026	0.6499	3.54	6.97E-06	0.0022	4.2
28	ES-08/09 Turbine	ES-08/09 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9e-Residue Gas(6)	0.026	0.6499	3.54	6.97E-06	0.0022	4.2
29	ES-10/11 Turbine	ES-10/11 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9f-Residue Gas(7)	0.026	0.6499	3.54	6.97E-06	0.0022	4.2
30	ES-22 Turbine	ES-22 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9g-Residue Gas(8)	0.026	0.6499	3.54	6.97E-06	0.0022	4.2
31	ES-17 Turbine	ES-17 Turbine Recompressor Maint./Blowdowns	ES-14-SSM	s9h-Residue Gas(9)	0.059	1.4765	8.05	1.58E-05	0.0049	9.5
32	ES-14	ES-14 Pilot and Purge Gas (2)	ES-14-SSM	Pilot&Purge-ES-14						(2)
33	ES-42	ES-42 Pilot and Purge Gas (2)	ES-42-SSM	Pilot&Purge-ES-42						(2)
34	ES-50	ES-50 Pilot and Purge Gas (2)	ES-50-SSM	Pilot&Purge-ES-50						(2)

Notes

(1) Each maintenance event is explained in more detail in the individual calculation sheets following this summary table. *White out partial footnotes on copy for reports*

(2) Pilot and Purge emissions are listed in the table but are not considered SSM emissions and are not included in the S

(3) The events numbers are listed in the left column of the table above. The highest emissions, both lb/hr and tpy, for e

See Page 2 - Total Emissions Scenarios

Indian Basin Gas Plant - Flare Maintenance Emissions Summary
ES-14 (Utiility Flare); ES-42 (Residue Gas Flare) and ES-50 (SSM Flare) / Startup, Shutdown, Maintenance (SSM)

Greenhouse Gases (GHGs)

Total Emissions Scenarios

I. Worst Case for Plant Turnaround Every Four Years		CH_4 ton/yr mass GHG	CH_4 ton/yr CO_2e	CO_2 ton/yr mass GHG	N_2O ton/yr mass GHG	N_2O ton/yr CO_2e	Total CO_2e
	Events occuring simultaneously as worst case*						
ES-50	8, 14	0.077	1.93	34.59	5.8E-05	0.02	36.5
ES-14	19, 22	1.47	36.77	230.06	4.5E-04	0.14	267.0
ES-42	21, 24	26.47	661.82	4141.10	0.0081	2.51	4,805.4
Total (I) - All Flares	**Worst case:** ES-50 & ES-42 simultaneously	26.55	663.75	4175.69	0.0082	2.529	4,842.0

II. Worst Case - Years when (4-yr) Plant Turnaround Does Not Occur			CH_4 ton/yr mass GHG	CH_4 ton/yr CO_2e	CO_2 ton/yr mass GHG	N_2O ton/yr mass GHG	N_2O ton/yr CO_2e	
	Events occuring simultaneously as worst case*							
ES-50	NOx - max lb/hr: Event #s 2,4,11,12	tpy: Event #s 3,4,11,12	0.90	22.54	244.64	4.1E-04	0.13	267.3
	CO - max lb/hr: Event #s 2,4,11,12	tpy: Event #s 3,4,11,13						
	SO2 - max lb/hr: Event #s 5 & 12	tpy: Event #s 4,9,16						
	VOC - max lb/hr: Event #s 2,5,11	tpy: Event #s 2,5,11						
	H2S - max lb/hr: Event #s 5 & 12	tpy: Event #s 4,9,16						
	Other S - max lb/hr: Event # 11	tpy: Event # 9						
ES-14	NOx - max lb/hr: Event #s 25, 31	tpy: Event #s 25, 31	0.092	2.31	12.60	2.5E-05	0.0077	14.9
	CO - max lb/hr: Event #s 25, 31	tpy: Event #s 25, 31						
	SO_2 - max lb/hr: --	tpy: --						
	VOC - max lb/hr: Event #s 25, 31	tpy: Event #s 25, 31						
	H2S - max lb/hr: --	tpy: --						
	Other S - max lb/hr: --	tpy: --						
ES-42	None		-	-	-	-	-	
Total (II) - All Flares (worst case)			0.99	24.85	257.24	4.3E-04	0.13	282.2

III. Worst Case from Each Individual Flare		CH_4 ton/yr mass GHG	CH_4 ton/yr CO_2e	CO_2 ton/yr mass GHG	N_2O ton/yr mass GHG	N_2O ton/yr CO_2e	
	Events occuring simultaneously as worst case*						
ES-50	Same as Scenario II above (4-yr turnaround) except H2S tpy - Event # 8 & #14	0.90	22.54	244.64	0.0004	0.13	267.3
ES-14	Same as Scenario II above (4-yr turnaround)	1.47	36.77	230.06	0.0005	0.14	267.0
ES-42	Same as Scenario II above (4-yr turnaround)	26.47	661.8	4141.10	0.0081	2.511	4,805.4

IV. Worst Case Total [All flares] - The largest of Scenario I or Scenario II totals, above	CH_4 ton/yr mass GHG	CH_4 ton/yr CO_2e	CO_2 ton/yr mass GHG	N_2O ton/yr mass GHG	N_2O ton/yr CO_2e	
	26.55	**663.75**	**4175.69**	**0.0082**	**2.53**	**4,842.0**

* The events numbers are listed in the first column of the table on page 1. The highest emissions, both lb/hr and tpy, for ea *White out partial footnotes on copy for reports*

Indian Basin Gas Plant - Flare Maintenance Emissions Summary
ES-14 (Utiility Flare); ES-42 (Residue Gas Flare) and ES-50 (SSM Flare) / Startup, Shutdown, Maintenance (SSM)

JG 8/2014 GHG worksheet vs above for flares:

Flare	CO2 tpy		CH4 tpy		N2O tpy	
	Oxy-wksht	Above	Oxy-wksht	Above	Oxy-wksht	Above
ES-14	536	230	3.736	1.5	0.00105	0.00045
ES-42	4230	4141	27.49	26.5	0.00828	0.00810
ES-50	374	245	1.46	0.9	0.00036	0.00041

Flare -CO2e	CO2		CH4 - CO2e		N2O-CO2e	
	Oxy-wksht	Above	Oxy-wksht	Above	Oxy-wksht	Above
ES-14	536	230	93.4	36.8	0.33	0.14
ES-42	4230	4141	687.3	661.8	2.57	2.51
ES-50	374	245	36.5	22.5	0.11	0.13

Total CO2e (Oxy workbook) 143908.60

CO2e OXY
5960

CO2e Above
5340

Worst case (actual)
CO2e Above
4,842

Note: The above are additive -worst case for each flare; however, the actual worst case is during turnaround with the flares that can operate simultaneously.

	1	2	3	4	5	6	7	8	9
			Current Permit	Current Permit	Current	Current	Current	Current Permit	Current Permit
			0.30	0.70	not used	not used	not used		
	NGL Vapors	**Condensate Stabilizer**	**Selexol AG**	**Acid Gas**	All Streams	Acid Gas Streams [3&4]	AG Streams Plus Condensate	**Plant Inlet**	**Residue Sales Gas**
MMSCFD	**0.758**	**1.301**	**0.43212**	**1.000**	**3.491**	**1.432**	**2.733**	**50**	**40**
Mol %									
Nitrogen	0.056	0.523	0.033	4.605	1.530	3.225	1.939	0.7411	0.9893
Carbon Dioxide	-	0.196	0.370	37.679	10.912	26.422	13.938	0.657	0
Hydrogen Sulfide		1.100	15.880	53.650	17.743	42.253	22.664	0.9	0
Methane	1.982	81.495	21.640	0.716	33.684	7.030	42.476	88.1708	98.256
Ethane	81.877	4.102	1.440	-	19.483	0.434	2.180	5.5872	0.7253
Propane	12.952	2.176	0.170	-	3.644	0.051	1.063	2.0636	0.0295
Isobutane	1.095	0.871	-	-	0.562	-	0.415	0.3961	0
n-Butane	1.549	2.299	-	-	1.193	-	1.095	0.706	0
Isopentane	0.239	1.996	-	-	0.796	-	0.950	0.252	0
n-Pentane	0.177	2.400	-	-	0.933	-	1.143	0.2253	0
Hexane	0.073	2.840	-	-	1.074	-	1.352	0.3011	0
H_2O			6.180		0.765	1.865	0.977		0
SXOL			0.010		0.001	0.003	0.002		0
COS			1.040		0.129	0.314	0.164	2.00E-07	0
CS_2			0.003		0.000	0.001	0.000	4.00E-07	0
Methyl Mercaptan			11.465		1.419	3.459	1.813	5.08E-05	0
Ethyl Mercaptan			35.330		4.373	10.660	5.586	1.28E-04	0
Dimethyl Sulfide			0.332		0.041	0.100	0.053	2.00E-06	0
I-Propyl Mercaptan			5.373		0.665	1.621	0.850	7.12E-05	0
T-Butyl Mercaptan			0.064		0.008	0.019	0.010	1.05E-05	0
Methyl Ethyl Sulfide			0.284		0.035	0.086	0.045	7.00E-06	0
S-Butyl Mecaptan/Thiophene			0.142		0.018	0.043	0.022	2.25E-05	0
I-Butyl Mercaptan			0.113		0.014	0.034	0.018	0	0
Diethyl Sulfide			0.009		0.001	0.003	0.001	0	0
N-Butyl Sulfide			0.029		0.004	0.009	0.005	0	0
N-Butyl Mercaptan			0.005		0.001	0.002	0.001	0	0
Dimethyl Disulfide			0.003		0.000	0.001	0.000	0	0
3-Methyl Thiophene			0.005		0.001	0.001	0.001	0	0
2-Methyl Thiophene			0.003		0.000	0.001	0.000	0	0
Dimethyl thiophene			0.006		0.001	0.002	0.001	0	0
Diethyl Disulfide			0.001		0.000	0.000	0.000	0	0
Trimethyl Thiophene			-		-	-	-	0	0
Undetermined Organic Sulfur			0.072		0.009	0.022	0.011	0	0
	100.000	100.000	100.000	96.650	99.040	97.661	98.774	100.000	100.000

VOC

NGL vapors based on flashing 3500 bpd from 300 psig and its bubble point to 200 psig.
Selexol AG Rates based on Dow Chemical Company Model and latest compositions, with H2S adjusted up for worst case.
Condensate Stabilizer Overhead composition based on 4/22/09 analysis and rates (richest analysis)

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	NGL Sales Meter			
Event	NGL Sales Meter Proving			
Gas Stream	NGL Vapors			Stream# 1
Btu/scf	1740.9			
% H_2S (volume)	0			
Design Gas Flow Rate, MMscfd	0.758			
Permit Gas Volume for Event, Mcfd	3.200	[3200 scf in 10 minutes] - For Permit		
Event hours/day	0.17	10 minutes		
Event days per year	12	1 event/month		
Event Hours/yr	2.0			
Wt. Frac. VOC in Gas Stream	0.2337			
379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.056	28.02	0.0156	0.048
Carbon dioxide		0	44.01	0.0000	NA
Hydrogen Sulfide		0	34.08	0.0000	NA
Methane		1.98	16.042	0.3179	0.98
Ethane		81.88	30.07	24.62	75.60
Propane		12.95	44.094	5.7109	17.54
Isobutane		1.095	58.12	0.6361	1.95
		1.55	58.12	0.9005	2.77
Isopentane	VOC	0.24	72.146	0.1727	0.53
n-pentane		0.18	72.146	0.1280	0.39
Hexane		0.073	86.17	0.0633	0.19
Heptanes		0	86.17	0	NA
Benzene		0	78.11	0	NA
Toluene		0	92.14	0	NA
Ethylbenzene		0	106.17	0	NA
xylene		0	106.17	0	NA
		100.00		32.56	100.00
VOC (C3+)		16.09		7.61	23.37

Emissions	**lb/hr**	**tpy**
NOx	4.61	0.0046
CO	12.37	0.012
SO_2	0	0
VOC	7.71	0.0077
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.0081
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	4.748
GHG N_2O (CO_2e)	-	0.002

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

	TCEQ Guidance RG-109	EPA AP -42	
Flare Emission Factors (EF)	(P. 20, Table 4; high Btu, non-steam assist)	Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s1a-NGL-Vap(1)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Pipeline pumps			
Event	Start-up/shutdown of pipeline pumps for maintenance			
Gas Stream	NGL Vapors		Stream# 1	
Btu/scf	1740.9			
% H_2S (volume)	0			
Design Gas Flow Rate, MMscfd	0.758			
Permit Gas Volume for Event, Mcfd	14.0	[14000 scf in 10 minutes]- For Permit		
Event hours/day	0.17	10	minutes	
Event days per year	12	1	event/month	
Event Hours/yr	2.00			
Wt. Frac. VOC in Gas Stream	0.23			
379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.056	28.02	0.0156	0.05
Carbon dioxide		0	44.01	0	NA
Hydrogen Sulfide		0	34.0758	0	NA
Methane		1.98	16.042	0.3179	0.98
Ethane		81.88	30.068	24.6187	75.6016
Propane		12.95	44.094	5.7109	17.54
Isobutane		1.095	58.12	0.6361	1.95
n-Butane		1.55	58.12	0.9005	2.77
Isopentane	**VOC**	0.24	72.146	0.1727	0.53
n-pentane		0.18	72.146	0.1280	0.39
Hexane		0.073	86.172	0.0633	0.19
Heptanes		0	86.1720	0	NA
Benzene		0	78.11	0	NA
Toluene		0	92.1402	0	NA
Ethylbenzene		0	106.167	0	NA
xylene		0	106.167	0	NA
		100.00		32.56	100.00
VOC (C3+)		16.09		7.61	23.37

Emissions	**lb/hr**	**tpy**
NOx	20.18	0.020
CO	54.11	0.054
SO_2	0	0
VOC	33.74	0.034
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.035
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	20.774
GHG N_2O (CO_2e)	-	0.010

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s1b-NGL-Vap(2)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	NGL Pipeline			
Event	Maintenance performed by pipeline company			
Gas Stream	NGL Vapors		Stream# 1	
Btu/scf	1740.9			
% H_2S (volume)	0			
Design Gas Flow Rate, MMscfd	0.758			
Permit Gas Volume for Event, Mcfd	1516	[1,516,000 scf in 2 days (48 hours)] - For Permit		
Event hours/day	24.00			
Event days per year	2			
Event Hours/yr	48.00			
Wt. Frac. VOC in Gas Stream	0.23			
379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.056	28.02	0.0156	0.05
Carbon dioxide		0	44.01	0	NA
Hydrogen Sulfide		0	34.0758	0	NA
Methane		1.98	16.042	0.3179	0.98
Ethane		81.88	30.068	24.6187	75.6016
Propane		12.95	44.094	5.7109	17.54
Isobutane		1.095	58.12	0.6361	1.95
n-Butane		1.55	58.12	0.9005	2.77
Isopentane	VOC	0.24	72.146	0.1727	0.53
n-pentane		0.18	72.146	0.1280	0.39
Hexane		0.073	86.172	0.0633	0.19
Heptanes		0	86.1720	0	NA
Benzene		0	78.11	0	NA
Toluene		0	92.1402	0	NA
Ethylbenzene		0	106.167	0	NA
xylene		0	106.167	0	NA
		100.00		32.56	100.00
VOC (C3+)		16.09		7.61	23.37

Emissions	lb/hr	tpy
NOx	15.18	0.36
CO	40.69	0.98
SO_2	0	0
VOC	25.37	0.61
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.64
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	374.92
GHG N_2O (CO_2e)	-	0.18

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s1c-NGL-Vap(3)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Condensate Stabilizer Compressor	
Event	Startup/Shutdown for Maintenance on Instrumentation	
Gas Stream	Condensate Stabilizer Stream	Stream# 2
Btu/scf	1247.20	
% H_2S (volume)	1.10	
Design Gas Flow Rate, MMscfd	1.301	
Permit Gas Volume for Event, Mcfd	3.600	[3600 scf blowdown in 5 minutes]- For Permit
Event hours/day	0.083	5 minutes
Event-days per year	6	
Event Hours/yr	0.50	
Wt. Frac. VOC in Gas Stream	0.361	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.523	28.020	0.15	0.63
Carbon dioxide		0	44.010	0.09	0.37
Hydrogen Sulfide		1	34.0758	0.37	1.61
Methane		81.50	16.042	13.07	56.02
Ethane		4.10	30.068	1.23	5.28
Propane	VOC	2.18	44.094	0.96	4.11
Isobutane	VOC	0.871	58.12	0.51	2.17
n-Butane	VOC	2.30	58.12	1.34	5.73
Isopentane	VOC	2.00	72.146	1.44	6.17
n-pentane	VOC	2.40	72.146	1.73	7.42
Hexanes +	VOC	2.840	86.172	2.45	10.49
Heptanes +	VOC	0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		23.34	100.00
VOC (C3+)		12.584		8.42	36.09

Emissions	**lb/hr**	**tpy**
NOx	7.44	0.0019
CO	19.94	0.0050
SO_2	80.24	0.020
VOC	19.20	0.0048
H_2S	0.85	2.13E-04
GHG CH_4 Uncombusted (CO_2e)	-	0.19
GHG CO_2 Uncombusted	-	0.0025
GHG CO_2 Combusted	-	1.78
GHG N_2O (CO_2e)	-	0.00092

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

	TCEQ Guidance RG-109	EPA AP -42	
Flare Emission Factors (EF)	(P. 20, Table 4; high Btu, non-steam assist)	Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s2a-Cond-Stab(1)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Condensate Stabilizer Compressor		
Event	Annual Overhaul of Stabilizer Compressor		
Gas Stream	Condensate Stabilizer Stream		Stream# 2
Btu/scf	1247.20		
% H_2S (volume)	1.10		
Design Gas Flow Rate, MMscfd	1.301		
Permit Gas Volume for Event, Mcfd	1301	[Event hours at max. flare/stream volume rate]- For Permit	
Event hours/day	24		
Event days per year	2	1 event/year	
Event Hours/yr	48		
Wt. Frac. VOC in Gas Stream	0.361		
C = 379 scf/mole	379		
DRE = Destruction Efficiency	0.98		

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.52	28.020	0.15	0.63
Carbon dioxide		0	44.010	0.09	0.37
Hydrogen Sulfide		1	34.0758	0.37	1.61
Methane		81.50	16.042	13.07	56.02
Ethane		4.10	30.068	1.23	5.28
Propane		2.18	44.094	0.96	4.11
Isobutane		0.871	58.12	0.51	2.17
n-Butane		2.30	58.12	1.34	5.73
Isopentane	VOC	2.00	72.146	1.44	6.17
n-pentane		2.40	72.146	1.73	7.42
Hexanes +		2.84	86.172	2.45	10.49
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		23.34	100.00
VOC (C3+)		12.584		8.42	36.09

Emissions	**lb/hr**	**tpy**
NOx	9.33	0.22
CO	25.02	0.60
SO_2	100.69	2.42
VOC	24.09	0.58
H_2S	1.07	0.026
GHG CH_4 Uncombusted (CO_2e)	-	22.44
GHG CO_2 Uncombusted	-	0.30
GHG CO_2 Combusted	-	214.52
GHG N_2O (CO_2e)	-	0.11

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s2b-Cond-Stab(2)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Condensate Stabilizer Compressor			
Event	Oil Change to Stabilizer Compressor			
Gas Stream	Condensate Stabilizer Stream			Stream# 2
Btu/scf	1247.20			
% H_2S (volume)	1.10			
Design Gas Flow Rate, MMscfd	1.301			
Permit Gas Volume for Event, Mcfd	108	[Event hours at max. flare/stream volume rate]- For Permit		
Event hours/day	2			
Event days per year	3	3 event/year		
Event Hours/yr	6			
Wt. Frac. VOC in Gas Stream	0.361			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.52	28.020	0.15	0.63
Carbon dioxide		0	44.01	0.09	0.37
Hydrogen Sulfide		1	34.08	0.37	1.61
Methane		81.50	16.04	13.07	56.02
Ethane		4.10	30.07	1.23	5.28
Propane		2.18	44.09	0.96	4.11
Isobutane		0.871	58.12	0.51	2.17
n-Butane		2.30	58.12	1.34	5.73
Isopentane	**VOC**	2.00	72.15	1.44	6.17
n-pentane		2.40	72.15	1.73	7.42
Hexanes +		2.84	86.17	2.45	10.49
Heptanes +		0	86.17	0	NA
Benzene		0	78.11	0	NA
Toluene		0	92.14	0	NA
Ethylbenzene		0	106.17	0	NA
xylene		0	106.17	0	NA
		100.00		23.34	100.00
VOC (C3+)		12.584		8.42	36.09

Emissions	**lb/hr**	**tpy**
NOx	9.33	0.028
CO	25.02	0.075
SO_2	100.69	0.30
VOC	24.09	0.072
H_2S	1.07	0.0032
GHG CH_4 Uncombusted (CO_2e)	-	2.80
GHG CO_2 Uncombusted	-	0.037
GHG CO_2 Combusted	-	26.82
GHG N_2O (CO_2e)	-	0.014

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

	TCEQ Guidance RG-109	EPA AP -42	
Flare Emission Factors (EF)	(P. 20, Table 4; high Btu, non-steam assist)	Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s2c-Cond-Stab(3)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM **Every 4 years**

Equipment/Process	Condensate Stabilizer Compressor			
Event	Shutdown for Plant Turnaround (Every 4 yrs)			
Gas Stream	Condensate Stabilizer Stream			Stream# 2
Btu/scf	1247.20			
% H_2S (volume)	1.10			
Design Gas Flow Rate, MMscfd	1.301			
Permit Gas Volume for Event, Mcfd	108	[Event hours at max. flare/stream volume rate]- For Permit		
Event hours/day	2			
Event days per year	1	**Every 4 years**		
Event Hours/yr	2	**Every 4 years**		
Wt. Frac. VOC in Gas Stream	0.361			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.52	28.020	0.15	0.63
Carbon dioxide		0	44.01	0.09	0.37
Hydrogen Sulfide		1.10	34.08	0.37	1.61
Methane		81.50	16.04	13.07	56.02
Ethane		4.10	30.07	1.23	5.28
Propane		2.18	44.09	0.96	4.11
Isobutane		0.871	58.12	0.51	2.17
n-Butane		2.30	58.12	1.34	5.73
Isopentane	VOC	2.00	72.15	1.44	6.17
n-pentane		2.40	72.15	1.73	7.42
Hexanes +		2.84	86.17	2.45	10.49
Heptanes +		0	86.17	0	NA
Benzene		0	78.11	0	NA
Toluene		0	92.14	0	NA
Ethylbenzene		0	106.17	0	NA
xylene		0	106.17	0	NA
		100.00		23.34	100.00
VOC (C3+)		12.584		8.42	36.09

Emissions	**lb/hr**	**tpy**
NOx	9.33	0.009
CO	25.02	0.025
SO_2	100.69	0.10
VOC	24.09	0.024
H_2S	1.07	0.0011
GHG CH_4 Uncombusted (CO_2e)	-	0.935
GHG CO_2 Uncombusted	-	0.012
GHG CO_2 Combusted	-	8.939
GHG N_2O (CO_2e)	-	0.0046

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s2d1-Cond-Stab(4)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM **Every 4 years**

Equipment/Process	Condensate Stabilizer Compressor	
Event	Startup for Plant Turnaround (Every 4 yrs)	
Gas Stream	Condensate Stabilizer Stream	Stream# 2
Btu/scf	1247.20	
% H_2S (volume)	1.10	
Design Gas Flow Rate, MMscfd	1.301	
Permit Gas Volume for Event, Mcfd	217	[Event hours at max. flare/stream volume rate]- For Permit
Event hours/day	4	
Event days per year	1	**Every 4 years**
Event Hours/yr	4	**Every 4 years**
Wt. Frac. VOC in Gas Stream	0.361	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.52	28.020	0.15	0.63
Carbon dioxide		0	44.01	0.09	0.37
Hydrogen Sulfide		1.10	34.08	0.37	1.61
Methane		81.50	16.04	13.07	56.02
Ethane		4.10	30.07	1.23	5.28
Propane		2.18	44.09	0.96	4.11
Isobutane		0.871	58.12	0.51	2.17
n-Butane		2.30	58.12	1.34	5.73
Isopentane	VOC	2.00	72.15	1.44	6.17
n-pentane		2.40	72.15	1.73	7.42
Hexanes +		2.84	86.17	2.45	10.49
Heptanes +		0	86.17	0	NA
Benzene		0	78.11	0	NA
Toluene		0	92.14	0	NA
Ethylbenzene		0	106.17	0	NA
xylene		0	106.17	0	NA
		100.00		23.34	100.00
VOC (C3+)		12.584		8.42	36.09

Emissions	**lb/hr**	**tpy**
NOx	9.33	0.019
CO	25.02	0.050
SO_2	100.69	0.20
VOC	24.09	0.048
H_2S	1.07	0.0021
GHG CH_4 Uncombusted (CO_2e)	-	1.87
GHG CO_2 Uncombusted	-	0.025
GHG CO_2 Combusted	-	17.88
GHG N_2O (CO_2e)	-	0.009

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s2d2-Cond-Stab(5)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor			
Event	Annual Overhaul - Start-up/Shutdown			
Gas Stream	Selexol AG			Stream# 3
Btu/scf	700.50			
% H_2S (volume)	15.88			
% Other Sulfur compounds	54.29			
Design Gas Flow Rate, MMscfd	0.432			
Permit Gas Volume for Event, Mcfd	434	[1500 scf blowdown + event hours at max. flare/stream volume rate]- For Permit		
Event hours/day	24			
Event days per year	3	1 event/year		
Event Hours/yr	72			
Wt. Frac. VOC in Gas Stream	0.0017			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		6.18	18	1.11	2.54
Nitrogen		0.033	28.020	0.01	0.021
Carbon dioxide		0.37	44.010	0.16	0.37
Hydrogen Sulfide		15.88	34.0758	5.41	12.34
Methane		21.64	16.042	3.47	7.92
Ethane		1.44	30.068	0.43	0.99
Propane		0.17	44.094	0.07	0.17
Isobutane		0.00	58.12	0.00	NA
n-Butane		0.00	58.12	0.00	NA
Isopentane	**VOC**	0.00	72.146	0.00	NA
n-pentane		0.00	72.146	0.00	NA
Hexanes +		0.00	86.172	0.00	NA
Heptanes +		0.00	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
Other sulfur compounds		54.287	61.1	33.17	75.65
		100.00		43.84	100.00
VOC (C3+)		0.17		0.07	0.17

Emissions	lb/hr	tpy		
NOx	0.86	0.031		
CO	6.96	0.25		
SO_2 (from H2S)	484.50	17.44	Subtotal SO2	
SO_2 (from other sulfur compounds)	1656.29	59.63	2140.79	77.07
VOC	0.071	0.0026		
H_2S	5.15	0.185		
Other sulfur compounds	31.62	1.14		
GHG CH_4 Uncombusted (CO_2e)	-	2.98		
GHG CO_2 Uncombusted	-	0.28		
GHG CO_2 Combusted	-	18.50		
GHG N_2O (CO_2e)	-	0.00071		
*Subtotal SO_2	2140.79	77.07		

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1
NOx, lb/MMBtu	0.0641	**0.068**
CO, lb/MMBtu	**0.5496**	0.37

s3a-Selexol AG(1)

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor			
Event	Quarterly Oil Change			
Gas Stream	Selexol AG			Stream# 3
Btu/scf	700.50			
% H_2S (volume)	15.88			
% Other Sulfur compounds	54.29			
Design Gas Flow Rate, MMscfd	0.432			
Permit Gas Volume for Event, Mcfd	74	[1500 scf blowdown + event hours at max. flare/stream volume rate] - For Permit		
Event hours/day	4			
Event days per year	4	4 event/year		
Event Hours/yr	16			
Wt. Frac. VOC in Gas Stream	0.0017			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		6.18	18	1.11	2.54
Nitrogen		0.033	28.020	0.01	0.02
Carbon dioxide		0.37	44.010	0.16	0.37
Hydrogen Sulfide		15.88	34.0758	5.41	12.34
Methane		21.64	16.042	3.47	7.92
Ethane		1.44	30.068	0.43	0.99
Propane		0.17	44.094	0.07	0.17
Isobutane		0.00	58.12	0.00	NA
n-Butane		0.00	58.12	0.00	NA
Isopentane	VOC	0.00	72.146	0.00	NA
n-pentane		0.00	72.146	0.00	NA
Hexanes +		0.00	86.172	0.00	NA
Heptanes +		0.00	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
Other sulfur compounds		54.29	61.09	33.17	75.65
		100.00		43.84	100.00
VOC (C3+)		0.17		0.075	0.17

Emissions	**lb/hr**	**tpy**		
NOx	0.88	0.0070		
CO	7.08	0.057		
SO_2 (from H2S)	492.87	3.94	Subtotal SO2	
SO_2 (from other sulfur compounds)	1684.94	13.48	2177.81	17.42
VOC	0.073	5.82E-04		
H_2S	5.24	0.042		
Other sulfur compounds	32.17	0.26		
GHG CH_4 Uncombusted (CO_2e)	-	0.67		
GHG CO_2 Uncombusted	-	0.063		
GHG CO_2 Combusted	-	4.18		
GHG N_2O (CO_2e)	-	0		
*Subtotal SO_2	2177.81	17.42		

Example Emissions Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	s3b-Selexol
CO, lb/MMBtu	**0.5496**	0.37	AG(2)

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor	
Event	Shutdown for Instrumentation Maintenance	
Gas Stream	Selexol AG	Stream# 3
Btu/scf	700.50	
% H_2S (volume)	15.88	
% Other Sulfur compounds	54.29	
Design Gas Flow Rate, MMscfd	0.432	
Permit Gas Volume for Event, Mcfd	10.50	[1500 scf blowdown + 0.5 event hours at max. flare/stream volume rate] - For Permit
Event hours/day	0.50	
Event days per year	60	60 event/year 5 times/month
Event Hours/yr	30	
Wt. Frac. VOC in Gas Stream	0.0017	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		6.18	18	1.11	2.54
Nitrogen		0.033	28.020	0.01	0.02
Carbon dioxide		0.37	44.010	0.16	0.37
Hydrogen Sulfide		15.88	34.0758	5.41	12.34
Methane		21.64	16.042	3.47	7.92
Ethane		1.44	30.068	0.43	0.99
Propane		0.17	44.094	0.07	0.17
Isobutane		0	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	**VOC**	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
Other sulfur compounds		54.29	61.1	33.17	75.65
		100.00		43.84	100.00
VOC (C3+)		0.17		0.075	0.17

Emissions	**lb/hr**	**tpy**		
NOx	1.00	0.015		
CO	8.09	0.12		
SO_2 (from H2S)	563.27	8.45	Subtotal SO2	
SO_2 (from other sulfur compounds)	1925.58	28.88	2488.85	37.33
VOC	0.083	0.0012		
H_2S	5.98	0.090		
Other sulfur compounds	36.76	0.55		
GHG CH_4 Uncombusted (CO_2e)	-	1.44		
GHG CO_2 Uncombusted	-	0.14		
GHG CO_2 Combusted	-	8.96		
GHG N_2O (CO_2e)	-	0		
*Subtotal SO_2	2488.85	37.33		

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1
NOx, lb/MMBtu	0.0641	**0.068**
CO, lb/MMBtu	**0.5496**	0.37

s3c-Selexol AG(3)

Maintenance Flare Emissions - ES-50-SSM **Every 4 years**

8/27/12_8:37AM email from Rodney Campbell (Oxy)

There are no emissions from flaring Selexol stream on Start-up

This scenario is therefore not necessary.

Equipment/Process	Acid Gas Compressor	
Event	Startup for Plant Turnaround (Every 4 yrs)	
Gas Stream	Selexol AG	Stream# 3
Btu/scf	700.50	
% H_2S (volume)	15.88	
% Other Sulfur compounds	54.29	
Design Gas Flow Rate, MMscfd	0.432	
Permit Gas Volume for Event, Mcfd	72.02	4 flaring event hours at max. flare/stream volume rate -[no shutdown emissions]
Event hours/day	4.0	**Every 4 years**
Event days per year	1.0	**Every 4 years**
Event Hours/yr	4	
Wt. Frac. VOC in Gas Stream	0.0017	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		6.18	18	1.11	2.54
Nitrogen		0.033	28.020	0.01	0.02
Carbon dioxide		0.37	44.010	0.16	0.37
Hydrogen Sulfide		15.88	34.0758	5.41	12.34
Methane		21.64	16.042	3.47	7.92
Ethane		1.44	30.068	0.43	0.99
Propane		0.17	44.094	0.07	0.17
Isobutane		0	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
Other sulfur compounds		54.29	61.1	33.17	75.65
		100.00		43.84	100.00
VOC (C3+)		0.17		0.075	0.17

Emissions	**lb/hr**	**tpy**		
NOx	0.86	0.002		
CO	6.93	0.01	Subtotal SO2	
SO_2 (from H2S)	482.82	0.97		
SO_2 (from other sulfur compounds)	1650.56	3.30	2133.38	4.27
VOC	0.071	0.0001		
H_2S	5.13	0.010		
Other sulfur compounds	31.51	0.06		
GHG CH_4 Uncombusted (CO_2e)	-	0.165		
GHG CO_2 Uncombusted	-	0.015		
GHG CO_2 Combusted	-	1.024		
GHG N_2O (CO_2e)	-	3.91E-05		
* Subtotal SO_2	2133.38	4.27		

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	s3d-Selexol AG(4)_(not needed)
CO, lb/MMBtu	**0.5496**	0.37	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor			
Event	Shutdown for Instrumentation Maintenance			
Gas Stream	Acid Gas		Stream# 4	
Btu/scf	340.00			
% H_2S (volume)	53.65			
Design Gas Flow Rate, MMscfd	1.00			
Permit Gas Volume for Event, Mcfd	22.33	[1500 scf blowdown + Event hours at max. flare/stream volume rate] - For Permit]		
Event hours/day	0.5			
Event days per year	60	60 event/year	5 times/month	
Event Hours/yr	30			
Wt. Frac. VOC in Gas Stream	0			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		0	18	0.00	NA
Nitrogen		4.60	28.020	1.29	3.56
Carbon dioxide		37.68	44.010	16.58	45.72
Hydrogen Sulfide		53.65	34.0758	18.28	50.41
Methane		0.72	16.042	0.11	0.32
Ethane		0	30.068	0.00	NA
Propane	VOC	0	44.094	0.00	NA
Isobutane	VOC	0	58.12	0.00	NA
n-Butane	VOC	0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane	VOC	0	72.146	0.00	NA
Hexanes +	VOC	0	86.172	0.00	NA
Heptanes +	VOC	0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		96.65		36.27	100.00
VOC (C3+)		0		0.00	0.00

Emissions	lb/hr	tpy
NOx	1.03	1.5E-02
CO	8.35	0.1252
SO_2	4046.64	60.70
VOC	0	0
H_2S	43.00	0.645
GHG CH_4 Uncombusted (CO_2e)	-	0.102
GHG CO_2 Uncombusted	-	29.27
GHG CO_2 Combusted	-	0.545
GHG N_2O (CO_2e)	-	0.016

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	
CO, lb/MMBtu	**0.5496**	0.37	s4a-Acid Gas(1)

Maintenance Flare Emissions - ES-50-SSM **Every 4 years**

Equipment/Process	Acid Gas Compressor	
Event	Shutdown for Plant Turnaround (Every 4 yrs)	
Gas Stream	Acid Gas	Stream# 4
Btu/scf	340.00	
% H_2S (volume)	53.65	
Design Gas Flow Rate, MMscfd	1.00	
Permit Gas Volume for Event, Mcfd	84.83	[1500 scf blowdown + Event hours at max. flare/stream volume rate] - For Permit]
Event hours/day	2.0	
Event days per year	1	**Every 4 years**
Event Hours/yr	2	**Every 4 years**
Wt. Frac. VOC in Gas Stream	0	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		0	18	0.00	NA
Nitrogen		4.60	28.020	1.29	3.56
Carbon dioxide		37.68	44.010	16.58	45.72
Hydrogen Sulfide		53.65	34.0758	18.28	50.41
Methane		0.72	16.042	0.11	0.32
Ethane		0	30.068	0.00	NA
Propane		0	44.094	0.00	NA
Isobutane		0	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	**VOC**	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		96.65		36.27	100.00
VOC (C3+)		0		0.00	0.00

Emissions	**lb/hr**	**tpy**
NOx	0.98	9.8E-04
CO	7.93	0.0079
SO_2	3842.79	3.84
VOC	0	0
H_2S	40.83	0.041
GHG CH_4 Uncombusted (CO_2e)	-	0.0064
GHG CO_2 Uncombusted	-	1.85
GHG CO_2 Combusted	-	0.035
GHG N_2O (CO_2e)	-	0.0010

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1
NOx, lb/MMBtu	0.0641	**0.068**
CO, lb/MMBtu	**0.5496**	0.37

s4b1-Acid Gas(2)

Maintenance Flare Emissions - ES-50-SSM **Every 4 years**

Equipment/Process	Acid Gas Compressor				
Event	Start-up for Plant Turnaround (Every 4 yrs)				
Gas Stream	Acid Gas			Stream# 4	
Btu/scf	340.00				
% H_2S (volume)	53.65				
Design Gas Flow Rate, MMscfd	1.00				
Permit Gas Volume for Event, Mcfd	750	[18 event hours at max. flare/stream volume rate] - For Permit]			
Event hours/day	18				
Event days per year	1	**Every 4 years**			
Event Hours/yr	18	**Every 4 years**			
Wt. Frac. VOC in Gas Stream	0				
C = 379 scf/mole	379				
DRE = Destruction Efficiency	0.98				

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		0	18	0.00	NA
Nitrogen		4.60	28.020	1.29	3.56
Carbon dioxide		37.68	44.010	16.58	45.72
Hydrogen Sulfide		53.65	34.0758	18.28	50.41
Methane		0.72	16.042	0.11	0.32
Ethane		0	30.068	0.00	NA
Propane		0	44.094	0.00	NA
Isobutane		0	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	**VOC**	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		96.65		36.27	100.00
VOC (C3+)		0		0.00	0.00

Emissions	lb/hr	tpy
NOx	0.96	0.0087
CO	7.79	0.070
SO_2	3774.85	33.97
VOC	0	0
H_2S	40.11	0.36
GHG CH_4 Uncombusted (CO_2e)	-	0.057
GHG CO_2 Uncombusted	-	16.39
GHG CO_2 Combusted	-	0.305
GHG N_2O (CO_2e)	-	0.0087

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	s4b2-Acid Gas(3)
CO, lb/MMBtu	**0.5496**	0.37	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor	
Event	Maintenance on Acid Gas Compressor - Shutdown	
Gas Stream	Acid Gas	Stream# 4
Btu/scf	340.00	
% H_2S (volume)	53.65	
Design Gas Flow Rate, MMscfd	1.000	
Permit Gas Volume for Event, Mcfd	43.17	- [1500 scf blowdown + **1 hour** at max. flare/stream rate - For Permit as the acid gas is shifted to the Sulfur plant]
Event hours/day	1	
Event days per year	3	
Event Hours/yr	3	1 event/year
Wt. Frac. VOC in Gas Stream	0	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		0	18	0.00	NA
Nitrogen		4.60	28.020	1.29	3.56
Carbon dioxide		37.68	44.010	16.58	45.72
Hydrogen Sulfide		53.65	34.0758	18.28	50.41
Methane		0.72	16.042	0.11	0.32
Ethane		0	30.068	0.00	NA
Propane	VOC	0	44.094	0.00	NA
Isobutane	VOC	0	58.12	0.00	NA
n-Butane	VOC	0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane	VOC	0	72.146	0.00	NA
Hexanes +	VOC	0	86.172	0.00	NA
Heptanes +	VOC	0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		96.65		36.27	100.00
VOC (C3+)		0		0	0

Emissions	lb/hr	tpy
NOx	0.998	0.0015
CO	8.07	0.0121
SO_2	3910.74	5.87
VOC	0	0
H_2S	41.55	0.062
GHG CH_4 Uncombusted (CO_2e)	-	0.0098
GHG CO_2 Uncombusted	-	2.83
GHG CO_2 Combusted	-	0.053
GHG N_2O (CO_2e)	-	0.0015

Example Emissions Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/ton

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tc

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	s4c1-Acid Gas(4)
CO, lb/MMBtu	**0.5496**	0.37	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor			
Event	Maintenance on Acid Gas Compressor - Startup			
Gas Stream	Acid Gas		Stream# 4	
Btu/scf	340.00			
% H_2S (volume)	53.65			
Design Gas Flow Rate, MMscfd	1.000			
Permit Gas Volume for Event, Mcfd	43.17	- [1500 scf blowdown + **1 hour** at max. flare/stream rate - For Permit as the acid gas is shifted to the Sulfur plant]		
Event hours/day	1			
Event days per year	3			
Event Hours/yr	3	1 event/year		
Wt. Frac. VOC in Gas Stream	0			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		0	18	0.00	NA
Nitrogen		4.60	28.020	1.29	3.56
Carbon dioxide		37.68	44.010	16.58	45.72
Hydrogen Sulfide		53.65	34.0758	18.28	50.41
Methane		0.72	16.042	0.11	0.32
Ethane		0	30.068	0.00	NA
Propane		0	44.094	0.00	NA
Isobutane		0	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		96.65		36.27	100.00
VOC (C3+)		0		0	0

Emissions	**lb/hr**	**tpy**
NOx	0.998	0.0015
CO	8.07	0.0121
SO_2	3910.74	5.87
VOC	0	0
H_2S	41.55	0.062
GHG CH_4 Uncombusted (CO_2e)	-	0.0098
GHG CO_2 Uncombusted	-	2.83
GHG CO_2 Combusted	-	0.053
GHG N_2O (CO_2e)	-	0.0015

Example Emissions Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/ton

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tc

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	s4c2-Acid Gas(5)
CO, lb/MMBtu	**0.5496**	0.37	

Maintenance Flare Emissions - ES-50-SSM

Equipment/Process	Acid Gas Compressor	
Event	Oil Change to AG Compressor	
Gas Stream	Acid Gas	Stream# 4
Btu/scf	340.00	
% H_2S (volume)	53.65	
Design Gas Flow Rate, MMscfd	1.000	
Permit Gas Volume for Event, Mcfd	43.17	- [1500 scf blowdown + **1 hour** at max. flare/stream rate - For Permit as the acid gas is shifted to the Sulfur plant]
Event hours/day	1	
Event days per year	4	
Event Hours/yr	4	4 event/year (quarterly)
Wt. Frac. VOC in Gas Stream	0	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Water		0	18	0.00	NA
Nitrogen		4.60	28.020	1.29	3.56
Carbon dioxide		37.68	44.010	16.58	45.72
Hydrogen Sulfide		53.65	34.0758	18.28	50.41
Methane		0.72	16.042	0.11	0.32
Ethane		0	30.068	0.00	NA
Propane		0	44.094	0.00	NA
Isobutane		0	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	**VOC**	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		96.65		36.27	100.00
VOC (C3+)		0		0	0

Emissions	lb/hr	tpy
NOx	1.00	0.0020
CO	8.07	0.016
SO_2	3910.74	7.82
VOC	0	0
H_2S	41.55	0.083
GHG CH_4 Uncombusted (CO_2e)	-	0.013
GHG CO_2 Uncombusted	-	3.77
GHG CO_2 Combusted	-	0.070
GHG N_2O (CO_2e)	-	0.0020

Example Emissions Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; low Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	0.0641	**0.068**	s4d-Acid Gas(6)
CO, lb/MMBtu	**0.5496**	0.37	

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	Gas Filters			
Event	Maintenance on Gas Filters in Plant			
Gas Stream	Inlet Gas		Stream#	8
Btu/scf	1150			
% H_2S (volume)	0.90			
% Other Sulfur compounds	2.93E-04			
Design Gas Flow Rate, MMscfd	50.00			
Permit Gas Volume for Event, Mcfd	38	[38000 scf filter blowdown in 30 minutes]- For Permit		
Event hours/day	0.50			
Event days per year	2	2 event/year		
Event Hours/yr	1.0			
Wt. Frac. VOC in Gas Stream	0.11			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.74	28.02	0.21	1.11
Carbon dioxide		0.66	44.01	0.29	1.54
Hydrogen Sulfide		0.90	34.08	0.31	1.63
Methane		88.17	16.04	14.14	75.31
Ethane		5.59	30.07	1.68	8.94
Propane	VOC	2.06	44.09	0.91	4.84
Isobutane	VOC	0.40	58.12	0.23	1.23
n-Butane	VOC	0.71	58.12	0.41	2.18
Isopentane	VOC	0.25	72.15	0.18	0.97
n-pentane	VOC	0.23	72.15	0.16	0.87
Hexanes +	VOC	0.30	86.17	0.26	1.38
Heptanes +	VOC	0	86.17	0.00	NA
Benzene		0	78.11	0.00	NA
Toluene		0	92.14	0.00	NA
Ethylbenzene		0	106.17	0.00	NA
xylene		0	106.17	0.00	NA
Other sulfur compounds		2.9E-04	67.50	0.00	0.0011
		100.00	100	18.78	100.00
VOC (C3+)		3.9441		2.15	11.47

Emissions	**lb/hr**	**tpy**		
NOx	12.06	0.0060		
CO	32.34	0.016		
SO_2 (from H2S)	115.50	0.058	Subtotal SO2	
SO_2 (from other sulfur compounds)	0.038	1.88E-05	115.54	0.058
VOC	8.64	0.0043		
H_2S	1.23	6.14E-04		
Other sulfur compounds	2.44	0.0012		
GHG CH_4 Uncombusted (CO_2e)	-	0.709		
GHG CO_2 Uncombusted	-	0.029		
GHG CO_2 Combusted	-	4.916		
GHG N_2O (CO_2e)	-	0.0030		
* Subtotal SO_2	115.54	0.058		

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

	TCEQ Guidance RG-109	EPA AP -42	
Flare Emission Factors (EF)	(P. 20, Table 4; high Btu, non-steam assist)	Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s8a-Plant Inlet(1)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-14-SSM 50% / ES-42-SSM 50% **Every 4 years**

Equipment/Process	Inlet Gas & Gas Filters blowdown		
Event	Shutdown for Plant Turnaround (Every 4 yrs)		
Gas Stream	Inlet Gas		Stream# 8
Btu/scf	1150		
% H_2S (volume)	0.90		
% Other Sulfur compounds	2.93E-04		
Design Gas Flow Rate, MMscfd	50.0		
Permit Gas Volume for Event, Mcfd	4167	- [2 event hours at max flare/stream volume rate] - For Permit	
Event hours/day	2		
Event days per year	1		
Event Hours/yr	NA	**Every 4 years**	
Wt. Frac. VOC in Gas Stream	0.11	**Every 4 years**	
C = 379 scf/mole	379		
DRE = Destruction Efficiency	0.98		

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.74	28.02	0.21	1.11
Carbon dioxide		0.66	44.01	0.29	1.54
Hydrogen Sulfide		0.90	34.08	0.31	1.63
Methane		88.17	16.04	14.14	75.31
Ethane		5.59	30.07	1.68	8.94
Propane	VOC	2.06	44.09	0.91	4.84
Isobutane	VOC	0.40	58.12	0.23	1.23
n-Butane	VOC	0.71	58.12	0.41	2.18
Isopentane	VOC	0.25	72.15	0.18	0.97
n-pentane	VOC	0.23	72.15	0.16	0.87
Hexanes +	VOC	0.30	86.17	0.26	1.38
Heptanes +	VOC	0	86.17	0.00	NA
Benzene		0	78.11	0.00	NA
Toluene		0	92.14	0.00	NA
Ethylbenzene		0	106.17	0.00	NA
xylene		0	106.17	0.00	NA
Other sulfur compounds		2.9E-04	67.50	0.00	0.0011
		100.00	100	18.78	100.00
VOC (C3+)		3.94		2.15	11.47

	Total		ES-14		ES-42	
Emissions	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**
NOx	330.63	0.33	165.31	0.17	165.31	0.17
CO	886.46	0.89	443.23	0.44	443.23	0.44
SO_2 (from H2S) *	3166.23	3.17	1583.11	1.58	1583.11	1.58
SO_2 (from other sulfur compounds) *	1.03	0.0010	0.52	0.00	0.52	0.00
VOC	237	0.24	118.42	0.12	118.42	0.12
H_2S	33.64	0.034	16.82	0.02	16.82	0.02
Other sulfur compounds	0.022	2.17E-05	0.01	0.00	0.01	0.00
GHG CH_4 Uncombusted (CO_2e)	-	38.877	-	19.44	-	19.44
GHG CO_2 Uncombusted	-	1.587	-	0.79	-	0.79
GHG CO_2 Combusted	-	269.517	-	134.76	-	134.76
GHG N_2O (CO_2e)	-	0.164	-	0.082	-	0.082
* Subtotal SO_2	3167.26	3.17	1583.63	1.58	1583.63	1.58

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	
CO, lb/MMBtu	0.2755	**0.37**	s8b1-Plant Inlet(2)

Maintenance Flare Emissions - ES-42-SSM **Every 4 years**

Equipment/Process	Inlet Gas		
Event	Start-up for Plant Turnaround (Every 4 yrs)		
Gas Stream	Inlet Gas		Stream# 8
Btu/scf	1150		
% H_2S (volume)	0.90		
% Other Sulfur compounds	2.93E-04		
Design Gas Flow Rate, MMscfd	50.000		
Permit Gas Volume for Event, Mcfd	37500	[18 event hours at max. flare/stream volume rate] - For Permit	
Event hours/day	18		
Event days per year	1		
Event Hours/yr	NA	**Every 4 years**	
Wt. Frac. VOC in Gas Stream	0.11	**Every 4 years**	
C = 379 scf/mole	379		
DRE = Destruction Efficiency	0.98		

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.74	28.02	0.21	1.11
Carbon dioxide		0.66	44.01	0.29	1.54
Hydrogen Sulfide		0.90	34.08	0.31	1.63
Methane		88.17	16.04	14.14	75.31
Ethane		5.59	30.07	1.68	8.94
Propane		2.06	44.09	0.91	4.84
Isobutane		0.40	58.12	0.23	1.23
n-Butane		0.71	58.12	0.41	2.18
Isopentane	**VOC**	0.25	72.15	0.18	0.97
n-pentane		0.23	72.15	0.16	0.87
Hexanes +		0.30	86.17	0.26	1.38
Heptanes +		0	86.17	0.00	NA
Benzene		0	78.11	0.00	NA
Toluene		0	92.14	0.00	NA
Ethylbenzene		0	106.17	0.00	NA
xylene		0	106.17	0.00	NA
Other sulfur compounds		2.9E-04	67.50	0.00	0.0011
		100.00	100	18.78	100.00
VOC (C3+)		3.94		2.15	11.47

Emissions		**Total** lb/hr	tpy
NOx		330.63	2.98
CO		886.46	7.98
SO_2 (from H2S)		3166.23	28.50
SO_2 (from other sulfur compounds)		1.03	0.0093
VOC		236.84	2.13
H_2S		33.64	0.30
Other sulfur compounds		0.000	0.30
GHG CH_4 Uncombusted (CO_2e)		-	349.89
GHG CO_2 Uncombusted		-	14.29
GHG CO_2 Combusted		-	2425.65
GHG N_2O (CO_2e)		-	1.47
	* Subtotal SO_2	3167.26	28.51

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

H_2S [Other sulfur compounds are calculated the same way using % other and MW_{other} vs. MW_{H2S}]

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x 24 hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s8b2-Plant
CO, lb/MMBtu	0.2755	**0.37**	Inlet(3)

Maintenance Flare Emissions - ES-14-SSM (50%) and ES-42-SSM (50%) **Every 4 years**

Equipment/Process	Residue Gas Production		
Event	Shutdown for Plant Turnaround (Every 4 yrs)		
Gas Stream	Residue Gas		Stream# 9
Btu/scf	1012.00		
% H_2S (volume)	0.00		
Design Gas Flow Rate, MMscfd	40.00		
Permit Gas Volume for Event, Mcfd	3333	[2 event hours at max. flare/stream volume rate]- For Permit	
Event hours/day	2.0		
Event days per year	1.0	**Every 4 years**	
Event Hours/yr	2.0	**Every 4 years**	
Wt. Frac. VOC in Gas Stream	0.00080		
C = 379 scf/mole	379		
DRE = Destruction Efficiency	0.98		

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.99	28.020	0.28	1.70
Carbon dioxide		0	44.010	0.00	NA
Hydrogen Sulfide		0	34.0758	0.00	NA
Methane		98.26	16.042	15.76	96.88
Ethane		0.73	30.068	0.22	1.34
Propane	VOC	0.030	44.094	0.01	0.080
Isobutane	VOC	0.00	58.12	0.00	NA
n-Butane	VOC	0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane	VOC	0	72.146	0.00	NA
Hexanes +	VOC	0	86.172	0.00	NA
Heptanes +	VOC	0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		16.27	100.00
VOC (C3+)		0.030		0.013	0.080

	Total		ES-14		ES-42			
Emissions	**lb/hr**	**tpy**	**lb/hr**	**tpy**	**lb/hr**	**tpy**		
NOx	232.76	0.23	116.38	0.12	116.38	0.12		
CO	624.07	0.62	312.03	0.31	312.03	0.31		
SO_2	0	0	0	0	0	0		
VOC	1.14	0.0011	0.57	5.72E-04	0.57	5.72E-04		
H_2S	0	0	0	0	0	0		
GHG CH_4 Uncombusted (CO_2e)	-	34.66	-	17.33	-	17.33	1.386351	1.257677
GHG CO_2 Uncombusted	-	0	-	0	-	0		
GHG CO_2 Combusted	-	189.02	-	94.51	-	94.51		
GHG N_2O (CO_2e)	-	0.12	-	0.058	-	0.058		

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	
CO, lb/MMBtu	0.2755	**0.37**	s9a1-Residue Gas(1)

Maintenance Flare Emissions - ES-42 **Every 4 years**

Equipment/Process	Residue Gas Production			
Event	Start-up after Plant Turnaround (Every 4 yrs)			
Gas Stream	Residue Gas		Stream# 9	
Btu/scf	1012.00			
% H_2S (volume)	0.00			
Design Gas Flow Rate, MMscfd	40.00			
Permit Gas Volume for Event, Mcfd	30000	[Event hours at max. flare/stream volume rate]- For Permit		
Event hours/day	18.0			
Event days per year	1.0	**Every 4 years**		
Event Hours/yr	18.0	**Every 4 years**		
Wt. Frac. VOC in Gas Stream	0.00080			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.99	28.020	0.28	1.70
Carbon dioxide		0	44.010	0.00	NA
Hydrogen Sulfide		0	34.0758	0.00	NA
Methane		98.26	16.042	15.76	96.88
Ethane		0.73	30.068	0.22	1.34
Propane	VOC	0.03	44.094	0.01	0.080
Isobutane	VOC	0.00	58.12	0.00	NA
n-Butane	VOC	0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane	VOC	0	72.146	0.00	NA
Hexanes +	VOC	0	86.172	0.00	NA
Heptanes +	VOC	0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		16.27	100.00
VOC (C3+)		0.0295		0.013	0.080

	Total	
Emissions	**lb/hr**	**tpy**
NOx	232.76	2.09
CO	624.07	5.62
SO_2	0	0
VOC	1.14	0.0103
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	311.93
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	1701.17
GHG N_2O (CO_2e)	-	1.04

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	
CO, lb/MMBtu	0.2755	**0.37**	s9a2-Residue Gas(2)

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-4 Turbine Pump			
Event	ES-4 pneumatic pump gas to Flare after maint./SD			
Gas Stream	Residue Gas		Stream# 9	
Btu/scf	1012.00			
% H_2S (volume)	0.00			
Design Gas Flow Rate, MMscfd	40.00			
Permit Gas Volume for Event, Mcfd	8.02	[385 Mcfd rate for up to 30 minutes]		
Event hours/day	0.50			
Event days per year	10.0			
Event Hours/yr	5.0			
Wt. Frac. VOC in Gas Stream	0.00080			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis	Mole %	Mol Wt.	MWi	Wt %
Nitrogen	0.99	28.020	0.28	1.70
Carbon dioxide	0	44.010	0.00	NA
Hydrogen Sulfide	0	34.0758	0.00	NA
Methane	98.26	16.042	15.76	96.88
Ethane	0.73	30.068	0.22	1.34
Propane	0.03	44.094	0.01	0.080
Isobutane	0.00	58.12	0.00	NA
n-Butane	0	58.12	0.00	NA
Isopentane VOC	0	72.146	0.00	NA
n-pentane	0	72.146	0.00	NA
Hexanes +	0	86.172	0.00	NA
Heptanes +	0	86.172	0.00	NA
Benzene	0	78.110	0.00	NA
Toluene	0	92.1402	0.00	NA
Ethylbenzene	0	106.167	0.00	NA
xylene	0	106.167	0.00	NA
	100.00		16.27	100.00
VOC (C3+)	0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	2.24	0.0056
CO	6.01	0.015
SO_2	0	0
VOC	0.011	2.75E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.834
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	4.548
GHG N_2O (CO_2e)	-	0.0028

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

	TCEQ Guidance RG-109	EPA AP -42	
Flare Emission Factors (EF)	(P. 20, Table 4; high Btu, non-steam assist)	Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	
CO, lb/MMBtu	0.2755	**0.37**	s9b-Residue Gas(3)

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-5 Turbine Pump			
Event	ES-5 pneumatic pump gas to Flare after maint./SD			
Gas Stream	Residue Gas		Stream# 9	
Btu/scf	1012.00			
% H_2S (volume)	0.00			
Design Gas Flow Rate, MMscfd	40.00			
Permit Gas Volume for Event, Mcfd	8.02	[385 Mcfd rate for up to 30 minutes]		
Event hours/day	0.50			
Event days per year	10.0			
Event Hours/yr	5.0			
Wt. Frac. VOC in Gas Stream	0.00080			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis	Mole %	Mol Wt.	MWi	Wt %
Nitrogen	0.99	28.020	0.28	1.70
Carbon dioxide	0	44.010	0.00	NA
Hydrogen Sulfide	0	34.0758	0.00	NA
Methane	98.26	16.042	15.76	96.88
Ethane	0.73	30.068	0.22	1.34
Propane	0.03	44.094	0.01	0.080
Isobutane	0.00	58.12	0.00	NA
n-Butane	0	58.12	0.00	NA
Isopentane VOC	0	72.146	0.00	NA
n-pentane	0	72.146	0.00	NA
Hexanes +	0	86.172	0.00	NA
Heptanes +	0	86.172	0.00	NA
Benzene	0	78.110	0.00	NA
Toluene	0	92.1402	0.00	NA
Ethylbenzene	0	106.167	0.00	NA
xylene	0	106.167	0.00	NA
	100.00		16.27	100.00
VOC (C3+)	0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	2.24	0.0056
CO	6.01	0.015
SO_2	0	0
VOC	0.011	2.75E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.834
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	4.548
GHG N_2O (CO_2e)	-	0.0028

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

	TCEQ Guidance RG-109	EPA AP -42	
Flare Emission Factors (EF)	(P. 20, Table 4; high Btu, non-steam assist)	Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s9c-Residue Gas(4)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-06/07 Turbine			
Event	ES-06/07 Turbine Recompressor Maint./Blowdowns			
Gas Stream	Residue Gas			Stream# 9
Btu/scf	1012.00			
% H_2S (volume)	0.00			
Design Gas Flow Rate, MMscfd	40.00			
Permit Gas Volume for Event, Mcfd	6.25	[6250 scf/min blowdown volume for 1 minute]		
Event hours/day	0.017	1 minute		
Event days per year	10.0			
Event Hours/yr	0.17			
Wt. Frac. VOC in Gas Stream	0.00080			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.99	28.020	0.28	1.70
Carbon dioxide		0	44.010	0.00	NA
Hydrogen Sulfide		0	34.0758	0.00	NA
Methane		98.26	16.042	15.76	96.88
Ethane		0.73	30.068	0.22	1.34
Propane	VOC	0.03	44.094	0.01	0.080
Isobutane	VOC	0.00	58.12	0.00	NA
n-Butane	VOC	0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane	VOC	0	72.146	0.00	NA
Hexanes +	VOC	0	86.172	0.00	NA
Heptanes +	VOC	0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		16.27	100.00
VOC (C3+)		0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	52.37	0.0044
CO	140.42	0.012
SO_2	0	0
VOC	0.26	2.15E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.650
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	3.544
GHG N_2O (CO_2e)	-	0.0022

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s9d-Residue Gas(5)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-08/09 Turbine	
Event	ES-08/09 Turbine Recompressor Maint./Blowdowns	
Gas Stream	Residue Gas	Stream# 9
Btu/scf	1012.00	
% H_2S (volume)	0.00	
Design Gas Flow Rate, MMscfd	40.00	
Permit Gas Volume for Event, Mcfd	6.25	[6250 scf/min blowdown volume for 1 minute]
Event hours/day	0.017	1 minute
Event days per year	10.0	
Event Hours/yr	0.17	
Wt. Frac. VOC in Gas Stream	0.00080	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.99	28.020	0.28	1.70
Carbon dioxide		0	44.010	0.00	NA
Hydrogen Sulfide		0	34.0758	0.00	NA
Methane		98.26	16.042	15.76	96.88
Ethane		0.73	30.068	0.22	1.34
Propane		0.03	44.094	0.01	0.080
Isobutane		0.00	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	VOC	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		16.27	100.00
VOC (C3+)		0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	52.37	0.0044
CO	140.42	0.012
SO_2	0	0
VOC	0.26	2.15E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.650
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	3.544
GHG N_2O (CO_2e)	-	0.0022

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s9e-Residue Gas(6)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-10/11 Turbine			
Event	ES-10/11 Turbine Recompressor Maint./Blowdowns			
Gas Stream	Residue Gas			Stream# 9
Btu/scf	1012.00			
% H_2S (volume)	0.00			
Design Gas Flow Rate, MMscfd	40.00			
Permit Gas Volume for Event, Mcfd	6.25	[6250 scf/min blowdown volume for 1 minute]		
Event hours/day	0.017	1 minute		
Event days per year	10.0			
Event Hours/yr	0.17			
Wt. Frac. VOC in Gas Stream	0.00080			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.99	28.020	0.28	1.70
Carbon dioxide		0	44.010	0.00	NA
Hydrogen Sulfide		0	34.0758	0.00	NA
Methane		98.26	16.042	15.76	96.88
Ethane		0.73	30.068	0.22	1.34
Propane		0.03	44.094	0.01	0.080
Isobutane		0.00	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	**VOC**	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		16.27	100.00
VOC (C3+)		0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	52.37	0.0044
CO	140.42	0.012
SO_2	0	0
VOC	0.26	2.15E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.650
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	3.544
GHG N_2O (CO_2e)	-	0.0022

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	
CO, lb/MMBtu	0.2755	**0.37**	s9f-Residue Gas(7)

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-22 Turbine	
Event	ES-22 Turbine Recompressor Maint./Blowdowns	
Gas Stream	Residue Gas	Stream# 9
Btu/scf	1012.00	
% H_2S (volume)	0.00	
Design Gas Flow Rate, MMscfd	40.00	
Permit Gas Volume for Event, Mcfd	6.25	[6250 scf/min blowdown volume for 1 minute]
Event hours/day	0.017	1 minute
Event days per year	10.0	
Event Hours/yr	0.17	
Wt. Frac. VOC in Gas Stream	0.00080	
C = 379 scf/mole	379	
DRE = Destruction Efficiency	0.98	

Gas Analysis		Mole %	Mol Wt.	MWi	Wt %
Nitrogen		0.99	28.020	0.28	1.70
Carbon dioxide		0	44.010	0.00	NA
Hydrogen Sulfide		0	34.0758	0.00	NA
Methane		98.26	16.042	15.76	96.88
Ethane		0.73	30.068	0.22	1.34
Propane		0.03	44.094	0.01	0.080
Isobutane		0.00	58.12	0.00	NA
n-Butane		0	58.12	0.00	NA
Isopentane	**VOC**	0	72.146	0.00	NA
n-pentane		0	72.146	0.00	NA
Hexanes +		0	86.172	0.00	NA
Heptanes +		0	86.172	0.00	NA
Benzene		0	78.110	0.00	NA
Toluene		0	92.1402	0.00	NA
Ethylbenzene		0	106.167	0.00	NA
xylene		0	106.167	0.00	NA
		100.00		16.27	100.00
VOC (C3+)		0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	52.37	0.0044
CO	140.42	0.012
SO_2	0	0
VOC	0.26	2.15E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	0.650
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	3.544
GHG N_2O (CO_2e)	-	0.0022

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)

tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s9g-Residue Gas(8)
CO, lb/MMBtu	0.2755	**0.37**	

Maintenance Flare Emissions - ES-14-SSM

Equipment/Process	ES-17 Turbine			
Event	ES-17 Turbine Recompressor Maint./Blowdowns			
Gas Stream	Residue Gas			Stream# 9
Btu/scf	1012.00			
% H_2S (volume)	0			
Design Gas Flow Rate, MMscfd	40.00			
Permit Gas Volume for Event, Mcfd	14.20	[14,200 scf blowdown volume for 2 minutes]		
Event hours/day	0.033	2 minute		
Event days per year	10.0			
Event Hours/yr	0.33			
Wt. Frac. VOC in Gas Stream	0.00080			
C = 379 scf/mole	379			
DRE = Destruction Efficiency	0.98			

Gas Analysis	Mole %	Mol Wt.	MWi	Wt %
Nitrogen	0.99	28.020	0.28	1.70
Carbon dioxide	0	44.010	0.00	NA
Hydrogen Sulfide	0	34.0758	0.00	NA
Methane	98.26	16.042	15.76	96.88
Ethane	0.73	30.068	0.22	1.34
Propane	0.03	44.094	0.01	0.080
Isobutane	0.00	58.12	0.00	NA
n-Butane	0	58.12	0.00	NA
Isopentane VOC	0	72.146	0.00	NA
n-pentane	0	72.146	0.00	NA
Hexanes +	0	86.172	0.00	NA
Heptanes +	0	86.172	0.00	NA
Benzene	0	78.110	0.00	NA
Toluene	0	92.1402	0.00	NA
Ethylbenzene	0	106.167	0.00	NA
xylene	0	106.167	0.00	NA
	100.00		16.27	100.00
VOC (C3+)	0.0295		0.013	0.080

Emissions	**lb/hr**	**tpy**
NOx	59.49	0.0099
CO	159.51	0.027
SO_2	0	0
VOC	0.29	4.87E-05
H_2S	0	0
GHG CH_4 Uncombusted (CO_2e)	-	1.476
GHG CO_2 Uncombusted	-	0
GHG CO_2 Combusted	-	8.052
GHG N_2O (CO_2e)	-	0.0049

Example Calculations

NOx & CO

lb/hr = Mcf/day x LHV (Btu/scf) x EF (lb/MMBtu) x 1000cf /Mcf x MM Btu/1E6 Btu x 1 day/24 hr
tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

SO_2 [98% was not assumed]

lb/hr = Mcf/day x % H_2S x 1 day/24 hrs x 1 lb-mole/379 Mcf x 1000 cf/Mcf x 1 lb-mole SO_2/lb-mole H_2S x 64 lb SO_2/lb-mole SO_2
tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

VOC

lb/hr = Mcf/day x 1 day/24 hr x 1 lb-mole/379 cf x 1000cf/Mcf x MW stream (lb/lb-mole) x Wt. Frac. VOC x (1-0.98 D.E.)
tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

H_2S

lb/hr = Mcf/day x % H2S x 1 day/24 hr x 1 lb-mole/379 cf x 1000 cf/Mcf x 34 lb/lb-mole x (1-0.98 D.E.)
tpy = lb/hr x hr/day x days/yr x 1 ton/2000 lb

GHG CH_4 Uncombusted (CO_2e)

tpy = Mscf/day x event day/year x Mole% (Mscf CH_4/Mscf gas) x (1-0.98) x 0.0192 tonnes/Mscf x 25 (GWP) x 1.1023113 ton/tonne

GHG CO_2 Uncombusted

tpy = Mscf/day x event day/year x Mole% (Mscf CO_2/Mscf gas) x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG CO_2 Combusted

tpy = Mscf/day x event day/year x (1-0.98) x ∑ [Mole % gas constituents x constituent's no. of carbons] x 0.0526 tonnes/Mscf x 1.1023113 ton/tonne

GHG N_2O (CO_2e)

tpy = scf/day x event day/year x HHV (MMbtu/scf) x 0.1 tonnes/MMbtu x 310 (GWP) x 1.1023113 ton/tonne

References

Flare Emission Factors (EF)	TCEQ Guidance RG-109 (P. 20, Table 4; high Btu, non-steam assist)	EPA AP -42 Table 13.5-1	
NOx, lb/MMBtu	**0.138**	0.068	s9h-Residue Gas(9)
CO, lb/MMBtu	0.2755	**0.37**	

ES-40 - GLYCOL DEHYDRATOR

Indian Basin Gas Plant

ES-40: Glycol Dehydrator Still Vent #1

Manufacturı McIver & Smith Fab.
Model: N/A

Emission Rates

Uncontrolled emissions

VOC	HAPs	Benzene	Toluene	Ethylbenzne	Xylenes	Units	
59.62	27.54	4.76	10.89	2.28	4.25	lb/hr	GRI-GLYCalc 4.0
261.1	120.6	20.9	47.7	10.0	18.6	tpy	lb/hr * 8760 hrs/yr / 2000lb/ton

Controlled emissions

VOC	HAPs	Benzene	Toluene	Ethylbenzne	Xylenes	Units	
59.62	27.54	4.76	10.89	2.28	4.25	lb/hr	Uncontrolled emissions
95%	95%	95%	95%	95%	95%	%	Control Efficiency
2.98	1.38	0.24	0.54	0.11	0.21	lb/hr	Uncontrolled emissions * (1- control efficiency)
13.1	6.0	1.0	2.4	0.5	0.9	tpy	lb/hr * 8760 hrs/yr / 2000lb/ton

Source: February 2003 - Air Permit Application prepared by Environmental Services Inc. (ESI) for Marathon Oil Company

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: ES-40
File Name: C:\Program Files\GRI-GLYCalc4\IBGP.ddf
Date: January 21, 2003

DESCRIPTION:

Description: 260 MMscf/day
11.2 Max Lean Glycol Flow Rate (GPM)
95% Controll by VRU

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	17.2684	414.442	75.6357
Ethane	6.1161	146.786	26.7884
Propane	5.1584	123.803	22.5940
Isobutane	1.7598	42.236	7.7080
n-Butane	3.9373	94.496	17.2456
Isopentane	1.6792	40.301	7.3550
n-Pentane	2.0960	50.303	9.1803
n-Hexane	5.3525	128.460	23.4439
Heptanes	6.4051	153.723	28.0544
Benzene	4.7647	114.354	20.8695
Toluene	10.8919	261.405	47.7065
Ethylbenzene	2.2792	54.701	9.9830
Xylenes	4.2513	102.032	18.6208
C8+ Heavies	11.0460	265.103	48.3813
Total Emissions	83.0060	1992.144	363.5663
Total Hydrocarbon Emissions	83.0060	1992.144	363.5663
Total VOC Emissions	59.6215	1430.916	261.1422
Total HAP Emissions	27.5396	660.951	120.6236
Total BTEX Emissions	22.1872	532.492	97.1798

EQUIPMENT REPORTS:

ABSORBER

NOTE: Because the Calculated Absorber Stages was below the minimum allowed, GRI-GLYCalc has set the number of Absorber Stages to 1.25 and has calculated a revised Dry Gas Dew Point.

Calculated Absorber Stages: 1.25
Calculated Dry Gas Dew Point: 5.53 lbs. H_2O/MMSCF

Temperature:	90.0 deg. F
Pressure:	944.0 psig
Dry Gas Flow Rate:	260.0000 MMSCF/day
Glycol Losses with Dry Gas:	2.8132 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	45.50 lbs. H2O/MMSCF
Calculated Lean Glycol Recirc. Ratio:	1.55 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	12.15%	87.85%
Nitrogen	100.00%	0.00%
Methane	100.00%	0.00%
Ethane	99.99%	0.01%
Propane	99.98%	0.02%
Isobutane	99.97%	0.03%
n-Butane	99.96%	0.04%
Isopentane	99.97%	0.03%
n-Pentane	99.96%	0.04%
n-Hexane	99.93%	0.07%
Heptanes	99.88%	0.12%
Benzene	96.95%	3.05%
Toluene	95.69%	4.31%
Ethylbenzene	94.63%	5.37%
Xylenes	92.20%	7.80%
C8+ Heavies	99.72%	0.28%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	17.90%	82.10%
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	0.50%	99.50%
n-Pentane	0.50%	99.50%
n-Hexane	0.50%	99.50%
Heptanes	0.50%	99.50%
Benzene	5.00%	95.00%
Toluene	7.91%	92.09%
Ethylbenzene	10.42%	89.58%
Xylenes	12.96%	87.04%
C8+ Heavies	12.04%	87.96%

STREAM REPORTS:

WET GAS STREAM

Temperature: 90.00 deg. F
Pressure: 958.70 psia
Flow Rate: 1.08e+007 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.59e-002	4.93e+002
Nitrogen	7.87e-001	6.30e+003
Methane	8.94e+001	4.10e+005
Ethane	5.67e+000	4.87e+004
Propane	1.99e+000	2.50e+004
Isobutane	3.86e-001	6.41e+003
n-Butane	6.57e-001	1.09e+004
Isopentane	2.36e-001	4.86e+003
n-Pentane	2.28e-001	4.69e+003
n-Hexane	3.12e-001	7.68e+003
Heptanes	1.86e-001	5.34e+003
Benzene	6.99e-003	1.56e+002
Toluene	9.59e-003	2.53e+002
Ethylbenzene	1.40e-003	4.24e+001
Xylenes	1.80e-003	5.46e+001
C8+ Heavies	7.99e-002	3.89e+003
Total Components	100.00	5.34e+005

DRY GAS STREAM

Temperature: 90.00 deg. F
Pressure: 958.70 psia
Flow Rate: 1.08e+007 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.17e-002	6.00e+001
Nitrogen	7.88e-001	6.30e+003
Methane	8.94e+001	4.10e+005
Ethane	5.67e+000	4.87e+004
Propane	1.99e+000	2.50e+004
Isobutane	3.86e-001	6.41e+003
n-Butane	6.58e-001	1.09e+004
Isopentane	2.36e-001	4.86e+003
n-Pentane	2.28e-001	4.69e+003
n-Hexane	3.12e-001	7.67e+003
Heptanes	1.86e-001	5.33e+003
Benzene	6.79e-003	1.51e+002
Toluene	9.19e-003	2.42e+002
Ethylbenzene	1.32e-003	4.02e+001
Xylenes	1.66e-003	5.03e+001
C8+ Heavies	7.98e-002	3.88e+003
Total Components	100.00	5.34e+005

LEAN GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.12e+001 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.84e+001	6.20e+003
Water	1.50e+000	9.45e+001
Nitrogen	4.72e-013	2.98e-011
Methane	9.21e-018	5.80e-016
Ethane	4.58e-008	2.89e-006
Propane	3.33e-009	2.10e-007
Isobutane	8.38e-010	5.28e-008
n-Butane	1.55e-009	9.77e-008
Isopentane	1.34e-004	8.44e-003
n-Pentane	1.67e-004	1.05e-002
n-Hexane	4.27e-004	2.69e-002
Heptanes	5.11e-004	3.22e-002
Benzene	3.98e-003	2.51e-001
Toluene	1.48e-002	9.35e-001
Ethylbenzene	4.21e-003	2.65e-001
Xylenes	1.00e-002	6.33e-001
C8+ Heavies	2.40e-002	1.51e+000
Total Components	100.00	6.30e+003

RICH GLYCOL STREAM

Temperature: 90.00 deg. F
Pressure: 958.70 psia
Flow Rate: 1.22e+001 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.10e+001	6.20e+003
Water	7.75e+000	5.28e+002
Nitrogen	4.35e-003	2.96e-001
Methane	2.53e-001	1.73e+001
Ethane	8.98e-002	6.12e+000
Propane	7.57e-002	5.16e+000
Isobutane	2.58e-002	1.76e+000
n-Butane	5.78e-002	3.94e+000
Isopentane	2.48e-002	1.69e+000
n-Pentane	3.09e-002	2.11e+000
n-Hexane	7.90e-002	5.38e+000
Heptanes	9.45e-002	6.44e+000
Benzene	7.36e-002	5.02e+000
Toluene	1.74e-001	1.18e+001
Ethylbenzene	3.73e-002	2.54e+000
Xylenes	7.17e-002	4.88e+000
C8+ Heavies	1.84e-001	1.26e+001
Total Components	100.00	6.81e+003

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 9.89e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.24e+001	4.33e+002
Nitrogen	4.06e-002	2.96e-001
Methane	4.13e+000	1.73e+001
Ethane	7.81e-001	6.12e+000
Propane	4.49e-001	5.16e+000
Isobutane	1.16e-001	1.76e+000
n-Butane	2.60e-001	3.94e+000
Isopentane	8.93e-002	1.68e+000
n-Pentane	1.11e-001	2.10e+000
n-Hexane	2.38e-001	5.35e+000
Heptanes	2.45e-001	6.41e+000
Benzene	2.34e-001	4.76e+000
Toluene	4.54e-001	1.09e+001
Ethylbenzene	8.24e-002	2.28e+000
Xylenes	1.54e-001	4.25e+000
C8+ Heavies	2.49e-001	1.10e+001
Total Components	100.00	5.17e+002

Mike S.

Wildcat Measurement Service
P.O. Box 1836
415 East Main St
Artesia, NM 88211-1836

12/24/02 1:16 PM
Phone: 505 748 8481
888-421-9453
Fax: 505-748-5552

GAS ANALYSIS REPORT

Analysis For:	MARATHON OIL COMPANY	Run No:	221224-101
Field Name:	INDIAN BASIN PLANT	Date Run:	12/24/2002
Well Name:	INLET GAS-GLYCOL SCRUBBER	Date Sampled:	12/20/2002
Station Number:		Producer:	MARATHON OIL CO.
Purpose:	SPOT-BTEX	County:	EDDY
Sample Deg. F:	90	State:	NM
Volume/Day:		Sampled By:	KARL HAENY
Formation:		Atmos Deg. F:	61
Line PSIG:	844		
Line PSIA:	957.1		

GAS COMPONENTS

		MOL%	GPM
Oxygen	O_2:	0.0000	
Carbon Dioxide	CO_2:	0.0000	
Nitrogen	N_2:	0.7877	
Hydrogen Sulfide	H_2S:	0.0000	
Methane	C1:	89.4455	
Ethane	C2:	5.6753	1.5136
Propane	C3:	1.9870	0.6404
Iso-Butane	IC4:	0.3661	0.1195
Nor-Butane	NC4:	0.6579	0.2069
Iso-Pentane	IC5:	0.2361	0.0862
Nor-Pentanes	NC5:	0.2278	0.0823
Hexanes	C6:	0.3421	0.1280
Heptanes	C7:	0.1865	0.0855
Octanes	C8:	0.1257	0.0647
Nonanes	C9:	0.0082	0.0046
Decanes	C10:	0.0031	0.0019
Totals		100.0000	2.8337

Pressure Base:	14.650
Real BTU Dry:	1144.845
Real BTU Wet:	1125.023
Calc. Ideal Gravity:	0.6247
Calc. Real Gravity:	0.6262
Field Gravity:	
Standard Pressure:	14.696
BTU Dry:	1142.318
BTU Wet:	1122.442
Z Factor:	0.9972
Average Mol Weight:	18.090
Average CuFt/Gal:	38.1004
Ethane+ GPM	2.8337
Propane+ GPM:	1.3203
Butane+ GPM:	0.7799
Pentane+ GPM:	0.4535
Hexanes + GPM:	0.2850
Heptanes + GPM:	0.1570
Octanes + GPM:	0.0712
Nonanes + GPM:	0.0065

BTEX Components, 100 % of Total Volume

N-Hexane:	0.1049	C6
Benzene:	0.0070	C6
Toluene:	0.0098	C7
Ethylbenzene:	0.0014	C8
Xylenes:	0.0016	C8

Analysis By: DON NORMAN

Remarks:

Post-it® Fax Note 7671	Date # of pages ▶
To VIJAY	From SCHWEBCH
Co./Dept.	Co.
Phone #	Phone #
Fax #	Fax #

Section 6.a

Green House Gas Emissions

(Submitting under 20.2.70, 20.2.72 20.2.74 NMAC)

Title V (20.2.70 NMAC), Minor NSR (20.2.72 NMAC), and PSD (20.2.74 NMAC) applicants must estimate and report greenhouse gas (GHG) emissions to verify the emission rates reported in the public notice, determine applicability to 40 CFR 60 Subparts, and to evaluate Prevention of Significant Deterioration (PSD) applicability. GHG emissions that are subject to air permit regulations consist of the sum of an aggregate group of these six greenhouse gases: carbon dioxide (CO_2), nitrous oxide (N_2O), methane (CH_4), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6).

Calculating GHG Emissions:

1. Calculate the ton per year (tpy) GHG mass emissions and GHG CO_2e emissions from your facility.
2. GHG mass emissions are the sum of the total annual tons of greenhouse gases without adjusting with the global warming potentials (GWPs). GHG CO_2e emissions are the sum of the mass emissions of each individual GHG multiplied by its GWP found in Table A-1 in 40 CFR 98 Mandatory Greenhouse Gas Reporting.
3. Emissions from routine or predictable start up, shut down, and maintenance must be included.
4. Report GHG mass and GHG CO_2e emissions in Table 2-P of this application. Emissions are reported in **short** tons per year and represent each emission unit's Potential to Emit (PTE).
5. All Title V major sources, PSD major sources, and all power plants, whether major or not, must calculate and report GHG mass and CO2e emissions for each unit in Table 2-P.
6. For minor source facilities that are not power plants, are not Title V, and are not PSD there are three options for reporting GHGs in Table 2-P: 1) report GHGs for each individual piece of equipment; 2) report all GHGs from a group of unit types, for example report all combustion source GHGs as a single unit and all venting GHGs as a second separate unit; 3) or check the following ☐ By checking this box, the applicant acknowledges the total CO2e emissions are less than 75,000 tons per year.

Sources for Calculating GHG Emissions:

- Manufacturer's Data
- AP-42 Compilation of Air Pollutant Emission Factors at http://www.epa.gov/ttn/chief/ap42/index.html
- EPA's Internet emission factor database WebFIRE at http://cfpub.epa.gov/webfire/
- 40 CFR 98 Mandatory Green House Gas Reporting except that tons should be reported in short tons rather than in metric tons for the purpose of PSD applicability.
- API Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Natural Gas Industry. August 2009 or most recent version.
- Sources listed on EPA's NSR Resources for Estimating GHG Emissions at http://www.epa.gov/nsr/clean-air-act-permitting-greenhouse-gases:

Global Warming Potentials (GWP):
Applicants must use the Global Warming Potentials codified in Table A-1 of the most recent version of 40 CFR 98 Mandatory Greenhouse Gas Reporting. The GWP for a particular GHG is the ratio of heat trapped by one unit mass of the GHG to that of one unit mass of CO_2 over a specified time period.

"Greenhouse gas" for the purpose of air permit regulations is defined as the aggregate group of the following six gases: carbon dioxide, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride. **(20.2.70.7 NMAC, 20.2.74.7 NMAC).** You may also find GHGs defined in 40 CFR 86.1818-12(a).

Metric to Short Ton Conversion:
Short tons for GHGs and other regulated pollutants are the standard unit of measure for PSD and title V permitting programs. 40 CFR 98 Mandatory Greenhouse Reporting requires metric tons.
1 metric ton = 1.10231 short tons (per Table A-2 to Subpart A of Part 98 – Units of Measure Conversions)

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-04
Source description: Turbine
Manufacturer: Solar
Model: Saturn 10-T1200

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 5713 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 1.1E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 1.1E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-05
Source description: Turbine
Manufacturer: Solar
Model: Saturn 10-T1200

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 5713 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 1.1E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 1.1E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-21
Source description: Turbine
Manufacturer: Solar
Model: Saturn 10-T1021

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 5713 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 1.1E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{104.52\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 1.1E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-06/07
Source description: Turbine
Manufacturer: Solar
Model: Centaur 40-4000T

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{331.42 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{53 \text{ kg } CO2}{\text{MMbtu}}$$

CO_2 = 18116 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{331.42 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3} \text{ kg } CH_4}{\text{MMbtu}}$$

CH_4 = 3.4E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{331.42 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4} \text{ kg } N_2O}{\text{MMbtu}}$$

N_2O = 3.4E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-08/09
Source description: Turbine
Manufacturer: Solar
Model: Centaur 40-4000T

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{331.42 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{53 \text{ kg CO2}}{\text{MMbtu}}$$

CO_2 = 18116 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{331.42 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3} \text{ kg } CH_4}{\text{MMbtu}}$$

CH_4 = 3.4E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{331.42 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4} \text{ kg } N_2O}{\text{MMbtu}}$$

N_2O = 3.4E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-10/11
Source description: Turbine
Manufacturer: Solar
Model: Centaur 40-4000T

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{331.42\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg } CO2}{\text{MMbtu}}$$

CO_2 = 18116 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{331.42\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 3.4E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{331.42\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 3.4E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Engine GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-22
Source description: Turbine
Manufacturer: Solar
Model: Centaur 40-4700S

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{372.57\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 20366 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{372.57\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 3.8E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{372.57\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 3.8E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Heater GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-02
Source description: Regeneration Gas Heater
Manufacturer: John Zink
Model: HEVD15

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{127.45\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 6967 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{127.45\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 1.3E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{127.45\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 1.3E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Heater GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-03
Source description: Glycol regeneration heater
Manufacturer: McIver & Smith
Model: 30Z

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{16.99 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{53 \text{ kg CO2}}{\text{MMbtu}}$$

CO_2 = 929 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{16.99 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3} \text{ kg } CH_4}{\text{MMbtu}}$$

CH_4 = 1.8E-02 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{16.99 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4} \text{ kg } N_2O}{\text{MMbtu}}$$

N_2O = 1.8E-03 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Boiler GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-12
Source description: Auxiliary Boiler
Manufacturer: York Shipley
Model: SPHC-500-N

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{142.15\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 7770 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{142.15\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 1.5E-01 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{142.15\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 1.5E-02 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Heater GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-15
Source description: Salt Bath Heater
Manufacturer: Maloney & Crawford
Model:

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{2.12 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{53 \text{ kg CO2}}{\text{MMbtu}}$$

CO_2 = 116 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{2.12 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3} \text{ kg } CH_4}{\text{MMbtu}}$$

CH_4 = 2.2E-03 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{2.12 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4} \text{ kg } N_2O}{\text{MMbtu}}$$

N_2O = 2.2E-04 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Heater GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-16
Source description: Salt Bath Heater
Manufacturer: Maloney & Crawford
Model:

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{2.12\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{53\ \text{kg CO2}}{\text{MMbtu}}$$

CO_2 = 116 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{2.12\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3}\ \text{kg } CH_4}{\text{MMbtu}}$$

CH_4 = 2.2E-03 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{2.12\ \text{MMscf}}{\text{yr}} \times \frac{1031\ \text{MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4}\ \text{kg } N_2O}{\text{MMbtu}}$$

N_2O = 2.2E-04 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Heater GHG Calculation

40 CFR 98 Subpart C

Emission unit(s): ES-43
Source description: Regeneration Gas Heater
Manufacturer: WHECO
Model: 4H2-24-8+SZ

CO_2 Calculation[1] (Eq C-1)

Click here to view Table C-1 to Subpart C of Part 98.

$$CO_2 = 1 \times 10^{-3} \times \frac{89.21 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{53 \text{ kg CO2}}{\text{MMbtu}}$$

CO_2 = 4877 tonnes CO_2 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

CH_4 Calculation[2] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$CH_4 = 1 \times 10^{-3} \times \frac{89.21 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-3} \text{ kg } CH_4}{\text{MMbtu}}$$

CH_4 = 9.2E-02 tonnes CH_4 / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

N_2O Calculation[3] (Eq C-8)

Click here to view Table C-1 to Subpart C of Part 98
Click here to view Table C-2 to Subpart C of Part 98

$$N_2O = 1 \times 10^{-3} \times \frac{89.21 \text{ MMscf}}{\text{yr}} \times \frac{1031 \text{ MMbtu}}{\text{MMscf}} \times \frac{1 \times 10^{-4} \text{ kg } N_2O}{\text{MMbtu}}$$

N_2O = 9.2E-03 tonnes N_2O / yr

Fuel usage and heat value carried forward from heater calculations in previous permit application.

Glycol Dehydrators GHG Calculations

Emission unit(s): ES-40
Source description: Glycol Dehy

CH_4 Vented Emissions

Click here to view Table 5-3 for emission factors:

$$E_{CH4} = \frac{260{,}000{,}000 \text{ scf}}{\text{day}} \times \frac{365 \text{ day}}{\text{year}} \times \frac{0 \text{ tonne } CH_4}{\#\#\#\# \text{ scf}}$$

E_{CH4} = 14.61 tonnes CH_4/yr
$E_{CH4\text{-}VRU}$ = 0.73 tonnes CH_4/yr

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

VRU Control Efficiency: 95 %

CO_2 Vented Emissions

$$E_{CO2} = 14.61 \text{ tonnes } CH_4 \times \frac{1 \text{ tonne mole } CH_4}{16 \text{ tonne } CH_4} \times \frac{1 \text{ tonne mole gas}}{0.8817 \text{ tonne mole } CH_4} \times \frac{0.00657 \text{ tonne mole } CO_2}{\text{tonne mole gas}} \times \frac{44 \text{ tonne } CO_2}{\text{tonne mole } CO_2}$$

E_{CO2} = 0.3 tonnes CO_2/yr
$E_{CO2\text{-}VRU}$ = 0.01 tonnes CO_2/yr

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

** CO2 and CH4 mol % from WIB VRU Gas Analysis

Flare GHG Calculations

40 CFR 98 Subpart W

Emission unit: ES-14
Source Descriptio Flare

CH_4 Calculation

Inlet Gas Stream

CH_4 Emissions at actual conditions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{2.08 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.882\ \text{scf CH}_4}{\text{scf gas}} \times \frac{1 - \text{\#\#\# scf noncombusted CH}}{\text{scf CH}_4\ \text{total}} = \mathbf{36{,}737.83}\ \textbf{scf CH}_4\ \textbf{/ yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.037 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0192\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{0.71}\ \textbf{tonnes CH}_4\ \textbf{/ yr}$$

Residue Gas Stream

CH_4 Emissions at actual conditions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{1.67 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.983\ \text{scf CH}_4}{\text{scf gas}} \times \frac{1 - \text{\#\#\# scf noncombusted CH}}{\text{scf CH}_4\ \text{total}} = \mathbf{32{,}752.00}\ \textbf{scf CH}_4\ \textbf{/ yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.033 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0192\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{0.63}\ \textbf{tonnes CH}_4\ \textbf{/ yr}$$

Flare Pilot and Purge gas

CH_4 Emissions at actual conditions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{6.36 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.983\ \text{scf CH}_4}{\text{scf gas}} \times \frac{1 - \text{\#\#\# scf noncombusted CH}}{\text{scf CH}_4\ \text{total}} = \mathbf{124{,}976.92}\ \textbf{scf CH}_4\ \textbf{/ yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.125 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0192\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{2.40}\ \textbf{tonnes CH}_4\ \textbf{/ yr}$$

CO_2 Calculation

Inlet Gas Stream

CO_2 Un-Combusted Emissions at actual conditions per 98.233(n) (Eq. W-20)[1]

$$E_{a,CO2\,(Un-Combusted)} = \frac{2.08 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.0066\ \text{scf CO}_2}{\text{scf gas}} = \mathbf{13{,}687.50}\ \ \mathbf{scf\ CO_2 / yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.014 \times 10^{6}\ \text{scf CO}_2}{\text{yr}} \times 0.0526\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{0.72}\ \ \mathbf{tonnes\ CO_2 / yr}$$

CO_2 Combusted Emissions at actual conditions per 98.233(n) (Eq. W-21)[1]

$$E_{a,CO2\,(Combusted)} = \frac{2.08 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{array}{l} \frac{0.882\ \text{lbmole CH}_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole CH}_4} \\ + \frac{0.056\ \text{lbmole C}_2\text{H}_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole C}_2\text{H}_6} \\ + \frac{0.021\ \text{lbmole C}_3\text{H}_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole C}_3\text{H}_8} \\ + \frac{0.011\ \text{lbmole C}_4\text{H}_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole C}_4\text{H}_{10}} \\ + \frac{0.008\ \text{lbmole C}_5\text{H}_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole C}_5\text{H}_{12}} \end{array} \right) = \mathbf{2{,}324{,}159.84}\ \ \mathbf{scf\ CO_2 / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{2.324 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0526\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{122.25}\ \ \mathbf{tonnes\ CO_2 / yr}$$

Residue Gas Stream

CO_2 Un-Combusted Emissions at actual conditions per 98.233(n) (Eq. W-20)[1]

$$E_{a,CO2\,(Un-Combusted)} = \frac{1.67 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0\ \text{scf CO}_2}{\text{scf gas}} = \mathbf{0.00}\ \ \mathbf{scf\ CO_2 / yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.000 \times 10^{6}\ \text{scf CO}_2}{\text{yr}} \times 0.0526\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{0.00}\ \ \mathbf{tonnes\ CO_2 / yr}$$

CO_2 Combusted Emissions at actual conditions per 98.233(n) (Eq. W-21)[1]

$$E_{a,CO2\,(Combusted)} = \frac{1.67 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{aligned} & \frac{0.983\ \text{lbmole CH}_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole CH}_4} \\ + & \frac{0.007\ \text{lbmole C}_2\text{H}_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole C}_2\text{H}_6} \\ + & \frac{3\text{E-}04\ \text{lbmole C}_3\text{H}_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole C}_3\text{H}_8} \\ + & \frac{0\ \ \text{lbmole C}_4\text{H}_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole C}_4\text{H}_{10}} \\ + & \frac{0\ \ \text{lbmole C}_5\text{H}_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole C}_5\text{H}_{12}} \end{aligned} \right) = \mathbf{1{,}629{,}986.62}\ \ \mathbf{scf\ CO_2 / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{1.630 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0526\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{85.74}\ \ \mathbf{tonnes\ CO_2 / yr}$$

Flare Pilot and Purge gas

CO_2 Un-Combusted Emissions at actual conditions per 98.233(n) (Eq. W-20)[1]

$$E_{a,CO2\,(Un-Combusted)} = \frac{6.36 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0\ \text{scf CO}_2}{\text{scf gas}} = \mathbf{0.00}\ \ \mathbf{scf\ CO_2 / yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.000 \times 10^{6}\ \text{scf } CO_2}{\text{yr}} \times 0.0526\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{0.00}\ \textbf{tonnes } \mathbf{CO_2}\textbf{ / yr}$$

CO_2 Combusted Emissions at actual conditions per 98.233(n) (Eq. W-21)[1]

$$E_{a,CO2\,(Combusted)} = \frac{6.36 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\frac{0.983\ \text{lbmole } CH_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole } CH_4} + \frac{0.007\ \text{lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole } C_2H_6} + \frac{3E\text{-}04\ \text{lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole } C_3H_8} + \frac{0\ \text{lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole } C_4H_{10}} + \frac{0\ \text{lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole } C_5H_{12}} \right) = \mathbf{6{,}219{,}794.27}\ \textbf{scf } \mathbf{CO_2}\textbf{ / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{6.220 \times 10^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0526\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = \mathbf{327.16}\ \textbf{tonnes } \mathbf{CO_2}\textbf{ / yr}$$

N_2O Calculation

Inlet Gas Stream

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{2.083 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.0012 \text{ MMBtu}}{\text{scf}} \times \frac{10^{-4} \text{ kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3} \text{ tonnes}}{\text{kg}} = \mathbf{0.0002} \textbf{ tonnes } \mathbf{N_2O / yr}$$

Residue Gas Stream

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{1.667 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.001 \text{ MMBtu}}{\text{scf}} \times \frac{10^{-4} \text{ kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3} \text{ tonnes}}{\text{kg}} = \mathbf{0.0002} \textbf{ tonnes } \mathbf{N_2O / yr}$$

Flare Pilot and Purge gas

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{6.360 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.001 \text{ MMBtu}}{\text{scf}} \times \frac{10^{-4} \text{ kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3} \text{ tonnes}}{\text{kg}} = \mathbf{0.0006} \textbf{ tonnes } \mathbf{N_2O / yr}$$

Flare GHG Calculations

40 CFR 98 Subpart W

Emission unit: ES-42
Source Descriptio Flare

CH_4 Calculation

Inlet Gas Stream

CH_4 Emissions at actual conditions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{37.50 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.882\ \text{scf CH}_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted CH}_4}{\text{scf CH}_4\ \text{total}} = 661{,}281.00\ \text{scf CH}_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.661 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0192\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = 12.70\ \text{tonnes CH}_4\,/\,\text{yr}$$

Residue Gas Stream

CH_4 Emissions at actual conditions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{30.00 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.983\ \text{scf CH}_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted CH}_4}{\text{scf CH}_4\ \text{total}} = 589{,}536.00\ \text{scf CH}_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.590 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0192\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = 11.32\ \text{tonnes CH}_4\,/\,\text{yr}$$

Flare Pilot and Purge gas

CH_4 Emissions at actual conditions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{9.20 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.983\ \text{scf CH}_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted CH}_4}{\text{scf CH}_4\ \text{total}} = 180{,}751.74\ \text{scf CH}_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.181 \times 10^{6}\ \text{scf CH}_4}{\text{yr}} \times 0.0192\ \frac{\text{kg}}{\text{scf}} \times \#^{-3}\ \frac{\text{tonnes}}{\text{kg}} = 3.47\ \text{tonnes CH}_4\,/\,\text{yr}$$

CO_2 Calculation

Inlet Gas Stream

CO_2 Un-Combusted Emissions at actual conditions per 98.233(n) (Eq. W-20)[1]

$$E_{a,CO2\,(Un-Combusted)} = \frac{37.50 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.0066 \text{ scf } CO_2}{\text{scf gas}} = \mathbf{246{,}375.00} \quad \mathbf{scf\ CO_2 / yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.246 \times 10^{6} \text{ scf } CO_2}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \mathbf{12.96} \quad \mathbf{tonnes\ CO_2 / yr}$$

CO_2 Combusted Emissions at actual conditions per 98.233(n) (Eq. W-21)[1]

$$E_{a,CO2\,(Combusted)} = \frac{37.50 \times 10^{6} \text{ scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{array}{l} \frac{0.882 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{1 \text{ lbmole C}}{\text{lbmole } CH_4} \\ + \frac{0.056 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} \\ + \frac{0.021 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} \\ + \frac{0.011 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \frac{0.008 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} \end{array} \right) = \mathbf{41{,}834{,}877.00} \quad \mathbf{scf\ CO_2 / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{41.835 \times 10^{6} \text{ scf } CH_4}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \mathbf{2200.51} \quad \mathbf{tonnes\ CO_2 / yr}$$

Residue Gas Stream

CO_2 Un-Combusted Emissions at actual conditions per 98.233(n) (Eq. W-20)[1]

$$E_{a,CO2\,(Un-Combusted)} = \frac{30.00 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0\ \ \text{scf } CO_2}{\text{scf gas}} = \mathbf{0.00}\ \ \textbf{scf } \mathbf{CO_2\,/\,yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.000 \times 10^{6}\ \text{scf } CO_2}{\text{yr}} \times 0.0526\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = \mathbf{0.00}\ \ \textbf{tonnes } \mathbf{CO_2\,/\,yr}$$

CO_2 Combusted Emissions at actual conditions per 98.233(n) (Eq. W-21)[1]

$$E_{a,CO2\,(Combusted)} = \frac{30.00 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{array}{l} \frac{0.983\ \text{lbmole } CH_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole } CH_4} \\ + \frac{0.007\ \text{lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole } C_2H_6} \\ + \frac{3E\text{-}04\ \text{lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole } C_3H_8} \\ + \frac{0\ \ \text{lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \frac{0\ \ \text{lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole } C_5H_{12}} \end{array} \right) = \mathbf{29{,}339{,}759.40}\ \ \textbf{scf } \mathbf{CO_2\,/\,yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{29.340 \times 10^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0526\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = \mathbf{1543.27}\ \ \textbf{tonnes } \mathbf{CO_2\,/\,yr}$$

Flare Pilot and Purge gas

CO_2 Un-Combusted Emissions at actual conditions per 98.233(n) (Eq. W-20)[1]

$$E_{a,CO2\,(Un-Combusted)} = \frac{9.20 \times 10^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0\ \ \text{scf } CO_2}{\text{scf gas}} = \mathbf{0.00}\ \ \textbf{scf } \mathbf{CO_2\,/\,yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.000 \times 10^{6} \text{ scf } CO_2}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \mathbf{0.00} \textbf{ tonnes } \mathbf{CO_2 / yr}$$

CO_2 Combusted Emissions at actual conditions per 98.233(n) (Eq. W-21)[1]

$$E_{a,CO2\,(Combusted)} = \frac{9.20 \times 10^{6} \text{ scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{array}{l} \frac{0.983 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{1 \text{ lbmole C}}{\text{lbmole } CH_4} \\ + \frac{0.007 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} \\ + \frac{3E\text{-}04 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} \\ + \frac{0 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \frac{0 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} \end{array} \right) = \mathbf{8{,}995{,}570.23} \textbf{ scf } \mathbf{CO_2 / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{8.996 \times 10^{6} \text{ scf } CH_4}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \mathbf{473.17} \textbf{ tonnes } \mathbf{CO_2 / yr}$$

N_2O Calculation

Inlet Gas Stream

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{37.500 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.0012 \text{ MMBtu}}{\text{scf}} \times \frac{10^{-4} \text{ kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3} \text{ tonnes}}{\text{kg}} = \mathbf{0.0043} \textbf{ tonnes } \mathbf{N_2O / yr}$$

Residue Gas Stream

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{30.000 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.001 \text{ MMBtu}}{\text{scf}} \times \frac{10^{-4} \text{ kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3} \text{ tonnes}}{\text{kg}} = \mathbf{0.0030} \textbf{ tonnes } \mathbf{N_2O / yr}$$

Flare Pilot and Purge gas

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{9.198 \times 10^{6} \text{ scf gas}}{\text{yr}} \times \frac{0.001 \text{ MMBtu}}{\text{scf}} \times \frac{10^{-4} \text{ kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3} \text{ tonnes}}{\text{kg}} = \mathbf{0.0009} \quad \textbf{tonnes } \mathbf{N_2O / yr}$$

Flare GHG Calculations

40 CFR 98 Subpart W

Emission unit: ES-50
Source Descriptio Flare

CH_4 Calculation

Condensate Stabilizer Stream

CH_4 Emissions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{0.22 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.81\ \text{scf } CH_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted } CH_4}{\text{scf } CH_4\ \text{total}} = 3{,}534.18\ \text{scf } CH_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.004 \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0192\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 0.06786\ \text{tonnes } CH_4\,/\,\text{yr}$$

Acid Gas Stream

CH_4 Emissions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{0.75 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.01\ \text{scf } CH_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted } CH_4}{\text{scf } CH_4\ \text{total}} = 107.45\ \text{scf } CH_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{\#\#\#\#\# \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0192\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 0.00206\ \text{tonnes } CH_4\,/\,\text{yr}$$

ES-46, ES-47, ES-48, ES-56 (VRU-Cond) Stream

CH_4 Emissions per 98.233(n) (Eq. W-19)[1]

$$E_{a,CH4\,(Un-Combusted)} = \frac{1.49 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.41\ \text{scf } CH_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted } CH_4}{\text{scf } CH_4\ \text{total}} = 12{,}177.87\ \text{scf } CH_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.012 \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0192\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 0.23382\ \text{tonnes } CH_4\,/\,\text{yr}$$

Flare Pilot and Purge gas

CH4 Emissions per 98.233(n) (Eq. W-19)1

$$E_{a,CH4\,(Un-Combusted)} = \frac{3.07 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.98\ \text{scf } CH_4}{\text{scf gas}} \times \frac{1 - \#\#\#\ \text{scf noncombusted } CH_4}{\text{scf } CH_4\ \text{total}} = 60{,}250.58\ \text{scf } CH_4\,/\,\text{yr}$$

CH_4 Mass Emissions per 98.233(v) (Eq. W-36)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,CH4\,(Un-Combusted)} = \frac{0.060 \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0192\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 1.16\ \text{tonnes } CH_4\,/\,\text{yr}$$

CO_2 Calculation

Condensate Stabilizer Stream

CO2 Un-Combusted Emissions per 98.233(n) (Eq. W-20)1

$$E_{a,CO2\,(Un-Combusted)} = \frac{0.22 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.002\ \text{scf } CO_2}{\text{scf gas}} = \mathbf{424.56}\ \ \text{scf } CO_2\text{ / yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{a,CO2\,(Un-Combusted)} = \frac{0.000 \times \#^{6}\ \text{scf } CO_2}{\text{yr}} \times 0.0526\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = \mathbf{0.0223}\ \ \text{tonnes } CO_2\text{ / yr}$$

CO2 Combusted Emissions per 98.233(n) (Eq. W-21)1

$$E_{a,CO2\,(Combusted)} = \frac{0.22 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{aligned} & \frac{0.815\ \text{lbmole } CH_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole } CH_4} \\ + & \frac{0.041\ \text{lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole } C_2H_6} \\ + & \frac{0.022\ \text{lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole } C_3H_8} \\ + & \frac{0.032\ \text{lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole } C_4H_{10}} \\ + & \frac{0.072\ \text{lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole } C_5H_{12}} \end{aligned} \right) = \mathbf{308{,}322.25}\ \ \text{scf } CO_2\text{ / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.308 \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0526\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 16.2178 \ \text{tonnes } CO_2\,/\,\text{yr}$$

Acid Gas Stream

CO2 Un-Combusted Emissions per 98.233(n) (Eq. W-20)1

$$E_{a,CO2\,(Un-Combusted)} = \frac{0.75 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.3768\ \text{scf } CO_2}{\text{scf gas}} = 282{,}589.50 \ \text{scf } CO_2\,/\,\text{yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.283 \times \#^{6}\ \text{scf } CO_2}{\text{yr}} \times 0.0526\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 14.864 \ \text{tonnes } CO_2\,/\,\text{yr}$$

CO2 Combusted Emissions per 98.233(n) (Eq. W-21)1

$$E_{a,CO2\,(Combusted)} = \frac{0.75 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{aligned} & \frac{0.007\ \text{lbmole } CH_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole } CH_4} \\ + & \frac{0\ \text{lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole } C_2H_6} \\ + & \frac{0\ \text{lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole } C_3H_8} \\ + & \frac{0\ \text{lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole } C_4H_{10}} \\ + & \frac{0\ \text{lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole } C_5H_{12}} \end{aligned} \right) = 5{,}264.81 \ \text{scf } CO_2\,/\,\text{yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\,(Un-Combusted)} = \frac{0.005 \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0526\,\frac{\text{kg}}{\text{scf}} \times \#^{-3}\,\frac{\text{tonnes}}{\text{kg}} = 0.2769 \ \text{tonnes } CO_2\,/\,\text{yr}$$

ES-46, ES-47, ES-48, ES-56 (VCS-Cond) Stream

CO2 Combusted Emissions per 98.233(n) (Eq. W-21)1

$$E_{a,CO2\,(Combusted)} = \frac{1.485 \times \#^{6} \text{ scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{array}{l} \frac{0.41 \text{ lbmole } CH_4}{\text{lbmole gas}} \times \frac{1 \text{ lbmole C}}{\text{lbmole } CH_4} \\ + \frac{0.169 \text{ lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2 \text{ lbmole C}}{\text{lbmole } C_2H_6} \\ + \frac{0.184 \text{ lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3 \text{ lbmole C}}{\text{lbmole } C_3H_8} \\ + \frac{0.139 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \frac{0.06 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} \\ + \frac{0.019 \text{ lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{6 \text{ lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \frac{0.014 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{7 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} \\ + \frac{0.006 \text{ lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{8 \text{ lbmole C}}{\text{lbmole } C_5H_{12}} \end{array} \right) = \mathbf{3{,}510{,}142.54} \text{ scf } CO_2 / \text{yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{a,CO2\,(Un-Combusted)} = \frac{3.510 \times \#^{6} \text{ scf } CH_4}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \mathbf{184.6335} \text{ tonnes } CO_2 / \text{yr}$$

Flare Pilot and Purge gas

CO2 Un-Combusted Emissions per 98.233(n) (Eq. W-20)1

$$E_{a,CO2\ (Un-Combusted)} = \frac{3.07 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0\ \ \text{scf } CO_2}{\text{scf gas}} = \ \ 0.00 \ \ \text{scf } CO_2 \text{ / yr}$$

CO_2 Un-Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\ (Un-Combusted)} = \frac{0.000 \times \#^{6}\ \text{scf } CO_2}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \ \ 0.00 \ \ \text{tonnes } CO_2 \text{ / yr}$$

CO2 Combusted Emissions per 98.233(n) (Eq. W-21)1

$$E_{a,CO2\ (Combusted)} = \frac{3.07 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times 0.98 \times \left(\begin{array}{l} \frac{0.983\ \text{lbmole } CH_4}{\text{lbmole gas}} \times \frac{1\ \text{lbmole C}}{\text{lbmole } CH_4} \\ + \frac{0.007\ \text{lbmole } C_2H_6}{\text{lbmole gas}} \times \frac{2\ \text{lbmole C}}{\text{lbmole } C_2H_6} \\ + \frac{3E\text{-}04\ \text{lbmole } C_3H_8}{\text{lbmole gas}} \times \frac{3\ \text{lbmole C}}{\text{lbmole } C_3H_8} \\ + \frac{0\ \ \text{lbmole } C_4H_{10}}{\text{lbmole gas}} \times \frac{4\ \text{lbmole C}}{\text{lbmole } C_4H_{10}} \\ + \frac{0\ \ \text{lbmole } C_5H_{12}}{\text{lbmole gas}} \times \frac{5\ \text{lbmole C}}{\text{lbmole } C_5H_{12}} \end{array} \right) = \ \ 2{,}998{,}523.41 \ \ \text{scf } CO_2 \text{ / yr}$$

CO_2 Combusted Mass Emissions per 98.233(v) (Eq. W-36)

$$E_{s,CO2\ (Un-Combusted)} = \frac{2.999 \times \#^{6}\ \text{scf } CH_4}{\text{yr}} \times 0.0526 \frac{\text{kg}}{\text{scf}} \times \#^{-3} \frac{\text{tonnes}}{\text{kg}} = \ \ 157.72 \ \ \text{tonnes } CO_2 \text{ / yr}$$

N_2O Calculation

Condensate Stabilizer Stream

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{0.217 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.0012\ \text{MMBtu}}{\text{scf}} \times \frac{10^{-4}\ \ \text{kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3}\ \text{tonnes}}{\text{kg}} = \ \ 0.000027 \ \ \text{tonnes } N_2O \text{ / yr}$$

Acid Gas Stream

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{0.750 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.0003\ \text{MMBtu}}{\text{scf}} \times \frac{10^{-4}\ \ \text{kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3}\ \text{tonnes}}{\text{kg}} = \ \ 0.000026 \ \ \text{tonnes } N_2O \text{ / yr}$$

Flare Pilot and Purge gas

N_2O Mass Emissions per 98.233(z) (Eq. W-40)

The Green House Gas Potential factor will be applied in the summary table.

$$E_{s,N2O} = \frac{3.066 \times \#^{6}\ \text{scf gas}}{\text{yr}} \times \frac{0.001\ \text{MMBtu}}{\text{scf}} \times \frac{10^{-4}\ \ \text{kg } N_2O}{\text{MMBtu}} \times \frac{10^{-3}\ \text{tonnes}}{\text{kg}} = \ \ 0.0003 \ \ \text{tonnes } N_2O \text{ / yr}$$

Storage Tank Emissions GHG Calculation

Vasquez-Beggs Equation (VBE)

Per 40 CFR 98 § 98.233(j)(2)
Emission unit: ES-46, ES-47, ES-48
Source Description:

STEP 1:

CALCULATION METHODOLOGY:
The first step is to calculate the flash gas specific gravity adjusted to 100 psig, as shown in Equation 5-16[1]. If the flash gas specific gravity at initial conditions, SG_i, is not known, the recommended default value of 0.90 will be used.

$$SG_x = 0.70 \times \left[1.0 + 0.00005912 \times 60.33 \times 325 \times \text{Log}\left(\frac{40.0 + 14.7}{114.7} \right) \right]$$

$$SG_x = 0.44$$

* Seperator Gas Gravity at Initial condition; API; Temp; Seperator Pressure are all carried forward from Vasquez-Beggs and/or E&P Tank submitted with the last application.

STEP 2:

The flash GOR is then calculated using equation 5-17[2]

$$R_s = 0.0178 \times 0.44 \times (40 + 14.7)^{1.187} \times \exp\left(\frac{23.931 \times 60.33}{325 + 460} \right)$$

$$R_s = 5.68 \text{ scf/bbl}$$

STEP 3:

Next, the output from the Vasquez-Beggs equation is converted to SI units using conversion factors from Table 3-4:

$$R_s = \frac{5.68 \text{ scf gas}}{\text{bbl crude}} \times \frac{m^3 \text{ gas}}{35.3147 \text{ scf gas}} \times \frac{\text{bbl crude}}{0.1589873 \ m^3 \text{ crude}}$$

$$R_s = 1.01 \ m^3 \text{gas}/ \ m^3 \text{ crude}$$

Working and Standing Loses

$$WSL = \#\#\# \times 1{,}248{,}952 \ \frac{\text{scf}}{\text{yr}} = 178{,}671 \ \frac{\text{scf}}{\text{yr}}$$

Storage Tank Emissions GHG Calculation

Vasquez-Beggs Equation (VBE)

Per 40 CFR 98 § 98.233(j)(2)
Emission unit: ES-46, ES-47, ES-48
Source Description:

STEP 4:

The flash gas contains gases besides CH_4 (and CO_2) and thus the R_S must be multiplied by the tank vent CH_4 (or CO_2) content. The CH_4 (or CO_2) emissions are estimated as: VRU Control Efficiency: 95 %

CH_4 Calculation

$$E_{CH4} = \frac{1.01\ \text{m}^3\ \text{gas}}{\text{m}^3\ \text{crude}} \times \frac{2.10\ \text{m}^3}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{\text{kgmole gas}}{40.94\ \text{m}^3} \times \frac{41\ \text{kgmole } CH_4}{100\ \text{kgmole gas}} \times \frac{16\ \text{kg } CH_4}{\text{kgmole } CH_4} \times \frac{\text{tonne}}{1000\ \text{kg}}$$

$E_{CH4\ to\ flare}$ = 512,070 scf/yr
E_{CH4} = 0.12 tonnes CH_4 / yr
$E_{CH4\text{-}VRU}$ = 0.0062 tonnes CH_4 / yr

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

CO_2 Calculation

$$E_{CO2} = \frac{1.01\ \text{m}^3\ \text{gas}}{\text{m}^3\ \text{crude}} \times \frac{2.10\ \text{m}^3}{\text{day}} \times \frac{365\ \text{day}}{\text{yr}} \times \frac{\text{kgmole gas}}{40.94\ \text{m}^3} \times \frac{0\ \text{kgmole } CO_2}{100\ \text{kgmole gas}} \times \frac{44\ \text{kg } CO_2}{\text{kgmole } CO_2} \times \frac{\text{tonne}}{1000\ \text{kg}}$$

E_{CO2} = 0.00 tonnes CO_2 / yr
$E_{CO2\text{-}VRU}$ = 0.00

C_{2+} Calculation

$$E_{voc} = 5.68\ \frac{\text{scf gas}}{\text{bbl crude}} \times 554.34\ \frac{\text{bbl}}{\text{day}} \times 365\ \frac{\text{day}}{\text{yr}} \times 0.59\ \frac{\text{scf } C_{2+}}{\text{scf gas}} = \mathbf{678{,}589}\ \frac{\textbf{scf}}{\textbf{yr}}$$

$$E_{voc\ to\ flare} = 678{,}589\ \frac{\text{scf}}{\text{yr}} \times 0.95\ \% = \mathbf{736{,}882}\ \frac{\textbf{scf}}{\textbf{yr}}$$

Storage Tank Emissions GHG Calculation

Vasquez-Beggs Equation (VBE)

Per 40 CFR 98 § 98.233(j)(2)
Emission unit: ES-49
Source Description:

STEP 1:

CALCULATION METHODOLOGY:

The first step is to calculate the flash gas specific gravity adjusted to 100 psig, as shown in Equation 5-16[1]. If the flash gas specific gravity at initial conditions, SG_i, is not known, the recommended default value of 0.90 will be used.

$$SG_x = 0.70 \times \left[1.0 + 0.00005912 \times 60.33 \times 325 \times \text{Log} \left(\frac{40.0 + 14.7}{114.7} \right) \right]$$

$$SG_x = \mathbf{0.44}$$

* Seperator Gas Gravity at Initial condition; API; Temp; Seperator Pressure are all carried forward from Vasquez-Beggs and/or E&P Tank submitted with the last application.

STEP 2:

The flash GOR is then calculated using equation 5-17[2]

$$R_s = 0.0178 \times 0.44 \times \left(40 + 14.7 \right)^{1.187} \times \exp \left(\frac{23.931 \times 60.33}{325 + 460} \right)$$

$$R_s = \mathbf{5.68\ scf/bbl}$$

STEP 3:

Next, the output from the Vasquez-Beggs equation is converted to SI units using conversion factors from Table 3-4:

$$R_s = \frac{5.68\ \text{scf gas}}{\text{bbl crude}} \times \frac{m^3\ \text{gas}}{35.3147\ \text{scf gas}} \times \frac{\text{bbl crude}}{0.1589873\ m^3\ \text{crude}}$$

$$R_s = \mathbf{1.01\ m^3 gas/ m^3 crude}$$

Working and Standing Loses

$$WSL=\#\#\# \times 0.00048 \frac{\text{tonnes}}{\text{yr}} = \mathbf{0.00016 \frac{tonnes}{yr}}$$

Storage Tank Emissions GHG Calculation

Vasquez-Beggs Equation (VBE)

Per 40 CFR 98 § 98.233(j)(2)
Emission unit: ES-49
Source Description:

STEP 4:

The flash gas contains gases besides CH_4 (and CO_2) and thus the R_S must be multiplied by the tank vent CH_4 (or CO_2) content. The CH_4 (or CO_2) emissions are estimated as:

VOC content: 5 %

CH_4 Calculation

$$E_{CH4} = \frac{1.01 \text{ m}^3\text{ gas}}{\text{m}^3\text{ crude}} \times \frac{0.12 \text{ m}^3}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{kgmole gas}}{40.94 \text{ m}^3} \times \frac{41 \text{ kgmole } CH_4}{100 \text{ kgmole gas}} \times \frac{16 \text{ kg } CH_4}{\text{kgmole } CH_4} \times \frac{\text{tonne}}{1000 \text{ kg}}$$

E_{CH4} = 0.00048 tonnes CH_4 / yr

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

CO_2 Calculation

$$E_{CO2} = \frac{1.01 \text{ m}^3\text{ gas}}{\text{m}^3\text{ crude}} \times \frac{0.12 \text{ m}^3}{\text{day}} \times \frac{365 \text{ day}}{\text{yr}} \times \frac{\text{kgmole gas}}{40.94 \text{ m}^3} \times \frac{0 \text{ kgmole } CO_2}{100 \text{ kgmole gas}} \times \frac{44 \text{ kg } CO_2}{\text{kgmole } CO_2} \times \frac{\text{tonne}}{1000 \text{ kg}}$$

E_{CO2} = 0.00 tonnes CO_2 / yr

Storage Tank Emissions GHG Calculation

Emission unit T-52
Source Description:

Based on the ratio of the tank throughput for tanks ES-46, 47, and 48 to T-42 (0.036) the CH_4 emissions will be:

$$0.036 \times 0.0062 \frac{\text{tonnes}}{\text{yr}} = \mathbf{0.00022} \frac{\textbf{tonnes}}{\textbf{yr}}$$

Loading GHG Calculation

Emission unit: ES-56
Source Description: Condensate Loadout

CALCULATION METHODOLOGY:

Select from Table 5-12, the corresponding emission factor for the specific loading type . 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

$$E_{CH4} = 41{,}000 \frac{lb}{yr} \times 6 \frac{scf}{lb} \times 0.41 \frac{scf\ CH_4}{scf\ gas} \times 95\ \%$$

$E_{CH4\ to\ flare}$ = **96,823 scf CH_4 / yr**

E_{CH4} = **0.3813 tonnes CH_4 / yr**

C_{2+} Emissions

$$E_{CH4} = 41{,}000 \frac{lb}{yr} \times 6 \frac{scf}{lb} \times 0.59 \frac{scf\ C_{2+}}{scf\ gas} \times 95\ \%$$

$E_{C2+\ to\ flare}$ = **139,331 scf C_{2+} / yr**

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

Equipment Leak GHG Calculation

Facility-Level Average Emission Factors Approach

THC Emissions Calculation

$$E_{THC} = \begin{pmatrix} 4 \frac{lb}{yr} \times 4{,}841 \text{ Connections} \\ 8 \frac{lb}{yr} \times 2{,}075 \text{ Flanges} \\ 39 \frac{lb}{yr} \times 166 \text{ Open-Ended Line} \\ 46 \frac{lb}{yr} \times 27 \text{ Pump Seals} \\ 87 \frac{lb}{yr} \times 1{,}748 \text{ Valves} \\ \#\# \frac{lb}{yr} \times 84 \text{ Other} \end{pmatrix} \times 45.36 \times \#^{-5} \frac{tonnes}{lb} = 94.6 \text{ tonnes THC/yr}$$

CH_4 Emissions

$$E_{CH4} = 94.6 \frac{\text{tonnes THC}}{\text{yr}} \times 0.75 \frac{\text{tonnes } CH_4}{\text{tonnes THC}} = \mathbf{71.227} \frac{\textbf{tonnes } \mathbf{CH_4}}{\textbf{yr}}$$

CO_2 Emissions

$$E_{CO2} = 94.6 \frac{\text{tonnes THC}}{\text{yr}} \times 0.02 \frac{\text{tonnes } CO_2}{\text{tonnes THC}} = \mathbf{1.456} \frac{\textbf{tonnes } \mathbf{CO_2}}{\textbf{yr}}$$

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.

PSD0295-M10-R2 (Unit ES-04)
Manufacturer test data and AP-42 Table 3.1-1

PSD0295-M10 Significant Revision application (Unit ES-17)
Manufacturer test data and Solar Turbine guarantee

PSD0295-M9-R2 (Unit ES-05)
Manufacturer test data and AP-42 Table 3.1-1

PSD0295-M9 (Unit FUG)
Protocol for Equipment Leak Emissions Estimates Table 2-4, EPA

PSD0295-M8R3 Technical Revision application (Unit ES-06/07)
Turbine stack test data and AP-42 Tables 3.1-1 and 3.1-2a

PSD0295-M8R1 Technical Revision application (Units GC-1, GC-2, ES-49, ES-60, ES-61, ES-62)

- Load Out Point Hose Disconnect & Fugitive Emissions:
  - Natural Gas Liquids Analysis
- New/Temporary Cooling Tower Emissions:
  - Field Service Report
  - NMAC Technical Memorandum, “Calculating TSP, PM-10, and PM-2.5 from Cooling Towers”
- Gas Chromatograph Emissions:
  - Inlet Gas Analysis
  - Sales Gas Analysis

PSD0295-M8 Significant Revision application (Units ES-08/09, ES-21, ES-22, ES-14 Steady State, ES-46)

- Condensate Analysis
- Condensate Stabilizer Reflux Analysis
- E&P TANK V2.0 Model Run to evaluate flashing losses (For informational purposes only; not used in
- calculations section)
- Vasquez-Beggs Calculations: API, “Exploration and Production Emission Calculator (EPEC) User’s Guide, pp. 3-15 and 3-16, 09/1997
- EPA AP-42, Section 5.2.2.1.1 Loading Losses, Table 5.2-1 Saturation Factors for Calculating Petroleum Liquid Loading Losses, 6/08
- TCEQ Air Permit Technical Guidance Document RG-109 (Draft), “Flares and Vapor Oxidizers“, October 2000, pp. 19-20, 26
- EPA AP-42 Table 1.4-1 and 1.4-2, Emission Factors for Criteria Pollutants from Natural Gas Combustion, 7/1998
- EPA AP-42 Table 3.1-1, Emission Factors for NO_x and CO from Stationary Gas Turbines , 4/2000
- EPA AP-42 Table 3.1-2a, Emission Factors for Criteria Pollutants and GHG from Stationary Gas Turbines, 4/2000
- Fuel Gas Analysis

PSD0295-M7R4 Technical Revision application (Units ES-08/09)

- CENTAUR 40-4002 Certified Test Report
- Engine Data Report
- EPA AP-42 Table 1.4-1 and 1.4-2, Emission Factors for Criteria Pollutants from Natural Gas Combustion, 7/1998
- EPA AP-42 Table 1.4-1 and 1.4-2, Emission Factors for Criteria Pollutants from Natural Gas Combustion, 7/1998.
- EPA AP-42 Table 3.1-1, Emission Factors for NOx and CO from Stationary Gas Turbines, 4/2000.
- EPA AP-42 Table 3.1-2a, Emission Factors for Criteria Pollutants and GHG from Stationary Gas Turbines, 4/2000.
- EPA Document 450/2-90-001a, "Air Emissions Species Manual", Profile Number 1208.
- API Publication No. 4683, "Correlation Equations to predict Reid Vapor Pressure and Properties of Gaseous Emissions for Exploration and Production Facilities," p.5-5, 11/1998.
- API, "Exploration and Production Emission Calculator (EPEC) User's Guide, pp. 3-14, 3-15, and 3-16,09/1997.
- Vasquez-Beggs method used to verify tank flashing losses calculations.
- EPA AP-42, Section 5.2.2.1.1 Loading Losses, Table 5.2-1 Saturation Factors for Calculating Petroleum Liquid Loading Losses, 6/08.
- TCEQ Air Permit Technical Guidance Document RG-109 (Draft), "Flares and Vapor Oxidizers," October 2000, pp. 19-20, 26.
- Fuel Gas Analysis.
- Greenhouse Gas Emissions Information

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	Engine Model **CENTAUR 50-6100S** **CS/MD 59F MATCH**
Job ID	
Inquiry Number	Fuel Type: **SD NATURAL GAS** — Water Injection: **NO**
Run By: **David A Pocengal** — Date Run: **15-Feb-17**	Engine Emissions Data **REV. 0.0**

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
1 — 5679 HP, 100.0% Load, Elev. 3821 ft, Rel. Humidity 60.0%, Temperature 0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	21.02	25.60	7.33
lbm/MMBtu (Fuel LHV)	0.100	0.122	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	1.13	1.38	0.40
lbm/hr	4.80	5.84	1.67
2 — 5576 HP, 100.0% Load, Elev. 3821 ft, Rel. Humidity 60.0%, Temperature 20.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	20.65	25.14	7.20
lbm/MMBtu (Fuel LHV)	0.100	0.122	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	1.13	1.38	0.40
lbm/hr	4.71	5.74	1.64
3 — 5179 HP, 100.0% Load, Elev. 3821 ft, Rel. Humidity 60.0%, Temperature 59.0 Deg. F			
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	19.54	23.80	6.81
lbm/MMBtu (Fuel LHV)	0.100	0.122	0.035
lbm/(MW-hr) (gas turbine shaft pwr)	1.16	1.40	0.40
lbm/hr	4.46	5.44	1.56

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg C, and between 50% and 100% load for gas, fuel, and between 65% and 100% load for liquid fuel (except f or the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg C and betwee
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED EMISSION PERFORMANCE

Customer	
Job ID	
Inquiry Number	
Run By: **David A Pocengal**	Date Run: **15-Feb-17**

Engine Model	
CENTAUR 50-6100S CS/MD 59F MATCH	
Fuel Type: **SD NATURAL GAS**	Water Injection: **NO**
Engine Emissions Data: **REV. 0.0**	

4	4584 HP 100.0% Load	Elev. 3821 ft	Rel. Humidity 60.0%	Temperature 85.0 Deg. F

	NOx EMISSIONS	CO EMISSIONS	UHC EMISSIONS
PPMvd at 15% O2	25.00	50.00	25.00
ton/yr	17.84	21.72	6.22
lbm/MMBtu (Fuel LHV)	0.099	0.120	0.034
lbm/(MW-hr) (gas turbine shaft pwr)	1.19	1.46	0.42
lbm/hr	4.07	4.96	1.42

Notes

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another.
2. Solar's typical SoLoNOx warranty, for ppm values, is available for greater than 0 deg F or -20 deg C, and between 50% and 100% load for gas, fuel, and between 65% and 100% load for liquid fuel (except f or the Centaur 40). An emission warranty for non-SoLoNOx equipment is available for greater than 0 deg F or -20 deg C and betwee
3. Fuel must meet Solar standard fuel specification ES 9-98. Emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide Product Information Letters to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.
6. Any emissions warranty is applicable only for steady-state conditions and does not apply during start-up, shut-down, malfunction, or transient event.

Solar Turbines
A Caterpillar Company

PREDICTED ENGINE PERFORMANCE

Customer	Model **CENTAUR 50-6100S**
	Package Type **CS/MD**
Job ID	Match **59F MATCH**
Run By **David A Pocengal** / Date Run **15-Feb-17**	Fuel System **GAS**
Engine Performance Code **REV. 4.17.1.19.11** / Engine Performance Data **REV. 0.1**	Fuel Type **SD NATURAL GAS**

DATA FOR NOMINAL PERFORMANCE

Elevation	feet	3821
Inlet Loss	in H2O	4.0
Exhaust Loss	in H2O	4.0
Accessory on GP Shaft	HP	15.5

		1	2	3	4
Engine Inlet Temperature	deg F	0	20.0	59.0	85.0
Relative Humidity	%	60.0	60.0	60.0	60.0
Driven Equipment Speed	RPM	16500	16500	16500	16500
Specified Load	HP	FULL	FULL	FULL	FULL
Net Output Power	HP	5679	5576	5179	4584
Fuel Flow	mmBtu/hr	47.87	47.07	44.78	41.30
Heat Rate	Btu/HP-hr	8429	8441	8647	9011
Therm Eff	%	30.187	30.143	29.427	28.238
Engine Exhaust Flow	lbm/hr	142369	138006	128291	119146
PT Exit Temperature	deg F	881	909	967	991
Exhaust Temperature	deg F	880	909	967	991

Fuel Gas Composition (Volume Percent)

Methane (CH4)	92.79
Ethane (C2H6)	4.16
Propane (C3H8)	0.84
N-Butane (C4H10)	0.18
N-Pentane (C5H12)	0.04
Hexane (C6H14)	0.04
Carbon Dioxide (CO2)	0.44
Hydrogen Sulfide (H2S)	0.0001
Nitrogen (N2)	1.51

Fuel Gas Properties

LHV (Btu/Scf)	939.2	Specific Gravity	0.5970	Wobbe Index at 60F	1215.6

This performance was calculated with a basic inlet and exhaust system. Special equipment such as low noise silencers, special filters, heat recovery systems or cooling devices will affect engine performance. Performance shown is "Expected" performance at the pressure drops stated, not guaranteed.

Summary of Results, Runs 1-3
(ES-06/07, Test Summary)
Operational Data, Concentrations, Exhaust Flow Rates,
Mass Emission Rates

Client: Oxy USA
Plant Name: Indian Basin Gas Plant (IBGP)
Source: North Recompressor (ES-06/07)
Date: 09/15/14
Technicians: WM

Test Number	***1***	***2***	***3***	
Date	9/15/14	9/15/14	9/15/14	
Start Time	3:36 PM	4:45 PM	5:53 PM	
Stop Time	4:36 PM	5:45 PM	6:53 PM	
Engine/Generator Operation				
NGP (%)	100.0	100.0	100.0	
NPT (%)	91.0	91.0	91.0	
T5 (F)	1140.0	1140.0	1140.0	
T1 (F)	72	74	73	
Suction Pressure (psi)	390.0	390.0	390.0	
Discharge Pressure (psi)	980.0	980.0	980.0	
Fuel Data				
Fuel Heating Value (Gross Btu/scf) *	1040	1040	1040	
Fuel O2 F-Factor (DSCFH/MMBTU) *	8710	8710	8710	
Fuel Flow Rate (SCFH)	33762.5	33837.50	33950.0	
Measured Emissions (dry)				***Averages***
NO_x (ppmv)	61.8	61.7	61.4	**61.6**
NO_x (ppmv @ 15% O_2)	81.7	80.9	80.4	**81.0**
CO (ppmv)	10.1	10.3	10.1	**10.2**
CO (ppmv @ 15% O_2)	13.4	13.5	13.3	**13.4**
O_2 (%)	16.44	16.40	16.39	**16.41**
CO_2 (%)	2.69	2.68	2.69	**2.69**
Fo Factor	1.66	1.68	1.68	**1.67**
Exhaust Flow Rates				
via EPA Method 19 (SCFH, dry)	1.43E+06	1.42E+06	1.43E+06	**1.43E+06**
Mass Emission Rates (Based on Method 19)				
NOx (lbs/hr) {Permit Limit = 18.4}	10.57	10.49	10.47	**10.51**
CO (lbs/hr) {Permit Limit = 15.3}	1.05	1.06	1.05	**1.06**
NOx (tons/yr) {Permit Limit = 80.7}	46.29	45.94	45.85	**46.02**
CO (tons/yr) {Permit Limit = 67.2}	4.61	4.66	4.60	**4.62**

* EPA Values

ES-06/07

(~~NOx~~, VOC)

SOLAR TURBINES INCORPORATED
ENGINE PERFORMANCE CODE REV. 3.13
CUSTOMER: Marathon Indian Basin
B ID: North, Center, and South Recompressors

DATE RUN: 29-Jan-03
RUN BY: Eric L Moore

NEW EQUIPMENT PREDICTED EMISSION PERFORMANCE
DATA FOR POINT NUMBER 1

Fuel: SD NATURAL GAS
Water Injection: NO
Number of Engines Tested: 4
Model: CENTAUR 40-4000 CS/MD STANDARD GAS
NEW STANDARD (PIP) COMBUSTOR
Emissions Data: REV. 0.0

Customer: Marathon Indian Basin
Inquiry Number: North, Center, and South Recompressors

The following predicted emissions performance is based on the following specific single point: (see attached)

Hp= 3198, %Full Load= 100.0, Elev= 3820 ft, %RH= 60.0, Temperature= 68.0 F

NOX		CO		UHC		
NOM	MAX	NOM	MAX	NOM	MAX	
101.35	**	14.20	**	2.79	**	PPMvd at 15% O2
55.27	**	4.71	**	0.53	**	ton/yr
0.402	**	0.034	**	0.004	**	lbm/MMBtu (Fuel LHV)
5.29	**	0.45	**	0.05	**	lbm/(MW-hr) (gas turbine shaft pwr)
12.62	**	1.08	**	0.12	**	lbm/hr

IMPORTANT NOTES

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another. The emission values on this form are only predicted emissions at the specific operating conditions listed.
.. Solar's typical SoLoNOx warranty is for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 80% and 100% load for liquid fuel. An emission warranty for non-SoLoNOx equipment is for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Predicted emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide generic documents to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can optionally provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. 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.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads ($\geq$80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60^{o}F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

MANLEY GAS TESTING, INC.
120 DOCK ROAD - ODESSA, TEXAS 432-367-3024

CHARGE....... 80 - 29
TEST NUMBER.. 41455

DATE SAMPLED...... 04-06-15
DATE RUN 04-07-15

METER NUMBER .. 40026

A SAMPLE OF INDIAN BASIN
RECEIVED FROM: WEST TEXAS LPG PIPELINE L.P.
LOCATION: TULSA OKLAHOMA

TICKET NUMBERS = 67016
COMPOSITE DATES = 04-01-15 TO 04-05-15

BEFORE BACK PRESSURE = 200 CC's
AFTER BACK PRESSURE = 200 CC's

FRACTIONAL ANALYSIS
CALCULATED @ 14.696 PSIA AND 60F

	MOLE%	LIQUID%	WEIGHT% (2)	WEIGHT% (4)
NITROGEN.......	0.00	0.00	0.00	0.0000
CARBON DIOXIDE.	0.00	0.00	0.00	0.0000
METHANE........	1.58	0.94	0.60	0.5951
ETHANE.........	43.30	40.75	30.91	30.9075
PROPANE........	33.53	32.50	35.10	35.1049
ISO-BUTANE.....	4.42	5.09	6.10	6.1016
NOR-BUTANE.....	9.77	10.86	13.50	13.5050
ISO-PENTANE....	2.37	3.05	4.06	4.0582
NOR-PENTANE....	2.31	2.95	3.96	3.9613
HEXANES+	2.72	3.86	5.77	5.7664
	100.00	100.00	100.00	100.0000

TOT. SP. GRAVITY... 0.4697
TOT. VAPOR PRESS. 497.866
TOT. MOLECULAR WT. 42.120

TOT. VAPOR PRESS. @ 100F

** CAPILLARY EXTENDED HEXANES+ CALCULATIONS **

SP. GRAVITY C6+ .. 0.7009
MOLECULAR WT C6+. 89.597
VAPOR PRESS C6+ .. 4.690
....
CF/GAL C6+ .. 25.042
LB/GAL C6+ .. 5.843

ANALYSIS BASED ON GPA STANDARDS 2177-13 & 2186-14

DISTRIBUTION / REMARKS :

LINDA BUCKLAND
OXY-L. CAVINS 713-985-1630/T. BERNAL 575-457-2544

LIQUID VOL% C1/C2 HIGH = 2.31 (LIQUID VOL% C1/C2 SPEC = 1.50%)

RUN BY K. CASWELL

APPROVED Kc

[*R] [~I-R~]

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

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.

Oxy - Indian Basin Gas Plant

Kyle Cain
Tom Bernal

Smart Chemical Services

Jerry Woodward

Field Service Report

DATE: 1-Dec-14

BOILERS

LOCATION	pH	P-ALK	M-ALK	2P-M	HARD	PO4	DEHA	IRON	COND	CYCLE
Boiler Feed Water	9.55	0	55	—	0			0.04	46	
Return Condensate	9.81								45	
North Boiler	11.48	150	245	55		150.0			1100	
Center Boiler	11.59	350	700	0		275.0			2900	
South Boiler	11.52	220	400	40		266.0			1800	
AUX. Boiler	10.16	30	30	30		42.0			45	
SRU WHB	Out	of	service							
Large Condenser	Out	of	service							
Small Condenser	Out	of	service							
RO Water	7.36				0				840	
Zeo. Treater	7.28				0				880	

COOLING TOWER

	pH	P-ALK	M-ALK	PO4	HARD	Br2	Ca	FTU	COND	IRON
Tower M.U.	7.20				650				810	
Cooling Tower	6.85	0	30	14.6	1700	0.2			2900	3.19
Cycles of Conc.					2.62				3.58	

SRB Date	SRB Col/ml	APB Date	APBCol/ml
12-Aug-13	1,000	12-Aug-13	10
29-Jul-13	100	29-Jul-13	0
8-Jul-13	10	8-Jul-13	10
24-Jun-13	100	24-Jun-13	100
17-Jun-13	100	17-Jun-13	10,000
10-Jun-13	10	10-Jun-13	1000
4-Jun-13	10	4-Jun-13	1000
13-May-13	10	13-May-13	100

C.T. pH READING	14.0
C.T. CONDUCTIVITY READING	2500

CONTROL PARAMETERS

	BOILERS	CWT	BFW	COND
pH	>11.0	7.2-7.8	8.5-9.5	8.5-9.5
COND.	<2400	2000-2400		
PO4	30-50	11.0-17.0		
IRON		<0.5	<0.1	<0.1

INVENTORY

LOCATION	24-Nov	1-Dec	GAL/DY	DEL
1924	110	80		
1913	82	62		
Alpha 120	0	0		
Bromine	110	110		
1933	50	35		
1947	87	80		
1862	55	55		
1939	74	71		

REMARKS:

1. The ~~pH and~~ conductivity controllers agrees with the lab test results. The cooling tower iron level continues to decrease. The blowdown will help bringthe iron level decrease as the PO4 level is very good. ~~The corrosion coupon keep is plugged~~. THE pH CONTROLLER IS RECALIBRATED AND WORKING PROPERLY, PH 6.77 CONTROLLER

2. The RO and zeolite waters had good hardness and are in good control.

3. The Auxilary Boilder is ~~not~~ operating. Please ~~decrease~~ INCREASE the blowdown of the ~~North~~ SOUTH Boiler SLIGHTLY to bring the conductivity within the 1800 umhos range to match the ~~South~~ NORTH and Center Boilers(these are operating correctly).

4. I set the SCS 1939 pump at 1 qt/day to keep the alkalinity steady.

Conductivity reading used to evaluate TDS content of the sample for cooling tower emission calculations.

SUSANA MARTINEZ
Governor
JOHN A. SANCHEZ
Lieutenant Governor

NEW MEXICO
ENVIRONMENT DEPARTMENT

Air Quality Bureau

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

RYAN FLYNN
Cabinet Secretary-Designate
BUTCH TONGATE
Deputy Secretary

TECHNICAL MEMORANDUM

DATE: September 9, 2013

TO: All Permitting Staff

FROM: Daren Zigich

THROUGH: Ted Schooley, Permit Program Manager
Ned Jerabek, Major Source Section Manager

SUBJECT: Calculating TSP, PM-10 and PM-2.5 from Cooling Towers

The goal of this memo is to offer a Department approved step-by-step approach for calculating particulate emissions from cooling towers. While the Department encourages using this approach, other approaches, that do not use a droplet settling ratio may be approved on a case-by-case basis.

Due to the variability of methods used by permittees to estimate particulate emissions from cooling towers, a consistent, defensible approach is warranted. For example, some permittees have used a droplet settling ratio from Reference 3 to lower the total potential emissions rate of total particulate matter (PM_{total}). This is unacceptable due to the following:

1. Particulate settling is not appropriate since any verification testing would be completed inside the cooling tower fan stack. All particulate mass that can be measured by an EPA reference method and are emitted to the atmosphere shall be counted as particulate emissions. Particle size distribution can then be used to modify the emission rate of each regulated particulate size.
2. The Department is not aware of information that verifies the droplet settling data is representative for arid climates where evaporation rates are high.
3. The droplet size distribution and % mass data from Reference 1 only consider droplets up to 600 microns. Reference 3 states that settling only exists for droplets greater than 450 microns. Reference 1 lists the % mass of droplets greater than 450 microns to be less than 1 percent of the total mass.

4. Reference 2 test data shows that towers with significant drift droplet diameters greater than 600 microns usually suffer from poor installation of the drift eliminator or from poor water distribution due to issues with the tower packing. Large droplets may indicate that the assumed or guaranteed drift eliminator efficiency is not being met. Providing emissions credit for poor installation, operation or maintenance runs counter to general Department practice.
5. References 1 and 2 make no reference to and assign no credit for the settling theory stated in Reference 3.

For the above reasons, the Reference 3 settling ratio is not an acceptable emissions reduction approach.

Acceptable Calculation Method

Cooling tower particulate emissions are a function of the Drift rate and the concentration of dissolved solids present in the water. The Drift rate is normally listed as a percentage of the circulating water flow rate of the cooling tower.

Step 1 – Establish maximum water circulation rate (Q_{circ}) for the cooling tower. This is usually dependent on the capacity of the circulation pumps and the plant cooling system and should be reported as gallons per minute (gpm). The circulation rate is the sum of the circulation rates for each cell in the tower and thus represents the total flow for the tower.

Step 2 – Establish Drift rate (Q_{drift}) of the cooling tower. This information is dependent on the drift eliminator design and is usually supplied by the tower manufacturer. If manufacturer data is unavailable, the standard drift of 0.02 percent, listed in AP-42, should be used.

Step 3 – Establish maximum Total Dissolved Solids concentration (TDS) in the circulating cooling water. This is dependent on the facility's operations. TDS should be reported as parts per million (ppm) or mg/l.

Step 4 – Calculate total potential hourly particulate emissions (PM_{total}) in pounds per hour (lbs/hr).

$$PM_{total} = TDS(mg/l) \times \frac{1(lbs/mg)}{453{,}600} \times 3.785(l/gal) \times Q_{circ}(gpm) \times \frac{Q_{drift}(\%Q_{circ})}{100} \times 60(min/hr)$$

Example: TDS = 3000 ppm or mg/l, Q_{circ} = 50,000 gpm, Q_{drift} = 0.004%

$$PM_{total} = 3000 \times (1/453{,}600) \times 3.785 \times 50{,}000 \times (0.004/100) \times 60$$

$$PM_{total} = 3.0 \text{ lbs/hr}$$

Step 5 – Estimate particulate size distribution of the PM_{total} to determine potential emissions of TSP/PM, PM_{10} and $PM_{2.5}$.

The current estimating technique used in References 1 and 2 employs a formula for determining a potential particulate size (i.e. diameter) for a given set of variables. The variables are:

d_d = Drift droplet diameter, microns
C_{TDS} = Concentration of TDS in the circulating water, ppm x 10^{-6}
ρ_w = Density of Drift droplet, g/cm^3
ρ_{salt} = Density of particle, g/cm^3

The equation for determining particle size/diameter (d_p), in microns is:

$$d_p = \frac{d_d}{(\rho_{salt} / \rho_w C_{TDS})^{1/3}}$$

The tables below list particle size related to droplet size for various concentrations (1000 ppm to 12,000 ppm) of TDS in the circulating cooling water. The density of the water droplet (ρ_w) is assumed to be 1.0 g/cm3 (based on density of pure water) and the average density of the TDS salts is assumed to be 2.5 g/cm3. This assumed density is selected based on the average density of common TDS constituents, $CaCO_3$, $CaSO_4$, $CaCl_2$ NaCl, Na_2SO_4, and Na_2CO_3. If actual circulating water constituents are available, that data may be used to estimate the dissolved solids average density.

To determine the droplet size that generates particulate matter of the applicable regulated diameters, TSP/PM (defined as 30 microns or less per NM AQB definition[1]), PM10 and PM2.5, find the column in the table that matches the maximum circulating water TDS concentration and read the values associated with the PM2.5, PM10 and TSP/PM boxes. Boxed values are not exactly equal to the applicable sizes, but are the values greater than and closest to the applicable sizes, given the listed water droplet values from Reference 1.

The far right column of each table provides mass distribution data from Reference 1. The values indicate what percent of the total particulate mass emission, calculated in Step 4, is associated with the applicable particulate size. Read the value that is on the same line (same color) as the applicable particulate size associated with the specified TDS concentration column.

Note: Although the relationship between droplet size and percent mass is not linear, a linear interpolation of the tabulated data is acceptable between two adjacent rows (particle size) to determine an estimate of percent mass for a specific particle size (i.e. PM30, PM10 and PM2.5). Particle sizes for droplets with a non-listed TDS ppm concentration may be calculated using the equation in Step 5.

Example: Continuing from Step 4,

PM_{total} = 3.0 lbs/hr
C_{TDS} = 3000 ppm

From Table:

$PM_{2.5}$:	d_d = 30	%Mass = 0.226%
PM_{10}:	d_d = 110	%Mass = 70.509%
TSP/PM:	d_d = 270	%Mass = 96.288%

The mass emission of each applicable particulate size is:

$PM_{2.5} = PM_{total}(\%Mass/100) = 3.0(0.00226) = 0.007$ lbs/hr
$PM_{10} = 3.0(.70509) = 2.115$ lbs/hr
TSP/PM = 3.0(.96288) = 2.889 lbs/hr

[1]Definition of TSP for purposes of permitting emission sources, 11/2/09, see P:\AQB-Permits-Section\NSR-TV-Common\Permitting-Guidance-Documents – Index & Links document

Size Distribution

1000 ppm (TDS)			2000 ppm			3000 ppm			% Mass
d_d	d_p		d_d	d_p		d_d	d_p		$\leq$
10	0.7387304		10	0.930527		10	1.0650435		0
20	1.4774608		20	1.8610539		20	2.130087	PM2.5	0.196
30	2.2161912		30	2.7915809	PM2.5	30	3.1951306	PM2.5	0.226
40	2.9549216	PM2.5	40	3.7221079		40	4.2601741		0.514
50	3.693652		50	4.6526349		50	5.3252176		1.816
60	4.4323825		60	5.5831618		60	6.3902611		5.702
70	5.1711129		70	6.5136888		70	7.4553046		21.348
90	6.6485737		90	8.3747427		90	9.5853917		49.812
110	8.1260345		110	10.235797	PM10	110	11.715479	PM10	70.509
130	9.6034953		130	12.096851		130	13.845566		82.023
150	11.080956	PM10	150	13.957905		150	15.975653		88.012
180	13.297147		180	16.749485		180	19.170783		91.032
210	15.513339		210	19.541066		210	22.365914		92.468
240	17.72953		240	22.332647		240	25.561045		94.091
270	19.945721		270	25.124228		270	28.756175		94.689
300	22.161912		300	27.915809		300	31.951306	TSP/PM30	96.288
350	25.855564		350	32.568444	TSP/PM30	350	37.276523		97.011
400	29.549216		400	37.221079		400	42.601741		98.34
450	33.242868	TSP/PM30	450	41.873714		450	47.926958		99.071
500	36.93652		500	46.526349		500	53.252176		99.071
600	44.323825		600	55.831618		600	63.902611		100

Size Distribution

4000 ppm (TDS)			5000 ppm			6000 ppm			% Mass
d_d	d_p		d_d	d_p		d_d	d_p		≤
10	1.1721197		10	1.2625337		10	1.3415607		0
20	2.3442393		20	2.5250675	PM2.5	20	2.6831215	PM2.5	0.196
30	3.516359	PM2.5	30	3.7876012		30	4.0246822		0.226
40	4.6884787		40	5.0501349		40	5.366243		0.514
50	5.8605984		50	6.3126686		50	6.7078037		1.816
60	7.032718		60	7.5752024		60	8.0493645		5.702
70	8.2048377		70	8.8377361		70	9.3909252		21.348
90	10.549077	PM10	90	11.362804	PM10	90	12.074047	PM10	49.812
110	12.893316		110	13.887871		110	14.757168		70.509
130	15.237556		130	16.412938		130	17.44029		82.023
150	17.581795		150	18.938006		150	20.123411		88.012
180	21.098154		180	22.725607		180	24.148093		91.032
210	24.614513		210	26.513208		210	28.172776		92.468
240	28.130872		240	30.300809	TSP/PM30	240	32.197458	TSP/PM30	94.091
270	31.647231	TSP/PM30	270	34.088411		270	36.22214		94.689
300	35.16359		300	37.876012		300	40.246822		96.288
350	41.024188		350	44.18868		350	46.954626		97.011
400	46.884787		400	50.501349		400	53.66243		98.34
450	52.745385		450	56.814018		450	60.370234		99.071
500	58.605984		500	63.126686		500	67.078037		99.071
600	70.32718		600	75.752024		600	80.493645		100

Size Distribution

7000 ppm (TDS)			8000 ppm			9000 ppm			% Mass
d_d	d_p		d_d	d_p		d_d	d_p		≤
10	1.4122241		10	1.4764371		10	1.5354962		0
20	2.8244482	PM2.5	20	2.9528742	PM2.5	20	3.0709923	PM2.5	0.196
30	4.2366724		30	4.4293112		30	4.6064885		0.226
40	5.6488965		40	5.9057483		40	6.1419846		0.514
50	7.0611206		50	7.3821854		50	7.6774808		1.816
60	8.4733447		60	8.8586225		60	9.2129769		5.702
70	9.8855688		70	10.33506	PM10	70	10.748473	PM10	21.348
90	12.710017	PM10	90	13.287934		90	13.819465		49.812
110	15.534465		110	16.240808		110	16.890458		70.509
130	18.358914		130	19.193682		130	19.96145		82.023
150	21.183362		150	22.146556		150	23.032442		88.012
180	25.420034		180	26.575867		180	27.638931		91.032
210	29.656707		210	31.005179	TSP/PM30	210	32.245419	TSP/PM30	92.468
240	33.893379	TSP/PM30	240	35.43449		240	36.851908		94.091
270	38.130051		270	39.863801		270	41.458396		94.689
300	42.366724		300	44.293112		300	46.064885		96.288
350	49.427844		350	51.675298		350	53.742365		97.011
400	56.488965		400	59.057483		400	61.419846		98.34
450	63.550085		450	66.439668		450	69.097327		99.071
500	70.611206		500	73.821854		500	76.774808		99.071
600	84.733447		600	88.586225		600	92.129769		100

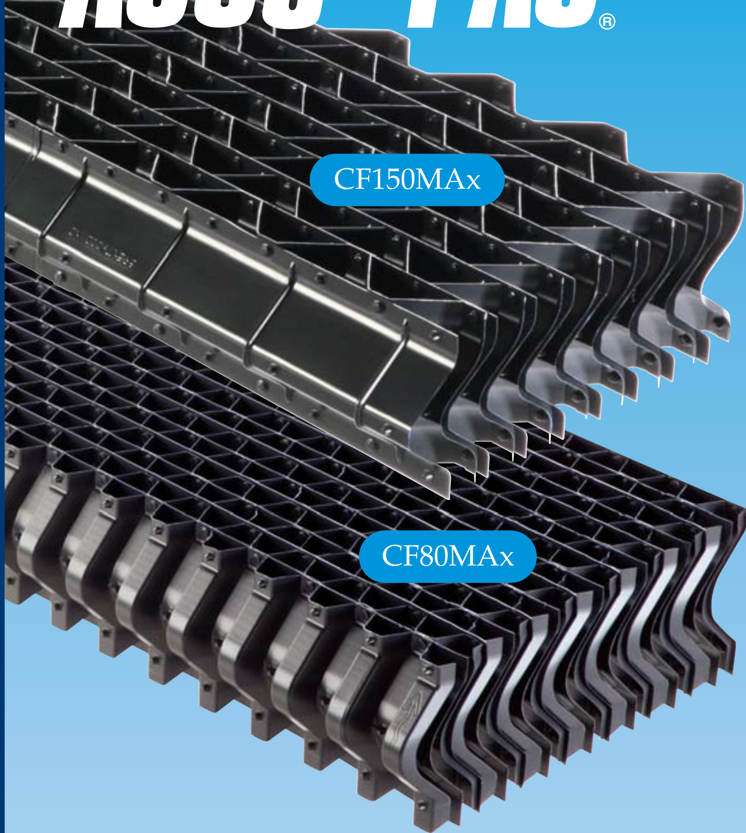
Size Distribution

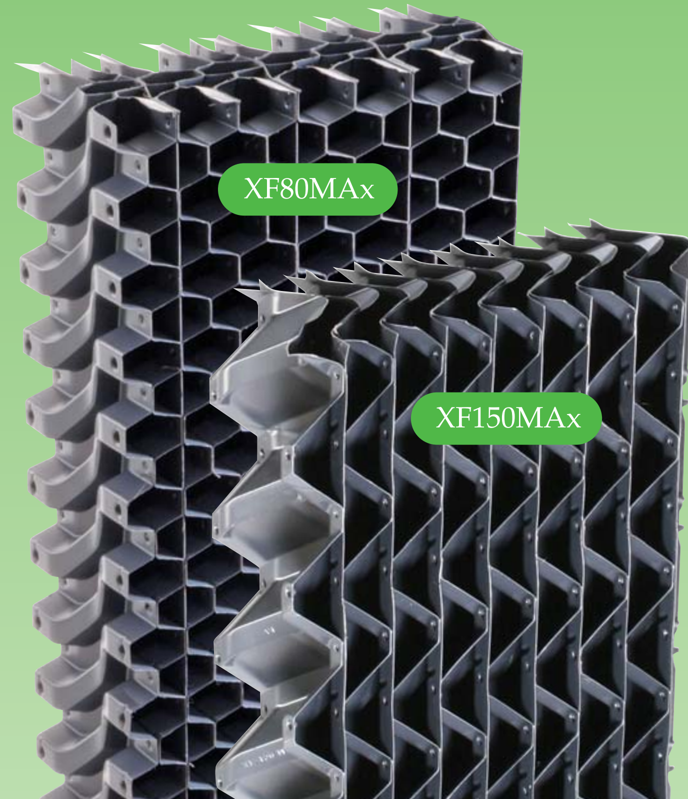
10,000 ppm (TDS)			11,000 ppm			12,000 ppm			% Mass
d_d	d_p		d_d	d_p		d_d	d_p		≤
10	1.5903253		10	1.6416091		10	1.6898701		0
20	3.1806507	PM2.5	20	3.2832181	PM2.5	20	3.3797403	PM2.5	0.196
30	4.770976		30	4.9248272		30	5.0696104		0.226
40	6.3613013		40	6.5664363		40	6.7594806		0.514
50	7.9516267		50	8.2080453		50	8.4493507		1.816
60	9.541952		60	9.8496544		60	10.139221	PM10	5.702
70	11.132277	PM10	70	11.491263	PM10	70	11.829091		21.348
90	14.312928		90	14.774482		90	15.208831		49.812
110	17.493579		110	18.0577		110	18.588572		70.509
130	20.674229		130	21.340918		130	21.968312		82.023
150	23.85488		150	24.624136		150	25.348052		88.012
180	28.625856		180	29.548963		180	30.417663	TSP/PM30	91.032
210	33.396832	TSP/PM30	210	34.47379	TSP/PM30	210	35.487273		92.468
240	38.167808		240	39.398618		240	40.556883		94.091
270	42.938784		270	44.323445		270	45.626494		94.689
300	47.70976		300	49.248272		300	50.696104		96.288
350	55.661387		350	57.456317		350	59.145455		97.011
400	63.613013		400	65.664363		400	67.594806		98.34
450	71.56464		450	73.872408		450	76.044156		99.071
500	79.516267		500	82.080453		500	84.493507		99.071
600	95.41952		600	98.496544		600	101.39221		100

References

1. Calculating Realistic PM10 Emissions from Cooling Towers, Abstract No. 216 Session No. AS-1b, J. Reisman and G. Frisbie, Greyston Environmental Consultants, Inc.
2. Cooling Tower Particulate Matter and Drift Rate Emissions Testing Using the Cooling Technology Institute Test Code – CTI ATC-140, August 2003 EPRI Cooling Tower Technology Conference, K. Hennnon, P.E., D. Wheeler, P.E., Power Generation Technology.
3. Effects of Pathogenic and Toxic Materials Transported Via Cooling Device Drift, Vol. 1 Technical Report, EPA-600/7-79-251a, H.D. Freudenthal, J.E. Rubinstein, and A. Uzzo, November 1979.

ACCU-PAC® CELLULAR DRIFT ELIMINATORS

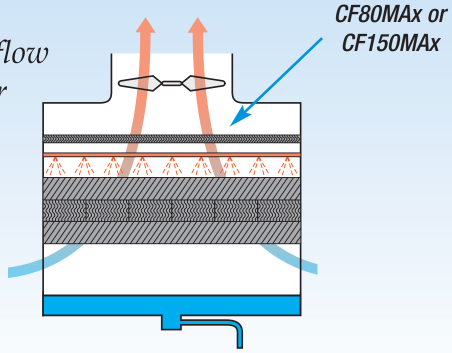




Counterflow Applications

Brentwood Counterflow Cellular Drift Eliminators are specifically-designed to achieve maximum drift removal. Unlike other drift eliminators designed for both counterflow and crossflow towers, Brentwood's counterflow eliminators have significantly lower pressure drop than dual-purpose eliminators.

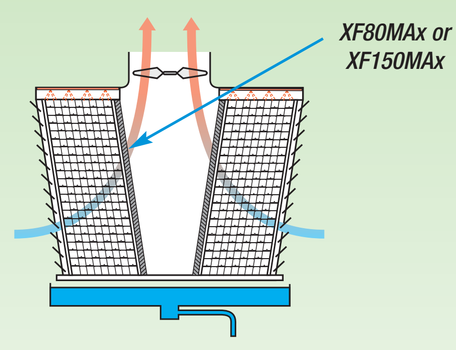
Counterflow Tower



Crossflow Applications

Brentwood Crossflow Cellular Drift Eliminators are specifically-designed to achieve maximum drift removal in crossflow applications by providing an upward flow path and a steep water drainage angle that directs the collected drift back to the wet section of the tower even when impacted by water spray.

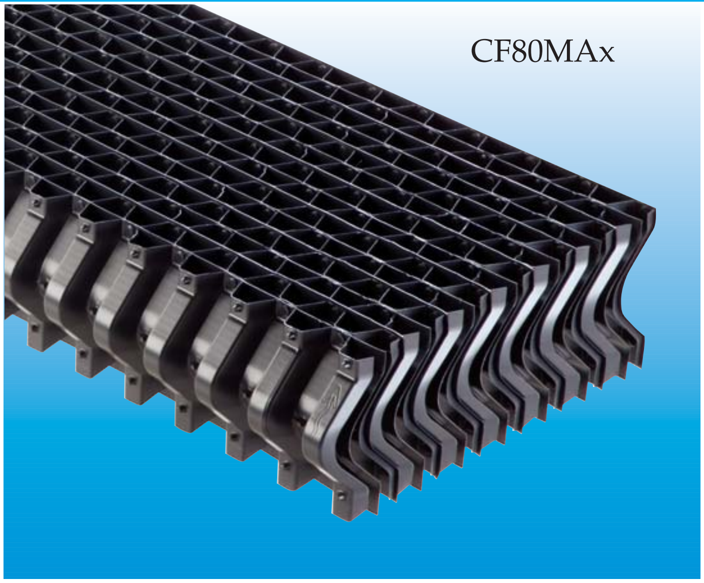
Crossflow Tower



Brentwood ACCU-PAC Cellular Drift Eliminator modules are constructed of a series of sinusoidal-shaped, corrugated, CTI STD-136, PVC sheets that are mechanically assembled to mating sinusoidal structural waves to form closed cells. These cells force the drift droplets carried in the airstream to make three distinct changes in direction. This diversion of the air flow creates centrifugal forces on the drift droplets, forcing them to be captured by inertial impaction with the cell walls and thereby removing the droplets from the airstream.

BRENTWOOD INDUSTRIES

COUNTERFLOW CELLULAR DRIFT ELIMINATORS



CF80MAx Counterflow Cellular Drift Eliminators are specifically-designed for applications requiring very low drift levels in counterflow Cooling Towers, Evaporative Cooling systems, Turbine Intake Hoods, and Scrubbers, providing the best drift removal efficiency. With field-verified drift test results of .0005% per CTI Standard 140 (the industry standard for testing of cooling tower drift), there is no need to use double layers of drift eliminators to achieve high drift-reduction efficiency.

FEATURES & BENEFITS

• Beveled Drainage Tip design (right) reduces pressure drop by up to 25% (based on air velocity of 800 fpm [4.1 m/s]) over non-beveled designs.

Beveled Drainage Tips

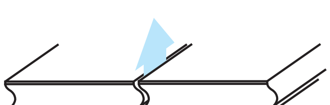
• Patented "MA" (Mechanical Assembly) Technology for environmentally-friendly glue-free packs

• Heavy duty CF80MAx modules are strong enough to span 6 ft (1.8m), requiring fewer support beams and less air blockage.

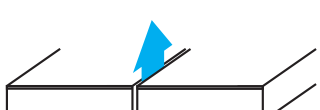
• Can be field cut for a tight fit around columns and other structures without sacrificing structural integrity. Dri-Seals are recommended for maximum performance.

• All Brentwood Cellular Drift Eliminator modules "nest" with the adjoining modules (below) to provide "seamless" panel installations.

• Raw material meets CTI Standard 136 and has a flame spread rating of 25 or less per ASTM E84.



Nested Seam



Flat Seam

CF150MAx Counterflow Cellular Drift Eliminators, are cost-effective, high-efficiency cellular drift eliminators designed specifically for counterflow Cooling Towers and Evaporative Cooling systems. With over 10 million square feet installed worldwide, the 150-series has been our most popular drift eliminator.

FEATURES & BENEFITS

• Engineered flute design provides high performance at a cost-effective price.

• Patented "MA" (Mechanical Assembly) Technology for environmentally-friendly glue-free packs

• Heavy duty CF150MAx modules are strong enough to span 6 ft (1.8m), requiring fewer support beams and less air blockage.

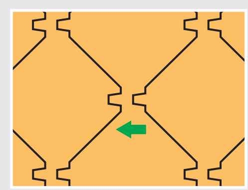
• Can be field cut for a tight fit around columns and other structures without sacrificing structural integrity.

• All Brentwood Cellular Drift Eliminator modules "nest" with the adjoining modules (below left) to provide "seamless" panel installations.

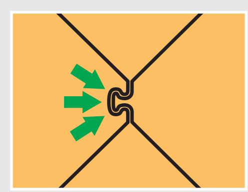
• Raw material meets CTI Standard 136 and has a flame spread rating of 25 or less per ASTM E84.

"MA" Technology

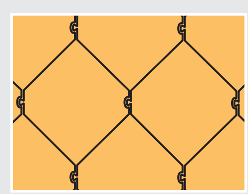
PAT. NOS. 6,544,628 and 6,640,427
U.S. AND INT'L PATENTS



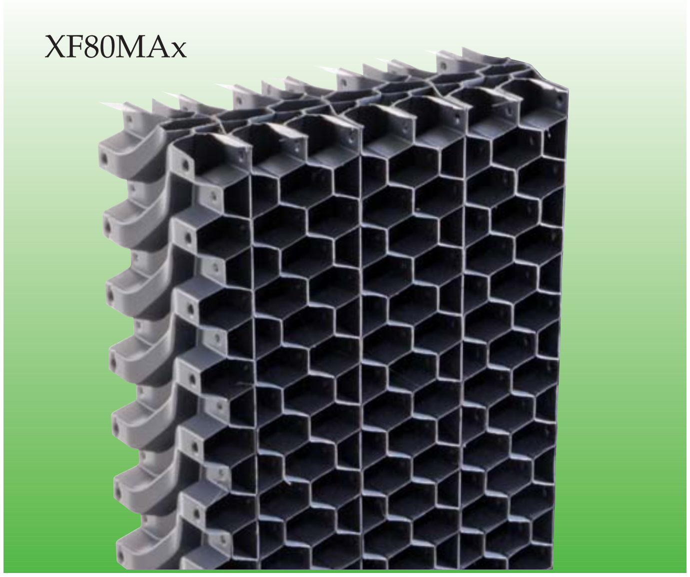
Male/Female attachment tabs align with and nest into the adjoining sheet's tabs.



Attachment tabs are pressure-sealed ...



... creating a strong, permanent bond without glue, solvents, or adhesives!



XF80MAx Crossflow Cellular Drift Eliminators provide the best available drift removal efficiency on the market today. The upward flow path, steep water drainage angle, and "tuned venturi section" make this the ideal product for factory-built crossflow towers.

FEATURES & BENEFITS

Tuned Venturi Section

• The upward flow path and steep water drainage angle maximizes the drift removal for crossflow applications, making it fully-effective even when installed vertically.

• The engineered venturi design (right) increases the velocity of the exit airflow to "scrub out" smaller droplets.

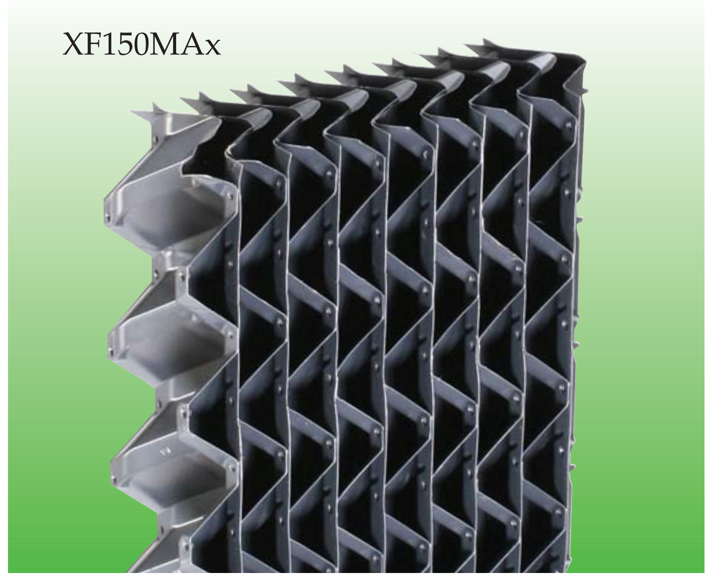
• The .86" (21.8 mm) flute spacing effectively removes drift (at the lowest pressure drop) in crossflow towers with high air velocities up to 800 fpm (4.0 m/s).

• Patented "MA" (Mechanical Assembly) Technology for environmentally-friendly, glue-free packs

• Can be field cut for a tight fit around columns and other structures without sacrificing structural integrity.

• All Brentwood Cellular Drift Eliminator modules "nest" with the adjoining modules (far left) to provide "seamless" panel installations.

• Raw material meets CTI Standard 136 and has a flame spread rating of 25 or less per ASTM E84.



XF150MAx Crossflow Cellular Drift Eliminators are specifically-designed to achieve maximum drift removal efficiency in Crossflow Cooling Towers by providing an upward flow path and discharge angle of 40-55° from horizontal (depending on installation angle) and molded-in drainage channels that direct the collected drift back to the wet section of the tower even when impacted by water spray.

FEATURES & BENEFITS

• The upward flow path and discharge angle of 40-55° increases fan efficiency by reducing pressure drop.

• Installed at the standard 10° from vertical (as shown at left on Brentwood XF-600 Supports), XF150MAx modules are strong enough to span 10 ft. (3.0 m), requiring fewer support beams and less air blockage.

XF150Max shown on Brentwood XF600 Supports

• Patented "MA" (Mechanical Assembly) Technology for environmentally-friendly, glue-free packs

• Can be field cut for a tight fit around columns and other structures without sacrificing structural integrity.

• High surface area (flute height of 1.50" [38mm]) provides high performance at a cost-effective price.

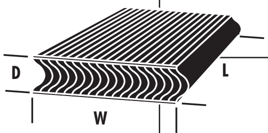
• All Brentwood Cellular Drift Eliminator modules "nest" with the adjoining modules (far left) to provide "seamless" panel installations.

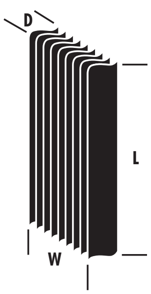
• Raw material meets CTI Standard 136 and has a flame spread rating of 25 or less per ASTM E84.

BRENTWOOD INDUSTRIES

ACCU-PAC® CELLULAR DRIFT ELIMINATORS

PRODUCT NUMBER	CELL SIZE	MODULE DIMENSIONS inches (mm) DEPTH (D)	WIDTH (W)	STANDARD LENGTHS (L)	SHEET THICKNESS*	DRY WEIGHT	MAX. SPAN**	DRIFT LOSS
COUNTERFLOW								
CF80MAx	.86 in (21.8 mm)	5.25 in (133 mm)	12 in (305 mm) or 18 in (457 mm)	2 to 12 ft. (610 to 3658 mm) in 1 ft. (305 mm) increments up to 6 ft. (1829 mm) and in 2 ft. (610 mm) increments over 6 ft. (1829 mm)	.013 in (.33 mm) Standard	1.6 lbs/ft² (7.8 kg/m²)	4 ft (1.2 m)	.0005%
					.020 in (.51 mm) Heavy Duty	2.2 lbs/ft² (10.7 kg/m²)	6 ft (1.8 m)	
CF150MAx	1.500 in (38.1 mm)	5.25 in (133 mm)	12 in (305 mm) or 18 in (457 mm)	2 to 12 ft. (610 to 3658 mm) in 1 ft. (305 mm) increments up to 6 ft. (1829 mm) and in 2 ft. (610 mm) increments over 6 ft. (1829 mm)	.015 in (.38 mm) Standard	1.0 lbs/ft² (4.9 kg/m²)	4 ft (1.2 m)	.001%
					.020 in (.51 mm) Heavy Duty	1.4 lbs/ft² (6.8 kg/m²)	6 ft (1.8 m)	
CROSSFLOW								
XF80MAx	.86 in (21.8 mm)	5.25 in (133 mm)	24 in (610 mm)	2 to 12 ft. (610 to 3658 mm) in 1 ft. (305 mm) increments up to 6 ft. (1829 mm) and in 2 ft. (610 mm) increments over 6 ft. (1829 mm)	.013 in (.33 mm) Standard	1.1 lbs/ft² (5.4 kg/m²)	8 ft (2.4 m)	TBD†
					.020 in (.51 mm) Heavy Duty	1.5 lbs/ft² (7.3 kg/m²)	10 ft (3.0 m)	
XF150MAx	1.500 in (38.1 mm)	5.25 in (133 mm)	12 in (305 mm) or 18 in (457 mm)	2 to 12 ft. (610 to 3658 mm) in 1 ft. (305 mm) increments up to 6 ft. (1829 mm) and in 2 ft. (610 mm) increments over 6 ft. (1829 mm)	.015 in (.38 mm) Standard	1.0 lbs/ft² (4.9 kg/m²)	8 ft (2.4 m)	.001%
					.020 in (.51 mm) Heavy Duty	1.4 lbs/ft² (6.8 kg/m²)	10 ft (3.0 m)	





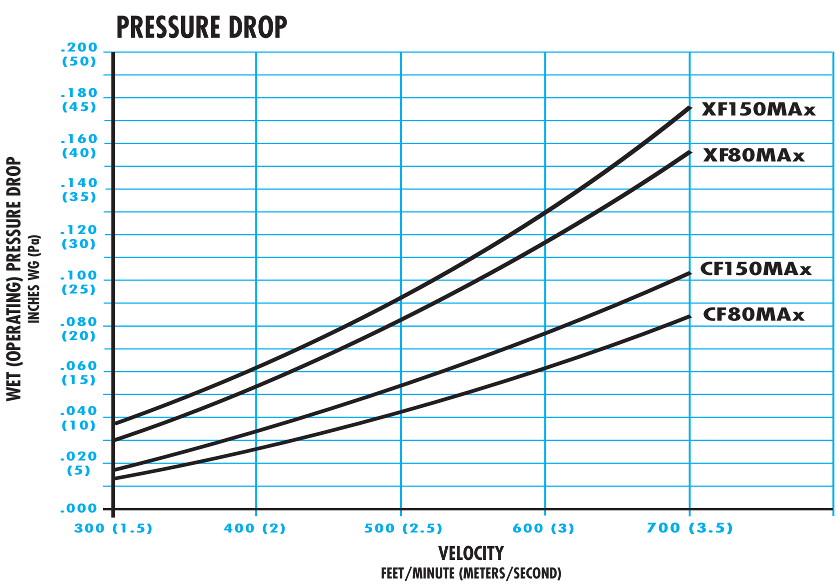
* Nominal sheet thickness after forming

** Counterflow: Tested at a maximum air temperature of 115°F (46°C) with 2 inch (51 mm) wide supports. Crossflow: Tested at a maximum air temperature of 115°F (46°C) installed at a 10° maximum angle.

† Drift loss value to be determined.

MATERIALS

All Brentwood Cellular Drift Eliminators are made from PVC material that meets CTI (Cooling Technology Institute) Standard 136 and are UV protected. These PVC compounds have outstanding resistance to weather exposure, and are nearly impervious to chemical degradation by alkalis and acids, grease, fats, oils, and biological attack. PVC has an excellent fire rating due to its self-extinguishing characteristics.



BRENTWOOD INDUSTRIES

Brentwood Industries, Inc., P.O. Box 605, 610 Morgantown Road, Reading, PA 19603, USA, *Phone* 1-610-236-1100, *Fax* 1-610-236-1199, *Email* ctsales@brentw.com

Brentwood Asia, Ltd., A3 Floor, Le Concorde Tower, 202 Rajchadapisek Road, Huaykwang, Bangkok 10310, Thailand, *Phone* 662-694-1060-2, *Fax* 662-694-1063, *Email* asiasales@brentw.com

Brentwood Europe, Pod Kastany 5, 160 00 Prague 6, Czech Republic, *Phone/Fax* +420 233 324 253, *Email* europesales@brentw.com

www.brentw.com

Wildcat Measurement Service
P.O.Box 1836
416 East Main Street
Artesia, NM 88211-1836

2/26/2015 12:28 PM
Phone: 575-746-3481
888-421-9453
Fax: 575-748-9852
dnorman@wildcatms.com

GAS ANALYSIS REPORT

Analysis For:	OXY USA, INC.	Run No:	2150221-05
Field Name:	INDIAN BASIN GAS PLANT	Date Run:	02/21/2015
Well Name:	INLET COMPRESSOR DISCHARGE	Date Sampled:	02/20/2015
Station Number:	C31305M	Producer:	OXY USA, INC.
Purpose:	MONTHLY	County:	EDDY
Sample Deg. F:	84.5	State:	NM
Volume/Day:	110105.0 MCF/DAY	Sampled By:	CHANDLER MONTGOMERY
Formation:		Atmos Deg. F:	77
Line PSIG:	969.8		
Line PSIA:	983.0		

GAS COMPONENTS

Component		MOL%	GPM
Oxygen	O_2:	0.0000	
Carbon Dioxide	$C0_2$:	0.4875	
Nitrogen	N_2:	2.3713	
Hydrogen Sulfide	H_2S:	0.1500	
Methane	C1:	81.9885	
Ethane	C2:	8.4920	2.3160
Propane	C3:	3.8789	1.0897
Iso-Butane	IC4:	0.5184	0.1730
Nor-Butane	NC4:	1.1299	0.3633
Iso-Pentane	IC5:	0.2705	0.1009
Nor-Pentanes	NC5:	0.2742	0.1013
Hexanes Plus	C6+:	0.4388	0.1946
Totals		100.0000	4.3388

Pressure Base:	15.025
Real BTU Dry:	1205.041
Real BTU Wet:	1184.414
Calc. Ideal Gravity:	0.6942
Calc. Real Gravity:	0.6961
Field Gravity:	
Standard Pressure:	14.696
Ideal BTU Dry:	1174.960
Ideal BTU Wet:	1154.516
Z Factor:	0.9969
Average Mol Weight:	20.1068
Average CuFt/Gal:	56.4092
26 lb. Product:	0.5945
Ethane+ GPM:	4.3388
Propane+ GPM:	2.0228
Butane+ GPM:	0.9331
Pentane+ GPM:	0.3968

Remarks:
H2S IN GAS STREAM ON LOCATION: 0.1500% = 1,500 PPM

Analysis By: Don Norman

Wildcat Measurement Service
P.O.Box 1836
416 East Main Street
Artesia, NM 88211-1836

2/26/2015 12:28 PM
Phone: 575-746-3481
888-421-9453
Fax: 575-748-9852
dnorman@wildcatms.com

GAS ANALYSIS REPORT

Analysis For:	OXY USA, INC.	Run No:	2150221-06
Field Name:	INDIAN BASIN GAS PLANT	Date Run:	02/21/2015
Well Name:	SALES GAS	Date Sampled:	02/20/2015
Station Number:	C31311M	Producer:	OXY USA, INC.
Purpose:	MONTHLY	County:	EDDY
Sample Deg. F:	93.1	State:	NM
Volume/Day:	88718.0 MCF/DAY	Sampled By:	CHANDLER MONTGOMERY
Formation:		Atmos Deg. F:	73
Line PSIG:	969.8		
Line PSIA:	983.0		

GAS COMPONENTS

		MOL%	GPM
Oxygen	O_2:	0.0000	
Carbon Dioxide	$C0_2$:	0.0000	
Nitrogen	N_2:	3.6930	
Hydrogen Sulfide	H_2S:	0.0000	
Methane	C1:	92.9331	
Ethane	C2:	3.2351	0.8823
Propane	C3:	0.1288	0.0362
Iso-Butane	IC4:	0.0044	0.0015
Nor-Butane	NC4:	0.0056	0.0018
Iso-Pentane	IC5:	0.0000	0.0000
Nor-Pentanes	NC5:	0.0000	0.0000
Hexanes Plus	C6+:	0.0000	0.0000
Totals		100.0000	0.9217

Pressure Base:	15.025
Real BTU Dry:	1023.912
Real BTU Wet:	1006.386
Calc. Ideal Gravity:	0.5862
Calc. Real Gravity:	0.5872
Field Gravity:	
Standard Pressure:	14.696
Ideal BTU Dry:	999.443
Ideal BTU Wet:	982.052
Z Factor:	0.9980
Average Mol Weight:	16.9787
Average CuFt/Gal:	59.5869
26 lb. Product:	0.0000
Ethane+ GPM:	0.9217
Propane+ GPM:	0.0395
Butane+ GPM:	0.0033
Pentane+ GPM:	0.0000

Remarks:
H2S IN GAS STREAM ON LOCATION: NONE DETECTED

Analysis By: Don Norman

Condensate Analysis

MOBILE ANALYTICAL LABS, INC.

P.O. BOX 69210
ODESSA, TEXAS 79769

LIQUID EXTENDED ANALYSIS

02/09/10 LAB # 5147

OCCIDENTAL PERMIAN
INDIAN BASIN PLANT
LIQUID OUT OF STABILIZER
325 °F

	MOL %	VOL %	WT %
METHANE	0.0000	0.0000	0.0000
CARBON DIOXIDE	0.0000	0.0000	0.0000
ETHANE	0.0033	0.0022	0.0011
PROPANE	0.0065	0.0044	0.0032
ISO-BUTANE	0.0012	0.0010	0.0008
N-BUTANE	0.0043	0.0034	0.0028
ISO-PENTANE	4.6211	4.2060	3.7298
N-PENTANE	11.6188	10.4819	9.3779
NEOHEXANE	0.9510	0.9884	0.9168
CYCLOPENTANE	2.4474	2.2924	2.1394
2-METHYLPENTANE	8.6912	8.9782	8.3789
3-METHYLPENTANE	5.6577	5.7476	5.4544
N-HEXANE	14.2496	14.5819	13.7359
METHYLCYCLOPENTANE	6.4222	5.6571	6.0466
BENZENE	3.2443	2.2596	2.8351
CYCLOHEXANE	7.5633	6.4071	7.1209
2-METHYLHEXANE	3.5469	4.1030	3.9758
3-METHYLHEXANE	3.1132	3.5566	3.4897
DIMETHYLCYCLOPENTANES	3.5684	3.7124	3.9196
N-HEPTANE	4.5231	5.1934	5.0702
METHYLCYCLOHEXANE	7.0349	7.0380	7.7273
TRIMETHYLCYCLOPENTANES	0.8579	0.9952	1.0770
TOLUENE	2.7054	2.2548	2.7887
2-METHYLHEPTANE	1.8371	2.3568	2.3476
3-METHYLHEPTANE	0.7793	0.9886	0.9958
DIMETHYLCYCLOHEXANES	1.6646	1.8829	2.0897
N-OCTANE	1.1094	1.4145	1.4177
ETHYL BENZENE	0.1287	0.1237	0.1529
M&P-XYLENES	0.8831	0.8469	1.0489
O-XYLENE	0.1377	0.1320	0.1635
C9 NAPHTHENES	0.5303	0.6714	0.7489
C9 PARAFFINS	1.2323	1.7177	1.7682
N-NONANE	0.2276	0.3187	0.3265
N-DECANE	0.0461	0.0703	0.0733
UNDECANE PLUS	0.5921	1.0119	1.0751
TOTALS	100.0000	100.0000	100.0000

SPECIFIC GRAVITY	0.705
SP.GR. C6+	0.718
SP.GR. C7+	0.739
TOTAL MOL. WT.	89.391
MOL. WT. C6+	92.742
MOL. WT. C7+	104.251
TOTAL CU.FT./GAL	25.031
CU.FT./GAL C6+	24.571
POUNDS/GALLON	5.878
POUNDS/GALLON C5+	5.878
VAPOR PRESSURE (psia)	5.837

NOTES:
SAMPLED 02/01/10 BY: SR
SPOT
CYLINDER NO. 3983

DISTRIBUTION:
MR. CLINT KIRKES

NOTE: CU.FT./GAL @ 14.65 PSIA

7-17-14_9:55AM

[Tabulated for Input to E&P Tanks]

For calcuation tables

HAPS	wt %	wt fraction
n-Hexane	13.7359	0.137359
2,2,4 TMP	-	-
Benzene	2.8351	0.028351
Toluene	2.7887	0.027887
Ethylbenzene	0.1529	0.001529
Xylene	1.2124	0.012124

Condensate Anaysis
Mobile Analytical Labs, 2/9/2010 Lab# 5147

	mol%	wt%			
METHANE	0	0			
CARBON DIOXIDE	0	0			
ETHANE	0.0033	0.0011			
PROPANE	0.0065	0.0032			
ISO-BUTANE	0.0012	0.0008			
N-BUTANE	0.0043	0.0028			
ISO-PENTANE	4.6211	3.7298			
N-PENTANE	11.6188	9.3779	*		
NEOHEXANE	0.951	0.9168	C6		
CYCLOPENTANE	2.4474	2.1394	C-5 - *Total incl. n-pentane =	14.0662	Pentane total
2-METHYLPENTANE	8.6912	8.3789	C6		
3-METHYLPENTANE	5.6577	5.4544	C6		
N-HEXANE	**14.2496**	**13.7359**			
METHYLCYCLOPENTANE	6.4222	6.0466	C6		
BENZENE	**3.2443**	**2.8351**			
CYCLOHEXANE	7.5633	7.1209	C6	29.2854	C6 Total
2-METHYLHEXANE	3.5469	3.9758	C7		
3-METHYLHEXANE	3.1132	3.4897	C7		
DIMETHYLCYCLOPENTANES	3.5684	3.9196	C7		
N-HEPTANE	4.5231	5.0702	C7	14.7516	C7 Total
METHYLCYCLOHEXANE	7.0349	7.7273	C8		
TRIMETHYLCYCLOPENTANES	0.8579	1.077	C8		
TOLUENE	**2.7054**	**2.7887**			
2-METHYLHEPTANE	1.8371	2.3476	C8		
3-METHYLHEPTANE	0.7793	0.9958	C8		
DIMETHYLCYCLOHEXANES	1.6646	2.0897	C8		
N-OCTANE	1.1094	1.4177	C8	13.2832	C8 Total
ETHYL BENZENE	**0.1287**	**0.1529**			
M&P-XYLENES	**0.8831**	**1.0489**			
O-XYLENE	**0.1377**	**0.1635**	**1.2124**		
C9 NAPHTHENES	0.5303	0.7489	C-9		
C9 PARAFFINS	1.2323	1.7682	C-9		
N-NONANE	0.2276	0.3265	C-9	1.9902	C9 Total
N-DECANE	0.0461	0.0733	C-10+		
UNDECANE PLUS	0.5921	1.0751	C10+	0.6382	C10+
	100.00	**100.00**			

59.95
40.05 listed sep.
100.00 Total

Ref: Mobile Analytical Labs, Inc. 2/9/2010, Liquid out of stabilizer

MOBILE ANALYTICAL LABS, INC.

P.O. BOX 69210
ODESSA, TEXAS 79769

LIQUID EXTENDED ANALYSIS

02/09/10 **LAB # 5148**

OCCIDENTAL PERMIAN
INDIAN BASIN PLANT
STABILIZER REFLUX

	MOL %	VOL %	WT %
METHANE	0.0784	0.0385	0.0190
CARBON DIOXIDE	0.0044	0.0022	0.0029
ETHANE	0.3872	0.3004	0.1759
PROPANE	3.9421	3.1509	2.6262
ISO-BUTANE	6.6434	6.3072	5.8336
N-BUTANE	27.8433	25.4675	24.4495
ISO-PENTANE	36.6203	38.8541	39.9150
N-PENTANE	23.0122	24.2016	25.0839
NEOHEXANE	0.1787	0.2166	0.2327
CYCLOPENTANE	0.2335	0.2550	0.2757
2-METHYLPENTANE	0.4232	0.5096	0.5510
3-METHYLPENTANE	0.2141	0.2536	0.2788
N-HEXANE	0.0141	0.0168	0.0183
METHYLCYCLOPENTANE	0.1253	0.1287	0.1593
BENZENE	0.0747	0.0606	0.0881
CYCLOHEXANE	0.0860	0.0850	0.1094
2-METHYLHEXANE	0.0281	0.0379	0.0425
3-METHYLHEXANE	0.0196	0.0260	0.0296
DIMETHYLCYCLOPENTANES	0.0144	0.0175	0.0214
N-HEPTANE	0.0145	0.0194	0.0219
METHYLCYCLOHEXANE	0.0214	0.0250	0.0318
TRIMETHYLCYCLOPENTANES	0.0014	0.0018	0.0023
TOLUENE	0.0095	0.0092	0.0132
2-METHYLHEPTANE	0.0039	0.0059	0.0068
3-METHYLHEPTANE	0.0008	0.0011	0.0013
DIMETHYLCYCLOHEXANES	0.0017	0.0022	0.0028
N-OCTANE	0.0008	0.0012	0.0014
ETHYL BENZENE	0.0003	0.0003	0.0005
M&P-XYLENES	0.0005	0.0006	0.0008
O-XYLENE	0.0000	0.0000	0.0000
C9 NAPHTHENES	0.0008	0.0012	0.0016
C9 PARAFFINS	0.0011	0.0018	0.0021
N-NONANE	0.0000	0.0000	0.0000
N-DECANE	0.0000	0.0000	0.0000
UNDECANE PLUS	0.0003	0.0006	0.0007
TOTALS	100.0000	100.0000	100.0000

SPECIFIC GRAVITY	0.609
SP.GR. C6+	0.687
SP.GR. C7+	0.725
TOTAL MOL. WT.	66.192
MOL. WT. C6+	85.364
MOL. WT. C7+	100.544
TOTAL CU.FT./GAL	29.200
CU.FT./GAL C6+	25.542
POUNDS/GALLON	5.077
POUNDS/GALLON C5+	5.243
VAPOR PRESSURE (psia)	44.862

used for vapor mw. (tank calcs)

NOTES:
SAMPLED 02/01/10 BY: SR
SPOT
CYLINDER NO. 5060

DISTRIBUTION:
MR. CLINT KIRKES

NOTE: CU.FT./GAL @ 14.65 PSIA

E&P Tanks Run*

```
*******************************************************************************
*     Project Setup Information                                               *
*******************************************************************************
Project File               : D:\Share\Clients Projects\ACTVE_CLIENT_PROJECTS\OXY_USA\IBGP-NSR-PermRev-Slu(
Flowsheet Selection        : Oil Tank with Separator
Calculation Method         : AP42
Control Efficiency         : 98.0%
Known Separator Stream     : Low Pressure Oil
Entering Air Composition   : No

Filed Name                 : IBGP Cond Tanks - Normal Operations, Vapors Collected  & Sent to Flare 98% DI
Date                       : 2014.07.17


*******************************************************************************
*     Data Input                                                              *
*******************************************************************************

Separator Pressure         : 40.00[psig]
Separator Temperature      : 325.00[F]
Ambient Pressure           : 14.70[psia]
Ambient Temperature        : 80.00[F]
C10+ SG                    : 0.8990
C10+ MW                    : 166.00

-- Low Pressure Oil -----------------------------------------------------------
   No.    Component             mol %
   1      H2S                   0.0000
   2      O2                    0.0000
   3      CO2                   0.0000
   4      N2                    0.0000
   5      C1                    0.0000
   6      C2                    0.0033
   7      C3                    0.0065
   8      i-C4                  0.0012
   9      n-C4                  0.0043
   10     i-C5                  4.6211
   11     n-C5                 14.0662
   12     C6                   29.2854
   13     C7                   14.7516
   14     C8                   13.2832
   15     C9                    1.9902
   16     C10+                  0.6382
   17     Benzene               3.2443
   18     Toluene               2.7054
   19     E-Benzene             0.1287
   20     Xylenes               1.0208
   21     n-C6                 14.2496
   22     224Trimethylp         0.0000

-- Sales Oil ------------------------------------------------------------------
Production Rate            : 234[bbl/day]
Days of Annual Operation   : 365 [days/year]
API Gravity                : 69.2
Reid Vapor Pressure        : 10.67[psia]
Bulk Temperature           : 80.00[F]

-- Tank and Shell Data --------------------------------------------------------
Diameter                   : 24.00[ft]
Shell Height               : 12.00[ft]
Cone Roof Slope            : 0.06
Average Liquid Height      : 12.00[ft]
Vent Pressure Range        : 0.06[psi]
Solar Absorbance           : 0.68

-- Meteorological Data --------------------------------------------------------
```

* shows zero flash gas, which is consistent with process data as condensate is stablized prior to being sent to storage. Vapors from stabilization are recycled.

Vosquez Beggs equations were used to calculate flashing losses to be conservative and consistent with previous permit app. representations.

City	: Roswell, NM
Ambient Pressure	: 14.70[psia]
Ambient Temperature	: 80.00[F]
Min Ambient Temperature	: 47.50[F]
Max Ambient Temperature	: 75.30[F]
Total Solar Insolation	: 1810.00[Btu/ft^2*day]

****
*   Calculation Results   *
****

-- Emission Summary --

Item	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]	Controlled [ton/yr]	Controlled [lb/hr]
Total HAPs	1.470	0.336	0.029	0.007
Total HC	8.842	2.019	0.177	0.040
VOCs, C2+	8.842	2.019	0.177	0.040
VOCs, C3+	8.842	2.019	0.177	0.040

Uncontrolled Recovery Info.

Vapor	229.2700 x1E-3	[MSCFD]
HC Vapor	229.2700 x1E-3	[MSCFD]
GOR	0.98	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]	Controlled [ton/yr]	Controlled [lb/hr]
1	H2S	0.000	0.000	0.000	0.000
2	O2	0.000	0.000	0.000	0.000
3	CO2	0.000	0.000	0.000	0.000
4	N2	0.000	0.000	0.000	0.000
5	C1	0.000	0.000	0.000	0.000
6	C2	0.001	0.000	0.000	0.000
7	C3	0.002	0.000	0.000	0.000
8	i-C4	0.000	0.000	0.000	0.000
9	n-C4	0.001	0.000	0.000	0.000
10	i-C5	1.035	0.236	0.021	0.005
11	n-C5	2.559	0.584	0.051	0.012
12	C6	2.909	0.664	0.058	0.013
13	C7	0.632	0.144	0.013	0.003
14	C8	0.219	0.050	0.004	0.001
15	C9	0.013	0.003	0.000	0.000
16	C10+	0.000	0.000	0.000	0.000
17	Benzene	0.219	0.050	0.004	0.001
18	Toluene	0.067	0.015	0.001	0.000
19	E-Benzene	0.001	0.000	0.000	0.000
20	Xylenes	0.009	0.002	0.000	0.000
21	n-C6	1.173	0.268	0.023	0.005
22	224Trimethylp	0.000	0.000	0.000	0.000
	Total	8.840	2.018	0.177	0.040

Zero Flash Gas

-- Stream Data ---

No.	Component	MW	LP Oil mol %	Flash Oil mol %	Sale Oil mol %	Flash Gas mol %	W&S Gas mol %	Total Emissions mol %
1	H2S	34.80	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
2	O2	32.00	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
3	CO2	44.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
4	N2	28.01	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
5	C1	16.04	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
6	C2	30.07	0.0033	0.0033	0.0033	0.0000	0.0259	0.0259
7	C3	44.10	0.0065	0.0065	0.0065	0.0000	0.0445	0.0445
8	i-C4	58.12	0.0012	0.0012	0.0012	0.0000	0.0065	0.0065
9	n-C4	58.12	0.0043	0.0043	0.0043	0.0000	0.0201	0.0201
10	i-C5	72.15	4.6211	4.6211	4.6132	0.0000	12.9981	12.9981
11	n-C5	72.15	14.0662	14.0662	14.0491	0.0000	32.1315	32.1315
12	C6	86.16	29.2854	29.2854	29.2834	0.0000	31.3721	31.3721
13	C7	100.20	14.7516	14.7516	14.7600	0.0000	5.9025	5.9025

14	C8	114.23	13.2832	13.2832	13.2941	0.0000	1.7853	1.7853
15	C9	128.28	1.9902	1.9902	1.9920	0.0000	0.0960	0.0960
16	C10+	166.00	0.6382	0.6382	0.6388	0.0000	0.0011	0.0011
17	Benzene	78.11	3.2443	3.2443	3.2450	0.0000	2.5427	2.5427
18	Toluene	92.13	2.7054	2.7054	2.7073	0.0000	0.6556	0.6556
19	E-Benzene	106.17	0.1287	0.1287	0.1288	0.0000	0.0107	0.0107
20	Xylenes	106.17	1.0208	1.0208	1.0217	0.0000	0.0744	0.0744
21	n-C6	86.18	14.2496	14.2496	14.2514	0.0000	12.3330	12.3330
22	224Trimethylp	114.24	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
	MW		89.18	89.18	89.18	0.00	80.09	80.09
	Stream Mole Ratio		1.0000	1.0000	0.9991	0.0000	0.0009	0.0009
	Heating Value	[BTU/SCF]				0.00	4379.88	4379.88
	Gas Gravity	[Gas/Air]				0.00	2.76	2.76
	Bubble Pt. @ 100F	[psia]	6.23	6.23	6.23			
	RVP @ 100F	[psia]	42.60	42.60	42.57			
	Spec. Gravity @ 100F		0.663	0.663	0.663			

Vasquez-Beggs

The Vasquez-Beggs and RMC methods differ from one another only in the technique used to calculate the gas-to-oil ratio. The Vasquez-Beggs equation may be expressed as follows:

$$GOR = C_1 \times CSG \times UP^{C_2} \times \exp\left(\frac{C_3 \times APIG}{T+460}\right) \tag{18}$$

where:

GOR = Gas-to-oil ratio (scf/bbl)
C_1, C_2, and C_3 = Correlation coefficients
CSG = Corrected specific gravity of the gas (for pure air, CSG = 1.0)
UP = Separator pressure (psia)
APIG = API gravity of the oil (°API)
T = Separator fluid temperature (°F)

The RMC equation may be expressed as follows:

$$GOR = \log^{-1}\left[0.4896 - 4.916 \times \log_{10}(ST) + 3.469 \times \log_{10}(SG) + 1.501 \times \log_{10}(UP) - 0.9213 \times \log_{10}(T)\right] \tag{19}$$

where:

GOR = Gas-to-oil ratio (scf/bbl)
ST = Tank oil specific gravity (for pure water, ST = 1.0)
SG = Separator gas specific gravity (for pure air, SG = 1.0)
UP = Separator pressure (psia)
T = Separator temperature (°F)

In order to calculate flashing losses, critical input fields include the following:

Q Annual stock throughput (bbl/yr)
SG Specific gravity of gas in the separator (dimensionless; for pure air, SG = 1.0)

UVP	Upstream vessel pressure (psig)
APIG	API gravity of the product (°API)
T	Fluid temperature in the upstream vessel (°F)
E	Estimated effectiveness of control strategies or devices (percent)

References

American Petroleum Institute (1991) *Evaporative loss from fixed roof tanks*. Chapter 19.1. [Bulletin 2518] American Petroleum Institute, Washington, D.C.

DB Robinson Research Ltd. (1997) *Production tanks emission model (E&P TANK Version 1.0): a program for estimating emissions from hydrocarbon production tanks*. In preparation for the American Petroleum Institute and the Gas Research Insitute. API Publication Number 4660. Washington, D.C.

Radian Corp. (1992) SPECIATE, version 1.50. Prepared for Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC by Radian Corp., Austin, TX, October.

Rollins J.B., McCain Jr. W.D., and Creeger J.T. (1990) Estimation of solution GOR of black oils. *Journal of Petroleum Technology*, January, 92-94.

U.S. Environmental Protection Agency (1996d) Compilation of air pollutant emission factors. Vol. 1: stationary point and area emission units. Section 7, AP-42, 5th ed. (January 1996); Supplements A and B (November 1996). Report prepared by Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Vasquez M. and Beggs D.H. (1980) Correlations for fluid physical property prediction. *Journal of Petroleum Technology*, June.

The SPECIATE database was derived from:

U.S. Environmental Protection Agency (1990) Air emission species manual. Vol. 1: volatile organic compound species profiles. 2nd ed. Report prepared by U.S. Environmental Protection Agency, Research Triangle Park, NC, EPA-450/2-90-001a.

Company Name:	OXY USA WTP LP	Permit	N/A
Facility Name:	Indian Basin Gas Plant	Date:	18-Aug-14

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	69.2	API
Separator Pressure (psig)	40	P
Separator Temperature (°F)	325	Ti
Separator Gas Gravity at Initail Condition	0.7	SGi
Stock Tank Barrels of Oil per day (BOPD)	250.700	Q
Stock Tank Gas Molecular Weight	66.19	MW
Fraction VOC (C3+) of Stock Tank Gas	1.0	VOC
Atmospheric Pressure (psia)	14.7	Patm

CONSTRAINTS:

16	>API>	58	°API	WARNING ..
50	>P+Patm>	5250	(psia)	WARNING ..
70	> Ti >	295	(°F)	WARNING ..
0.56	>SGi>	1.18	(MW/28.97)	ok
None	> Q >	None	(BOPD)	ok
18	>MW>	125	(lb/lb-mole)	ok
0.5	>Voc>	1.00	Fraction	ok
20	> Rs >	2070	(scf/STB)	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Oil/Condensate Tank (ES-46)

SSM scenario

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	**< 30**	**>= 30**	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	**6.80**	**scf/bbl**	***for P + Patm =***	***54.7***

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	**53.48**	**TPY**

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	**52.94**	**TPY**	***from "FLASHING" of oil from separator to tank press***

2.65 tpy SSM Scenario /5% VCS-COND Downtime [Normally Controlled with VCS-COND and Flare 98% D.E.]

Company Name: **OXY USA WTP LP**
Facility Name: **Indian Basin Gas Plant**

Permit **N/A**
Date: **18-Aug-14**

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	69.2	**API**
Separator Pressure (psig)	40	**P**
Separator Temperature (°F)	325	**Ti**
Separator Gas Gravity at Initail Condition	0.7	**SGi**
Stock Tank Barrels of Oil per day (BOPD)	93.200	**Q**
Stock Tank Gas Molecular Weight	66.19	**MW**
Fraction VOC (C3+) of Stock Tank Gas	1.0	**VOC**
Atmospheric Pressure (psia)	14.7	**Patm**

CONSTRAINTS:

16	**>API>**	**58**	**°API**	WARNING .
50	**>P+Patm>**	**5250**	**(psia)**	WARNING ..
70	**> Ti >**	**295**	**(°F)**	WARNING ..
0.56	**>SGi>**	**1.18**	**(MW/28.97)**	ok
None	**> Q >**	**None**	**(BOPD)**	ok
18	**>MW>**	**125**	**(lb/lb-mole)**	ok
0.5	**>Voc>**	**1.00**	**Fraction**	ok
20	**> Rs >**	**2070**	**(scf/STB)**	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Oil/Condensate Tank (ES-47)

SSM scenario

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	**< 30**	**>= 30**	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	**6.80**	**scf/bbl**	***for P + Patm =***	***54.7***

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	**19.88**	**TPY**

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	**19.68**	**TPY**	***from "FLASHING" of oil from separator to tank press***

0.98 tpy SSM Scenario /5% VCS-COND Downtime [Normally Controlled with VCS-COND and Flare 98% D.E.]

Company Name:	**OXY USA WTP LP**	Permit	**N/A**
Facility Name:	**Indian Basin Gas Plant**	Date:	**18-Aug-14**

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	69.2	**API**
Separator Pressure (psig)	40	**P**
Separator Temperature (°F)	325	**Ti**
Separator Gas Gravity at Initail Condition	0.7	**SGi**
Stock Tank Barrels of Oil per day (BOPD)	139.700	**Q**
Stock Tank Gas Molecular Weight	66.19	**MW**
Fraction VOC (C3+) of Stock Tank Gas	1.0	**VOC**
Atmospheric Pressure (psia)	14.7	**Patm**

CONSTRAINTS:

16	**>API>**	**58**	°API	WARNING ..
50	**>P+Patm>**	**5250**	**(psia)**	WARNING ..
70	**> Ti >**	**295**	**(°F)**	WARNING ..
0.56	**>SGi>**	**1.18**	**(MW/28.97)**	ok
None	**> Q >**	**None**	**(BOPD)**	ok
18	**>MW>**	**125**	**(lb/lb-mole)**	ok
0.5	**>Voc>**	**1.00**	**Fraction**	ok
20	**> Rs >**	**2070**	**(scf/STB)**	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	**6.80**	**scf/bbl**

for P + Patm = *54.7*

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Oil/Condensate Tank (ES-48)

SSM scenario

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	**29.80**	**TPY**

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	**29.50**	**TPY**

from "FLASHING" of oil from separator to tank press

1.48 tpy SSM Scenario /5% VCS-COND Downtime [Normally Controlled with VCS-COND and Flare 98% D.E.]

Company Name:	OXY USA WTP LP	Permit	N/A
Facility Name:	Indian Basin Gas Plant	Date:	18-Aug-14

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	69.2	API
Separator Pressure (psig)	40	P
Separator Temperature (°F)	325	Ti
Separator Gas Gravity at Initail Condition	0.7	SGi
Stock Tank Barrels of Oil per day (BOPD)	14.500	Q
Stock Tank Gas Molecular Weight	66.19	MW
Fraction VOC (C3+) of Stock Tank Gas	1.0	VOC
Atmospheric Pressure (psia)	14.7	Patm

CONSTRAINTS:

16	>API>	58	°API	WARNING .
50	>P+Patm>	5250	(psia)	WARNING .
70	> Ti >	295	(°F)	WARNING .
0.56	>SGi>	1.18	(MW/28.97)	ok
None	> Q >	None	(BOPD)	ok
18	>MW>	125	(lb/lb-mole)	ok
0.5	>Voc>	1.00	Fraction	ok
20	> Rs >	2070	(scf/STB)	WARNING .

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Water with 5% Oil/Condensate Tank (ES-49)

Example Calculation for Normal Operations

[Water tank is not connected to VCS-COND or ES-50 flare]

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	6.80	scf/bbl	*for P + Patm = 54.7*

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	3.09	TPY

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	3.06	TPY	*from "FLASHING" of oil from separator to tank press*

0.15 tpy Normal Operations - Water with up to 5% VOC

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)

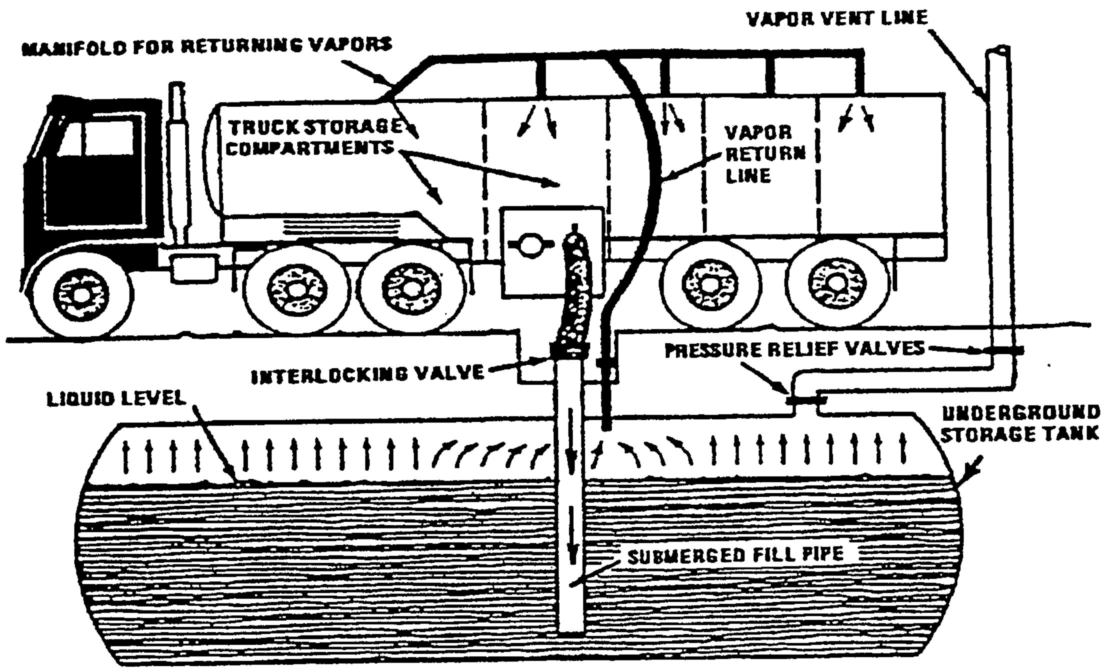


Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

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.

The saturation factor, S, represents the expelled vapor's fractional approach to saturation, and it accounts for the variations observed in emission rates from the different unloading and loading methods. Table 5.2-1 lists suggested saturation factors.

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in Equation 1 by an overall reduction efficiency term:

$$\left(1 - \frac{\text{eff}}{100}\right)$$

The overall reduction efficiency should account for the capture efficiency of the collection system as well as both the control efficiency and any downtime of the control device. Measures to reduce loading emissions include selection of alternate loading methods and application of vapor recovery equipment. The latter captures organic vapors displaced during loading operations and recovers the vapors by the use of refrigeration, absorption, adsorption, and/or compression. The recovered product is piped back to storage. Vapors can also be controlled through combustion in a thermal oxidation unit, with no product recovery. Figure 5.2-6 demonstrates the recovery of gasoline vapors from tank trucks during loading operations at bulk terminals. Control efficiencies for the recovery units range from 90 to over 99 percent, depending on both the nature of the vapors and the type of control equipment used.[5-6] However, not all of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water).[7] A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change) A collection efficiency of 70 percent should be assumed for trucks not passing one of these annual leak tests[6].

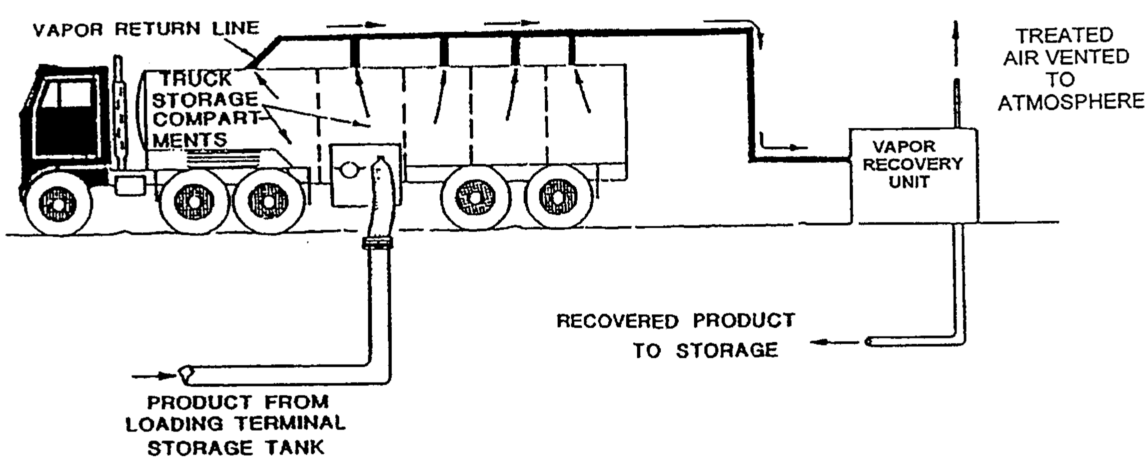


Figure 5.2-6. Tank truck loading with vapor recovery.

Sample Calculation -

Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8000 gal
Gasoline Reid vapor pressure (RVP) is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95 percent
Vapor collection efficiency is 98.7 percent (NSPS-level annual leak test)

Loading loss equation -

$$L_L = 12.46 \frac{SPM}{T} \left(1 - \frac{eff}{100}\right)$$

where:

S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of gasoline (see Figure 7.1-6) = 6.6 psia
M = molecular weight of gasoline vapors (see Table 7.1-2) = 66
T = temperature of gasoline = 540°R
eff = overall reduction efficiency (95 percent control x 98.7 percent collection) = 94 percent

$$L_L = 12.46 \frac{(1.00)(6.6)(66)}{540} \left(1 - \frac{94}{100}\right)$$

$$= 0.60 \ \text{lb}/10^3 \text{gal}$$

Total loading losses are:

$$(0.60 \ \text{lb}/10^3 \ \text{gal})(8.0 \times 10^3 \ \text{gal}) = 4.8 \ \text{pounds (lb)}$$

Measurements of gasoline loading losses from ships and barges have led to the development of emission factors for these specific loading operations.[8] These factors are presented in Table 5.2-2 and should be used instead of Equation 1 for gasoline loading operations at marine terminals. Factors are expressed in units of milligrams per liter (mg/L) and pounds per 1000 gallons (lb/10^3 gal).

TNRCC

October 2000
RG-109 (Draft)

Air Permit Technical Guidance for Chemical Sources:

Flares and Vapor Oxidizers

printed on recycled paper

Air Permits Division

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

Chapter 5—Emission Factors, Efficiencies, and Calculations

This chapter provides detailed instructions for the calculations necessary to verify BACT and estimate emissions from flares and vapor oxidizers. Flares must be checked to determine whether they will satisfy the flow and thermal requirements of 40 CFR § 60.18, and their emissions are determined by the use of emission factors. Example calculations are provided for these flare calculations.

Oxidizer emissions are determined by using previous sampling results or emission factors from the manufacturer or AP-42. These calculations are very similar to the flare calculations and are only discussed in general terms.

Flares: Introduction

Although emissions from emergency flares are not included in a permit when it is issued, emissions should be estimated for both routine process flares and emergency flares. Sometimes, emissions of routine pilot gas combustion may be included in an issued permit for emergency flares (although not required).

In this section, the *flare* emission factors and destruction efficiencies are presented first. This information is followed by sample *calculations* that demonstrate how to ensure that the requirements of 40 CFR § 60.18 are satisfied and how to estimate emissions from a flare. Flare data in Attachment B (typical refinery flare) will be used as a basis in most of the following calculations. Flare data in Attachment C (acid gas flare) will be used as a basis in the example calculations for SO_2 emissions.

Flare Emission Factors

The usual flare destruction efficiencies and emission factors are provided in Table 4. The high-Btu waste streams referred to in the table have a heating value greater than 1,000 Btu/scf.

Flare Destruction Efficiencies

Claims for destruction efficiencies greater than those listed in Table 4 will be considered on a case-by-case basis. The applicant may make one of the three following demonstrations to justify the higher destruction efficiency: (1) general method, (2) 99.5 percent justification, or (3) flare stack sampling.

Table 4. Flare Factors

Waste Stream	Destruction/Removal Efficiency (DRE)		
VOC	98 percent (generic) 99 percent for compounds containing no more than 3 carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide and propylene oxide		
H_2S	98 percent		
NH_3	case by case		
CO	case by case		
Air Contaminants	**Emission Factors**		
thermal NO_x	steam-assist:	high Btu	0.0485 lb/MMBtu
		low Btu	0.068 lb/MMBtu
	other:	high Btu	0.138 lb/MMBtu
		low Btu	0.0641 lb/MMBtu
fuel NO_x	NO_x is 0.5 wt percent of inlet NH_3, other fuels case by case		
CO	steam-assist:	high Btu	0.3503 lb/MMBtu
		low Btu	0.3465 lb/MMBtu
	other:	high Btu	0.2755 lb/MMBtu
		low Btu	0.5496 lb/MMBtu
PM	none, required to be smokeless		
SO_2	100 percent S in fuel to SO_2		

*The only exeption ot this is if inorganics might be emitted from the flare. In the case of landfills, the AP-42 PM factor may be used. In other cases, the emissions should be based on the composition of the waste stream routed to the flare.

The NO_x emissions also need to be corrected for the fuel NO_x from ammonia. In this case, 11.2 lb. ammonia/hr(0.005)(250/200) = **0.08 lb/hr** NO_x. This results in total NO_x emissions of 2.62 lb/hr and 9.15 tons per year.

Particulate Emissions. Particulate emissions should be negligible and should therefore not be estimated, since smoking flares are excluded from permitting as defined in 30 TAC Section 111.111. There may be cases where there are noncombustible elements (such as metals) associated with the VOC being combusted. If this is the case, these emissions should be estimated based on sampling results from the waste stream. The AP-42 landfill flare particulate matter factor may be used if the flare controls landfill gas.

The following sample calculation demonstrates how to handle waste streams with hydrogen sulfide.

H_2S Emissions. For instances where a waste stream to a flare contains H_2S, assume that 100 percent by weight of H_2S is converted to SO_2 (the H_2S allowable DRE is 98 percent but actual flare operation could combust almost 100 percent of the waste stream). Referring to Attachment C, convert the design maximum H_2S volumetric waste flow rate into a molar flow rate using the ideal gas law:

$$\frac{(4.5\,ft^3/\text{min})(14.7\,psia)(60\,\text{min}/hr)}{(10.73\ psia{\cdot}ft^3/lbmol/°R\ )(528\,°R\ )} \bullet\ 0.701\ lbmol\ H_2S/hr$$

One mole of H_2S will form one mole of SO_2:

$$\frac{(0.701\ lbmol\ H_2S/hr)(1\ lbmol\ SO_2/lbmol\ H_2S)}{(1\ lbmol\ SO_2/64\ lb)} \bullet\ 44.9\ lb\ SO_2/hr$$

and as much as 2 percent of the H_2S will remain:

(0.02)(0.701 lbmol H_2S/hr)(34 lb. H_2S/lbmol) = **0.48 lb H_2S/hr**

Calculations for annual emissions should be performed in a similar manner using the average H_2S flow rate of 3.5 scfm, resulting in 0.55 lbmol H_2S/hr, and 34.9 lb. SO_2/hr. The annual SO_2 emissions should then be estimated on a TPY basis:

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_x) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO_x[b] Emission Factor (lb/10^6 scf)	NO_x[b] Emission Factor Rating	CO Emission Factor (lb/10^6 scf)	CO Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO_x burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO_x burners	50	D	84	B
Controlled - Low NO_x burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from lb/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

[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.

ES-04
ES-05

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
✗ Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. 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.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

ES-06/07
ES-08/09
ES-10/11

Table 3.1-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO_X) AND CARBON MONOXIDE (CO) FROM STATIONARY GAS TURBINES

Emission Factors[a]				
Turbine Type	Nitrogen Oxides		Carbon Monoxide	
Natural Gas-Fired Turbines[b]	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
Uncontrolled	3.2 E-01	A	8.2 E-02[d]	A
Water-Steam Injection	1.3 E-01	A	3.0 E-02	A
Lean-Premix	9.9 E-02	D	1.5 E-02	D
Distillate Oil-Fired Turbines[e]	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[f] (Fuel Input)	Emission Factor Rating
Uncontrolled	8.8 E-01	C	3.3 E-03	C
Water-Steam Injection	2.4 E-01	B	7.6 E-02	C
Landfill Gas-Fired Turbines[g]	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[h] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.4 E-01	A	4.4 E-01	A
Digester Gas-Fired Turbines[j]	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[k] (Fuel Input)	Emission Factor Rating
Uncontrolled	1.6 E-01	D	1.7 E-02	D

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief".

[b] Source Classification Codes (SCCs) for natural gas-fired turbines include 2-01-002-01, 2-02-002-01, 2-02-002-03, 2-03-002-02, and 2-03-002-03. 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.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020.

[d] It is recognized that the uncontrolled emission factor for CO is higher than the water-steam injection and lean-premix emission factors, which is contrary to expectation. The EPA could not identify the reason for this behavior, except that the data sets used for developing these factors are different.

[e] SCCs for distillate oil-fired turbines include 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[f] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[g] SCC for landfill gas-fired turbines is 2-03-008-01.

[h] Emission factors based on an average landfill gas heating value of 400 Btu/scf at 60°F. To convert from (lb/MMBtu), to (lb/10^6 scf) multiply by 400.

[j] SCC for digester gas-fired turbine is 2-03-007-01.

[k] Emission factors based on an average digester gas heating value of 600 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf) multiply by 600.

ES-04
ES-05
ES-06/07
ES-08/09
ES-10/11
ES-17
ES-21
ES-22

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Pollutant	Emission Factors[a] - Uncontrolled			
	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
* PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.

[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.

[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.

[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.

[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.

[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.

[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).

[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).

[j] VOC emissions are assumed equal to the sum of organic emissions.

[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.

[l] Emission factors are based on combustion turbines using water-steam injection.

Wildcat Measurement Service
P.O.Box 1836
416 East Main Street
Artesia, NM 88211-1836

Fuel

1/30/2009 3:28 PM
Phone: 575-746-3481
888-421-9453
Fax: 575-748-9852
dnorman@wildcatms.com

GAS ANALYSIS REPORT

Analysis For:	MARATHON OIL COMPANY
Field Name:	INDIAN BASIN GAS PLANT
Well Name:	OUTLET FUEL GAS
Station Number:	OUTLETFUE
Purpose:	QUARTERLY
Sample Deg. F:	42.0
Volume/Day:	806.0 MCF/DAY
Formation:	
Line PSIG:	193.0
Line PSIA:	206.2

Run No:	290130-29
Date Run:	01/30/2009
Date Sampled:	01/27/2009
Producer:	MARATHON OIL CO.
County:	EDDY
State:	NM
Sampled By:	LARRY LEJEUNE
Atmos Deg. F:	32

GAS COMPONENTS

		MOL%	GPM
Oxygen	O_2:	0.0000	
Carbon Dioxide	CO_2:	0.0000	
Nitrogen	N_2:	0.8208	
Hydrogen Sulfide	H_2S:	0.0000	
Methane	C1:	98.3905	
Ethane	C2:	0.7504	0.1995
Propane	C3:	0.0383	0.0105
Iso-Butane	IC4:	0.0000	0.0000
Nor-Butane	NC4:	0.0000	0.0000
Iso-Pentane	IC5:	0.0000	0.0000
Nor-Pentanes	NC5:	0.0000	0.0000
Hexanes Plus	C6+:	0.0000	0.0000
Totals		100.0000	0.2100

Pressure Base:	14.650
Real BTU Dry:	1006.868
Real BTU Wet:	989.193
Calc. Ideal Gravity:	0.5614
Calc. Real Gravity:	0.5623
Field Gravity:	
Standard Pressure:	14.696
Ideal BTU Dry:	1007.987
Ideal BTU Wet:	990.448
Z Factor:	0.9980
Average Mol Weight:	16.2563
Average CuFt/Gal:	59.2285
26 lb. Product:	0.0000
Ethane+ GPM	0.2100
Propane+ GPM:	0.0105
Butane+ GPM:	0.0000
Pentane+ GPM:	0.0000

Remarks:
H2S IN GAS STREAM ON LOCATION: NONE DETECTED

Analysis By: Don Norman

Solar® Turbines
A Caterpillar Company

Solar Turbines Incorporated

9330 Sky Park Court
San Diego, CA 92123
Tel: (858) 694-1616

Submitted Electronically

September 5, 2014

Ben Midgette
Occidental Oil and Gas
Benjamin_Midgette@oxy.com

RE: Centaur 40 Routine Maintenance Overhaul – Indian Basin

Dear Mr. Midgette:

The existing Centaur 40-4002 turbine package (S/N: CC80578) will undergo a routine overhaul scheduled for the fourth quarter of 2014 utilizing Solar Turbines Incorporated's (Solar's) Engine Exchange Program. The exchange engine core that will be installed will consist of C40-4702 hardware de-rated to the C40-4002 rating.

It is a standard practice to utilize 4702 hardware on the 4002 rating as the hardware is similar between the Centaur models. The exchange engine core that will be installed (4702 de-rated to 4002) will be thermodynamically equivalent and have the same output and emissions characteristics as the existing 4002 engine and is therefore considered a like-kind exchange. Though the exchange engine will operate at the 4002 rating, signage for inventory tracking purposes will display the 4702 denomination ('ID No.' on the engine data tag). However, the turbine performance, also listed on the data tag, will reflect the de-rate and will match the original engine.

As this exchange will be a like for like 'routine maintenance' procedure there should be no further actions required per NSPS Subparts GG or KKKK.

Please feel free to contact me at 858.505.8554 if you have any questions or need any additional information.

Sincerely,
Solar Turbines Incorporated
Anthony Pocengal
Principal Environmental Engineer
pocengal_anthony@solarturbines.com

cc: Bill Boyd, Solar

Solar Turbines
A Caterpillar Company

Solar Turbines Incorporated
215 Centre Park Blvd.
Desoto, TX 75115
(972) 228-5500

Two Shaft Gas Turbine Certified Test Report

Date of Test	:	10-Oct-14
Model No.	:	CENTAUR 40
Version	:	4002

		Gas Producer	**Power Turbine**
Serial Number	:	OHJ14-C3032	TUI14-92666
Part Number	:	EC47RC-C8G00000	E173169-300
Purpose of Test	:	OVERHAUL	OVERHAUL
Test Specification	:	ES1892	ES1892

Approvals

Test Engineer	:	Payne, John	10-10-14 Date
Product Engineer	:	Payne, Heather	10-10-14 Date

Solar Turbines
A Caterpillar Company

Solar Turbines Incorporated
DeSoto, Texas
COMBUSTION and LIFE LIMITED COMPONENTS

GAS PRODUCER

Gas Producer Serial Number:	OHJ14-C3032
Gas Producer Part Number:	EC47RC-C8G00000

Combustion Components

Combustor Liner	
Serial Number:	HLJ01-93848
Part Number:	E128218-501
Fuel Injectors	
Part Number:	130805-700

Life Limited Components

First Stage Turbine Disk	
Serial Number:	DAI14-85897
Part Number:	E173160-201
Remaining Service Life:	150,000 Hours
Second Stage Turbine Disk	
Serial Number:	DAA95-C9150
Part Number:	E173162-201
Remaining Service Life:	78,500 Hours

POWER TURBINE

Power Turbine Serial Number:	TUI14-92666
Power Turbine Part Number	E173169-300

Life Limited Components

Third Stage Turbine Disk	
Serial Number:	DAI00-C0811
Part Number:	E173163-201
Remaining Service Life:	122,500 Hours

CORRECTED PERFORMANCE TEST SUMMARY GAS FUEL

Solar Turbines - Desoto, Texas
Two-Shaft Gas Turbine Certified Test Report
Corrected to Sea Level, No Duct Losses, 60% Rel. Humidity and Match Temp.

Equipment Summary

Date	10-Oct-14	Time	1:12:04 PM	Version	4002
GP S/N	OHJ14-C3032	Match Temp.	80.0	CS Curve	PT30200
PT S/N	TUI14-92666	Std Temp.	80.0	Test Spec	ES1892
FuelType	Gas			Data Pt.	14

Corrected Performance Summary

Parameter Name	Units	Results	Min	Max
Corrected NGP	%	99.9	99.9	100.1
Corrected NPT	%	95.8	95.2	97.2
Corrected HP	HP	3855	3670	
Corrected SFC	BTU/HP HR	9528		9740
Corrected TRIT	°F	1608	1592	1612
Corrected T5	°F	1118.0		
Corrected T7	°F	831.9		
Corrected WA	PPS	37.0		
T5 Base	°F	1118.0		
Thermal Efficiency	%	26.70	NA	

Engine Parameters

Parameter Name	Units	Results	Min	Max
T1_0_AVG	°F	88.8		
T2_0_AVG	°F	638.7		
T2_0_SPR	°F	4.0		6
T5_1_AVG	°F	1143.6		
T5_1_DEL	°F	44.0		150
T7_1_AVG	°F	857.3		
T7_1_DEL	°F	4.3		20
T5/T3	RATIO	0.7631		
Angle IGV	°	0.0	2	8
P_CD	PSIG	114.0		
P2_P1	RATIO	9.1		
P_TC	PSIG	77.7	76.3	85.8

Solar Turbines - Desoto, Texas
Two-Shaft Gas Turbine Certified Test Report
Corrected to Sea Level, No Duct Losses, 60% Rel. Humidity and Match Temp.

Equipment Summary

Date	10-Oct-14	Time	1:12:04 PM	Version	4002
GP S/N	OHJ14-C3032	Match Temp.	80.0	CS Curve	PT30200
PT S/N	TUI14-92666	Std Temp.	80.0	Test Spec	ES1892
FuelType	Gas			Data Pt.	14

Lube System Parameters

Location	Pressure		Flow		Min	Max
Brg 1	51.1	psig	6.5	gpm	5.3	6.7
Brg 2	56.8	psig	17.8	gpm	14.6	20.0
Brg 3	63.9	psig	7.5	gpm	6.1	8.6
Brg 4	63.3	psig	12.3	gpm	10.4	13.9
Brg 5	55.8	psig	11.9	gpm	10.1	13.4
Lube Oil Temp			134.6	°F	110	155
Lube Oil Press Limits					45.0	65.0
Lube Oil Tank Vent Pressure			2.0	IN H2O		4.9

Data Tag Info

Model No.	CENTAUR 40
Version	4002
I.D. No.	EC47RC-C8G00000
Turbine S/N	OHJ14-C3032
Power (G/L)	3961 / NA HP ISO Dry
Turbine RPM	15000
Output RPM	15500
T5 Base Uncomp (G/L)	1118 F / NA
T5 Comp	120159-25 OR 120902-10
T5 Setpoint (G/L)	1140 F / NA
Vane Angle	0.0

Engineer's Note: - Due to engine being derated from a 4702 to a 4002 Angle IGV is below limit and is accepted by Engineering.

CORRECTED PERFORMANCE
TEST DATA
GAS FUEL

Solar Turbines
A Caterpillar Company

Model	4002	Date	10-Oct-14
Equipment	CENTAUR 40	Time	1:12 PM

	Gas Producer	Power Turbine		
Serial Number	OHJ14-C3032	TUI14-92666		
Part Number	EC47RC-C8G00000	E173169-300		
Production Order Number	DPR877203	DPR877202		
Purpose of Test	OVERHAUL	OVERHAUL		
Test Specification	1892			
Test Engineer	Payne, John	Data Pt.	14	
TQA Review	Payne, Heather			
Test Technician	Diegas, Leo		AvgOnOff	1
			HighLowOut	1
			Samples	20

RUN INFORMATION

K_FUEL_TYP	1		K_N_GP_100	15000	rpm
T_AMB	89.2	°F	K_N_PT_100	15500	rpm
PCT_RH	58.4	%			
P_BARO	29.24	" Hg	K_NUM_SHAFT	2	
K_ENGCON	4702		STD_TEMP	80.0	°F
ANGL_IGV	0.0	deg			

ENGINE OUTPUT

PCT N_GP	100.78	%	COR_PCT_N_GP	99.87	%
N_GP	15117	rpm	COR_N_GP	14980	rpm
PCT_N_PT	96.24	%	COR_PCT_N_PT	95.79	%
N_PT	14917	rpm	COR_N_PT	14848	rpm
TRIT	1638.1	°F	COR_T_RIT	1607.8	°F
PWR_SHP	3733	Hp	COR_PWR_SHP	3855	Hp
WM_AIR	35.8	pps	COR_WM_AIR	37.0	pps
SFCMBTU	36.7	MMBtu/Hr	COR_SFC	9528	Btu/Hp-hr
T2_0_AVG	638.7	°F	COR_T2_0	622.6	°F
T5_1_AVG	1143.6	°F	COR_T5_1	1118.0	°F
T7_1_AVG	857.3	°F	COR_T7_1	831.9	°F
P2_P1	9.1	ratio	T5_T3W	0.7631	
			T5_1_BASE_CD	NA	°F
			T5 BASE DER	1118	°F

FUEL:NATURAL GAS OR LIQUID

K_FUEL_TYP	1	NATURAL GAS	WV_NG_01	39.00	cfm
T_LIQ	90.5	°F	WV_NG_02	39.23	cfm
			P_NG_01	229.9	psig
WM NG 01	1784.4	pph	P_NG_02	229.1	psig
WM NG 02	1794.1	pph	T_NG_01	66.5	°F
WM NG AVG	1789.3	pph	T_NG_02	65.1	°F
WM DEL NG	0.54	%	SG NG	0.5882	
HHV_NG	991	Btu/scf	LHV_NG	20198	Btu/lb

ENGINE DATA REPORT

	Gas Producer	Power Turbine		
Serial Number	OHJ14-C3032	TUI14-92666	Data Pt.	14
Part Number	EC47RC-C8G00000	E173169-300	Date	10-Oct-14
Solar P.O.	DPR877203	DPR877202	Time	1:12 PM

LUBE OIL

P_OIL_MAN	65.2	psig	T_OIL_MAN	134.6	°F
P_BRG 1	51.1	psig	WV_BRG 1	6.5	gpm
P_BRG 2	56.8	psig	WV_BRG 2	17.8	gpm
P_BRG 3	63.9	psig	WV_BRG 3	7.5	gpm
P_BRG 4	63.3	psig	WV_BRG 4	12.3	gpm
P_BRG 5	55.8	psig	WV_BRG 5	11.9	gpm
P_SMP_HI	2.1		PD_SMP	1.98	" H_2O
P_SMP_LO	0.1				

THRUST BRG PARAMETERS

T_GP_TBRG_01	N/A	°F	T_PT_TBRG_01	N/A	°F
T_GP_TBRG_02	N/A	°F	T_PT_TBRG_02	N/A	°F

COMPRESSOR INLET

T_VNTRI	89.2	°F	P_BARO_ABS	14.36	psia
T1_0_01	88.7	°F	P1_0_01	-3.13	" H_2O
T1_0_02	88.9	°F	P1_0_02	-3.20	" H_2O
T1_0_03	88.4	°F	P1_0_03	-3.13	" H_2O
T1_0_04	89.0	°F	P1_0_04	-3.16	" H_2O
T1_0_AVG	88.8	°F	P1_0_AVG	-3.18	" H_2O
T1_0_SPR	0.6	°F	P1_0_SPR	0.11	" H_2O
TD_T1_TV	0.41	°F	P0_AVG	-4.23	" H_2O
P_VNTRI_PLNM	-0.39	" H_2O			
P1_1_01	-74.78	" H_2O	P_VNTRI_01	-31.41	" H_2O
P1_1_02	-105.37	" H_2O	P_VNTRI_02	-31.33	" H_2O
P1_1_03	-85.24	" H_2O	P_VNTRI_03	-31.07	" H_2O
P1_1_AVG	-88.46	" H_2O	P_VNTRI_04	-30.71	" H_2O
P1_1_SPR	30.59	" H_2O	P_VNTRI_AVG	-31.15	" H_2O
			P_VNTRI_SPR	0.71	" H_2O

COMPRESSOR DISCHARGE

T2_0_01	639.9	°F	T2_0_04	639.6	°F
T2_0_02	638.8	°F	T2_0_05	640.0	°F
T2_0_03	636.3	°F	T2_0_06	637.7	°F
T2_0_AVG	638.7	°F	T2_0_SPR	4.0	°F
P2_P1	9.1	Ratio	P_TC	77.7	psig
P_CD	114.0	psig	PPTBLEED	N/A	psig

TURBINE TEMPERATURES

T5_1_01	1156.2	°F	T5_1_DEL	44.0	°F
T5_1_02	1151.8	°F	T5_1_SPR	76.3	°F
T5_1_03	1121.2	°F			
T5_1_04	1154.8	°F	T5_1_MAX	1175.9	°F
T5_1_05	1099.6	°F	T5_1_MIN	1099.6	°F
T5_1_06	1175.9	°F	T5_1_AVG	1143.6	°F

ENGINE DATA REPORT

	Gas Producer	Power Turbine		
Serial Number	OHJ14-C3032	TUI14-92666	Data Pt.	14
Part Number	EC47RC-C8G00000	E173169-300	Date	10-Oct-14
Solar P.O.	DPR877203	DPR877202	Time	1:12 PM

EXHAUST TEMPERATURES AND PRESSURES

T7_1_01	857.5	°F	T7_1_08	858.2	°F
T7_1_02	856.2	°F	T7_1_09	857.2	°F
T7_1_03	854.3	°F	T7_1_10	857.8	°F
T7_1_04	853.0	°F	T7_1_11	858.1	°F
T7_1_05	858.4	°F	T7_1_12	857.4	°F
T7_1_06	859.9	°F	T7_1_13	858.1	°F
T7_1_07	858.9	°F	T7_1_14	857.5	°F
P7_1_01	1.04	" H_2O	T7_1_AVG	857.3	°F
P7_1_02	2.08	" H_2O	T7_1_MAX	859.9	°F
P7_1_03	1.20	" H_2O	T7_1_MIN	853.0	°F
P7_1_04	2.73	" H_2O	T7_1_SPR	6.9	°F
P7 AVG	1.75	" H_2O	T7_1_DEL	4.3	°F
P7_SPR	1.69	" H_2O			

PERFORMANCE PARAMETERS

EA_THRM	26.70	%
ET_COMP	0.8543	
EA_TURB_OA	0.8834	
WQ_1_0	627.43	
WQ_3_1	141.44	
WQ_5_1	455.13	
HEAT BAL.	0.9840	ratio

DYNOMOMETER PARAMETERS

F_DYNO_01	789.97	lbs
P_AIR_DYNO_SEAL	27.42	psig
P_H2O_DYNO_SUP	159.12	psig
P_OIL_DYNO_FWD	176.65	psig
P_OIL_DYNO_FWD	174.90	psig
WV_OIL_DYN_FWD	1.39	gpm
WV_OIL_DYN_AFT	1.47	gpm
T_H2O_DYNO_SUP	79.80	°F
T_H2O_DYNO_OUT	116.82	°F

EMISSION PARAMETERS

ISO_NOX	N/A	PPMV
NOX	N/A	PPMV
CO	N/A	PPMV
HC	N/A	PPMV
O2	N/A	%
CO2	N/A	%

FULL LOAD SUMMARY
GAS FUEL

Solar Turbines - Desoto, Texas
Two-Shaft Gas Turbine Certified Test Report
Corrected to Sea Level, No Duct Losses, 60% Rel. Humidity and Match Temp.

Equipment Summary

Date	10-Oct-14	Time	1:37:10 PM	Version	4002
GP S/N	OHJ14-C3032	Match Temp.	80.0	CS Curve	CS3830
PT S/N	TUI14-92666	Std Temp.	89.4	Test Spec	ES1892
FuelType	Gas			Data Pt.	15

Full Load Performance Summary

Parameter Name	Units	Results
Corrected NGP	%	99.5
Corrected NPT	%	95.6
Corrected HP	HP	3719
Corrected SFC	BTU/HP HR	9578
Corrected TRIT	°F	1611.9
PCD	PSIG	110.8
T1 Average	°F	89.4
T2 Average	°F	630.2
T5 Average	°F	1118.8
T7 Average	°F	844.3

Full Load Emissions Summary

ISO_NOX	ppmv	111.2
NOX	ppmv corr. to 15% O_2	96.8
CO	ppmv corr. to 15% O_2	9.7
HC	ppmv corr. to 15% O_2	0.9
O2	%	16.6
CO2	%	2.5

Current Permit (effective):

ES-08/09

OXY USA WTP LP

Indian Basin Gas Plant

Unit ID - Description	**ES-08/09 Solar Centaur 40-4000 Turbine**	
Fuel	Natural Gas	
Annual Use	26130	MW-hrs
Hourly Load Rate	2.98	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	4000	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	13077	Btu/KW-hr
Efficiency	26.1%	percent
Heat Rate	9807	BTU/hp-hr
Heat Input	39.01	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	1.27	MMdscf/hr

Constituent	ppm	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	lb/hr	tons/yr
Nitrogen Oxides (as NO_2)	83	12.62	lb/hr	55.28	12.62	46%	18.4	80.7
Carbon Monoxide (CO)	35	0.083	lb/MMBtu	14.18	3.24	374%	15.3	67.2
Hydrocarbons (VOC) as CH_4	2	0.12	lb/hr	0.53	0.12	1004%	1.3	5.8
Sulfur Dioxide (SO_2)	0.1	-	-	0.110	0.025	0%	0.0251	0.11
Particulate matter (as PM_{10})	0.0014	0.0067	lb/MMBtu	1.145	0.261	25%	0.327	1.4

ppm - not used

* Emission Factors

NOx = 12.62 lb/hr (Manufacturer's Test data)

CO = 0.082 lb/MMBtu (AP-42, Table 3.1-1, 4/00) x 1031/1020 (adjustment per footnote b) =0.083 lb/MMBtu.

VOC = 0.12 lb/hr (Manufacturer's Test data)

SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv

4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/26.12% Eff.)/1000 x load MW/hr = SO_2 lb/hr

PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.

Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Proposed 9/10/2014 Permit Revision

Indian Basin Gas Plant

ES-08/09

Revised 12-9-14

Unit ID - Description	**ES-08/09 Solar Centaur 40-4000 Turbine**	
Fuel	Natural Gas	
Annual Use	26130	MW-hrs
Hourly Load Rate	2.98	MW
HHV of Fuel	1031	Btu/scf
Engine Rating	4000	BHP
Load Percent	100%	percent
Annual Operating Hours	8760	hrs/yr
Heat Rate	13077	Btu/KW-hr
Efficiency	26.1%	percent
Heat Rate	9807	BTU/hp-hr
Heat Input	39.01	MMBTU/hr
Dry Fd	9190	dscf/MMBTU
Exhaust Flow	1.27	MMdscf/hr

Constituent	Emission Factor (EF)*	EF Units	tons/yr	lb/hr	Safety Factor	**lb/hr**	**tons/yr**
Nitrogen Oxides (as NO_2)	13.09	lb/hr	57.33	13.09	18%	15.4	**67.4**
Carbon Monoxide (CO)	0.083	lb/MMBtu	14.18	3.24	20%	3.9	**17.0**
Hydrocarbons (VOC) as CH_4	0.12	lb/hr	0.53	0.12	1004%	1.3	**5.8**
Sulfur Dioxide (SO_2)	4.0	ppm	0.110	0.025	0%	0.0251	**0.11**
Particulate matter (as PM_{10})	0.0067	lb/MMBtu	1.145	0.261	25%	0.327	**1.4**

* Emission Factors

NOx = 13.09 lb/hr (TRC Stack Test Data, September 2014)
CO = 0.082 lb/MMBtu (AP-42, Table 3.1-1, 4/00) x 1031/1020 (adjustment per footnote b) =0.083 lb/MMBtu.
VOC = 0.12 lb/hr (Manufacturer's Test data)
SO_2 = Calculated using maximum H_2S content of natural gas fuel of 4 ppmv
4ppmv H_2S x 64 lb/lb-mole SO_2 x lb-mole/385.3 scf x 1 scf/1031 Btu x (3413 Btu/kW-hrs/26.12% Eff.)/1000 x load MW/hr = SO_2 lb/hr
PM_{10} = 0.0066 lb/MMBtu (AP-42, Table 3.1-2a, 4/00) x 1031/1020 (adjustment per footnote c) =0.0067 lb/MMBtu.
Note: For gas-fueled turbines PM_{10} is used as a surrogate for $PM_{2.5}$ and TSP

Emission Factors - Comparison

Pollutant	EF Source	lb/hr	g/hp-hr	lb/MMBtu	Notes
NOx	Src Test	-	-	-	
	AP-42	12.62	1.44	0.32	For loads >80%
	Test Data	**13.09**	1.48	0.34	
CO	Src Test	-	-	-	
	AP-42	3.23	0.37	**0.083**	For loads >80%
	Mfr	1.08	0.12	0.028	
VOC	Src Test	-	-	-	
	AP-42	0.083	0.009	0.0021	For loads >80%
	Mfr	**0.12**	0.014	0.0031	
PM	Src Test	-	-	-	
	AP-42	0.260	0.030	**0.0067**	For loads >80%
	Mfr	-	-	-	

Red font = units of EF source
Blue font - Units converted from EF source units

Proposed 9/10/2014 Permit Revision

Summary of Results, Runs 1-3
(ES-08/09, Test Summary)
Operational Data, Concentrations, Exhaust Flow Rates, Mass Emission Rates

Client:	Oxy USA
Plant Name:	Indian Basin Gas Plant (IBGP)
Source:	Center Recompressor (ES-08/09)
Date:	09/17/14
Technicians:	WM

Test Number	*1*	*2*	*3*	
Date	9/17/14	9/17/14	9/17/14	
Start Time	12:37 PM	1:44 PM	2:53 PM	
Stop Time	1:37 PM	2:44 PM	3:53 PM	
Engine/Generator Operation				
NGP (%)	100.0	100.0	100.0	
NPT (%)	90.0	90.0	90.0	
T5 (F)	1160.0	1160.0	1160.0	
Suction Pressure (psi)	380.0	380.0	380.0	
Discharge Pressure (psi)	970.0	970.0	970.0	
PCD (psi)	106.0	106.0	106.0	
Fuel Data				
Fuel Heating Value (Gross Btu/scf) *	1040	1040	1040	
Fuel O2 F-Factor (DSCFH/MMBTU) *	8710	8710	8710	
Fuel Flow Rate (SCFH)	38991.7	38983.3	38991.7	
Measured Emissions (dry) (corrected for instrument drift)				Averages
NO_x (ppmv)	71.7	70.9	68.6	**70.4**
NO_x (ppmv @ 15% O_2)	87.6	86.4	83.8	**86.0**
CO (ppmv)	7.5	7.4	8.1	**7.7**
CO (ppmv @ 15% O_2)	9.2	9.1	9.9	**9.4**
O_2 (%)	16.07	16.06	16.07	**16.07**
CO_2 (%)	2.80	2.80	2.81	**2.80**
Fo Factor	1.72	1.73	1.72	**1.72**
Exhaust Flow Rates				
via EPA Method 19 (SCFH, dry)	1.53E+06	1.52E+06	1.53E+06	**1.53E+06**
Mass Emission Rates (Based on Method 19)				
NOx (lbs/hr) {Permit Limit = 17.7}	13.09	12.91	12.52	**12.84**
CO (lbs/hr) {Permit Limit = 1.3}	0.84	0.82	0.90	**0.85**
NOx (tons/yr) {Permit Limit = 77.6}	57.34	56.54	54.86	**56.25**
CO (tons/yr) {Permit Limit = 5.7}	3.66	3.61	3.92	**3.73**

* EPA Values

Proposed 9/10/2014 Permit Revision

ES-08/09
(~~NOx~~, VOC)

OLAR TURBINES INCORPORATED
NGINE PERFORMANCE CODE REV. 3.13
USTOMER: Marathon Indian Basin
OB ID: North, Center, and South Recompressors

DATE RUN: 29-Jan-03
RUN BY: Eric L Moore

NEW EQUIPMENT PREDICTED EMISSION PERFORMANCE
DATA FOR POINT NUMBER 1

Fuel: SD NATURAL GAS
Water Injection: NO
Number of Engines Tested: 4
Model: CENTAUR 40-4000 CS/MD STANDARD GAS
NEW STANDARD (PIP) COMBUSTOR
Emissions Data: REV. 0.0

Customer: Marathon Indian Basin
Inquiry Number: North, Center, and South Recompressors

he following predicted emissions performance is based on the following
pecific single point: (see attached)

= 3198, %Full Load= 100.0, Elev= 3820 ft, %RH= 60.0, Temperature= 68.0 F

NOX NOM	NOX MAX	CO NOM	CO MAX	UHC NOM	UHC MAX	
101.35	**	14.20	**	2.79	**	PPMvd at 15% O2
55.27	**	4.71	**	0.53	**	ton/yr
0.402	**	0.034	**	0.004	**	lbm/MMBtu (Fuel LHV)
5.29	**	0.45	**	0.05	**	lbm/(MW-hr) (gas turbine shaft pwr)
12.62	**	1.08	**	0.12	**	lbm/hr

IMPORTANT NOTES

1. For short-term emission limits such as lbs/hr., Solar recommends using "worst case" anticipated operating conditions specific to the application and the site conditions. Worst case for one pollutant is not necessarily the same for another. The emission values on this form are only predicted emissions at the specific operating conditions listed.
   Solar's typical SoLoNOx warranty is for greater than 0 deg F, and between 50% and 100% load for gas fuel, and between 80% and 100% load for liquid fuel. An emission warranty for non-SoLoNOx equipment is for greater than 0 deg F and between 80% and 100% load.
3. Fuel must meet Solar standard fuel specification ES 9-98. Predicted emissions are based on the attached fuel composition, or, San Diego natural gas or equivalent.
4. If needed, Solar can provide generic documents to address turbine operation outside typical warranty ranges, as well as non-warranted emissions of SO2, PM10/2.5, VOC, and formaldehyde.
5. Solar can optionally provide factory testing in San Diego to ensure the actual unit(s) meet the above values within the tolerances quoted. Pricing and schedule impact will be provided upon request.

Unchanged Calculations Supporting Documentation

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 lb/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

[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, 4.2×10^4 $lb/10^6$ 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.

ES-04
ES-05
ES-06/07
ES-08/09
ES-10/11
ES-17
ES-21
ES-22

Table 3.1-2a. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM STATIONARY GAS TURBINES

Emission Factors[a] - Uncontrolled				
Pollutant	Natural Gas-Fired Turbines[b]		Distillate Oil-Fired Turbines[d]	
	(lb/MMBtu)[c] (Fuel Input)	Emission Factor Rating	(lb/MMBtu)[e] (Fuel Input)	Emission Factor Rating
CO_2[f]	110	A	157	A
N_2O	0.003[g]	E	ND	NA
Lead	ND	NA	1.4 E-05	C
SO_2	0.94S[h]	B	1.01S[h]	B
Methane	8.6 E-03	C	ND	NA
VOC	2.1 E-03	D	4.1 E-04[j]	E
TOC[k]	1.1 E-02	B	4.0 E-03[l]	C
PM (condensible)	4.7 E-03[l]	C	7.2 E-03[l]	C
PM (filterable)	1.9 E-03[l]	C	4.3 E-03[l]	C
* PM (total)	6.6 E-03[l]	C	1.2 E-02[l]	C

[a] Factors are derived from units operating at high loads (≥80 percent load) only. For information on units operating at other loads, consult the background report for this chapter (Reference 16), available at "www.epa.gov/ttn/chief". ND = No Data, NA = Not Applicable.
[b] SCCs for natural gas-fired turbines include 2-01-002-01, 2-02-002-01 & 03, and 2-03-002-02 & 03.
[c] Emission factors based on an average natural gas heating value (HHV) of 1020 Btu/scf at 60°F. To convert from (lb/MMBtu) to (lb/10^6 scf), multiply by 1020. Similarly, these emission factors can be converted to other natural gas heating values.
[d] SCCs for distillate oil-fired turbines are 2-01-001-01, 2-02-001-01, 2-02-001-03, and 2-03-001-02.
[e] Emission factors based on an average distillate oil heating value of 139 MMBtu/10^3 gallons. To convert from (lb/MMBtu) to (lb/10^3 gallons), multiply by 139.
[f] Based on 99.5% conversion of fuel carbon to CO_2 for natural gas and 99% conversion of fuel carbon to CO_2 for distillate oil. CO_2 (Natural Gas) [lb/MMBtu] = (0.0036 scf/Btu)(%CON)(C)(D), where %CON = weight percent conversion of fuel carbon to CO_2, C = carbon content of fuel by weight, and D = density of fuel. For natural gas, C is assumed at 75%, and D is assumed at 4.1 E+04 lb/10^6scf. For distillate oil, CO_2 (Distillate Oil) [lb/MMBtu] = (26.4 gal/MMBtu) (%CON)(C)(D), where C is assumed at 87%, and the D is assumed at 6.9 lb/gallon.
[g] Emission factor is carried over from the previous revision to AP-42 (Supplement B, October 1996) and is based on limited source tests on a single turbine with water-steam injection (Reference 5).
[h] All sulfur in the fuel is assumed to be converted to SO_2. S = percent sulfur in fuel. Example, if sulfur content in the fuel is 3.4 percent, then S = 3.4. If S is not available, use 3.4 E-03 lb/MMBtu for natural gas turbines, and 3.3 E-02 lb/MMBtu for distillate oil turbines (the equations are more accurate).
[j] VOC emissions are assumed equal to the sum of organic emissions.
[k] Pollutant referenced as THC in the gathered emission tests. It is assumed as TOC, because it is based on EPA Test Method 25A.
[l] Emission factors are based on combustion turbines using water-steam injection.

VOC Profile Speciation Report

Profile Name : Crude Oil Production - Gathering Tanks
Profile Number : 1208
Data Quality : C

Control Device : Uncontrolled
Reference(s) : 96
Data Source : Seven samples from Oklahoma Glen Sand and Dutcher formations were taken in stainless steel canisters and analyzed using a GC with cryogenic sample pre-concentration and flame ionization detection.

SCC Assignments: 40400302

Saroad	CAS Number	Name	Spec_MW	Spec_WT	Peak	Normalized (excl. ethane) VOC Vapor Wt Frac.	
43202	74-84-0	ETHANE	30.07	9.28			
43204	74-98-6	PROPANE	44.09	25.84		3.16×10^{-1}	
43212	106-97-8	N-BUTANE	58.12	20.03		2.45×10^{-1}	
43220	109-66-0	N-PENTANE	72.15	7.30		8.94×10^{-2}	
43229	107-83-5	2-METHYLPENTANE	86.17	1.80		2.20×10^{-2}	
43230	96-14-0	3-METHYL PENTANE	86.17	1.03		1.26×10^{-2}	
43231	110-54-3	HEXANE	86.17	2.20		2.69×10^{-2}	*
43232	142-82-5	HEPTANE	100.20	1.21		1.48×10^{-2}	
43233	111-65-9	OCTANE	114.23	0.70		8.57×10^{-3}	
43242	287-92-3	CYCLOPENTANE	70.14	0.51		6.25×10^{-3}	
43247	108-08-7	2,4-DIMETHYLPENTANE	100.20	0.06		7.35×10^{-4}	
43248	110-82-7	CYCLOHEXANE	84.16	0.90		1.10×10^{-2}	
43261	108-87-2	METHYLCYCLOHEXANE	98.21	1.23		1.51×10^{-2}	
43262	96-37-7	METHYLCYCLOPENTANE	84.16	1.48		1.81×10^{-2}	
43263	591-76-4	2-METHYL HEXANE	100.20	0.37		4.53×10^{-3}	
43274	565-59-3	2,3 DIMETHYL PENTANE	100.20	0.16		1.96×10^{-3}	
43276	79-29-8	2,3 DIMETHYLBUTANE	86.17	0.20		2.45×10^{-3}	
43288	1678-91-7	ETHYLCYCLOHEXANE	112.23	0.28		3.43×10^{-3}	
43291	75-83-2	2,2-DIMETHYLBUTANE	86.17	0.08		9.80×10^{-4}	
43295	589-34-4	3-METHYLHEXANE	100.20	0.51		6.25×10^{-3}	
43296	592-27-8	2-METHYLHEPTANE	114.23	0.52		6.37×10^{-3}	
43298		3-METHYLHEPTANE	114.23	0.24		2.94×10^{-3}	
43910	75-28-5	2-ME-PROPANE	58.10	7.14		8.74×10^{-2}	
43911	78-78-4	2-ME-BUTANE	72.20	6.29		7.70×10^{-2}	
43912	540-84-1	2,2,4-TRIME-PENTANE	114.20	0.56		6.86×10^{-3}	*
45201	71-43-2	BENZENE	78.11	0.12		1.47×10^{-3}	*
45202	108-88-3	TOLUENE	92.13	0.23		2.82×10^{-3}	*
45203	100-41-4	ETHYLBENZENE	106.16	0.09		1.10×10^{-3}	*
45204	95-47-6	O-XYLENE	106.16	0.11		1.35×10^{-3}	*
90010		M-XYLENE AND P-XYLENE	106.16	0.46		5.63×10^{-3}	*
TOTAL				90.93		1.00	

* - HAPs

Source: US EPA Document 450/2-90-001a, "Air Emissions Species Manual", Profile Number 1208, 01/1990.

Table 5-3. Average speciation profiles modeled for the 94-tank data set, mole percent.

Species	Flash Gas – Mean Mole Percent Contribution		W&S Gas – Mean Mole Percent Contribution	
	Percent of total gas stream (Std. Deviation)	Percent of THC	Percent of total gas stream (Std. Deviation)	Percent of THC
H_2S	0.89 (2.58)	na	1.33 (3.63)	na
CO_2	8.16 (18.18)	na	7.31 (15.93)	na
N_2	1.33 (3.78)	na	0.34 (1.94)	na
CH_4	36.75 (22.56)	41.00	20.36 (23.30)	22.36
C_2H_6	15.12 (6.12)	16.87	18.65 (9.76)	20.49
C_3H_8	16.45 (7.72)	18.35	25.48 (13.58)	28.00
i-C_4H_{10}	4.67 (2.94)	5.21	6.22 (4.07)	6.83
n-C_4H_{10}	7.77 (4.41)	8.67	9.94 (6.51)	10.92
i-C_5H_{12}	2.93 (1.73)	3.27	3.39 (2.02)	3.72
n-C_5H_{12}	2.49 (1.61)	2.77	2.88 (1.99)	3.17
Hexanes	1.03 (0.75)	1.15	1.18 (0.84)	1.30
Heptanes	0.96 (0.78)	1.07	1.14 (0.98)	1.26
Octanes	0.40 (0.38)	0.45	0.49 (0.47)	0.54
Nonanes	0.09 (0.10)	0.10	0.12 (0.13)	0.13
Benzene	0.12 (0.17)	0.14	0.16 (0.30)	0.18
Toluene	0.10 (0.12)	0.11	0.14 (0.23)	0.15
Ethylbenzene	0.00 (0.00)	0.00	0.01 (0.01)	0.01
Xylenes	0.03 (0.04)	0.03	0.04 (0.06)	0.04
n-Hexane	0.70 (0.58)	0.78	0.82 (0.69)	0.90
Pentanes+	0.00 (0.00)	0.00	0.00 (0.00)	0.00

Source: API Publication No. 4683, "Correlation Equations to Predict Reid Vapor Pressure and Properties of Gaseous Emissions for Exploration and Production Facilities," p. 5-5, 11/1998.

Estimation of Flash Gas Speciation from Average API sample--Mean mole % analysis (1)

Vapor Stream	MW	Vapor Mole Frac. *of THC*	Vapor Weight $MW_{species}$ x MF	Wt. Frac. Vapor THC	Wt. Frac. Vapor VOC- Only	**wt. frac of VOC**			Vapor MW (Vap. wt. frac x MW) THC
Methane	16	0.410000	6.5600	0.18					2.9
Ethane	30	0.168700	5.0610	0.14					4.2
Propane	44	0.183500	8.0740	0.22	0.22	0.3298			9.8
Isobutane	58	0.052100	5.0286	0.14	0.14	**0.2054**			8.1
n-Butane	58	0.086700	3.0218	0.08	0.08	**0.1234**			4.9
Pentanes	72	0.060400	4.3488	0.12	0.12	**0.1776**			8.7
n-hexane	86	0.007800	0.6708	0.02	0.02	**0.0274**	*	**2.74E-02**	1.6
Hexanes	86	0.011500	0.9890	0.03	0.03	**0.0404**			2.4
Heptanes	100	0.010700	1.0700	0.03	0.03	**0.0437**			3.0
Benzene	78	0.001400	0.1092	0.00	0.00	**0.0045**	*	**4.46E-03**	0.2
Toluene	92	0.001100	0.1012	0.00	0.00	**0.0041**	*	**4.13E-03**	0.3
Ethylbenzene	106	0.000000	0.0000	0.00	0.00	**0.0000**			0.0
Xylene	106	0.000300	0.0318	0.00	0.00	**0.0013**	*	**1.30E-03**	0.1
C8 + Heavies	178.9	0.005800	1.0376	0.03	0.03	**0.0424**			5.1
Total		**1.00000**	**36.10**	1.00	0.68	**1.00**			**51.2**
VOC		0.421		0.678	TRUE				

(1) American Petroleum Institute, "Correlation Equations to Predict Reid Vapor Pressure and Properties of Gaseous Emissions for Exploration and Production Facilities," Publication 4683, Table 5-3, Flash Gas as Mean Mole Percent of Total Hydrocarbons, Nov.1998, page 5-5.

[Note: Actual methane & ethane mole fractions are expected to be larger than represented above. Thus, VOCs & HAPs will be overestimated]

* Wt. fractions used to speciate Flash Gas.

Example 3 shows how to speciate total fugitive hydrocarbon emissions calculated using EPA Average Emission Factors.

Table 2. Speciation Fractions for Total Hydrocarbon (THC) Emissions Calculated Using EPA Average Emission Factors

	Gas	Heavy Oil	Light Oil	Water/Oil
Methane	0.687	0.942	0.612	0.612
Non-methane	0.313	0.058	0.388	0.388
VOC	0.171	0.030	0.296	0.296
C6+ *	0.00693	0.00752	0.02300	0.02300
Benzene	0.00069	0.00935	0.00121	0.00121
Toluene	0.00038	0.00344	0.00105	0.00105
Ethyl-Benzene	0.00003	0.00051	0.00016	0.00016
Xylenes	0.00009	0.00372	0.00033	0.00033

* The C6+ fraction can be used to calculate an upper limit for n-hexane

EXAMPLE 1 – Using EPA Average Emission Factors and Actual Component Counts to Calculate Total Hydrocarbon Emissions

Example 1 shows the calculation of total hydrocarbon emissions from a typical light crude oil production operation. Column A of the table shows the actual count of components grouped by component type and stream; Column B of the table shows EPA Average Emission Factors repeated from Table 1; Column C shows calculated total hydrocarbon emissions found by multiplying the respective sub-columns in Columns A and B. The calculated total hydrocarbon emissions are 34.6 lb/day from gas service components, 360 lb/day from light oil service components, and 1.3 lb/day from water/oil service components for a total of 396 lb/day.

EXAMPLE 1. Table of Calculated Values

	(A) Count				(B) THC Emission Factors (lb/comp-day)			(C) Calculated THC Emissions (lb/day)			
	Gas	Lt Oil	Water/Oil	Total	Gas	Lt Oil	Water/Oil	Gas	Lt Oil	Water/Oil	Total
nnectors	291	5,332	69	5,692	1.1E-02	1.1E-02	5.8E-03	3.20	58.7	0.40	62.3
nges	107	1,756	28	1,891	2.1E-02	5.8E-03	1.5E-04	2.25	10.2	0.00	12.4
en-Ends	10	176	3	189	1.1E-01	7.4E-02	1.3E-02	1.10	13.0	0.04	14.2
iers	6	98	1	105	4.7E-01	4.0E-01	7.4E-01	2.82	39.2	0.74	42.8
mp Seals	0	5	0	5	1.3E-01	6.9E-01	1.3E-03	0.00	3.5	0.00	3.5
ves	105	1,811	24	1,940	2.4E-01	1.3E-01	5.2E-03	25.20	235.4	0.12	260.8
L	519	9,178	125	9,822				34.6	360.0	1.30	396.0

15

Source: API Publication No. 4638, "Calculation Notebook for Oil and Gas Production Equipment Fugitive Emissions," p. 15, 04/1996.

where:

M_V = Stock vapor molecular weight (lb/lb mole; =50 for crude oil)
P_{VA} = Stock vapor pressure at the average daily liquid surface temperature (psia)
Q = Annual stock net throughput (bbl/yr).
K_N = Working loss turnover factor (unitless)
K_p = Working loss product factor (unitless)

Please note that if the stock level never changes (that is, filling and emptying always occur simultaneously and at equal rates; e.g., a separator tank) $Q = 0$.

In order to calculate working losses, critical input fields include the following:

Q Annual stock throughput (bbl/yr)
K_p Working loss product factor (unitless)

Tank type (horizontal or vertical)

D Tank shell diameter (ft)
H_s Tank shell height for vertical tanks, shell length for horizontal tanks (ft)
M_V Molecular weight of the tank vapor
RVP Reid vapor pressure (psia)

Nearest city (select from list)

Paint color and condition (select from lists)

E Estimated effectiveness of control strategies or devices (percent)

Flashing losses. Flashing losses (L_f) in tons/yr are calculated according to the following equation:

$$L_f = GOR \times Q \times GD \times \frac{ton}{2000lb} \qquad (15)$$

where:

GOR = Gas-to-oil ratio (scf/bbl)
Q = Annual throughput (bbl/yr)
GD = Tank vent hydrocarbon gas density (lb/ft^3)

The tank vent hydrocarbon gas density (GD) can be calculated from the following equation:

$$GD = C \times M_c \times \left(\frac{P_a}{RT}\right) \qquad (16)$$

where:

C = Concentration of total hydrocarbons (THC) in tank vent gas (mole fraction, a number between 0.0 and 1.0)
M_c = Molecular weight of total hydrocarbons (THC) in tank vent gas (lb/lb mole)

Source: API, "Exploration and Production Emission Calculator (EPEC) User's Guide," pp. 3-14, 3-15, and 3-16, 09/1997.

P_a = Pressure of vented tank gas at atmospheric pressure (psia)
R = Ideal gas constant (10.731 psia ft^3/lb mole °R)
T = Temperature of vented tank gas (°R)

At standard temperature (60°F) and pressure (14.7 psia) the above equation becomes:

$$GD = \frac{C \times M_c}{379 scf / lb\ mole} \quad (17)$$

Assuming default values of C = 1.0 and M_c = 50 lb/lb mole, the above equation calculates a conservative value of 0.132 lb/ft^3 for GD. Users are encouraged to enter an estimate of GD based upon field measurement data or other data sources.

The Vasquez-Beggs and RMC methods differ from one another only in the technique used to calculate the gas-to-oil ratio. The Vasquez-Beggs equation may be expressed as follows:

$$GOR = C_1 \times CSG \times UP^{C_2} \times \exp\left(\frac{C_3 \times APIG}{T + 460}\right) \quad (18)$$

where:
GOR = Gas-to-oil ratio (scf/bbl)
C_1, C_2, and C_3 = Correlation coefficients
CSG = Corrected specific gravity of the gas (for pure air, CSG = 1.0)
UP = Separator pressure (psia)
APIG = API gravity of the oil (°API)
T = Separator fluid temperature (°F)

The RMC equation may be expressed as follows:

$$GOR = \log^{-1}\left[0.4896 - 4.916 \times \log_{10}(ST) + 3.469 \times \log_{10}(SG) + 1.501 \times \log_{10}(UP) - 0.9213 \times \log_{10}(T)\right] \quad (19)$$

where:
GOR = Gas-to-oil ratio (scf/bbl)
ST = Tank oil specific gravity (for pure water, ST = 1.0)
SG = Separator gas specific gravity (for pure air, SG = 1.0)
UP = Separator pressure (psia)
T = Separator temperature (°F)

In order to calculate flashing losses, critical input fields include the following:

Q Annual stock throughput (bbl/yr)
SG Specific gravity of gas in the separator (dimensionless; for pure air, SG = 1.0)

Source: API, "Exploration and Production Emission Calculator (EPEC) User's Guide," pp. 3-14, 3-15, and 3-16, 09/1997.

UVP Upstream vessel pressure (psig)
APIG API gravity of the product (°API)
T Fluid temperature in the upstream vessel (°F)
E Estimated effectiveness of control strategies or devices (percent)

References

American Petroleum Institute (1991) *Evaporative loss from fixed roof tanks*. Chapter 19.1. [Bulletin 2518] American Petroleum Institute, Washington, D.C.

DB Robinson Research Ltd. (1997) *Production tanks emission model (E&P TANK Version 1.0): a program for estimating emissions from hydrocarbon production tanks*. In preparation for the American Petroleum Institute and the Gas Research Insitute. API Publication Number 4660. Washington, D.C.

Radian Corp. (1992) SPECIATE, version 1.50. Prepared for Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC by Radian Corp., Austin, TX, October.

Rollins J.B., McCain Jr. W.D., and Creeger J.T. (1990) Estimation of solution GOR of black oils. *Journal of Petroleum Technology*, January, 92-94.

U.S. Environmental Protection Agency (1996d) Compilation of air pollutant emission factors. Vol. 1: stationary point and area emission units. Section 7, AP-42, 5th ed. (January 1996); Supplements A and B (November 1996). Report prepared by Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC.

Vasquez M. and Beggs D.H. (1980) Correlations for fluid physical property prediction. *Journal of Petroleum Technology*, June.

The SPECIATE database was derived from:

U.S. Environmental Protection Agency (1990) Air emission species manual. Vol. 1: volatile organic compound species profiles. 2nd ed. Report prepared by U.S. Environmental Protection Agency, Research Triangle Park, NC, EPA-450/2-90-001a.

Source: API, "Exploration and Production Emission Calculator (EPEC) User's Guide," pp. 3-14, 3-15, and 3-16, 09/1997.

Company Name:	OXY USA WTP LP	Permit	N/A
Facility Name:	Indian Basin Gas Plant	Date:	19-Mar-10

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	60.33	API
Separator Pressure (psig)	40	P
Separator Temperature (°F)	325	Ti
Separator Gas Gravity at Initail Condition	0.7	SGi
Stock Tank Barrels of Oil per day (BOPD)	358.700	Q
Stock Tank Gas Molecular Weight	63.50	MW
Fraction VOC (C3+) of Stock Tank Gas	0.990	VOC
Atmospheric Pressure (psia)	14.7	Patm

CONSTRAINTS:

16	>API>	58	°API	WARNING ..
50	>P+Patm>	5250	(psia)	WARNING ..
70	> Ti >	295	(°F)	WARNING ..
0.56	>SGi>	1.18	(MW/28.97)	ok
None	> Q >	None	(BOPD)	ok
18	>MW>	125	(lb/lb-mole)	ok
0.5	>Voc>	1.00	Fraction	ok
20	> Rs >	2070	(scf/STB)	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Oil/Condensate Tank (ES-46)

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	0.0178
C2	~~1.0937~~	1.187	1.187
C3	~~25.724~~	23.931	23.931

Rs =	5.68	scf/bbl	*for P + Patm =* *54.7*

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	61.38	TPY

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	60.76	TPY	*from "FLASHING" of oil from separator to tank press*

3.04 tpy Controlled with VRU (95% C.E. with 5% down time)

Company Name:	OXY USA WTP LP	Permit	N/A
Facility Name:	Indian Basin Gas Plant	Date:	19-Mar-10

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	60.33	API
Separator Pressure (psig)	40	P
Separator Temperature (°F)	325	Ti
Separator Gas Gravity at Initail Condition	0.7	SGi
Stock Tank Barrels of Oil per day (BOPD)	32.600	Q
Stock Tank Gas Molecular Weight	63.50	MW
Fraction VOC (C3+) of Stock Tank Gas	0.990	VOC
Atmospheric Pressure (psia)	14.7	Patm

CONSTRAINTS:

16	>API>	58	°API	WARNING ..
50	>P+Patm>	5250	(psia)	WARNING ..
70	> Ti >	295	(°F)	WARNING ..
0.56	>SGi>	1.18	(MW/28.97)	ok
None	> Q >	None	(BOPD)	ok
18	>MW>	125	(lb/lb-mole)	ok
0.5	>Voc>	1.00	Fraction	ok
20	> Rs >	2070	(scf/STB)	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Oil/Condensate Tank (ES-47)

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	5.68	**scf/bbl**	*for P + Patm =* *54.7*

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	5.58	TPY

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	5.52	TPY	*from "FLASHING" of oil from separator to tank press*

0.28 tpy Controlled with VRU (95% C.E. with 5% down time)

Company Name:	OXY USA WTP LP	Permit	N/A
Facility Name:	Indian Basin Gas Plant	Date:	19-Mar-10

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	60.33	API
Separator Pressure (psig)	40	P
Separator Temperature (°F)	325	Ti
Separator Gas Gravity at Initail Condition	0.7	SGi
Stock Tank Barrels of Oil per day (BOPD)	163.100	Q
Stock Tank Gas Molecular Weight	63.50	MW
Fraction VOC (C3+) of Stock Tank Gas	0.990	VOC
Atmospheric Pressure (psia)	14.7	Patm

CONSTRAINTS:

16	>API>	58	°API	WARNING ..
50	>P+Patm>	5250	(psia)	WARNING ..
70	> Ti >	295	(°F)	WARNING ..
0.56	>SGi>	1.18	(MW/28.97)	ok
None	> Q >	None	(BOPD)	ok
18	>MW>	125	(lb/lb-mole)	ok
0.5	>Voc>	1.00	Fraction	ok
20	> Rs >	2070	(scf/STB)	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Oil/Condensate Tank (ES-48)

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	0.0178
C2	~~1.0937~~	1.187	1.187
C3	~~25.724~~	23.931	23.931

Rs =	5.68	scf/bbl	*for P + Patm =*	*54.7*

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	27.91	TPY

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	27.63	TPY	*from "FLASHING" of oil from separator to tank press*

1.38 tpy Controlled with VRU (95% C.E. with 5% down time)

Company Name:	OXY USA WTP LP	Permit	N/A
Facility Name:	Indian Basin Gas Plant	Date:	19-Mar-10

Volatile Organic Compound Emission Calculation for Flashing

Vasquez - Beggs Solution Gas/Oil Ratio Correlation Method

(For Estimating VOC Flashing Emissions, Using Stock Tank Gas-Oil Ratios For Crude Oil Facilities)

INPUTS:

Stock Tank API Gravity	60.33	API
Separator Pressure (psig)	40	P
Separator Temperature (°F)	325	Ti
Separator Gas Gravity at Initail Condition	0.7	SGi
Stock Tank Barrels of Oil per day (BOPD)	32.600	Q
Stock Tank Gas Molecular Weight	63.50	MW
Fraction VOC (C3+) of Stock Tank Gas	0.990	VOC
Atmospheric Pressure (psia)	14.7	Patm

CONSTRAINTS:

16	>API>	58	°API	WARNING ..
50	>P+Patm>	5250	(psia)	WARNING ..
70	> Ti >	295	(°F)	WARNING ..
0.56	>SGi>	1.18	(MW/28.97)	ok
None	> Q >	None	(BOPD)	ok
18	>MW>	125	(lb/lb-mole)	ok
0.5	>Voc>	1.00	Fraction	ok
20	> Rs >	2070	(scf/STB)	WARNING ..

SGx = Dissolved gas gravity at 100 psig = SGi [1.0+0.00005912*API*Ti*Log(Pi/114.7)]

SGx =	0.4

Document Notes:

VERIFICATION OF FLASH EMISSIONS USING NMED PROGRAM

Water with 5% Oil/Condensate Tank (ES-49)

Rs = (C1 * SGx * Pi^C2) exp ((C3 * API) / (Ti + 460))

Where:

Rs	Gas/Oil Ratio of liquid at pressure of interest
SGx	Dissolved gas gravity at 100 psig
Pi	Pressure of initial condition (psia)
API	API Gravity of liquid hydrocarbon at final condition
Ti	Temperature of initial condition (F)

Constants

	°API Gravity		
°APTI →	< 30	>= 30	Given °API
C1	~~0.0362~~	0.0178	**0.0178**
C2	~~1.0937~~	1.187	**1.187**
C3	~~25.724~~	23.931	**23.931**

Rs =	5.68	scf/bbl	*for P + Patm =*	*54.7*

THC = Rs * Q * MW * 1/385 scf/lb-mole * 365 D/Yr * 1 ton/2000 lb.s

THC	Total Hydrocarbon (tons/year)
Rs	Solution Gas/Oil Ratio (scf/STB)
Q	Oil Production Rate (bbl/day)
MW	Molecular Weight of Stock Tank Gas (lb/lb-mole)
385	Volume of 1 lb-mole of gas at 14.7 psia and 68 F (WAQS&R Std Cond)

THC =	5.58	TPY

VOC = THC * Frac. of C3+ in the Stock Tank Vapor

VOC =	5.52	TPY	*from "FLASHING" of oil from separator to tank press*

0.014 tpy Water with ony 5% VOC and Controlled with VRU (95% C.E. with 5% down time)

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)

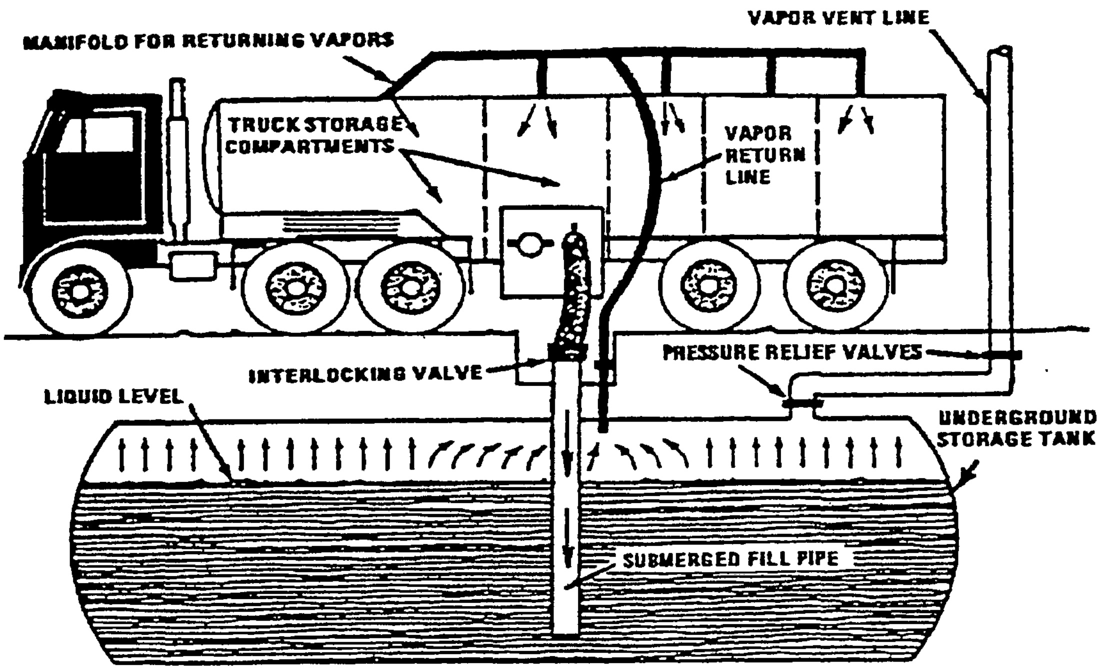


Figure 5.2-5. Tank truck unloading into a service station underground storage tank and practicing "vapor balance" form of emission control.

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.

The saturation factor, S, represents the expelled vapor's fractional approach to saturation, and it accounts for the variations observed in emission rates from the different unloading and loading methods. Table 5.2-1 lists suggested saturation factors.

Emissions from controlled loading operations can be calculated by multiplying the uncontrolled emission rate calculated in Equation 1 by an overall reduction efficiency term:

$$\left(1 - \frac{\text{eff}}{100}\right)$$

The overall reduction efficiency should account for the capture efficiency of the collection system as well as both the control efficiency and any downtime of the control device. Measures to reduce loading emissions include selection of alternate loading methods and application of vapor recovery equipment. The latter captures organic vapors displaced during loading operations and recovers the vapors by the use of refrigeration, absorption, adsorption, and/or compression. The recovered product is piped back to storage. Vapors can also be controlled through combustion in a thermal oxidation unit, with no product recovery. Figure 5.2-6 demonstrates the recovery of gasoline vapors from tank trucks during loading operations at bulk terminals. Control efficiencies for the recovery units range from 90 to over 99 percent, depending on both the nature of the vapors and the type of control equipment used.[5-6] However, not all of the displaced vapors reach the control device, because of leakage from both the tank truck and collection system. The collection efficiency should be assumed to be 99.2 percent for tanker trucks passing the MACT-level annual leak test (not more than 1 inch water column pressure change in 5 minutes after pressurizing to 18 inches water followed by pulling a vacuum of 6 inches water).[7] A collection efficiency of 98.7 percent (a 1.3 percent leakage rate) should be assumed for trucks passing the NSPS-level annual test (3 inches pressure change) A collection efficiency of 70 percent should be assumed for trucks not passing one of these annual leak tests[6].

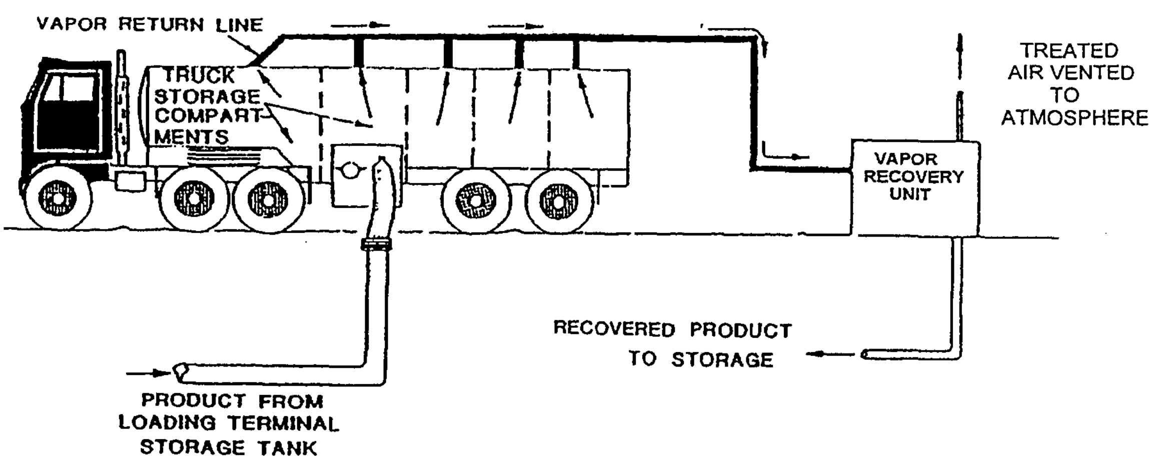


Figure 5.2-6. Tank truck loading with vapor recovery.

Sample Calculation -

Loading losses (L_L) from a gasoline tank truck in dedicated vapor balance service and practicing vapor recovery would be calculated as follows, using Equation 1:

Design basis -

Cargo tank volume is 8000 gal
Gasoline Reid vapor pressure (RVP) is 9 psia
Product temperature is 80°F
Vapor recovery efficiency is 95 percent
Vapor collection efficiency is 98.7 percent (NSPS-level annual leak test)

Loading loss equation -

$$L_L = 12.46 \frac{SPM}{T} \left(1 - \frac{eff}{100}\right)$$

where:

S = saturation factor (see Table 5.2-1) - 1.00
P = true vapor pressure of gasoline (see Figure 7.1-6) = 6.6 psia
M = molecular weight of gasoline vapors (see Table 7.1-2) = 66
T = temperature of gasoline = 540°R
eff = overall reduction efficiency (95 percent control x 98.7 percent collection) = 94 percent

$$L_L = 12.46 \frac{(1.00)(6.6)(66)}{540} \left(1 - \frac{94}{100}\right)$$

$$= 0.60 \text{ lb}/10^3 \text{gal}$$

Total loading losses are:

$$(0.60 \text{ lb}/10^3 \text{ gal})(8.0 \times 10^3 \text{ gal}) = 4.8 \text{ pounds (lb)}$$

Measurements of gasoline loading losses from ships and barges have led to the development of emission factors for these specific loading operations.[8] These factors are presented in Table 5.2-2 and should be used instead of Equation 1 for gasoline loading operations at marine terminals. Factors are expressed in units of milligrams per liter (mg/L) and pounds per 1000 gallons (lb/10^3 gal).

TNRCC

October 2000
RG-109 (Draft)

Air Permit Technical Guidance for Chemical Sources:

Flares and Vapor Oxidizers

printed on
recycled paper

Air Permits Division

TEXAS NATURAL RESOURCE CONSERVATION COMMISSION

Chapter 5—Emission Factors, Efficiencies, and Calculations

This chapter provides detailed instructions for the calculations necessary to verify BACT and estimate emissions from flares and vapor oxidizers. Flares must be checked to determine whether they will satisfy the flow and thermal requirements of 40 CFR § 60.18, and their emissions are determined by the use of emission factors. Example calculations are provided for these flare calculations.

Oxidizer emissions are determined by using previous sampling results or emission factors from the manufacturer or AP-42. These calculations are very similar to the flare calculations and are only discussed in general terms.

Flares: Introduction

Although emissions from emergency flares are not included in a permit when it is issued, emissions should be estimated for both routine process flares and emergency flares. Sometimes, emissions of routine pilot gas combustion may be included in an issued permit for emergency flares (although not required).

In this section, the *flare* emission factors and destruction efficiencies are presented first. This information is followed by sample *calculations* that demonstrate how to ensure that the requirements of 40 CFR § 60.18 are satisfied and how to estimate emissions from a flare. Flare data in Attachment B (typical refinery flare) will be used as a basis in most of the following calculations. Flare data in Attachment C (acid gas flare) will be used as a basis in the example calculations for SO_2 emissions.

Flare Emission Factors

The usual flare destruction efficiencies and emission factors are provided in Table 4. The high-Btu waste streams referred to in the table have a heating value greater than 1,000 Btu/scf.

Flare Destruction Efficiencies

Claims for destruction efficiencies greater than those listed in Table 4 will be considered on a case-by-case basis. The applicant may make one of the three following demonstrations to justify the higher destruction efficiency: (1) general method, (2) 99.5 percent justification, or (3) flare stack sampling.

Table 4. Flare Factors

Waste Stream	Destruction/Removal Efficiency (DRE)		
VOC	98 percent (generic) 99 percent for compounds containing no more than 3 carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide and propylene oxide		
H_2S	98 percent		
NH_3	case by case		
CO	case by case		
Air Contaminants	**Emission Factors**		
thermal NO_x	steam-assist:	high Btu	0.0485 lb/MMBtu
		low Btu	0.068 lb/MMBtu
	other:	high Btu	0.138 lb/MMBtu
		low Btu	0.0641 lb/MMBtu
fuel NO_x	NO_x is 0.5 wt percent of inlet NH_3, other fuels case by case		
CO	steam-assist:	high Btu	0.3503 lb/MMBtu
		low Btu	0.3465 lb/MMBtu
	other:	high Btu	0.2755 lb/MMBtu
		low Btu	0.5496 lb/MMBtu
PM	none, required to be smokeless		
SO_2	100 percent S in fuel to SO_2		

*The only exeption ot this is if inorganics might be emitted from the flare. In the case of landfills, the AP-42 PM factor may be used. In other cases, the emissions should be based on the composition of the waste stream routed to the flare.

The NO_x emissions also need to be corrected for the fuel NO_x from ammonia. In this case, 11.2 lb. ammonia/hr(0.005)(250/200) = **0.08 lb/hr** NO_x. This results in total NO_x emissions of 2.62 lb/hr and 9.15 tons per year.

Particulate Emissions. Particulate emissions should be negligible and should therefore not be estimated, since smoking flares are excluded from permitting as defined in 30 TAC Section 111.111. There may be cases where there are noncombustible elements (such as metals) associated with the VOC being combusted. If this is the case, these emissions should be estimated based on sampling results from the waste stream. The AP-42 landfill flare particulate matter factor may be used if the flare controls landfill gas.

The following sample calculation demonstrates how to handle waste streams with hydrogen sulfide.

H_2s Emissions. For instances where a waste stream to a flare contains H_2S, assume that 100 percent by weight of H_2S is converted to SO_2 (the H_2S allowable DRE is 98 percent but actual flare operation could combust almost 100 percent of the waste stream). Referring to Attachment C, convert the design maximum H_2S volumetric waste flow rate into a molar flow rate using the ideal gas law:

$$\frac{(4.5\,ft^3/\mathrm{min})(14.7\,psia)(60\,\mathrm{min}/hr)}{(10.73\ psia{\cdot}ft^3/lbmol/°R\ )(528\,°R\ )} \bullet\ 0.701\ lbmol\ H_2S/hr$$

One mole of H_2S will form one mole of SO_2:

$$\frac{(0.701\ lbmol\ H_2S/hr)(1\ lbmol\ SO_2/lbmol\ H_2S)}{(1\ lbmol\ SO_2/64\ lb)} \bullet\ 44.9\ lb\ SO_2/hr$$

and as much as 2 percent of the H_2S will remain:

(0.02)(0.701 lbmol H_2S/hr)(34 lb. H_2S/lbmol) = **0.48 lb H_2S/hr**

Calculations for annual emissions should be performed in a similar manner using the average H_2S flow rate of 3.5 scfm, resulting in 0.55 lbmol H_2S/hr, and 34.9 lb. SO_2/hr. The annual SO_2 emissions should then be estimated on a TPY basis:

Wildcat Measurement Service
P.O.Box 1836
416 East Main Street
Artesia, NM 88211-1836

1/30/2009 3:28 PM

Phone: 575-746-3481
888-421-9453
Fax: 575-748-9852
dnorman@wildcatms.com

Fuel

GAS ANALYSIS REPORT

Analysis For:	MARATHON OIL COMPANY	Run No:	290130-29
Field Name:	INDIAN BASIN GAS PLANT	Date Run:	01/30/2009
Well Name:	OUTLET FUEL GAS	Date Sampled:	01/27/2009
Station Number:	OUTLETFUE	Producer:	MARATHON OIL CO.
Purpose:	QUARTERLY	County:	EDDY
Sample Deg. F:	42.0	State:	NM
Volume/Day:	806.0 MCF/DAY	Sampled By:	LARRY LEJEUNE
Formation:		Atmos Deg. F:	32
Line PSIG:	193.0		
Line PSIA:	206.2		

GAS COMPONENTS

		MOL%	GPM
Oxygen	O_2:	0.0000	
Carbon Dioxide	CO_2:	0.0000	
Nitrogen	N_2:	0.8208	
Hydrogen Sulfide	H_2S:	0.0000	
Methane	C1:	98.3905	
Ethane	C2:	0.7504	0.1995
Propane	C3:	0.0383	0.0105
Iso-Butane	IC4:	0.0000	0.0000
Nor-Butane	NC4:	0.0000	0.0000
Iso-Pentane	IC5:	0.0000	0.0000
Nor-Pentanes	NC5:	0.0000	0.0000
Hexanes Plus	C6+:	0.0000	0.0000
Totals		100.0000	0.2100

Pressure Base:	14.650
Real BTU Dry:	1006.868
Real BTU Wet:	989.193
Calc. Ideal Gravity:	0.5614
Calc. Real Gravity:	0.5623
Field Gravity:	
Standard Pressure:	14.696
Ideal BTU Dry:	1007.987
Ideal BTU Wet:	990.448
Z Factor:	0.9980
Average Mol Weight:	16.2563
Average CuFt/Gal:	59.2285
26 lb. Product:	0.0000
Ethane+ GPM	0.2100
Propane+ GPM:	0.0105
Butane+ GPM:	0.0000
Pentane+ GPM:	0.0000

Remarks:
H2S IN GAS STREAM ON LOCATION: NONE DETECTED

Analysis By: Don Norman

GREENHOUSE GAS EMISSIONS

[INFORMATION USED TO DETERMINE EMISSIONS

- Table 3-4 – Conversion Factors
- Table 5-12 – Simplified TOC Emission Factors for Loading Losses
- Table C-1 – Default Factors & High Heat Values for Various types of fuel
- Table C-2 – Default CH_2 & N_20 Emission Factors for Various Types of Fuel
- Table 6-2 – Facility – Level Average Fugitive Emission Factors
- Table 5-2 – Segment Specific Uncontrolled Gas Dehydration CH_4 Emission Factors (Excludes Glycol-Assisted Pump Emissions)
- Table 1-A – Global Warming Potentials
- Table 4-11 – GHG Emission Factors for Gas Flares in Developed Countries
- Table 5-23 – Production Segment CH4 Emission Factors for Maintenance and Turnaround Activities

Table 3-4. Conversion Factors

	Common US Units	API-Preferred SI Units	Other Conversions
Mass		1 kilogram	= 2.20462 pounds (lb) = 1000* grams (g) = 0.001 metric tonnes (tonne)
	1 pound (lb)	= 0.4535924 kilograms	= 453.5924 grams (g)
	1 short ton (ton)	= 907.1847 kilograms	= 2000* pounds (lb)
	1 metric tonne (tonne)	= 1000* kilograms	= 2204.62 pounds (lb) = 1.10231 tons

Table 3-4. Conversion Factors, continued

	Common US Units	API-Preferred SI Units	Other Conversions
Volume		1 cubic meter (m^3)	= 1000 *liters (L) = 35.3147 cubic feet (ft^3) = 264.172 gallons
	1 cubic foot (ft^3)	= 0.02831685 cubic meters (m^3)	= 28.31685 liters (L) = 7.4805 gallons
	1 gallon (gal)	3.785412×10^{-3} cubic meters (m^3)	= 3.785412 liters (L)
	1 barrel (bbl)	= 0.1589873 cubic meters (m^3)	= 158.9873 liters (L) = 42* gallons (gal)
Length		1 meter (m)	= 3.28084 feet = 6.213712×10^{-4} miles
	1 inch (in)	= 0.0254* meters (m)	= 2.54* centimeters
	1 foot (ft)	= 0.3048* meters (m)	
	1 mile	= 1609.344* meters (m)	= 1.609344* kilometers
Power		1 Watt (W)	= 1* joule (J)/second = 9.47817×10^{-4} Btu/second = 1.34102×10^{-3} horsepower (hp)
	1 megawatt	10^6 Watts (W)	= 10^{6}* Joules/second = 1000* kilowatts (10^3 W)
	1 horsepower (hp)	= 745.6999 Watts (W)	= 0.7456999 kilowatts = 0.706787 Btu/second
Energy		1 Joule (J) 0.001 kilo Joules (kJ)	= 9.47817×10^{-4} Btu = 2.778×10^{-7} kilowatt-hour = 0.737562 foot-$pounds_{force}$
	1 horsepower-hour (hp-hr)	= 2.68452×10^6 Joules (J)	= 2544.43 Btu = 0.7456999 kilowatt-hour
	1 kilowatt-hour	= $3.6^* \times 10^6$ Joules (J)	= 3412.14 Btu = 1.34102 horsepower-hours = 3600* kilo-Joules
	1 Btu	= 1055.056 Joules (J)	= 3.93015×10^{-4} horsepower-hours = 2.93071×10^{-4} kilowatt-hours
	1 million Btu (10^6 Btu)	= 1.055056×10^9 Joules (J)	= 1.055056 giga-Joules (10^9 J) = 293.071 kilowatt-hours
	1 therm	= 1.055056×10^8 Joules (J)	= 100.000 Btu = 29.3071 kilowatt-hours
Pressure		1 kilo-Pascal (10^3 Pa)	= 9.869233×10^{-3} atmosphere (atm)
	1 atmosphere (atm)	= 101.325* kilo-Pascals (10^3 Pa)	= 14.696 pounds per square inch (psi)

Table 3-4. Conversion Factors, continued

	Common US Units	API Preferred SI Units	Other Conversions
Heating Value			
Mass basis:	1 Btu/pound	= 2326.000 Joules/kilogram (J/kg)	
Volume basis:	1 Btu/cubic foot (Btu/ft^3)	= 37,258.95 Joules/cubic meter (J/m^3)	= 0.133681 Btu/gallon
Emission Factor:		1 kilogram/giga-Joule (kg/10^9 J)	= 2.32600 pound/million Btu (lb/10^6 Btu)
	1 pound/million Btu (lb/10^6 Btu)	= 0.429923 kilograms/giga-Joule (kg/10^9 J)	= 0.429923 tonnes/tera-Joule (tonnes/10^{12} J) = 429.923 grams/giga-Joule (g/10^9 J)
Barrels of Oil Equivalent (BOE)			
All Fuel Types	1 BOE	= 6.12×10^9 J	= 5.8×10^6 Btu = 2279.49 horsepower-hours = 1699.81 kilowatt-hours
Natural Gas	1 BOE	= 159.920 m^3	= 5,647.52 ft^3
Note: The BOE volume equivalent for natural gas was calculated by dividing the 5.8E+06 Btu/BOE by the heating value of natural gas (pipeline quality) from Table 3-8 (1,027 Btu/scf).			
Natural Gas Liquids	1 BOE	= 0.231327 m^3	= 1.455 bbl = 231.327 L = 61.11 gal = 8.16992 ft^3

Footnotes:

* indicates the conversion factor is exact; any succeeding digits would be zeros.

psig = Gauge pressure.

psia = Absolute pressure (note psia = psig + atmospheric pressure).

Table 5-12. Simplified TOC Emission Factors for Loading Losses

Loading Type	Units		Crude Oil [a,b,c]
Rail / Truck Loading [d] Submerged Loading – Dedicated normal service	Original Units	lb TOC/10^3 gal loaded	2
		mg TOC/L loaded	240
	Converted Units [e]	tonne TOC/ 10^6 gal loaded	0.91
		tonne TOC/10^3 m^3 loaded	0.240
Rail / Truck Loading [d] Submerged Loading – Vapor balance service	Original Units	lb TOC/10^3 gal loaded	3
		mg TOC/L loaded	400
	Converted Units [e]	tonne TOC/ 10^6 gal loaded	1.51
		tonne TOC/10^3 m^3 loaded	0.400
Rail / Truck Loading [d] Splash Loading – Dedicated normal service	Original Units	lb TOC/10^3 gal loaded	5
		mg TOC/L loaded	580
	Converted Units [e]	tonne TOC/ 10^6 gal loaded	2.20
		tonne TOC/10^3 m^3 loaded	0.580
Rail / Truck Loading [d] Splash Loading – Vapor balance service	Original Units	lb TOC/10^3 gal loaded	3
		mg TOC/L loaded	400
	Converted Units [e]	tonne TOC/ 10^6 gal loaded	1.51
		tonne TOC/10^3 m^3 loaded	0.400
Marine Loading [f] – Ships/ocean barges	Original Units	lb TOC/10^3 gal loaded	0.61
		mg TOC/L loaded	73
	Converted Units [e]	tonne TOC/ 10^6 gal loaded	0.28
		tonne TOC/10^3 m^3 loaded	0.073
Marine Loading [f] – Barges	Original Units	lb TOC/10^3 gal loaded	1.0
		mg TOC/L loaded	120
	Converted Units [e]	tonne TOC/ 10^6 gal loaded	0.45
		tonne TOC/10^3 m^3 loaded	0.120

Footnotes and Sources:

[a] The factors shown are for total organic compounds. AP-42 reports that the VOC comprises approximately 85% of the TOC for crude oil. Thus, a simplifying assumption for the CH_4 content of the TOC is 15% in the absence of site-specific data, recognizing that this will likely overestimate emissions.

[b] EPA, AP-42, Section 5, Tables 5.2-5 and 5.2-6, 2008.

[c] The example crude oil has an RVP of 5 psia.

[d] The rail/truck loading emission factors were derived using Equation B-5 assuming a liquid temperature of 60°F.

[e] Converted from original emission factors provided in units of mg/L in AP-42. Thus, round-off errors may result in some small differences when converting from the emission factors provided in units of lb/10^3 gallons.

[f] Marine loading factors based on a loaded liquid temperature of 60°F.

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
Pipeline (Weighted U.S. Average)	1.028×10^{-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
Still Gas	0.143	66.72
Kerosene	0.135	75.20
Liquefied petroleum gases (LPG)	0.092	62.98
Propane	0.091	61.46
Propylene	0.091	65.95
Ethane	0.096	62.64
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
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
Fossil fuel-derived fuels (solid)	mmBtu/short ton	kg CO_2/mmBtu
Municipal Solid Waste[1]	9.95	90.7
Tires	26.87	85.97
Fossil fuel-derived 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
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 (100%)	0.084	68.44
Biodiesel (100%)	0.128	73.84
Rendered Animal Fat	0.125	71.06
Vegetable Oil	0.120	81.55

[1] Allowed only for units that do not generate steam and use Tier 1.

TABLE C–2 TO SUBPART C OF PART 98—DEFAULT CH_4 AND N_2O EMISSION FACTORS FOR VARIOUS TYPES OF FUEL

Fuel type	Default CH_4 emission factor (kg CH_4/mmBtu)	Default N_2O emission factor (kg N_2O/mmBtu)
Coal and Coke (All fuel types in Table C–1)	1.1×10^{-2}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All fuel types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels—Solid (All fuel types in Table C–1)	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels—Liquid (All fuel types in Table C–1)	1.1×10^{-03}	1.1×10^{-04}

Note: Those employing this table are assumed to fall under the IPCC definitions of the "Energy Industry" or "Manufacturing Industries and Construction". In all fuels except for coal the values for these two categories are identical. For coal combustion, those who fall within the IPCC "Energy Industry" category may employ a value of 1g of CH_4/MMBtu.

[1] Allowed only for units that do not generate steam and use Tier 1.

Table 6-2. Facility-Level Average Fugitive Emission Factors

Source	Emission Factor Original Units	Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b] Converted Units	Factor Reference
Production					
Onshore oil production	0.5173 lb CH_4/bbl produced	95.5	78.8 mole % CH_4	2.346E-04 tonnes CH_4/bbl produced 1.476E-03 tonnes CH_4/m^3 produced	EPA petroleum methane emissions study; see derivation in Appendix C
Offshore oil production	0.2069 lb CH_4/bbl produced	Not available	78.8 mole % CH_4	9.386E-05 tonnes CH_4/bbl produced 5.903E-04 tonnes CH_4/m^3 produced	Assumed to be 40% of the onshore oil production emission factor
Onshore gas production	57.33 lb CH_4/10^6scf produced	52.9	78.8 mole % CH_4	2.601E-02 tonnes CH_4/10^6 scf produced 9.184E-01 tonnes CH_4/10^6 m^3 produced	GRI/EPA Study, Vol. 2; see derivation in Appendix C
Offshore gas production	22.93 lb CH_4/10^6scf produced	Not available	78.8 mole % CH_4	1.040E-02 tonnes CH_4/10^6 scf produced 3.673E-01 tonnes CH_4/10^6 m^3 produced	Assumed to be 40% of the onshore gas production emission factor
Gas processing plants	64.43 lb CH_4/10^6scf processed	82.2	86.8 mole % CH_4	2.922E-02 tonnes CH_4/10^6 scf processed 1.032E+00 tonnes CH_4/10^6 m^3 processed	GRI/EPA Study, Vol. 2; see derivation in Appendix C
Gas storage stations	1,491,936 lb CH_4/station-yr	74.7	93.4 mole % CH_4	6.767E+02 tonnes CH_4/station-yr	GRI/EPA Study, Vol. 2; see derivation in Appendix C
Gas transmission pipelines					
CH_4 from pipeline leaks	7,928 lb CH4/mile-yr	113	93.4 mole % CH_4	3.596E+00 tonnes CH_4/mile-yr 2.235E+00 tonnes CH_4/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 from oxidation [c]	7.59 lb CO_2/mile-yr	70.3	2 mole % CO_2	3.443E-03 tonnes CO_2/mile-yr 2.140E-03 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 from pipeline leaks [d]	466.0 lb CO_2/mile-yr	113	2 mole % CO_2	2.114E-01 tonnes CO_2/mile-yr 1.313E-01 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
Crude transmission pipelines [e]	Not applicable				

Table 6-2. Facility-Level Average Fugitive Emission Factors, continued

Source	Emission Factor, Original Units	Uncertainty [a] (± %)	Gas Content Basis of Factor	Emission Factor [b], Converted Units	Factor Reference
Gas distribution pipelines					
CH_4 from pipeline leaks	3,557 lb CH_4/mile-yr	62.7	93.4 mole % CH_4	1.613E+00 tonnes CH_4/mile-yr 1.002E+00 tonnes CH_4/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 from oxidation [c]	1,236 lb CO_2/mile-yr	76.6	2 mole % CO_2	5.606E-01 tonnes CO_2/mile-yr 3.484E-01 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
CO_2 [d] from pipeline leaks	235.4 lb CO_2/mile-yr	74.4	2 mole % CO_2	1.068E-01 tonnes CO_2/mile-yr 6.636E-02 tonnes CO_2/km-yr	GRI/EPA Study, Vols. 2 and 9; see derivation in Appendix C
Refining [f]					Derived from data provided in Appendix F. Mid range capacity was assumed to convert emissions to a throughput basis
Fuel gas system – 50,000 to 99,000 bbl/day refinery	10.2 tonnes CH_4/yr (fuel gas – make gas	Not available	Not available	3.75E-07 tonnes CH_4/bbl feedstock 2.36E-06 tonnes CH_4/m^3 feedstock	
Fuel gas system – 100,000 to 199,000 bbl/day refinery	77 tonnes CH_4/yr	Not available	Not available	1.41E-06 tonnes CH_4/bbl feedstock 8.88E-06 tonnes CH_4/m^3 feedstock	
Natural gas system – 50,000 to 99,000 bbl/day refinery	26 tonnes CH_4/yr	Not available	Not available	9.56E-07 tonnes CH_4/bbl feedstock 6.01E-06 tonnes CH_4/m^3 feedstock	
Natural gas system – 100,000 to 199,000 bbl/day refinery	55 tonnes CH_4/yr	Not available	Not available	1.01E-06 tonnes CH_4/bbl feedstock 6.34E-06 tonnes CH_4/m^3 feedstock	

Footnotes and Sources:

Harrison, M.R., L.M. Campbell, T.M. Shires, and R.M. Cowgill. Methane *Emissions from the Natural Gas Industry, Volume 2: Technical Report*, Final Report, GRI-94/0257.1 and EPA-600/R-96-080b, Gas Research Institute and U.S. Environmental Protection Agency, June 1996

Campbell, L.M., M.V. Campbell, and D.L. Epperson. *Methane Emissions from the Natural Gas* Industry, *Volume 9: Underground Pipelines*, Final Report, GRI-94/0257.26 and EPA-600/R-96-080i, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

Harrison, M.R., T.M. Shires, R.A. Baker, and C.J. Loughran. *Methane Emissions from the U.S. Petroleum Industry*. Final Report, EPA-600/R-99-010, U.S. Environmental Protection Agency, February 1999

API refinery CH_4 fugitive emissions study provided in Appendix F.

[a] Uncertainty is based on a 95% confidence interval from the data used to develop the original emission factor.

[b] The emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] A portion of CH_4 emitted from underground pipeline leaks is oxidized to form CO_2.

[d] Combines CO_2 emissions from equipment and pipelines based on a concentration of 2 mole % CO_2 in the pipeline gas.

Footnotes and Sources for Table 6-2, continued:

[e] As discussed in Section 5, only "live" crude will contain CH_4 (and possibly CO_2). Weathered crude (crude which has reached atmospheric pressure) contains no CH_4 or CO_2. See Appendix E for further discussion on the CH_4 and CO_2 content of "weathered" crude and other oil and natural gas products. If transmission pipelines are used to transport "live" crude oil, CH_4 (and CO_2, if present) emissions should be calculated using engineering judgment.

[f] Refinery fugitive CH_4 emission factors were derived from data from an API refinery CH_4 fugitive emissions study provided in Appendix F. The estimated refinery fugitive CH_4 emission rates from the study for the fuel gas and natural gas systems were divided by the refinery feed capacity for the two refineries in the study, a 50,000 to 99,000 bbl/day "single train (multiply HDS)" refinery and a 100,000 to 199,000 bbl/day "old multi-train refinery." The mid-point of the range of the refinery capacities was assumed when deriving the emission factors (i.e., the estimated CH_4 fugitive emission rates were divided by 74,500 bbl feed/day for the smaller refinery and by 149,500 bbl feed/day for the larger refinery). Refer to Appendix F for the data used to estimate the emission factors.

TABLE 5-2. Segment Specific Uncontrolled Gas Dehydration CH_4 Emission Factors (Excludes Glycol-Assisted Pump Emissions)

Industry Segment	CH4 Emission Factor a , Original Units	CH4 Emission Factor b , Converted to Tonnes Basis	Content Basis for	Uncertainty [c] (+/- %)
Production	275.57 scf/10^6 scf gas processed	0.0052859 tonnes/10^6 scf gas processed 0.18667 tonnes/10^6 m^3 gas processed	78.8 mole %	191
Gas processing	121.55 scf/10^6 scf gas processed	0.0023315 tonnes/10^6 scf gas processed 0.082338 tonnes/10^6 m^3 gas processed	86.8 mole %	249
Gas transmission	93.72 scf/10^6 scf gas processed	0.001798 tonnes/10^6 scf gas processed 0.06349 tonnes/10^6 m^3 gas processed	93.4 mole %	257
Gas storage	117.18 scf/10^6 scf gas processed	0.0022477 tonnes/10^6 scf gas processed 0.079377 tonnes/10^6 m^3 gas processed	93.4 mole %	197

Footnotes and Sources:

[a] Myers, D.B. *Methane Emissions from the Natural Gas Industry, Volume 14: Glycol Dehydrators, Final Report*, GRI-94/0257.31 and EPA-600/R-96-080n, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.
[b] CH_4 emission factors converted from scfy are based on 60°F and 14.7 psia.

[c] Uncertainty is based on a 95% confidence interval; however, because the data used to calculate the reference emission factor were unavailable, the uncertainty at a 95% confidence interval was calculated based in the source, assuming a data set size of 10on the uncertainty at a 90% confidence interval presented

Table 5-3. GRI-GLYCalcTM-Generated Dehydration Methane Emission Factors
Includes Glycol Gas-Assisted Pump Emissions

Mode of Operation	CH_4 Emission Factor a,b , Original Units	CH_4 Emission Factor c, Converted to Tonnes per Gas Processed Basis
Gas pump without a flash separator	82.63 tonne/yr per 10^6 Nm^3/day gas processed	0.00641 tonnes/10^6 scf gas processed 0.2264 tonnes/10^6 m^3 gas processed
Gas pump with a flash separator	1.98 tonne/yr per 10^6 Nm^3/day gas processed	0.000154 tonnes/10^6 scf gas processed 0.00542 tonnes/10^6 m^3 gas processed
Electric pump without a flash separator	21.46 tonne/yr per 10^6 Nm^3/day gas processed	0.001665 tonnes/10^6 scf gas processed 0.05879 tonnes/10^6 m^3 gas processed
Electric pump with a flash separator	1.64 tonne/yr per 106 Nm^3/day gas processed	0.000127 tonnes/10^6 scf gas processed 0.00449 tonnes/10^6 m^3 gas processed

Footnotes and Sources:

[a] Texaco, 1999. Based on results from GRI Report No. GRI-98/0073, *Investigation of Condenser Efficiency for HAP Control from Glycol Dehydrator Reboiler Vent Streams: Analysis of Data from the EPA 114 Questionnaire and GRI's Condenser Monitoring Program*.
[b] Uncertainty data are not available from this source.
[c] CH_4 emission factors are based on 60°F and 14.7 psia.

TABLE A–1 TO SUBPART A OF PART 98—GLOBAL WARMING POTENTIALS

[100-Year Time Horizon]

Name	CAS No.	Chemical formula	Global warming potential (100 yr.)
Carbon dioxide	124–38–9	CO_2	1
Methane	74–82–8	CH_4	21
Nitrous oxide	10024–97–2	N_2O	310
HFC–23	75–46–7	CHF_3	11,700
HFC–32	75–10–5	CH_2F_2	650
HFC–41	593–53–3	CH_3F	150
HFC–125	354–33–6	C_2HF_5	2,800
HFC–134	359–35–3	$C_2H_2F_4$	1,000
HFC–134a	811–97–2	CH_2FCF_3	1,300
HFC–143	430–66–0	$C_2H_3F_3$	300
HFC–143a	420–46–2	$C_2H_3F_3$	3,800
HFC–152	624–72–6	CH_2FCH_2F	53
HFC–152a	75–37–6	CH_3CHF_2	140
HFC–161	353–36–6	CH_3CH_2F	12
HFC–227ea	431–89–0	C_3HF_7	2,900
HFC–236cb	677–56–5	$CH_2FCF_2CF_3$	1,340
HFC–236ea	431–63–0	CHF_2CHFCF_3	1,370
HFC–236fa	690–39–1	$C_3H_2F_6$	6,300
HFC–245ca	679–86–7	$C_3H_3F_5$	560
HFC–245fa	460–73–1	$CHF_2CH_2CF_3$	1,030
HFC–365mfc	406–58–6	$CH_3CF_2CH_2CF_3$	794
HFC–43–10mee	138495–42–8	$CF_3CFHCFHCF_2CF_3$	1,300
Sulfur hexafluoride	2551–62–4	SF_6	23,900
Trifluoromethyl sulphur pentafluoride	373–80–8	SF_5CF_3	17,700
Nitrogen trifluoride	7783–54–2	NF_3	17,200
PFC–14 (Perfluoromethane)	75–73–0	CF_4	6,500
PFC–116 (Perfluoroethane)	76–16–4	C_2F_6	9,200
PFC–218 (Perfluoropropane)	76–19–7	C_3F_8	7,000
Perfluorocyclopropane	931–91–9	$C\text{-}C_3F_6$	17,340
PFC–3–1–10 (Perfluorobutane)	355–25–9	C_4F_{10}	7,000
Perfluorocyclobutane	115–25–3	$C\text{-}C_4F_8$	8,700
PFC–4–1–12 (Perfluoropentane)	678–26–2	C_5F_{12}	7,500
PFC–5–1–14 (Perfluorohexane)	355–42–0	C_6F_{14}	7,400
PFC–9–1–18	306–94–5	$C_{10}F_{18}$	7,500
HCFE–235da2 (Isoflurane)	26675–46–7	$CHF_2OCHClCF_3$	350
HFE–43–10pccc (H–Galden 1040x)	E1730133	$CHF_2OCF_2OC_2F_4OCHF_2$	1,870
HFE–125	3822–68–2	CHF_2OCF_3	14,900
HFE–134	1691–17–4	CHF_2OCHF_2	6,320
HFE–143a	421–14–7	CH_3OCF_3	756
HFE–227ea	2356–62–9	$CF_3CHFOCF_3$	1,540
HFE–236ca12 (HG–10)	78522–47–1	$CHF_2OCF_2OCHF_2$	2,800
HFE–236ea2 (Desflurane)	57041–67–5	$CHF_2OCHFCF_3$	989
HFE–236fa	20193–67–3	$CF_3CH_2OCF_3$	487
HFE–245cb2	22410–44–2	$CH_3OCF_2CF_3$	708
HFE–245fa1	84011–15–4	$CHF_2CH_2OCF_3$	286
HFE–245fa2	1885–48–9	$CHF_2OCH_2CF_3$	659
HFE–254cb2	425–88–7	$CH_3OCF_2CHF_2$	359
HFE–263fb2	460–43–5	$CF_3CH_2OCH_3$	11
HFE–329mcc2	67490–36–2	$CF_3CF_2OCF_2CHF_2$	919
HFE–338mcf2	156053–88–2	$CF_3CF_2OCH_2CF_3$	552
HFE–338pcc13 (HG–01)	188690–78–0	$CHF_2OCF_2CF_2OCHF_2$	1,500
HFE–347mcc3	28523–86–6	$CH_3OCF_2CF_2CF_3$	575
HFE–347mcf2	E1730135	$CF_3CF_2OCH_2CHF_2$	374
HFE–347pcf2	406–78–0	$CHF_2CF_2OCH_2CF_3$	580
HFE–356mec3	382–34–3	$CH_3OCF_2CHFCF_3$	101
HFE–356pcc3	160620–20–2	$CH_3OCF_2CF_2CHF_2$	110
HFE–356pcf2	E1730137	$CHF_2CH_2OCF_2CHF_2$	265
HFE–356pcf3	35042–99–0	$CHF_2OCH_2CF_2CHF_2$	502
HFE–365mcf3	378–16–5	$CF_3CF_2CH_2OCH_3$	11
HFE–374pc2	512–51–6	$CH_3CH_2OCF_2CHF_2$	557
HFE–449sl (HFE–7100)	163702–07–6	$C_4F_9OCH_3$	297
Chemical blend	163702–08–7	$(CF_3)_2CFCF_2OCH_3$	
HFE–569sf2 (HFE–7200)	163702–05–4	$C_4F_9OC_2H_5$	59
Chemical blend	163702–06–5	$(CF_3)_2CFCF_2OC_2H_5$	
Sevoflurane	28523–86–6	$CH_2FOCH(CF_3)_2$	345
HFE–356mm1	13171–18–1	$(CF_3)_2CHOCH_3$	27
HFE–338mmz1	26103–08–2	$CHF_2OCH(CF_3)_2$	380
(Octafluorotetramethy-lene)hydroxymethyl group	NA	$X\text{-}(CF_2)_4CH(OH)\text{-}X$	73
HFE–347mmy1	22052–84–2	$CH_3OCF(CF_3)_2$	343
Bis(trifluoromethyl)-methanol	920–66–1	$(CF_3)_2CHOH$	195
2,2,3,3,3-pentafluoropropanol	422–05–9	$CF_3CF_2CH_2OH$	42
PFPMIE	NA	$CF_3OCF(CF_3)CF_2OCF_2OCF_3$	10,300

NA = not available.

Table 4-11. GHG Emission Factors for Gas Flares in Developed Countries [a]

Original Units							
Flare Source	**Emission Factors**						
	CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	1.2E-03	±25	7.6E-07	±25	2.1E-08	-10 to +1000	$Gg/10^6\ m^3$ gas production
Flaring - sweet gas processing	1.8E-03	±25	1.2E-06	±25	2.5E-08	-10 to +1000	$Gg/10^6\ m^3$ raw gas feed
Flaring - sour gas processing	3.6E-03	±25	2.4E-06	±25	5.4E-08	-10 to +1000	$Gg/10^6\ m^3$ raw gas feed
Flaring - conventional oil production	4.1E-02	±50	2.5E-05	±50	6.4E-07	-10 to +1000	$Gg/10^3\ m^3$ conventional oil production
Flaring - heavy oil/cold bitumen production	2.2E-02	±75	1.4E-04	±75	4.6E-07	-10 to +1000	$Gg/10^3\ m^3$ heavy oil production
Flaring - thermal oil production	2.7E-02	±75	1.6E-05	±75	2.4E-07	-10 to +1000	$Gg/10^3\ m^3$ thermal bitumen production
Flaring – refining [d,e]	No data	No data	0.189	No data	No data	No data	$scf/10^3$ bbl refinery feed
Units Converted to tonnes/10^6 scf or tonnes/1000 bbl							
Flare Source	**Emission Factors**						
	CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	3.4E-02	±25	2.2E-05	±25	5.9E-07	-10 to +1000	$tonnes/10^6$ scf gas production
Flaring - sweet gas processing	5.1E-02	±25	3.4E-05	±25	7.1E-07	-10 to +1000	$tonnes/10^6$ scf raw gas feed
Flaring - sour gas processing	0.10	±25	6.8E-05	±25	1.5E-06	-10 to +1000	$tonnes/10^6$ scf raw gas feed
Flaring - conventional oil production	6.5	±50	4.0E-03	±50	1.0E-04	-10 to +1000	$tonnes/10^3$ bbl conventional oil production
Flaring - heavy oil/cold bitumen production	3.5	±75	2.2E-02	±75	7.3E-05	-10 to +1000	$tonnes/10^3$ bbl heavy oil production
Flaring - thermal oil production	4.3	±75	2.5E-03	±75	3.8E-05	-10 to +1000	$tonnes/10^3$ bbl thermal bitumen production
Flaring - refining [d,e]	No data	No data	3.63E-06	No data	No data	No data	$tonnes/10^3$ bbl refinery feed

Table 4-11. GHG Emission Factors for Gas Flares in Developed Countries [a], continued

Units Converted to tonnes/$10^6\ m^3$ or tonnes/1000 m^3							
	Emission Factors						
Flare Source	CO_2	Uncertainty [b] (%)	CH_4	Uncertainty [b] (%)	N_2O	Uncertainty [b] (%)	Units
Flaring - gas production [c]	1.2	±25	7.6E-04	±25	2.1E-05	-10 to +1000	$tonnes/10^6\ m^3$ gas production
Flaring - sweet gas processing	1.8	±25	1.2E-03	±25	2.5E-05	-10 to +1000	$tonnes/10^6 m^3$ raw gas feed
Flaring - sour gas processing	3.6	±25	2.4E-03	±25	5.4E-05	-10 to +1000	$tonnes/10^6 m^3$ raw gas feed
Flaring - conventional oil production	41.0	±50	2.5E-02	±50	6.4E-04	-10 to +1000	$tonnes/10^3\ m^3$ conventional oil production
Flaring - heavy oil/cold bitumen production	22.0	±75	1.4E-01	±75	4.6E-04	-10 to +1000	$tonnes/10^3\ m^3$ heavy oil production
Flaring - thermal oil production	27.0	±75	1.6E-02	±75	2.4E-04	-10 to +1000	$tonnes/10^3\ m^3$ thermal bitumen production
Flaring – refining [d,e]	No data	No data	2.28E-05	No data	No data	No data	$tonnes/10^3\ m^3$ refinery feed

Footnotes and Sources:

[a] IPCC, *2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2, Chapter 4 (Fugitive Emissions)*. Table 4.2.4, 2006 Revised November 2008.

[b] Uncertainty based on a 95% confidence interval (IPCC, Volume 2, Chapter 4, Section 4.2.2.7.2, 2006 Revised November 2008).

[c] IPCC reports that flared volumes should be used to estimate flare emissions instead of the above emission factors when such data are available. IPCC reports that flared volume based emission factors are 0.012, 2.0 and 0.000023 $Gg/10^6\ m^3$ of gas flared for CH_4, CO_2, and N_2O, respectively, based on a flaring efficiency of 98% and a typical gas analysis at a gas processing plant (91.9% CH_4, 0.58% CO_2, 0.68% N_2 and 6.84% non-CH_4 hydrocarbons, by volume).

[d] U.S. Environmental Protection Agency (EPA). *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2007*. Table A-127, April 15, 2009.

[e] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia.

Table 5-23. Production Segment CH_4 Emission Factors for Maintenance and Turnaround Activities

Source	CH_4 Emission Factor [a], Original Units	CH_4 Emission Factor [b], Converted to Tonnes Basis	CH_4 Content Basis of Factor [c]	Uncertainty [d] (±%)
Vessel blowdowns	78 scfy/vessel	0.0015 tonnes/vessel-yr	78.8 mole %	326
Compressor starts [e]	8,443 scfy/compressor	0.1620 tonnes/ compressor-yr	78.8 mole %	190
Compressor blowdowns	3,774 scfy/compressor	0.07239 tonnes/ compressor-yr	78.8 mole %	179
Gas well workovers [f] (tubing maintenance)	2,454 scf/workover	0.04707 tonnes/workover	Not given	924
Oil well workovers [f] (tubing maintenance)	96 scf/workover	0.0018 tonnes/workover	Not given	Not available
Gathering gas pipeline blowdowns	309 scfy/mile	0.00593 tonnes/mile-yr 0.00368 tonne/km-yr	78.8 mole %	39.5
Onshore gas well completion [g]	$1,712\times10^3$ scf/ completion-day	25.9 tonne/completion-day	78.8 mole %	Not available
Offshore gas well completion [g]	$\sim8,700\times10^3$ scf/ completion-day	131.5 tonne/completion-day	78.8 mole %	Not available
Oil pump stations (maintenance) [h]	1.56 lb/yr-station	7.076E-04 tonnes/station-yr	Not given	Not available

Footnotes and Sources:

[a] Shires, T.M. *Methane Emissions from the Natural Gas Industry, Volume 7: Blow and Purge Activities, Final Report*, GRI-94/0257.24 and EPA-600/R-96-080g, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[b] CH_4 emission factors converted from scf or m^3 are based on 60°F and 14.7 psia. The CH_4 emission factors can be adjusted based on the relative concentrations of CH_4 and CO_2 to estimate CO_2 emissions.

[c] Shires, T.M., and M.R. Harrison. *Methane Emissions from the Natural Gas Industry, Volume 6: Vented and Combustion Source Summary, Final Report*, GRI-94/0257.23 and EPA-600/R-96-080f, Gas Research Institute and U.S. Environmental Protection Agency, June 1996.

[d] Uncertainty based on a 95% confidence interval.

[e] An EPA Gas STAR paper on engine starts reports that typical production compressor engine start-ups vent 1,000 to 5,000 scf of gas with each start-up attempt (EPA Gas STAR, PRO Fact Sheet No. 101, September 2004). This equates to 0.015 to 0.076 tonnes CH_4/start-up attempt assuming 78.8 mole % CH_4 in the gas.

[f] Factor taken from: Tilkicioglu, B.H. *Annual Methane Emission Estimate of the Natural Gas Systems in the United States*, Phase II. Pipeline Systems Incorporated (PSI), September 1990. An EPA Gas STAR paper on installing plunger lift systems in gas wells presents a gas well workover emission factor of 2000 scf CH_4/workover, which equates to 0.0384 tonnes CH_4/workover (EPA Gas STAR, Lessons Learned - Installing Plunger Lift Systems in Gas Wells, October 2003). Gas STAR also reports that the number of gas well workovers conducted in a year typically ranges from 1 to 15.

[g] EIA, U.S. Natural Gas Markets: Mid-Term Prospects for Natural Gas Supply, December 2001. Cites data for initial rates of production for completions in 2000. Offshore factor interpolated from chart "Initial Flow Rates of New Natural Gas Well Completions, 1985-2000." The total gas basis was converted to a CH_4 basis assuming 78.8 mole % CH_4 in production using the GRI/EPA average CH_4 composition for production operations.

[h] Tilkicioglu, B.H and D.R. Winters. *Annual Methane Emission Estimate of the Natural Gas and Petroleum Systems in the United States*, Pipeline Systems Incorporated (PSI), December 1989.

Click Below to Return to the Following Calculation Page:
Blowdown

Section 8

Map(s)

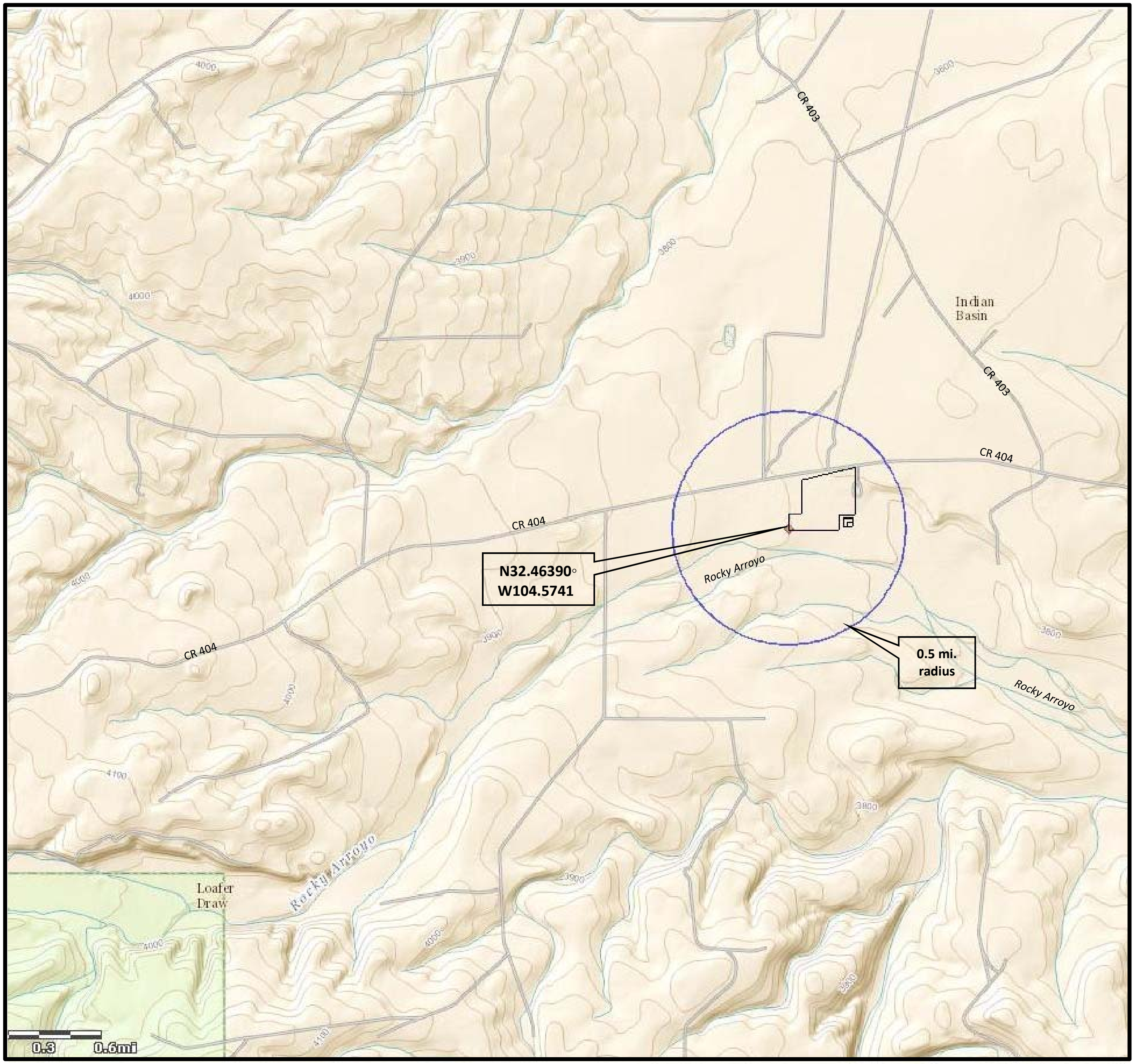
A map such as a 7.5 minute topographic quadrangle showing the exact location of the source. The map shall also include the following:

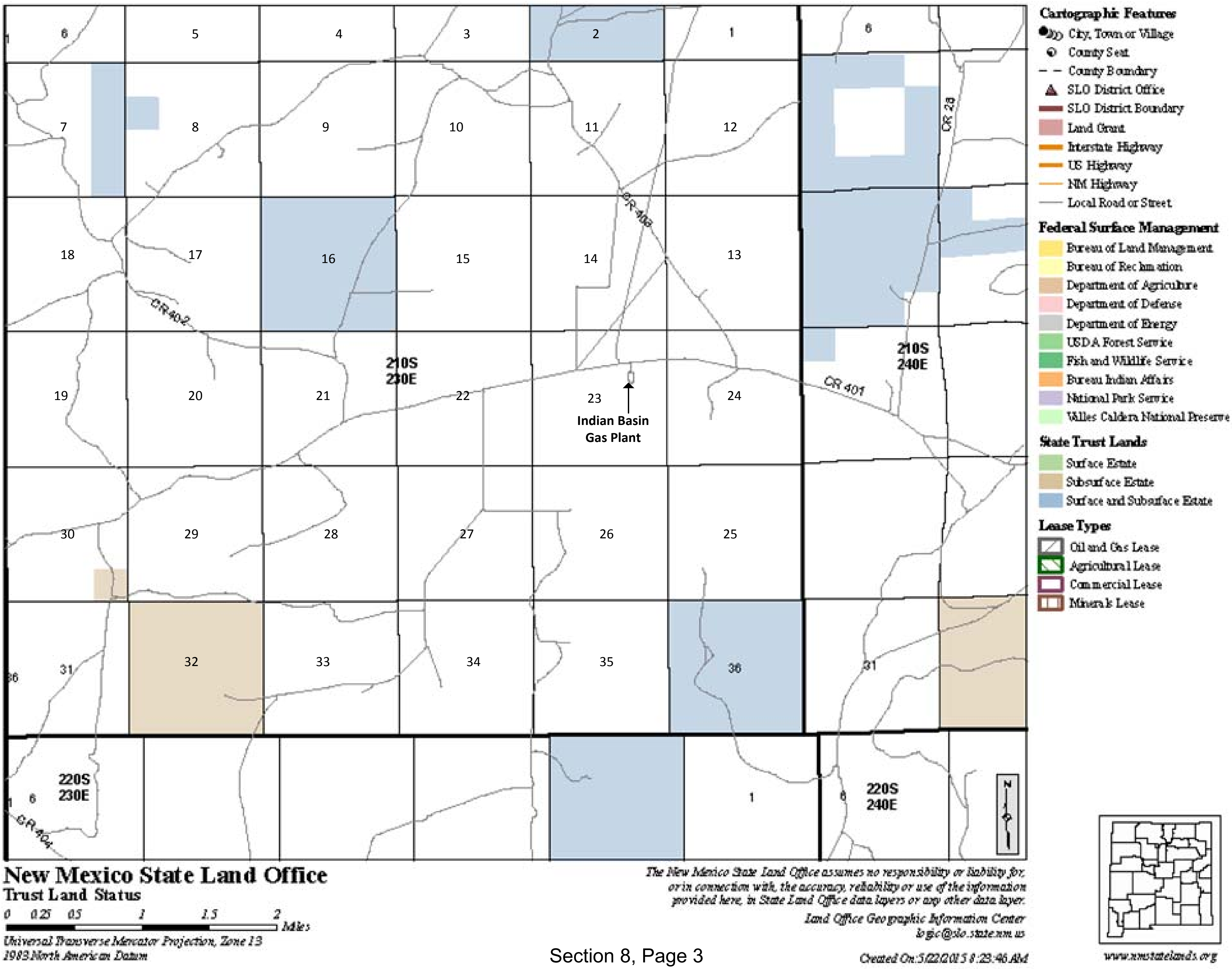
The UTM or Longitudinal coordinate system on both axes	An indicator showing which direction is north
A minimum radius around the plant of 0.8km (0.5 miles)	Access and haul roads
Topographic features of the area	Facility property boundaries
The name of the map	The area which will be restricted to public access
A graphical scale	

To save paper and to standardize the application format, delete this sentence, and begin your submittal for this attachment on this page.

Indian Basin Gas Plant

NOTES: Data available from U.S. Geological Survey, National Geospatial Program.





Cartographic Features
City, Town or Village
County Seat
County Boundary
SLO District Office
SLO District Boundary
Land Grant
Interstate Highway
US Highway
NM Highway
Local Road or Street
Federal Surface Management
Bureau of Land Management
Bureau of Reclamation
Department of Agriculture
Department of Defense
Department of Energy
USDA Forest Service
Fish and Wildlife Service
Bureau Indian Affairs
National Park Service
Valles Caldera National Preserve
State Trust Lands
Surface Estate
Subsurface Estate
Surface and Subsurface Estate
Lease Types
Oil and Gas Lease
Agricultural Lease
Commercial Lease
Minerals Lease
21OS
23OE
21OS
24OE
22OS
23OE
22OS
24OE
CR 402
CR 403
CR 401
CR 404
CR 28
Indian Basin
Gas Plant
New Mexico State Land Office
Trust Land Status
0 0.25 0.5 1 1.5 2
Miles
Universal Transverse Mercator Projection, Zone 13
1983 North American Datum
The New Mexico State Land Office assumes no responsibility or liability for, or in connection with, the accuracy, reliability or use of the information provided here, in State Land Office data layers or any other data layer.
Land Office Geographic Information Center
logic@slo.state.nm.us
Created On: 5/22/2015 8:23:46 AM
www.nmstatelands.org

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”)

This section does not apply to this action. This section is only for NSR applications submitting under 20.2.72 or 20.2.74 NMAC.

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 Indian Basin Gas Plant receives produced natural gas, condensate, and water from oil field production facilities. The condensate and water are separated and the water is pumped to a disposal well. The condensate is stabilized in a steam-reboiler stabilizer and the stabilizer overhead vapors are compressed and returned to the plant inlet. After stabilization, the condensate and any additional separated water are stored in atmospheric tanks. The condensate is then put into tank trucks for sale and the water is piped to the disposal well. The condensate tanks are connected to a vapor recovery system.

The field gas enters the plant where it is then sweetened in an amine-sweetening system. The H2S and CO2 removed from the rich amine solution flows to a disposal well for injection after compression.

The sweetened gas from the amine system flows to the glycol dehydration system to remove water. Additional dehydration may be accomplished using a four-bed molecular sieve system. A direct-fired regeneration gas heater regenerates the molecular sieve beds. The dry gas is then passed to a cryogenic unit for liquid recovery. Heat exchangers and two expander-compressors are used to obtain low temperatures that condense natural gas liquids. The residue gas is then compressed into a transmission line for sale. Natural gas liquids can be piped off-site or may be loaded out to truck through the proposed natural gas liquid load out point.

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 for emission sources located at the facility

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.

X Yes ☐ **No**

Common Ownership or Control: Surrounding or associated sources are under common ownership or control as this source.

X Yes ☐ **No**

Contiguous or Adjacent: Surrounding or associated sources are contiguous or adjacent with this source.

X Yes ☐ **No**

C. Make a determination:

X 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.

- This section is not required. This Title V Revision is being submitted under 20.2.20 NMAC.

Section 13

Determination of State & Federal Air Quality Regulations

This section lists each state and federal air quality regulation that may apply to your facility and/or equipment that are stationary sources of regulated air pollutants.

Not all state and federal air quality regulations are included in this list. Go to the Code of Federal Regulations (CFR) or to the Air Quality Bureau's regulation page to see the full set of air quality regulations.

Required Information for Specific Equipment:
For regulations that apply to specific source types, in the 'Justification' column **provide any information needed to determine if the regulation does or does not apply**. **For example**, to determine if emissions standards at 40 CFR 60, Subpart IIII apply to your three identical stationary engines, we need to know the construction date as defined in that regulation; the manufacturer date; the date of reconstruction or modification, if any; if they are or are not fire pump engines; if they are or are not emergency engines as defined in that regulation; their site ratings; and the cylinder displacement.

Required Information for Regulations that Apply to the Entire Facility:
See instructions in the 'Justification' column for the information that is needed to determine if an 'Entire Facility' type of regulation applies (e.g. 20.2.70 or 20.2.73 NMAC).

Regulatory Citations for Regulations That Do Not, but Could Apply:
If there is a state or federal air quality regulation that does not apply, but you have a piece of equipment in a source category for which a regulation has been promulgated, you must **provide the low level regulatory citation showing why your piece of equipment is not subject to or exempt from the regulation. For example** if you have a stationary internal combustion engine that is not subject to 40 CFR 63, Subpart ZZZZ because it is an existing 2 stroke lean burn stationary RICE with a site rating of more than 500 brake HP located at a major source of HAP emissions, your citation would be 40 CFR 63.6590(b)(3)(i). **We don't want a discussion of every non-applicable regulation, but if it is possible a regulation could apply, explain why it does not. For example,** if your facility is a power plant, you do not need to include a citation to show that 40 CFR 60, Subpart OOO does not apply to your non-existent rock crusher.

Regulatory Citations for Emission Standards:
For each unit that is subject to an emission standard in a source specific regulation, such as 40 CFR 60, Subpart OOO or 40 CFR 63, Subpart HH, include the low level regulatory citation of that emission standard. Emission standards can be numerical emission limits, work practice standards, or other requirements such as maintenance. **Here are examples:** a glycol dehydrator is subject to the general standards at 63.764C(1)(i) through (iii); an engine is subject to 63.6601, Tables 2a and 2b; a crusher is subject to 60.672(b), Table 3 and all transfer points are subject to 60.672(e)(1)

Federally Enforceable Conditions:
All federal regulations are federally enforceable. All Air Quality Bureau State regulations are federally enforceable except for the following: affirmative defense portions at 20.2.7.6.B, 20.2.7.110(B)(15), 20.2.7.11 through 20.2.7.113, 20.2.7.115, and 20.2.7.116; 20.2.37; 20.2.42; 20.2.43; 20.2.62; 20.2.63; 20.2.86; 20.2.89; and 20.2.90 NMAC. Federally enforceable means that EPA can enforce the regulation as well as the Air Quality Bureau and federally enforceable regulations can count toward determining a facility's potential to emit (PTE) for the Title V, PSD, and nonattainment permit regulations.

INCLUDE ANY OTHER INFORMATION NEEDED TO COMPLETE AN APPLICABILITY DETERMINATION OR THAT IS RELEVENT TO YOUR FACILITY'S NOTICE OF INTENT OR PERMIT.

EPA Applicability Determination Index for 40 CFR 60, 61, 63, etc: http://cfpub.epa.gov/adi/

Example of a Table for State Regulations:

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
20.2.1 NMAC	General Provisions	Yes	Facility	General Provisions apply to Notice of Intent, Construction, and Title V permit applications.
20.2.3 NMAC	Ambient Air Quality Standards NMAAQS	Yes	Facility	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. Title V applications, see exemption at 20.2.3.9 NMAC
20.2.7 NMAC	Excess Emissions	Yes	Facility	All Title V major sources are subject to Air Quality Control Regulations, as defined in 20.2.7 NMAC, and are thus subject to the requirements of this regulation. Also listed as applicable in NSR Permit PSD0295-M10R3.
20.2.33 NMAC	Gas Burning Equipment - Nitrogen Dioxide	No	N/A	This facility does not have existing or new gas burning equipment (external combustion emission sources, such as gas fired boilers and heaters) having a heat input of greater than 1,000,000 million British Thermal Units per year per unit.
20.2.34 NMAC	Oil Burning Equipment: NO_2	No	N/A	This facility does not have oil burning equipment (external combustion emission sources, such as oil fired boilers and heaters) having a heat input of greater than 1,000,000 million British Thermal Units per year per unit.
20.2.35 NMAC	Natural Gas Processing Plant – Sulfur	No	N/A	This regulation could apply to existing (prior to July 1, 1974) or new (on or after July 1, 1974) natural gas processing plants that use a Sulfur Recovery Unit to reduce sulfur emissions. The facility is not subject to this regulation since the acid gas is sent to an off-site AGI well and does not have an SRU.
20.2.37 and 20.2.36 NMAC	Petroleum Processing Facilities and Petroleum Refineries	N/A	N/A	**These regulations were repealed by the Environmental Improvement Board. If you had equipment subject to 20.2.37 NMAC before the repeal, your combustion emission sources are now subject to 20.2.61 NMAC.**
20.2.38 NMAC	Hydrocarbon Storage Facility	No	N/A	1) 20.2.38.7 Definitions: In addition to the terms defined in 20.2.2 NMAC (Definitions), as used in this Part: A. "New hydrocarbon storage facility" means any hydrocarbon storage facility, or part thereof, the fabrication, erection, installation, or modification of which is commenced on or after January 1, 1975. B. "New tank battery" means any tank battery, or part thereof, the fabrication, erection, installation, or modification of which is commenced on or after January 1, 1975. E. "Tank battery" means a tank or group of tanks that receive crude oil or condensate from a well for storage until shipment. The condensate tanks and skimmer basin oil tanks meet the definition of new hydrocarbon storage facility (A). However, there are no applicable requirements in 20.2.38. (2) 20.2.38.109 NMAC – Tank storage associated with petroleum production or processing facility - The owner or operator shall not place, hold or store hydrocarbons containing hydrogen sulfide in a container associated with a petroleum production facility or petroleum processing facility and having a capacity of 20,000 gallons or greater with a throughput of at least 30,000 gallon per week, unless the container is equipped as specified – **Not applicable because there are no hydrocarbon storage tanks which contain hydrogen sulfide that have a capacity greater than 476 bbl. ES-46, 47, and 48 and do not contain H_2S and ES-52 is 210 bbl.** (3) 20.2.38.112 NMAC - New tank battery -- more than 65,000 gallons capacity - **Not applicable because ES-46, 47, 48, and 52 are not considered to be a tank battery per 20.2.38.7 NMAC definition above. The tanks do not receive crude oil or condensate from a well for storage until shipment, as the IBGP is not a field site.**

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
20.2.39 NMAC	Sulfur Recovery Plant - Sulfur	No	**N/A**	This regulation could apply to sulfur recovery plants that are not part of petroleum or natural gas processing facilities. This regulation does not apply to the IBGP. The sulfur recovery operations are shut down.
20.2.50 NMAC	Oil and Gas Sector – Ozone Precursor Pollutants	No	N/A	This regulation establishes emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NOx) for oil and gas production, processing, compression, and transmission sources. 20.2.50 NMAC subparts below: Check the box for the subparts that are applicable: ☐113 – Engines and Turbines ☐114 – Compressor Seals ☐115 – Control Devices and Closed Vent Systems ☐116 – Equipment Leaks and Fugitive Emissions ☐ 117 – Natural Gas Well Liquid Unloading ☐ 118 – Glycol Dehydrators ☐ 119 – Heaters ☐ 120 – Hydrocarbon Liquid Transfers ☐121 – Pig Launching and Receiving ☐122 – Pneumatic Controllers and Pumps ☐ 123 – Storage Vessels ☐124 – Well Workovers ☐ 125 – Small Business Facilities ☐126 – Produced Water Management Unit ☐127 – Flowback Vessels and Preproduction Operations Facility is currently shut down therefore
20.2.61.109 NMAC	Smoke & Visible Emissions	Yes	ES-02 ES-03 ES-04 ES-05 ES-06/07 ES-08/09 ES-10/11 ES-12 ES-17 ES-21 ES-22	This regulation that limits opacity to 20% applies to Stationary Combustion Equipment, such as engines, boilers, heaters, and flares unless your equipment is subject to another state regulation that limits particulate matter such as 20.2.19 NMAC (see 20.2.61.109 NMAC). **If equipment at your facility was subject to the repealed regulation 20.2.37 NMAC it is now subject to 20.2.61 NMAC.**
20.2.70 NMAC	Operating Permits	Yes	Facility	Applies if your facility's potential to emit (PTE) is 100 tpy or more of any regulated air pollutant other than HAPs; and/or a HAPs PTE of 10 tpy or more for a single HAP or 25 or more tpy for combined HAPs; is subject to a 20.2.79 NMAC nonattainment permit; or is a facility subject to a federal regulation that requires you to obtain a Title V permit such as landfills or air curtain incinerators. The Indian Basin Gas Plant is a Title V major source of NO_x and CO; it is not a major source for HAPs.
20.2.71 NMAC	Operating Permit Fees	Yes	Facility	If subject to 20.2.70 NMAC and your permit includes numerical ton per year emission limits, you are subject to 20.2.71 NMAC and normally applies to the entire facility.
20.2.72 NMAC	Construction Permits	Yes	Facility	Applies if your facility's potential emission rate (PER) is greater than 10 pph or greater than 25 tpy for any pollutant subject to a state or federal ambient air quality standard (does not include VOCs or HAPs); if the PER of lead is 5 tpy or more; if your facility is subject to 20.2.72.400 NMAC; or if you have equipment subject to 40 CFR 60 Subparts I and OOO, 40 CFR 61 Subparts C and D.

State Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)
				The Indian Basin Gas Plant is subject to 20.2.72 NMAC and complies with NSR Permit PSD0295-M10-R3.
20.2.73 NMAC	NOI & Emissions Inventory Requirements	Yes	Facility	You could be required to submit **Emissions Inventory Reporting per** 20.2.73.300 NMAC if your facility is subject to 20.2.73.200, 20.2.72, or emits more than 1 ton of lead or 10 tons of TSP, PM10, PM2.5, SOx, NOx CO, or VOCs in any calendar year. All facilities that are a Title V Major Source as defined at 20.2.70.7.R NMAC, are subject to Emissions Inventory Reporting.
20.2.74 NMAC	Permits – Prevention of Significant Deterioration (PSD)	Yes	Facility	The Indian Basin Gas Plant is a PSD major source of NOx. **20.2.74.7.AG(2)** A stationary source not listed in Table 1 of this Part (20.2.74.501 NMAC) and which emits or has the potential to emit stack emissions of two hundred fifty (250) tons per year or more of any regulated pollutant
20.2.75 NMAC	Construction Permit Fees	No	Facility	This facility is subject to 20.2.72 NMAC and is in turn subject to 20.2.75 NMAC. You are not subject to the 75.11.E annual fees if you are subject to 20.2.71 NMAC.
20.2.77 NMAC	New Source Performance	Yes	Units subject to 40 CFR 60	This is a stationary source which is subject to the requirements of 40 CFR Part 60, as amended through September 23, 2013. (1) NSPS Kb ES-47 ES-48 (2) NSPS GG ES-06/07 ES-08/09 ES-10/11 ES-22 (3) NSPS KKK* VRU-ES-40-SB ES-46 ES-47 ES-48 VCS-COND (Mol. sieve dehy#2) ES-14 (VOC components), ES-50 (VOC components) ES-17 (compressor) (4) NSPS KKKK ES-17 (5) NSPS OOOO** New Fugitive components (FUG) including the new piping components associated with the NGL load out.
20.2.78 NMAC	Emission Standards for HAPS	No	N/A	This facility does not emit hazardous air pollutants which are subject to the requirements of 40 CFR Part 61, as amended through December 31, 2010.
20.2.79 NMAC	Permits – Nonattainment Areas	No	N/A	This facility is not subject to this regulation as it is not located in a nonattainment area.
20.2.80 NMAC	Stack Heights	No	N/A	There are no stack height requirements cited in NSR Permit PSD0295-M10R3.

State Regulation Citation	**Title**	**Applies? Enter Yes or No**	**Unit(s) or Facility**	**Justification: (You may delete instructions or statements that do not apply in the justification column to shorten the document.)**
20.2.82 NMAC	MACT Standards for source categories of HAPS	Yes	Units Subject to 40 CFR 63	This regulation applies to all sources emitting hazardous air pollutants, which are subject to the requirements of 40 CFR Part 63, as amended through August 29, 2013. The IBGP glycol dehydrator unit ES-40 is subject to 40 CFR part 63 Subpart HH requirements for TEG dehydrators at area sources of HAPs. There are recordkeeping and reporting requirements however, the site qualifies for an exemption from the emissions reduction standards since benzene emissions are less than 1 ton per year.

Example of a Table for Applicable Federal Regulations (Note: This is not an exhaustive list):

Federal Regulation Citation	**Title**	**Applies? Enter Yes or No**	**Unit(s) or Facility**	**Justification:**
40 CFR 50	NAAQS	Yes	Facility	Defined as applicable at 20.2.70.7.E.11, Any national ambient air quality standard The facility will be in compliance with permitted emission limits. Air dispersion modeling previously conducted for this site was determined to be sufficient to assure compliance with applicable NAAQS.
NSPS 40 CFR 60, Subpart A	General Provisions	Yes	Units subject to 40 CFR 60	Applies if any other NSPS subpart applies. NSPS GG : ES-06/07, ES-08/09, ES-10/11, & ES-22 NSPS Kb : ES-47 & ES-48 NSPS KKK*: fugitive emissions (FUG) associated with units, which commenced construction, reconstruction or modification after January 20, 1984 and on or after August 23, 2011, including VRU-ES-40-SB, flares (ES-14 and ES-50), ES-17 (inlet compressor). NSPS OOOO: fugitive piping component emissions associated with ES-17 (inlet compressor turbine). NSPS KKKK: ES-17 ES-42 flare is not in VOC service and thus NSPS KKK does not apply.
NSPS 40 CFR60.40a, Subpart Da	Subpart Da, Performance Standards for **Electric Utility Steam Generating Units**	No	N/A	The facility does not have any Steam Generating Units with heat input greater than 250 MMBtu/hr.
NSPS 40 CFR60.40b Subpart Db	**Electric Utility Steam Generating Units**	No	N/A	The facility does not have any steam generating units with a heat input capacity greater than 100 MMBtu/hr.

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
40 CFR 60.40c, Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	No	N/A	The facility does not have any steam generating units with a heat input capacity greater than 10 MMBtu/hr and less than 100 MMBtu/hr.
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	No	N/A	This regulation establishes performance standards for storage vessels that are used to store petroleum liquids for which construction, reconstruction, or modification commenced after May 18, 1978 and prior to July 23, 1984. There are no petroleum liquid storage vessels which commenced construction, reconstruction, or modification after May 18, 1978 and prior to July 23, 1984. Accordingly, this regulation does not apply.
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	Yes	ES-47 ES-48	This facility has two storage vessels, emission units ES-47 and ES-48, with a capacity greater than or equal to 75 cubic meters (m^3) that is used to store volatile organic liquids (VOL) for which construction, reconstruction, or modification is commenced after July 23, 1984. Two oil/condensate storage tanks, ES-47 and ES-48, installed in 2003 at the IBGP, are subject to NSPS Kb, 60.112b(a). These tanks are equipped with a vapor collection system (VCS-COND) that routes vapors to the flare ES-50. The tanks are located after the point of custody transfer since the material comes from field sites to the plant. “Custody transfer” is further defined by EPA as “the transfer of produced petroleum and/or condensate after processing and/or treatment in the producing operations, from storage vessels or automatic transfer facilities to pipelines or any other forms of transportation (40 CFR 60.111b). It was concluded that custody transfer already occurred when the produced oil/condensate leaves the producing site.
NSPS 40 CFR 60.330 Subpart GG	**Stationary Gas Turbines**	Yes	ES-06/07 ES-08/09 ES-10/11 ES-22	Units ES-06/07, ES-08/09, ES-10/11, and ES-22 have a heat input = 39.01, 39.01, 39.01, 50.32, and 43.85 Btu/hour which is greater than the 10 MMBtu/hour threshold. These units were installed in 1980, 1980, 1980, 1989, and 1979, respectively which is after the October 3, 1977 applicability date.
NSPS 40 CFR 60, Subpart KKK	Leaks of VOC from **Onshore Gas Plants**	Yes	Flares – Blown streams with VOC: ES-14 ES-14 – SSM ES-50 ES-50-SSM VRU-ES-40-SB VCSCOND ES-17	Affected Facility with Leaks of VOC from Onshore Gas Plants. Any affected facility under paragraph (a) of this section that commences construction, reconstruction, or modification after January 20, 1984, is subject to the requirements of this subpart. The group of all equipment (each pump, pressure relief device, open-ended valve or line, valve, compressor, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by this subpart) except compressors (defined in § 60.631) within a process unit is an affected facility. A compressor station, dehydration unit, sweetening unit, underground storage tank, field gas gathering system, or liquefied natural gas unit is covered by this subpart if it is located at an onshore natural gas processing plant. If the unit is not located at the plant site, then it is exempt from the provisions of this subpart. The following are affected facilities for this NSPS for Equipment Leaks of VOC from Onshore Natural Gas Processing (60.630-636):

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
			compress	- Vapor recovery unit (VRU-ES-40-SB) compressor – installed on the glycol dehydration unit (ES-40) and skimmer basin tank including one oil tank (ES-52) (Associated components); - The ES-17 inlet compressor; - The recompressor #4 turbine, ES-22 are in residue (i.e. pipeline quality) gas service and not subject to NSPS KKK; - Fugitive emissions (FUG) subject to NSPS KKK include components associated with newer units; - Blowdown emissions to the utility flare ES-14 and the SSM flare ES-50, which may contain VOC, are included in the NSPS KKK monitoring program; - The vapor collection system (VCS-COND) installed on the condensate gunbarrel/tanks ES-46, ES-47, and ES-48 have components subject to NSPS KKK. The rest of the Indian Basin Gas Plant was constructed prior to January 20, 1984 and NSPS KKK is not applicable.
NSPS 40 CFR Part 60 Subpart LLL	Standards of Performance for **Onshore Natural Gas Processing**: SO_2 Emissions	No	N/A	The facility is a natural gas processing plant, including a sweetening unit constructed after January 20, 1984; however, the acid gas is completely reinjected into an off-site disposal well and therefore, 40 CFR 60.640 does not apply. The original amine treater (and SRU) was constructed prior to January 20, 1984, the effective date of Subpart LLL, and is not subject to Subpart LLL.
NSPS 40 CFR Part 60 Subpart KKKK	Standards of Performance for Stationary Combustion Turbines	Yes	ES-17	This regulation applies to stationary combustion turbines with a heat input at peak load equal to or greater than 10.7 gigajoules (10 MMBtu) per hour, based on the higher heating value of the fuel, which commenced construction, modification, or reconstruction after February 18, 2005. This unit meets the NO_x and SO_2 limitations from §60.4320 and §60.4330.
NSPS 40 CFR Part 60 Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution for which construction, modification or reconstruction commenced after August 23, 2011 and before September 18, 2015	Yes	FUG Fugitive piping components associate with the inlet compress or ES-17* New fugitive emission components [Equipment leaks (60.5400)]	The rule applies to “affected” facilities that are constructed, modified, or reconstructed after Aug 23, 2011 (40 CFR 60.5365): gas wells, including fractured and hydraulically refractured wells, centrifugal compressors, reciprocating compressors, pneumatic controllers, certain equipment at natural gas processing plants, sweetening units at natural gas processing plants, and storage vessels. * These are piping components due to the turbine compressor switching from residue gas to inlet gas service. The fugitives added from the LOTO, level controller, and the monitoring system will not be installed between the applicability dates of August 23, 2011 to September 18, 2015. Therefore they are not subject to this regulation.
NSPS 40 CFR Part 60 Subpart OOOOa	Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced **After** September 18, 2015	No	N/A	This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015.

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
				The storage vessels at this facility commenced construction prior to September 18, 2015 and are not subject to this regulation. The replacement of the level controller and LOTO and the addition of the leak monitoring system do not trigger a modification or reconstruction under NSPS OOOOa and are therefore not subject to NSPS OOOOa. **Since the addition and replacement from the above fugitive emissions does not trigger NSPS OOOOa, any existing NSPS regulations associated with each process unit (ie NSPS OOOO and NSPS KKK) will be followed and are accounted for in the above regulatory analyses for NSPS OOOO and NSPS KKK.**
NSPS 40 CFR 60 Subpart IIII	Standards of performance for Stationary Compression Ignition Internal Combustion Engines	No	N/A	There are no units subject to NSPS IIII at Indian Basin Gas Plant.
NSPS 40 CFR Part 60 Subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines	No	N/A	There are no internal combustion engines at the IBGP; hence, this subpart does not apply to the facility.
NSPS 40 CFR 60 Subpart TTTT	Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units	No	N/A	There are no units subject to NSPS TTTT at Indian Basin Gas Plant.
NSPS 40 CFR 60 Subpart UUUU	Emissions Guidelines for Greenhouse Gas Emissions and Compliance Times for Electric Utility Generating Units	No	N/A	There are no units subject to NSPS UUUU at Indian Basin Gas Plant.
NSPS 40 CFR 60, Subparts WWW, XXX, Cc, and Cf	Standards of performance for Municipal Solid Waste (MSW) Landfills	No	N/A	Indian Basin Gas Plant is not a MSW Landfill therefore this regulation does not apply.
NESHAP 40 CFR 61 Subpart A	General Provisions	No	Units Subject to 40 CFR 61	There are currently no applicable subparts. Subpart M applicability should be reviewed in the future if there is a possibility of demolition or renovation work that may contain asbestos containing materials.
NESHAP 40 CFR 61 Subpart E	National Emission Standards for **Mercury**	No	N/A	The provisions of this subpart are applicable to those 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
NESHAP 40 CFR 61 Subpart V	National Emission Standards for **Equipment Leaks** (Fugitive Emission Sources)	No	N/A	The provisions of this subpart apply to each of the following sources that are intended to operate in volatile hazardous air pollutant (VHAP) service: pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, connectors, surge control vessels, bottoms receivers, and control devices or systems required by this subpart. VHAP service means a piece of equipment either contains or contacts a fluid (liquid or gas) that is at least 10 percent by weight of VHAP. VHAP means a substance regulated under this

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
				subpart for which a standard for equipment leaks of the substance has been promulgated. Benzene is a VHAP (See 40 CFR 61 Subpart J). Link to 40 CFR 61 Subpart V IBGP does not have equipment in VHAP service as determined according to the provisions of 61.245(d).
MACT 40 CFR 63, Subpart A	General Provisions	Yes	Units Subject to 40 CFR 63	This subpart applies because 40 CFR 63, Subpart HH for area source TEG dehydrators is applicable.
MACT 40 CFR 63.760 Subpart HH	**Oil and Natural Gas Production Facilities**	Yes	ES-40	This facility is Subject to the requirements of 40 CFR 63 Subpart HH, which includes requirements applicable to area sources with TEG dehydrators although the site is not a "major" source of hazardous air pollutants (HAPs). The glycol dehydrator unit ES-40 qualifies for exemption from the emission reduction standards since benzene emissions are less than 1 ton per year (tpy). However, the unit is subject to recordkeeping and reporting requirements.
MACT 40 CFR 63 Subpart HHH		No	N/A	This subpart applies to owners and operators of natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user (if there is no local distribution company), and that are major sources of hazardous air pollutants (HAP) emissions as defined in §63.1271. This facility is not a major source of HAPs; hence, this subpart is not applicable.
MACT 40 CFR 63 Subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Industrial, Commercial, and Institutional Boilers & Process Heaters	No	N/A	There are no units subject to MACT DDDDD at the Indian Basin Gas Plant.
MACT 40 CFR 63 Subpart UUUUU	National Emission Standards for Hazardous Air Pollutants Coal & Oil Fire Electric Utility Steam Generating Unit	No	N/A	There are no units subject to MACT UUUUU at the Indian Basin Gas Plant.
MACT 40 CFR 63 Subpart ZZZZ	National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines (**RICE MACT**)	No	N/A	Facilities are subject to this subpart if they own or operate a stationary RICE, except if the stationary RICE is being tested at a stationary RICE test cell/stand. This facility does not own or operate a stationary RICE; hence, this subpart is not applicable.

Federal Regulation Citation	Title	Applies? Enter Yes or No	Unit(s) or Facility	Justification:
40 CFR 64	**Compliance Assurance Monitoring**	No	N/A	Not applicable as there is no emission unit major in and of itself.
40 CFR 68	**Chemical Accident Prevention**	Yes	N/A	This facility is a stationary source that has more than a threshold quantity of a regulated substance in a process, as determined under §68.115, 40 CFR 68 The facility maintains a current RMP for these chemicals.
Title IV – Acid Rain 40 CFR 72	**Acid Rain**	No	N/A	This part establishes the acid rain program. This facility is not an acid rain source. This regulation does not apply.
Title IV – Acid Rain 40 CFR 73	**Sulfur Dioxide** Allowance Emissions	No	N/A	This regulation establishes sulfur dioxide allowance emissions for certain types of facilities. This facility is not an acid rain source.
Title IV-Acid Rain 40 CFR 75	**Continuous Emissions Monitoring**	No	N/A	See 40 CFR 75.2. This may apply if your facility generates commercial electric power or electric power for sale.
Title IV – Acid Rain 40 CFR 76	**Acid Rain** Nitrogen Oxides **Emission Reduction Program**	No	N/A	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**	No	N/A	Not Applicable –facility does not "service", "maintain" or "repair" class I or class II appliances nor "disposes" of the appliances. Note: Disposal definition in 82.152: Disposal means the process leading to and including: (1) The discharge, deposit, dumping or placing of any discarded appliance into or on any land or water; (2) The disassembly of any appliance for discharge, deposit, dumping or placing of its discarded component parts into or on any land or water; or (3) The disassembly of any appliance for reuse of its component parts. "Major maintenance, service, or repair means" any maintenance, service, or repair that involves the removal of any or all of the following appliance components: compressor, condenser, evaporator, or auxiliary heat exchange coil; or any maintenance, service, or repair that involves uncovering an opening of more than four (4) square inches of "flow area" for more than 15 minutes.

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.

Submittal of operational plan to mitigate emissions with this application is not required. Startup and shutdown procedures are performed according to guidelines, which dictate proper procedural sequence to minimize emissions from the facility during such activities.

Equipment located at the plant are equipped with various safety devices that aid in preventing excess emissions to the atmosphere in the event of an operational emergency. In the event of a malfunction, startup, shutdown, or scheduled maintenance in which emission rates from the facility exceed permitted allowables, Oxy will notify the AQB in accordance with 20.2.7 NMAC and the equipment responsible for the exceedance will be repaired as soon as possible.

Section 15

Alternative Operating Scenarios

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

Alternative Operating Scenarios: Provide all information required by the department to define alternative operating scenarios. This includes process, material and product changes; facility emissions information; air pollution control equipment requirements; any applicable requirements; monitoring, recordkeeping, and reporting requirements; and compliance certification requirements. Please ensure applicable Tables in this application are clearly marked to show alternative operating scenario.

Construction Scenarios: When a permit is modified authorizing new construction to an existing facility, NMED includes a condition to clearly address which permit condition(s) (from the previous permit and the new permit) govern during the interval between the date of issuance of the modification permit and the completion of construction of the modification(s). There are many possible variables that need to be addressed such as: Is simultaneous operation of the old and new units permitted and, if so for example, for how long and under what restraints? In general, these types of requirements will be addressed in Section A100 of the permit, but additional requirements may be added elsewhere. Look in A100 of our NSR and/or TV permit template for sample language dealing with these requirements. Find these permit templates at: www.env.nm.gov/air-quality/permitting-section-procedures-and-guidance/. Compliance with standards must be maintained during construction, which should not usually be a problem unless simultaneous operation of old and new equipment is requested.

In this section, under the bolded title "Construction Scenarios", specify any information necessary to write these conditions, such as: conservative-realistic estimated time for completion of construction of the various units, whether simultaneous operation of old and new units is being requested (and, if so, modeled), whether the old units will be removed or decommissioned, any PSD ramifications, any temporary limits requested during phased construction, whether any increase in emissions is being requested as SSM emissions or will instead be handled as a separate Construction Scenario (with corresponding emission limits and conditions, etc.

No alternative operating scenarios are proposed with this application.

Section 16

Air Dispersion Modeling

1) Minor Source Construction (20.2.72 NMAC) and Prevention of Significant Deterioration (PSD) (20.2.74 NMAC) ambient impact analysis (modeling): Provide an ambient impact analysis as required at 20.2.72.203.A(4) and/or 20.2.74.303 NMAC and as outlined in the Air Quality Bureau's Dispersion Modeling Guidelines found on the Planning Section's modeling website. If air dispersion modeling has been waived for one or more pollutants, attach the AQB Modeling Section modeling waiver approval documentation.
2) SSM Modeling: Applicants must conduct dispersion modeling for the total short term emissions during routine or predictable startup, shutdown, or maintenance (SSM) using realistic worst case scenarios following guidance from the Air Quality Bureau's dispersion modeling section. Refer to "Guidance for Submittal of Startup, Shutdown, Maintenance Emissions in Permit Applications (http://www.env.nm.gov/aqb/permit/app_form.html) for more detailed instructions on SSM emissions modeling requirements.
3) Title V (20.2.70 NMAC) ambient impact analysis: Title V applications must specify the construction permit and/or Title V Permit number(s) for which air quality dispersion modeling was last approved. Facilities that have only a Title V permit, such as landfills and air curtain incinerators, are subject to the same modeling required for preconstruction permits required by 20.2.72 and 20.2.74 NMAC.

What is the purpose of this application?	Enter an X for each purpose that applies
New PSD major source or PSD major modification (20.2.74 NMAC). See #1 above.	
New Minor Source or significant permit revision under 20.2.72 NMAC (20.2.72.219.D NMAC). See #1 above. **Note:** Neither modeling nor a modeling waiver is required for VOC emissions.	
Reporting existing pollutants that were not previously reported.	
Reporting existing pollutants where the ambient impact is being addressed for the first time.	
Title V application (new, renewal, significant, or minor modification. 20.2.70 NMAC). See #3 above.	
Relocation (20.2.72.202.B.4 or 72.202.D.3.c NMAC)	
Minor Source Technical Permit Revision 20.2.72.219.B.1.d.vi NMAC for like-kind unit replacements.	
Other: i.e. SSM modeling. See #2 above.	
This application does not require modeling since this is a No Permit Required (NPR) application.	
This application does not require modeling since this is a Notice of Intent (NOI) application (20.2.73 NMAC).	
This application does not require modeling according to 20.2.70.7.E(11), 20.2.72.203.A(4), 20.2.74.303, 20.2.79.109.D NMAC and in accordance with the Air Quality Bureau's Modeling Guidelines.	X

Check each box that applies:

☐ See attached, approved modeling **waiver for all** pollutants from the facility.
☐ See attached, approved modeling **waiver for some** pollutants from the facility.
☐ Attached in Universal Application Form 4 (UA4) is a **modeling report for all** pollutants from the facility.
☐ Attached in UA4 is a **modeling report for some** pollutants from the facility.
☒ No modeling is required.

Air quality modeling for this site was last completed in October of 2016.

Section 17

Compliance Test History

(Submitting under 20.2.70, 20.2.72, 20.2.74 NMAC)

To show compliance with existing NSR permits conditions, you must submit a compliance test history. The table below provides an example.

To save paper and to standardize the application format, delete this sentence and the samples in the Compliance Test History Table, and begin your submittal for this attachment on this page.

Compliance Test History Table

Unit No.	Test Description	Test Date
ES-04	Turbine Generator #1 - Portable analyzer test for NOx and CO	9/18/2017; 2/14/2020
ES-05	Turbine Generator #2 - Portable analyzer test for NOx and CO	6/2/2017; 2/14/2020
ES-06 & 07	Turbine Recompressor #1 - 40 CFR Pt. 60 Appx. A, compliance testing for NOx and CO	1/5/2017; 2/14/2020
ES-08 & 09	Turbine Recompressor #2 - 40 CFR Pt. 60 Appx. A, compliance testing for NOx and CO	1/5/2017; 2/14/2020
ES-10 & 11	Turbine Recompressor #3 - 40 CFR Pt. 60 Appx. A, compliance testing for NOx and CO	1/6/2017; 2/14/2020
ES-17	Turbine Inlet Compressor - 40 CFR Pt. 60 Appx. A, compliance testing for NOx and CO	9/18/2017; 4/22/2020
ES-21	Turbine Generator #3 - Portable analyzer test for NOx and CO	1/5/2017; 2/14/2020
ES-22	Turbine Recompressor #4 - 40 CFR Pt. 60 Appx. A, compliance testing for NOx and CO	1/6/2017; 4/28/2020
ES-50	MSS Flare – Initial performance test to verify designed and operated according to 40 CFR 60.18	12/15/2010

Section 19

Requirements for Title V Program

Who Must Use this Attachment:

* Any major source as defined in 20.2.70 NMAC.
* Any source, including an area source, subject to a standard or other requirement promulgated under Section 111 - Standards of Performance for New Stationary Sources, or Section 112 Hazardous Air Pollutants, of the 1990 federal Clean Air Act ("federal Act"). Non-major sources subject to Sections 111 or 112 of the federal Act are exempt from the obligation to obtain an 20.2.70 NMAC operating permit until such time that the EPA Administrator completes rulemakings that require such sources to obtain operating permits. In addition, sources that would be required to obtain an operating permit solely because they are subject to regulations or requirements under Section 112(r) of the federal Act are exempt from the requirement to obtain an Operating Permit.
* Any Acid Rain source as defined under title IV of the federal Act. The Acid Rain program has additional forms. See www.env.nm.gov/air-quality/air-quality-title-v-operating-permits-guidance-page/. Sources that are subject to both the Title V and Acid Rain regulations are encouraged to submit both applications simultaneously.
* Any source in a source category designated by the EPA Administrator ("Administrator"), in whole or in part, by regulation, after notice and comment.

19.1 - 40 CFR 64, Compliance Assurance Monitoring (CAM) (20.2.70.300.D.10.e NMAC)

Any source subject to 40CFR, Part 64 (Compliance Assurance Monitoring) must submit all the information required by section 64.7 with the operating permit application. The applicant must prepare a separate section of the application package for this purpose; if the information is already listed elsewhere in the application package, make reference to that location. Facilities not subject to Part 64 are invited to submit periodic monitoring protocols with the application to help the AQB to comply with 20.2.70 NMAC. Sources subject to 40 CFR Part 64, must submit a statement indicating your source's compliance status with any enhanced monitoring and compliance certification requirements of the federal Act.

Not applicable as facility is not subject to 40 CFR 64.

19.2 - Compliance Status (20.2.70.300.D.10.a & 10.b NMAC)

Describe the facility's compliance status with each applicable requirement at the time this permit application is submitted. This statement should include descriptions of or references to all methods used for determining compliance. This statement should include descriptions of monitoring, recordkeeping and reporting requirements and test methods used to determine compliance with all applicable requirements. Refer to Section 2, Tables 2-N and 2-O of the Application Form as necessary. (20.2.70.300.D.11 NMAC) For facilities with existing Title V permits, refer to most recent Compliance Certification for existing requirements. Address new requirements such as CAM, here, including steps being taken to achieve compliance.

Based on information and belief formed after reasonable inquiry, Oxy believes that the Indian Basin Gas Plant is in compliance with each applicable requirement identified in Section 13 of this application. In the event that Oxy should discover new information affecting the compliance statue of the facility, Oxy will make appropriate notifications and/or take corrective actions. Oxy has submitted required Title V Annual Compliance Certifications (ACC) and Deviation Reports for Indian Basin Gas Plant required in Title V Permit P103-R2-M1 condition A109.

19.3 - Continued Compliance (20.2.70.300.D.10.c NMAC)

Provide a statement that your facility will continue to be in compliance with requirements for which it is in compliance at the time of permit application. This statement must also include a commitment to comply with other applicable requirements as they come into effect during the permit term. This compliance must occur in a timely manner or be consistent with such schedule expressly required by the applicable requirement.

The Indian Basin Gas Plant will continue to be in compliance with requirements for which it is in compliance at the time of this permit application and will comply with other applicable requirements as they come into effect during the permit term.

19.4 - Schedule for Submission of Compliance (20.2.70.300.D.10.d NMAC)

You must provide a proposed schedule for submission to the department of compliance certifications during the permit term. This certification must be submitted annually unless the applicable requirement or the department specifies a more frequent period. A sample form for these certifications will be attached to the permit.

Compliance certifications will be submitted annually, as required by Title V Permit P103-R2-M1 Condition A109.B. The ACC will be submitted according to the following:
A. A Semi-Annual Report of monitoring activities is due within 45 days following the end of every 6-month reporting period. The six month reporting period starts on December 1st and June 1st of each year.
B. The Annual Compliance Certification Report is due within 30 days of the end of every 12-month reporting period. The 12-month reporting period starts on December 1st of each year.

19.5 - Stratospheric Ozone and Climate Protection

In addition to completing the four (4) questions below, you must submit a statement indicating your source's compliance status with requirements of Title VI, Section 608 (National Recycling and Emissions Reduction Program) and Section 609 (Servicing of Motor Vehicle Air Conditioners).

---

1. Does your facility have any air conditioners or refrigeration equipment that uses CFCs, HCFCs or other ozone-depleting substances? ☒ **Yes** ☐ **No**

2. Does any air conditioner(s) or any piece(s) of refrigeration equipment contain a refrigeration charge greater than 50 lbs? ☐ **Yes** ☒ **No**
   (If the answer is yes, describe the type of equipment and how many units are at the facility.)

3. Do your facility personnel maintain, service, repair, or dispose of any motor vehicle air conditioners (MVACs) or appliances ("appliance" and "MVAC" as defined at 82. 152)? ☐ **Yes** ☒ **No**

4. Cite and describe which Title VI requirements are applicable to your facility (i.e. 40 CFR Part 82, Subpart A through G.)

The requirements in Title VI, Section 608 (National Recycling and Emissions Reduction Program) and section 609 (Servicing of Motor Vehicle Air Conditioners) do not apply. The Indian Basin Gas Plant does not “service”, “maintain”, or “repair” Class I of Class II appliances nor “disposes” of the appliances. The Indian Basin Gas Plant may have appliances containing Class I and/or Class II refrigerants; however, Oxy uses only certified technicians to service or dispose of such equipment. Oxy does not service motor vehicle air conditions at Indian Basin Gas Plant.

Note: Disposal definition in 82.152: Disposal means the process leading to and including: (1) The discharge, deposit, dumping or placing of any discarded appliance into or on any land or water; (2) The disassembly of any appliance for discharge, deposit, dumping, or placing of its discarded component parts into or on any land or water; or (3) The disassembly of any appliance for reuse of its component parts. "Major maintenance, service, or repair means "any maintenance, service, or repair that involves the removal of any or all of the following appliance components: compressor, condenser, evaporator, or auxiliary heat exchange coil; or any maintenance, service, or repair that involves uncovering an opening of more than four (4) square inches of "flow area" for more than 15 minutes.

19.6 - Compliance Plan and Schedule

Applications for sources, which are not in compliance with all applicable requirements at the time the permit application is submitted to the department, must include a proposed compliance plan as part of the permit application package. This plan shall include the information requested below:

A. Description of Compliance Status: (20.2.70.300.D.11.a NMAC)
A narrative description of your facility's compliance status with respect to all applicable requirements (as defined in 20.2.70 NMAC) at the time this permit application is submitted to the department.

B. Compliance plan: (20.2.70.300.D.11.B NMAC)
A narrative description of the means by which your facility will achieve compliance with applicable requirements with which it is not in compliance at the time you submit your permit application package.

C. Compliance schedule: (20.2.70.300D.11.c NMAC)
A schedule of remedial measures that you plan to take, including an enforceable sequence of actions with milestones, which will lead to compliance with all applicable requirements for your source. This schedule of compliance must be at least as stringent as that contained in any consent decree or administrative order to which your source is subject. The obligations of any consent decree or administrative order are not in any way diminished by the schedule of compliance.

D. Schedule of Certified Progress Reports: (20.2.70.300.D.11.d NMAC)
A proposed schedule for submission to the department of certified progress reports must also be included in the compliance schedule. The proposed schedule must call for these reports to be submitted at least every six (6) months.

E. Acid Rain Sources: (20.2.70.300.D.11.e NMAC)
If your source is an acid rain source as defined by EPA, the following applies to you. For the portion of your acid rain source subject to the acid rain provisions of title IV of the federal Act, the compliance plan must also include any additional requirements under the acid rain provisions of title IV of the federal Act. Some requirements of title IV regarding the schedule and methods the source will use to achieve compliance with the acid rain emissions limitations may supersede the requirements of title V and 20.2.70 NMAC. You will need to consult with the Air Quality Bureau permitting staff concerning how to properly meet this requirement.

NOTE: The Acid Rain program has additional forms. See www.env.nm.gov/air-quality/air-quality-title-v-operating-permits-guidance-page/. Sources that are subject to both the Title V and Acid Rain regulations are **encouraged** to submit both applications **simultaneously**.

No compliance plan required. IBGP sources are in compliance with the applicable requirements.

19.7 - 112(r) Risk Management Plan (RMP)

Any major sources subject to section 112(r) of the Clean Air Act must list all substances that cause the source to be subject to section 112(r) in the application. The permittee must state when the RMP was submitted to and approved by EPA.

The original Risk Management Plan was submitted to the EPA in 1999. The RMP was renewed on 05/14/2019.

19.8 - Distance to Other States, Bernalillo, Indian Tribes and Pueblos

Will the property on which the facility is proposed to be constructed or operated be closer than 80 km (50 miles) from other states, local pollution control programs, and Indian tribes and pueblos (20.2.70.402.A.2 and 20.2.70.7.B NMAC)?

(If the answer is yes, state which apply and provide the distances.)

The Indian Basin Gas Plant is 53 km (33 miles) from Texas.

19.9 - Responsible Official

Provide the Responsible Official as defined in 20.2.70.7.AD NMAC:

Jim Richardson
Asset Director EOR Plants
5 Greenway Plaza, Suite 110
Houston, TX 77046-0621
713-497-2006
Jim_Richardson@oxy.com

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.

There is no other relevant information to present.

Section 22: Certification

Company Name: OXY USA WTP LP

I, Femi Serrano, 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 10th day of October, 2023, upon my oath or affirmation, before a notary of the State of

TEXAS.

Femi Serrano
*Signature

10/10/2023
Date

Femi Serrano
Printed Name

Manager Air Quality, EOR
Title

Scribed and sworn before me on this 10th day of October, 2023.

KIM HOFFMAN
NOTARY PUBLIC
STATE OF TEXAS
ID# 132081423
EXPIRES 7-10-2027

My authorization as a notary of the State of TEXAS expires on the

10th day of July, 2027.

Notary's Signature

10.10.2023
Date

KIM HOFFMAN
Notary's Printed Name

*For Title V applications, the signature must be of the Responsible Official as defined in 20.2.70.7.AE NMAC.