Schwartz, Colin

From: Yates, Lisa A <Lisa.A.Yates@conocophillips.com>
Sent: Thursday, January 19, 2017 1:21 PM
To: Schwartz, Colin
Subject: RE: ConocoPhillips Ute Compressor Station
Attachments: IMG_0042.jpg

Hi, Colin!

I did enjoy the holidays as I took two weeks off and still playing catch up from it! I hope you enjoyed the holidays as well. You were on my list to follow up with this week to ensure you have all that you need to complete your review, as SUIT is anxious for us to wrap this up.

There are three (3) 300-bbl condensate tanks onsite, but only two of the tanks (TK-5080 and TK-5081) are in service. We have isolated the tank (TK-8094A) associated with the dehydration system making it permanently out of service and are requesting for it to be removed from the permit as part of the dehydration system (emission sources DEHY-1 and TK-8094A). Attached is the photo of the tank in question that SUIT asked for during their audit of the site they made in December to ensure we complied with the NOV that was issued. The tank was isolated from the process back in August of 2016, but not marked "Out of Service". That was corrected in December of 2016 as per the photo.

Please let me know if you need any further information to complete your review.

Kind regards,

Lisa A. Yates
ConocoPhillips Company
Rockies Business Unit
Senior Environmental Coordinator
(w) 832-486-2761
(c) 832-494-7071

From: Schwartz, Colin [mailto:Schwartz.Colin@epa.gov]
Sent: Thursday, January 19, 2017 1:11 PM
To: Yates, Lisa A <Lisa.A.Yates@conocophillips.com>
Subject: [EXTERNAL]RE: ConocoPhillips Ute Compressor Station

Hey Lisa,

Hope you had a great holiday season.

I had one more question regarding onsite tanks: Are there 3- 300 bbl condensate tanks or 2?

The process and settlement agreement seem to suggest that 2 tanks are present but a table with existing emission units shows 3.

Thank you,

Colin C. Schwartz

Schwartz, Colin

From:	Yates, Lisa A <Lisa.A.Yates@conocophillips.com>
Sent:	Wednesday, December 07, 2016 1:21 PM
To:	Schwartz, Colin
Subject:	RE: ConocoPhillips Ute Compressor Station

Hi, Colin!

I needed to confirm the process flow for the Ute Compressor Station prior to responding to you. The process description is as follows:

> Field gas is gathered and transported to the facility via pipelines for gas/liquid separation and compression. The inlet fluid flows through a two-phase inlet separator where gas and liquids are separated. The liquids flow to two 300-bbl above ground condensate storage tanks where oil and free water separate out. The water is transferred to a 120-bbl pit tank, where it is stored until it is hauled away via tank truck to a commercial facility for proper disposal. The oil is sold as product and shipped off-site via tank truck. The gas is compressed then transported off-site via pipeline. Liquids that drop out during compression are routed to the two condensate storage tanks.

If you should need additional information, please do not hesitate in contacting me.

Kind regards,

Lisa A. Yates

Senior Environmental Coordinator
ConocoPhillips Company
Rockies Business Unit
Office # 832-486-2761
Mobile # 832-494-7071
lisa.a.yates@conocophillips.com

From: Schwartz, Colin [mailto:Schwartz.Colin@epa.gov]
Sent: Monday, December 05, 2016 2:54 PM
To: Yates, Lisa A <Lisa.A.Yates@conocophillips.com>
Subject: [EXTERNAL]RE: ConocoPhillips Ute Compressor Station

Lisa,

Thank you for all of the documents you have provided!

I did have one final question: Which process description should be used for this site? I have two:

"The natural gas entering the compressor station flows through an inlet separator and mist screens where most of the water is removed. The water produced by this step is transferred to an on-site storage tank and eventually disposed of in a Class II underground disposal well."

I have also read:

"The natural gas entering the compressor station flows through suction scrubbers where most of the water is removed. The natural gas condensate produced by this step is transferred to on-site condensate storage tanks."

Thanks again,

Colin C. Schwartz
Environmental Scientist
Air Permits Division
US EPA Region 8- Denver, CO
303-312-6043

From: Yates, Lisa A [mailto:Lisa.A.Yates@conocophillips.com]
Sent: Monday, December 05, 2016 12:28 PM
To: Schwartz, Colin <Schwartz.Colin@epa.gov>
Subject: FW: ConocoPhillips Ute Compressor Station

Colin,

As discussed on the phone today in regards to your first question below, I am attaching the SMNSR permit application ConocoPhillips submitted to EPA Region 8 on August 28, 2012 for the Ute Compressor Station along with the Title V SUIT application that reflects the values that were found on page 3 of 3 of our amended SMNSR request.

Background: ConocoPhillips originally applied for Title V for this facility back on May 12, 2011. ConocoPhillips and EPA Region 8 settled on alleged violations found at the facility on September 30, 2011 (CAA-08-2011-0032). Upon meeting the terms and conditions of the CAA, the facility achieved a synthetic minor status. A SMNSR application was submitted on August 28, 2012 and approved by EPA as SMNSR-SU-000054-2012.001 on September 15,2014. An email from Ms. Claudia Smith from EPA dated December 17, 2014 informed ConocoPhillips that the Ute Compressor Station required a Title V because the dehydrator on site is subject to the major source requirements of MACT HH. ConocoPhillips applied for a Title V permit with the Southern Ute Indian Tribe which was approved and became effective on November 4, 2015 (Title V Permit #V-SUIT-0056-2015.00).

As discussed on the phone, the values found in Table 2 of the Technical Support Document for Permit # SMNSR-SU-000054-2012.001 may erroneously reflect the original Title V application values.

Please review these attachments to determine if they satisfy your inquiry in regards to our values reported in the amended permit application. As for your other two questions, the answers are as follows:

2. Could you provide photos of the decommissioned units being fully cut off from the facility, power, gas line, and all other necessary production connections showing that the decommissioned units are in fact disconnected? Also, could you note if the units will be disconnected but staying on site or they are moved off site? *Pictures of the decommissioned dehydration unit are included in a Dehydration Decommissioning Report that was submitted to SUIT on September 28, 2016. The unit(s) have indeed been disconnected, but are remaining on site until they can be utilized elsewhere. If the occasion arises they the sales gas needs to be dehydrated, the appropriate permits will be obtained prior to placing a dehydration unit in service.*
3. Could you provide the effected date of the settlement agreement (Enforcement Case ID:2016-5)? *Settlement agreement went into effect September 12, 2016.*

Should require any additional information, please do not hesitate in contacting me.

Kind regards,

Lisa A. Yates

Senior Environmental Coordinator
ConocoPhillips Company
Rockies Business Unit
Office # 832-486-2761
Mobile # 832-494-7071
lisa.a.yates@conocophillips.com

From: Schwartz, Colin [mailto:Schwartz.Colin@epa.gov]
Sent: Wednesday, November 23, 2016 10:52 AM
To: Lane, Myke K <Myke.K.Lane@conocophillips.com>
Cc: airquality@southernute-nsn.gov
Subject: [EXTERNAL]ConocoPhillips Ute Compressor Station

Mr. Lane,

The Environmental Protection Agency (EPA) is reviewing your request to administratively amend ConocoPhillips Ute Compressor Station per the Settlement Agreement and Stipulated Final Compliance Order (Enforcement Case ID: 2016-05) with the Southern Ute Indian Tribe. The EPA has been going over the request received October 5, 2016 regarding the decommissioning of the Dehydration system and we have a few questions we would like answered:

1. The facility-wide emissions estimates noted in section C.5 do not match with the original technical support document for criteria pollutants either controlled or uncontrolled PTE. Could you please submit facility wide emissions in a format matching Table 2 from the Technical Support Document SMNSR-SU-000054-2012.001? If these emission calculations have changed, we will need updated emission calculations.
2. Could you provide photos of the decommissioned units being fully cut off from the facility, power, gas line, and all other necessary production connections showing that the decommissioned units are in fact disconnected? Also, could you note if the units will be disconnected but staying on site or they are moved off site?
3. Could you provide the effected date of the settlement agreement (Enforcement Case ID:2016-5)

The EPA would appreciate a response within 45 days of this email. However with the holiday season upon us, if this is not possible, please contact me and we can discuss a more reasonable date.

Thank you,

Colin C. Schwartz
Environmental Scientist
Air Permits Division
US EPA Region 8- Denver, CO
303-312-6043

Rocky Mountain Business Unit -
San Juan Asset
P.O. Box 4289
Farmington, NM 87499-4289
(505) 326-9700

September 30, 2016

Federal Minor NSR Permit Coordinator
U.S. EPA, Region 8
1595 Wynkoop Street, 8P-AR
Denver, CO 80202-1129
Send Via Email: R8airpermitting@epa.gov

Reference: Application to Amend SMNSR-SU-000054-2012.001
ConocoPhillips – Ute Compressor Station
Addition of Monthly AVO Inspections

Attached please find ConocoPhillips Company's application to amend the referenced Synthetic Minor New Source Review permit.

ConocoPhillips Company (COPC) is requesting an amendment to the referenced Tribal Minor New Source Review Permit to incorporate additional monthly auditory, visual and olfactory (AVO) monitoring of the condensate storage tanks (emission units TK-5080 and TK-5081), and establish legally and practically enforceable requirements.

Incorporation of the additional monitoring will enable ConocoPhillips to fulfill requirements from a Settlement Agreement and Stipulated Final Compliance Order (Enforcement Case ID: 2016-05) with the Southern Ute Indian Tribe Environmental Programs Division, Air Quality Program (SUIT).

This amendment includes decommissioning of the dehydration system and the associated decreases in the potential to emit emissions. This application includes the decrease in emissions from the Potential To Emit (PTE) Table in the August 28, 2012 Tribal Minor Source Permit Application.

Should you have any questions or additional information is required to demonstrate the dehydrations system has been permanently decommissioned, please do not hesitate to contact me.

Respectfully submitted,

Michael K. Lane, PE
Senior Environmental Coordinator
ConocoPhillips Company

Cc: Stephen Ellison, ConocoPhillips Managing Council
Sharon Zubrod, ConocoPhillips RBU HSER Manager

Air Quality Technical Manager, Southern Ute Indian Tribe Air Quality Program
P.O. Box 737 MS#84, Ignacio, CO 81137, airquality@southernute-nsn.gov

Attachments:
Administrative Permit Amendment Request

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
FEDERAL MINOR NEW SOURCE REVIEW PROGRAM IN INDIAN COUNTRY

Administrative Permit Amendment Request

(Form AMEND)

Please check box to show how you are using this form

- ☐ **Correction to a Typographical Error**
- X **Incorporation of More Frequent Monitoring or Reporting**
- ☐ **Increase in Allowable Emissions (SEE INSTRUCTIONS!)**
- ☐ **Other**

Use of this information request form is voluntary and not yet approved by the Office of Management and Budget. The following is a check list of the type of information that Region 8 will use to process information on your proposed permit amendment. While submittal of this form is not required, it does offer details on the information we will use to complete your requested approval and providing the information requested may help expedite the process. Use of application forms for this program is currently under Office of Management and Budget review and these information request forms will be replaced/updated after that review is completed.

Please submit information to following two entities:

Federal Minor NSR Permit Coordinator
U.S. EPA, Region 8
1595 Wynkoop Street, 8P-AR
Denver, CO 80202-1129
R8airpermitting@epa.gov

For more information, visit:
http://www.epa.gov/caa-permitting/tribal-nsr-permitting-region-8

The Tribal Environmental Contact for the specific reservation:

Air Quality Technical Manager
Southern Ute Indian Tribe Air Quality Program
P.O. Box 737 MS#84, Ignacio, CO 81137
dpowers@southernute-nsn.gov

If you need assistance in identifying the appropriate Tribal Environmental Contact and address, please contact:

R8airpermitting@epa.gov

A. COMPANY INFORMATION

Company Name (Who owns this facility?) ConocoPhillips Company	
Company Contact (Who is the primary contact at the company that owns this facility?**)** **Lisa Yates**	Title Sr. Environmental Coordinator
Mailing Address 935 N. Eldridge Parkway, Houston, TX 77079	
Email Address Lisa.a.yates@conocophillips.com	
Telephone Number 281-293-1459	Facsimile Number

B. FACILITY INFORMATION

Facility Name on the Permit to Be Amended Ute Compressor Station
Minor Source Permit To Construct Number (MC-xxx-xxxx-xx.xx) SMNSR-SU-000054-2012.001
Date of Most Recent Permit Action (this should be the same permit to which you are requesting the amendment) October 15, 2014

C. DESCRIPTION OF THE PROPOSED AMENDMENT

Provide a narrative description of the requested amendment to the permit and the following:

1. **Why the proposed change can be made through this form. (See instructions).**

ConocoPhillips Company (COPC) is requesting an amendment to the referenced Tribal Minor New Source Review Permit to incorporate additional monthly auditory, visual and olfactory (AVO) monitoring of the condensate storage tanks (emission units TK-5080 and TK-5081), and establish legally and practically enforceable requirements. Incorporation of the additional monitoring will enable ConocoPhillips to fulfill requirements from a Settlement Agreement and Stipulated Final Compliance Order (Enforcement Case ID: 2016-05) with the Southern Ute Indian Tribe Environmental Programs Division, Air Quality Program (SUIT).

2. **Information presented in enough detail to document how the facility is currently operating and how it is proposed to operate. A narrative description of all of the facility processes along with a process flow diagram to enable EPA to understand the effect the proposed change has on emission unit or (pollutant generating activity).**

COPC has permanently decommissioned the glycol dehydration system which included the following equipment: coaleser filter, contactor, reboiler, still vent condenser, and condensate storage tank. Decommissioning the dehydration system was to comply with terms in the previously referenced settlement agreement with the SUIT. Decommissioning of the system will decrease VOC and HAPs emissions from the facility as noted in the table below.

In addition to decommissioning the dehydration system, the SUIT is requiring COPC to request amendment of the referenced Tribal Minor New Source Review permit to incorporate monthly inspections of the condensate storage tanks to ensure proper operation.

3. **Emissions calculations and all supporting data necessary to establish the proposed post-change allowable emission limits. The requested information must be provided for each emissions unit (or pollutant-generating activity).**

The only emissions being reduced are those associated with the decommissioned dehy system (Emission Units DEHY-1 & TK-8094A). The following summarizes the potential to emit (PTE) emissions from the August 28, 2012 application for NOx, CO, VOC and SO2.

Emission Unit ID	Regulated Air Pollutants and Pollutants for which the Source is Major (tons/yr)					
	NOx	**VOC**	**SO2**	**PM10**	**CO**	**Lead**
DHEY-1	0.05	6.36	0.01	0.01	0.04	--
TK-8094A	--	0.52	--	--	--	--

4. **The proposed changes to be made to specific terms and conditions of the permit. A redline/strike out version of the permit may be used for this purpose.**

COPC shall inspect the condensate tanks (TK-5080 and TK-5081) each month using auditory, visual, and olfactory (AVO) methods to detect leaks that could result in air emissions. This includes inspection of the thief hatches, storage tanks and associated process piping but excludes normal storage tank venting. Monthly inspections must be separated by at least 14 calendar days.

a. In the event that a leak or defect is detected, COPC shall repair the leak or defect according to the following schedule:
   i. A first attempt at repair must be made no later than 15 calendar days after the leak is detected.
   ii. If the repair involves installation of parts that cannot be obtained within the first 15 calendar-day window, the repair may be delayed until the next 15 calendar-day period.
   iii. Repair must be completed no later than 30 calendar days after the leak or defect is detected.
   iv. If repair cannot be completed within the 30-day window due to a need to shutdown of the entire facility and/or unavailability of replacement parts, the Repair may be delayed unit the next process unit shutdown. Leaking equipment shall be repaired by the end of the next process shutdown.
   v. Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while waiting repair.
b. COPC shall maintain records of each AVO inspection to include the date of the inspection, a description of each leak or defect identified, the corrective actions taken to repair the leak or defect, and the date of repair. These records must be kept for 5 years from the date of inspection.

5. **The following table with Facility-wide Emission Estimates:**

<table>
<tr><th>Pollutant</th><th>Pre-Change Allowable Emissions (tpy)</th><th>Post Change Allowable Emissions (tpy)</th><th></th></tr>
<tr><td>PM</td><td>0.84</td><td>0.83</td><td rowspan="12">PM - Particulate Matter
PM_{10} - Particulate Matter less than 10 microns in size
$PM_{2.5}$ - Particulate Matter less than 2.5 microns in size
SO_2 - Sulfur Oxides
NOx - Nitrogen Oxides
CO - Carbon Monoxide
VOC - Volatile Organic Compound
Pb - Lead and lead compounds
Fluorides - Gaseous and particulates
H_2SO_4 - Sulfuric Acid Mist
H_2S - Hydrogen Sulfide
TRS - Total Reduced Sulfur
RSC - Reduced Sulfur Compounds</td></tr>
<tr><td>PM_{10}</td><td>0.84</td><td>0.83</td></tr>
<tr><td>$PM_{2.5}$</td><td>0.84</td><td>0.83</td></tr>
<tr><td>SO_2</td><td>1.99</td><td>1.98(1)</td></tr>
<tr><td>NO_x</td><td>56.94</td><td>56.89(1)</td></tr>
<tr><td>CO</td><td>57.24</td><td>57.20(1)</td></tr>
<tr><td>VOC</td><td>46.98</td><td>40.10(1)</td></tr>
<tr><td>Pb</td><td>-</td><td>-</td></tr>
<tr><td>Fluorides</td><td>-</td><td>-</td></tr>
<tr><td>H_2SO_4</td><td>-</td><td>-</td></tr>
<tr><td>H_2S</td><td>-</td><td>-</td></tr>
<tr><td>TRS</td><td>-</td><td>-</td></tr>
<tr><td>RSC</td><td>-</td><td>-</td><td></td></tr>
</table>

(1) Post Allowable Emissions based on decreased emissions following the decommissioning of emission units DEHY-1 and TK-8094A**.** Refer to the PTE Table in the August 28, 2012 Tribal Minor Source Permit application.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www2.epa.gov/aboutepa/epa-region-8-mountains-and-plains

Ref: 8P-AR

Ms. Lori Marquez
ConocoPhillips Company
3401 E. 30th Street, P.O. Box 4289
Farmington, New Mexico 87499

SEP 15 2014

Re: ConocoPhillips Company, Ute Compressor Station, Permit # SMNSR-SU-000054-2012.001, Synthetic Minor New Source Review Permit

Dear Ms. Marquez:

The Environmental Protection Agency has completed its review of ConocoPhillips Company's request to obtain a synthetic minor permit to construct pursuant to the Tribal Minor New Source Review (MNSR) Permit Program at 40 CFR Part 49 for the Ute Compressor Station. Based on the information submitted in your application, the EPA hereby issues the enclosed final MNSR permit to construct. Please review each condition carefully and note any restrictions placed on this source.

A 30-day public comment period was held from May 12, 2014 to June 11, 2014. The EPA received comments from ConocoPhillips Company on June 6, 2014. No other comments were received during the public comment period. The EPA's response to the public comments is also enclosed. The EPA made some revisions to the permit based on the comments. The final permit will be effective on October 15, 2014.

Pursuant to 40 CFR 49.159, 30 days after the final permit decision has been issued, any person who commented on the specific terms and conditions of the draft permit, may petition the Environmental Appeals Board to review any term or condition of the permit. Any person who failed to comment on the specific terms and conditions of this permit may petition for administrative review only to the extent that the changes from the draft to the final permit or other new grounds were not reasonably ascertainable during the public comment period. The 30-day period within which a person may request review begins with this notice of the final permit decision. If an administrative review of the final permit is requested, the specific terms and conditions of the permit that are the subject of the request for review must be stayed.

If you have any questions concerning the enclosed final permit please contact Claudia Smith of my staff at (303) 312-6520.

Sincerely,

Callie A. Videtich
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures

cc: Brenda Jarrell, Air Quality Program Manager, Southern Ute Indian Tribe Environmental Program

Enclosure - Response to Comments

Comments from ConocoPhillips Company (ConocoPhillips) on the Proposed Permit to Construct for the Ute Compressor Station pursuant to the Tribal Minor New Source Review Permit Program at 40 CFR Part 49 (MNSR)

1. Permit Condition I.A.

   ConocoPhillips requested that Table 1 of the Technical Support Document for the proposed permit be included in Condition I.A of this permit, because the proposed permit does not include a complete list of emissions sources operating currently at Ute Compressor Station. ConocoPhillips asserts that inclusion of this list is necessary to clearly indicate all emission sources listed in the permit application and technical support document are covered by this permit.

   The requested change has not been made to the final permit. This MNSR permit is not an operating permit covering all emission units at the facility. As explained in the proposed permit, pursuant to 40 CFR 49.151(c)(1)(ii)(D) of the MNSR rule, existing sources whose limits were established through mechanisms such as a consent decree, are required to apply for a permit under the MNSR permit program to transfer the limits to a MNSR permit. This MNSR permit covers only those emission units for which emission limitations were previously established in the September 30, 2011, Consent Agreement, Docket No. CAA-08-2011-0032 (Consent Agreement).

2. Permit Condition I.C. Requirements for Engines

   ConocoPhillips requested that the title of Condition I.C. (formerly I.E.) be revised to "Requirements for *1,478 Horsepower* Engine~~s~~", because the one 1,478 horsepower engine at the Ute Compressor Station is the only engine subject to requirements under this MNSR permit.

   The requested change has been made to the final permit. We agree that this change is warranted to clarify that the requirements only apply to the 1,478 horsepower engine at the facility.

3. Permit Condition I.C.5(l) under Requirements for Engines

   ConocoPhillips requested Condition I.C.5(1) (formerly I.E.5(1)) be revised as follows: "The Permittee is not required to conduct emissions monitoring of NO_X, CO, and CH_2O emissions and parametric monitoring of exhaust temperature and catalyst differential pressure on engines that have not operated ~~during~~ *for more than 10% of* the monitoring period." ConocoPhillips believes this adds needed clarification that a minimal period of operation during the monitoring period does not trigger a monitoring or testing requirement.

   This requested change has not been made to the final permit. The intent of this condition is to specify that an engine that has not operated during the monitoring period does not need to be started up to meet testing or monitoring requirements. However, if an engine is operating during a time when monitoring is required, such as to meet the continuous temperature monitoring requirement, the parameters should be monitored. If an engine is shut down after the most recent catalyst pressure drop measurement or emissions measurement, and is not started up before the next subsequent monitoring requirement, such monitoring would not need to be met until the engine is started up again.

4. Permit Condition I.G.4(b) under Requirements for Reporting

ConocoPhillips requested that Condition I.G.4(b) (formerly I.I.4(b)) be removed from the permit, because the Leak Detection and Repair (LDAR) monitoring protocol on file with the EPA for the Ute Compressor Station allows 15 days for an initial repair attempt for any identified leak. ConocoPhillips believes a reporting requirement for leaks left unrepaired for more than 5 days but less than 15 is overly burdensome and misleading. A leak repaired within 15 days is not a deviation under the current protocol. ConocoPhillips asserted that removal of this condition would be consistent with the protocol and with permit SMNSR-SU-000030-2011.001 issued by the EPA for a similar facility operated by ConocoPhillips.

The requested deletion has not been made in the final permit. It is not necessary to remove the condition to address the concern by ConocoPhillips, as an identified leak would not be considered a deviation of the emission or operational limits in the permit. A deviation would occur if ConocoPhillips did not follow the approved LDAR protocol on file with the EPA, for example in this particular scenario, if an identified leak was not repaired within 15 days after it was identified. Therefore, reporting would be required if the leak was still not repaired 20 days after it was discovered (15 days plus 5 days). Furthermore, the EPA-issued permit referenced for another facility operated by ConocoPhillips contains the exact same language as that which ConocoPhillips requested to be deleted, so the condition in this permit is already consistent with the referenced permit.

Comments from ConocoPhillips on the Technical Support Document for the Proposed Permit to Construct for the Ute Compressor Station pursuant to the MNSR Permit Program

1. Section III. A

ConocoPhillips requested that the first paragraph in this section of the technical support document be revised as follows: "The natural gas industry uses engines to compress natural gas as it is processed and prior to further pipeline distribution. ConocoPhillips operates a *1,478 hp* natural gas-fired, 4-stroke lean-burn reciprocating internal combustion engine for natural gas compression…". ConocoPhillips believes this revision is necessary to provide clarification that emission limits and controls discussed in Sections III.A. 1-3 apply only to the 1,478 hp engine at the Ute Compressor Station.

2. Section III.A.3(d)

ConcocoPhillips requested that this paragraph in the technical support document be revised as follows: "Portable analyzer monitoring *or performance testing* of NO_X and CO emissions is to be performed quarterly…However, portable monitoring *or performance testing* of NO_X and CO emissions is to return to quarterly if semi-annual monitoring results indicate an exceedance…". ConocoPhillips asserted that the requested revision will ensure that the technical support document is consistent with the proposed permit, as the proposed permit allows quarterly or semi-annual performance testing to be conducted in lieu of quarterly or semi-annual portable analyzer monitoring.

The technical support document for a proposed permit is not an enforceable document. The final permit is the enforceable document. There is no regulatory requirement in the MNSR rule for a technical support document associated with issuance of a final permit and we do not generally make changes to *the technical support documents for proposed permits based on public comments. ConocoPhillips' comments on the technical support document for the proposed permit are a part of the permit record and any requested revisions are, therefore, documented in the permanent permit record.*

United States Environmental Protection Agency
Region 8 Air Program
1595 Wynkoop Street
Denver, CO 80202

Air Pollution Control
Synthetic Minor Source Permit to Construct

40 CFR 49.151

 # SMNSR-SU-000054-2012.001

Permit to Construct to establish legally and practically enforceable limitations and requirements on sources at an existing facility.

Permittee:

ConocoPhillips Company

Permitted Facility:

Ute Compressor Station
Southern Ute Indian Reservation
La Plata County, Colorado

Summary

On August 29, 2012, the EPA received an application from the ConocoPhillips Company (ConocoPhillips) requesting a synthetic minor permit for the Ute Compressor Station in accordance with the requirements of the Tribal Minor New Source Review Permit Program at 40 CFR Part 49 (MNSR).

The Ute Compressor Station is located within the exterior boundaries of the Southern Ute Indian Reservation in Colorado and dehydrates and compresses natural gas. The natural gas comes from wells located in the vicinity of the Florida River producing natural gas from the Fruitland Coal Formation. The natural gas entering the compressor station flows through an inlet separator and mist screens where most of the water is removed. The water produced by this step is transferred to an on-site storage tank and eventually disposed of in a Class II underground disposal well.

This permit does not authorize the construction of any new emission sources, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is intended only to incorporate required and requested emission limits and provisions from the following documents:

A. A September 30, 2011, Consent Agreement, Docket No. CAA-08-2011-0032 (Consent Agreement). This permit reflects the incorporation of the required emissions limits and provisions of a Consent Agreement between the EPA and ConocoPhillips. The attainment of this MNSR permit is a required element of the Consent Agreement. The requirement in the Consent Agreement to comply with National Emission Standards for Hazardous Air Pollutants (NESHAP) from Oil and Natural Gas Production Facilities at 40 CFR Part 63, Subpart HH for the dehydration system is a separately enforceable requirement of the NESHAP for Source Categories at 40 CFR Part 63 and is not included in this permit.

   The Consent Agreement requires that ConocoPhillips control the carbon monoxide (CO) and formaldehyde (CH_2O) emissions from one (1) lean-burn engine rated at 1,478 horsepower (hp). In addition, the Consent Agreement requires that ConocoPhillips implement a leak detection and repair (LDAR) program for tanks at the facility, and retrofit or replace all existing high-bleed pneumatics with low-bleed or no-bleed pneumatics.

B. An August 29, 2012, application from ConocoPhillips requesting a synthetic minor permit for the Ute Compressor Station to transfer the requirements of the Consent Agreement to a federally enforceable non-Title V permit (where they will become applicable requirements).

Upon compliance with this MNSR permit, the legally and practically enforceable reductions in emissions can be used when determining the applicability of other Clean Air Act (CAA) requirements, such as the Prevention of Significant Deterioration (PSD) Permit Program at 40 CFR Part 52 and the Title V Operating Permit Program at 40 CFR Part 71 (Part 71).

The EPA has determined that issuance of this MNSR permit will not contribute to National Ambient Air Quality Standards (NAAQS) violations, or have potentially adverse effects on ambient air quality.

<u>Table of Contents</u>

I. Conditional Permit to Construct

A. General Information

Facility:	ConocoPhillips Ute Compressor Station
Permit Number:	SMNSR-SU-000054-2012.001
SIC Code and SIC Description:	1311- Crude Petroleum and Natural Gas Production

Site Location:	Corporate Office Location
Ute Compressor Station	ConocoPhillips Company
SW ¼, SE ¼ Sec 14 and 15 T32N R11W	San Juan Business Unit
Southern Ute Indian Reservation	P.O. Box 4289
La Plata County, CO	Farmington, NM 87499

The equipment listed in this permit shall be operated by the ConocoPhillips Company at the following location:

Latitude 37.0173N, Longitude -108.0201W

B. Applicability

1. This permit is being issued under the authority of the MNSR permitting program.

2. The requirements in this permit have been created, at the Permittee's request and pursuant to Consent Agreement #CAA-08-2011-0032, to establish legally and practically enforceable requirements for limiting nitrogen oxides (NO_X), CO, and CH_2O engine emissions, upgrading pneumatic controls, and implementing an LDAR program.

3. Any conditions established for this facility or any specific units at this facility pursuant to any permit issued under the authority of the PSD Permit Program or MNSR shall continue to apply.

4. By issuing this permit, EPA does not assume any risk of loss which may occur as a result of the operation of the permitted facility by the Permittee, Owner, and/or Operator, if the conditions of this permit are not met by the Permittee, Owner, and/or Operator.

C. Requirements for 1,478 Horsepower Engine

1. Construction and Operational Limits:

   The Permittee shall install and operate emission controls as specified in this permit on one (1) reciprocating internal combustion engine meeting the following specifications:

   (a) Operated as a 4-stroke lean-burn;

   (b) Fired with natural gas; and

   (c) Limited to a maximum site rating of 1,478 hp.

2. Emission Limits

(a) Emissions from the engine shall not exceed the following:

(i) NO_x: 5.5 pounds per hour (lb/hr);

(ii) CO: 2.7 lb/hr; and

(iii) CH_2O: 0.22 lb/hr.

(b) Emission limits shall apply at all times, unless otherwise specified in this permit.

3. Control and Operational Requirements

(a) The Permittee shall ensure that the engine is equipped with a catalytic control system capable of reducing the uncontrolled emissions of CO and CH_2O to meet the emission limits specified in this permit.

(b) The Permittee shall install, operate, and maintain a temperature sensing device (i.e., thermocouple or resistance temperature detectors) before the catalytic control system on the engine in order to continuously monitor the exhaust temperature at the inlet of the catalyst bed. The temperature sensing device shall be calibrated and operated by the Permittee according to manufacturer and/or vendor specifications or specifications developed by the Permittee or vendor.

(c) Except during startups, which shall not to exceed 30 minutes, the engine exhaust temperature of the engine, at the inlet to the catalyst bed, shall be maintained at all times the engine operates with an inlet temperature of at least 450 °F and no more than 1,350 °F.

(d) During operation, the pressure drop across the catalyst bed on the engine shall be maintained to within ±2 inches of water from the baseline pressure drop measured during the most recent performance test. The baseline pressure drop for the catalyst bed shall be determined at 100% ± 10% of the engine load measured during the most recent performance test.

(e) The Permittee shall only fire the engine with natural gas. The natural gas shall be pipeline-quality in all respects except that the carbon dioxide (CO_2) concentration in the gas is not required to be within pipeline-quality.

(f) The Permittee shall follow, for the engine and its respective catalytic control system, the manufacturer and/or recommended maintenance schedule and procedures or equivalent maintenance schedule and procedures developed by the Permittee or vendor to ensure optimum performance of the engine and its respective catalytic control system.

(g) The Permittee may rebuild the existing permitted engine or replace the existing permitted engine with an engine of the same horsepower rating, and configured to operate in the same manner as the engine being rebuilt or replaced. Any emission limits, requirements, control technologies, testing or other provisions that apply to the permitted engine that is rebuilt or replaced shall also apply to the rebuilt and replaced engine.

(h) The Permittee may resume operation without the catalytic control system during an engine break-in period, not to exceed 200 operating hours, for rebuilt and replaced engines.

4. Performance Testing Requirements

(a) Performance tests shall be conducted on the engine for measuring NO_X, CO, and CH_2O emissions to demonstrate compliance with each emission limitation in this permit. The performance tests shall be conducted in accordance with appropriate reference methods specified in 40 CFR Part 63, Appendix A and 40 CFR Part 60, Appendix A, or an EPA approved American Society for Testing and Materials (ASTM) method. The Permittee may submit to the EPA a written request for approval of an alternate test method, but shall only use that alternate test method after obtaining approval from the EPA.

(i) The initial performance test for the engine shall be conducted within 90 calendar days of startup of a new engine.
(ii) Subsequent performance tests for CH_2O emissions shall be conducted within 12 months of the most recent performance test.
(iii) Performance tests shall be conducted within 90 calendar days of each catalyst replacement.
(iv) Performance tests shall be conducted within 90 calendar days of startup of all rebuilt and replaced engines.

(b) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, or processes or operational parameters the day of the engine testing or during the engine testing. Any such tuning or adjustments may result in a determination by the EPA that the test is invalid. Artificially increasing the engine load to meet testing requirements is not considered engine tuning or adjustments.

(c) The Permittee shall not abort any engine test that demonstrates non-compliance with the emission limits in this permit.

(d) All performance tests conducted on the engine shall meet the following requirements:

(i) The pressure drop across the catalyst bed and the inlet temperature to the catalyst bed shall be measured and recorded at least once during each performance test.

(ii) All tests for NO_X and CO emissions shall be performed simultaneously.

(iii) All tests shall be performed at a maximum operating rate (90% to 110% of the maximum achievable engine load available on the day of the test). The Permittee may submit to the EPA a written request for approval of an alternate load level for testing, but shall only test at that alternate load level after obtaining approval from the EPA.

(iv) During each test run, data shall be collected on all parameters necessary to document how emissions were measured and calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.).

(v) Each test shall consist of at least three 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of the emission limits in this permit.

(vi) Performance test plans shall be submitted to the EPA for approval 60 calendar days prior to the date the test is planned.

(vii) Performance test plans that have already been approved by the EPA for the emission unit approved in this permit may be used in lieu of new test plans unless the EPA requires the submittal and approval of new test plans. The Permittee may submit new plans for EPA approval at any time.

(viii) The test plans shall include and address the following elements:

(A) Purpose of the test;
(B) Engines and catalytic control systems to be tested;
(C) Expected engine operating rate(s) during the test;
(D) Sampling and analysis procedures (sampling locations, test methods, laboratory identification);
(E) Quality assurance plan (calibration procedures and frequency, sample recovery and field documentation, chain of custody procedures); and
(F) Data processing and reporting (description of data handling and quality control procedures, report content).

(e) The Permittee shall notify the EPA at least 30 calendar days prior to scheduled performance testing. The Permittee shall notify the EPA at least 1 week prior to scheduled performance testing if the testing cannot be performed.

(f) If the permitted engine is not operating, the Permittee does not need to start up the engine solely to conduct a performance test. The Permittee may conduct the performance test when the engine is started up again.

5. Monitoring Requirements

(a) The Permittee shall continuously monitor the engine exhaust temperature at the inlet to the catalyst bed.

(b) Except during startups, which shall not exceed 30 minutes, if the engine's exhaust temperature at the inlet to the catalyst bed deviates from the acceptable ranges specified in this permit then the following actions shall be taken. The Permittee's completion of any or all of these actions shall not constitute, nor qualify as, an exemption from any other emission limits in this permit.

(i) Within 24 hours of determining a deviation of the engine exhaust temperature at the inlet to the catalyst bed, the Permittee shall investigate. The investigation shall include testing the temperature sensing device, inspecting the engine for performance problems and assessing the catalytic control system for possible damage that could affect catalytic system effectiveness (including, but not limited to, catalyst housing damage, and fouled, destroyed or poisoned catalyst).

(ii) If the engine exhaust temperature at the inlet to the catalyst bed can be corrected by following the engine manufacturer and/or recommended procedures or equivalent procedures developed by the Permittee or vendor, and the catalytic control system has not been damaged, then the Permittee shall correct the engine exhaust temperature at the inlet to the catalyst bed within 24 hours of inspecting the engine and catalytic control system.

(iii) If the engine exhaust temperature at the inlet to the catalyst bed cannot be corrected using the engine manufacturer and/or recommended procedures or equivalent procedures developed by the Permittee or vendor, or the catalytic control system has been damaged, then the affected engine shall cease operating immediately and shall not be returned to routine service until the following has been met:

(A) The engine exhaust temperature at the inlet to the catalyst bed is measured and found to be within the acceptable temperature range for that engine; and

(B) The catalytic control system has been repaired or replaced, if necessary.

(c) The Permittee shall monitor the pressure drop across the catalyst bed on the engine every 30 days using pressure sensing devices before and after the catalyst bed to obtain a direct reading of the pressure drop (also referred to as the differential pressure). *[Note to Permittee: Differential pressure measurements, in general, are used to show the pressure across the filter elements. This information will determine when the elements of the catalyst bed are fouling, blocked or blown out and thus require cleaning or replacement.]*

(d) The Permittee shall perform the first measurement of the pressure drop across the catalyst bed on the engine no more than 30 days from the date of the initial performance test. Thereafter, the Permittee shall measure the pressure drop across the catalyst bed, at a minimum, every 30 days. Subsequent performance tests, as required in this permit, can be used to meet the periodic pressure drop monitoring requirements provided it occurs within the 30-day window. The pressure drop reading can be a one-time measurement on that day, the average of performance test runs conducted on that day, or an average of all the measurements taken on that day if continuous readings are taken.

(e) If the pressure drop reading exceeds ± 2 inches of water from the baseline pressure drop established during the most recent performance test, then the following actions shall be taken. The Permittee's completion of any or all of these actions shall not constitute, nor qualify as, an exemption from any other emission limits in this permit:

(i) Within 24 hours of determining a deviation of the pressure drop across the catalyst bed, the Permittee shall investigate. The investigation shall include testing the pressure transducers and assessing the catalytic control system for possible damage that could affect catalytic system effectiveness (including, but not limited to, catalyst housing damage, and plugged, fouled, destroyed or poisoned catalyst).

(ii) If the pressure drop across the catalyst bed can be corrected by following the catalytic control system manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, and the catalytic control system has not been damaged, then the Permittee shall correct the problem within 24 hours of inspecting the catalytic control system.

(iii) If the pressure drop across the catalyst bed cannot be corrected using the catalytic control system manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, or the catalytic control system is damaged, then the Permittee shall do one of the following:

(A) Conduct a performance test within 90 calendar days, as specified in this permit, to ensure that the NO_X, CO, and CH_2O emission limits are being met and to re-establish the pressure drop across the catalyst bed. The Permittee shall measure CO and NO_X emissions using a portable analyzer and a monitoring protocol approved by the EPA to establish a new temporary pressure drop baseline until a performance test can be scheduled and completed; or

(B) Cease operating the affected engine immediately. The engine shall not be returned to routine service until the pressure drop is measured and found to be within the acceptable pressure range for that engine as determined from the most recent performance test. Corrective action may include removal and cleaning of the catalyst or replacement of the catalyst.

(f) The Permittee shall measure NO_X and CO emissions from the engine at least quarterly to demonstrate compliance with the engine's emission limits in this permit. To meet this requirement, the Permittee shall:

(i) Measure NO_X and CO emissions at the normal operating load using a portable analyzer and a monitoring protocol approved by the EPA or conduct a performance test as specified in this permit;

(ii) Measure the NO_X and CO emissions simultaneously; and

(iii) Commence monitoring for NO_X and CO emissions within 3 months of the Permittee's submittal of the initial performance test results for NO_X and CO emissions to the EPA.

(g) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, or processes or operational parameters on the day of or during measurements. Any such tuning or adjustments may result in a determination by the EPA that the result is invalid. Artificially increasing an engine load to meet the testing requirements is not considered engine tuning or adjustments.

(h) If the results of 2 consecutive quarterly portable analyzer measurements demonstrate compliance with the NO_X and CO emission limits, the required monitoring frequency may change from quarterly to semi-annually.

(i) If the results of any subsequent portable analyzer measurements demonstrate non-compliance with the NO_X or CO emission limits, required monitoring frequency shall change from semi-annually to quarterly.

(j) The Permittee shall submit portable analyzer specifications and monitoring protocols for NO_X and CO to the EPA at the following address for approval at least 45 calendar days prior to the date of initial portable analyzer monitoring:

U.S. Environmental Protection Agency, Region 8
Office of Enforcement, Compliance & Environmental Justice
Air Toxics and Technical Enforcement Program, 8ENF-AT
1595 Wynkoop Street
Denver, Colorado 80202

(k) Portable analyzer specifications and monitoring protocols that have already been approved by the EPA for the emission units approved in this permit may be used in lieu of new protocols unless the EPA requires the submittal and approval of a new protocol. The Permittee may submit a new protocol for EPA approval at any time.

(l) The Permittee is not required to conduct emissions monitoring of NO_X, CO, and CH_2O emissions and parametric monitoring of exhaust temperature and catalyst differential pressure on engines that have not operated during the monitoring period. The Permittee shall certify that the engine did not operate during the monitoring period in the annual report specified in this permit.

6. Recordkeeping Requirements

(a) Records shall be kept of manufacturer and/or vendor specifications or equivalent specifications developed by the Permittee or vendor, and maintenance requirements for the engine, catalytic control system, temperature-sensing device, and pressure-measuring device.

(b) Records shall be kept of all calibration and maintenance conducted for the engine, catalytic control system, temperature-sensing device, and pressure-measuring device.

(c) Records shall be kept that are sufficient to demonstrate that the fuel used for the engine is pipeline-quality natural gas in all respects, with the exception of CO_2 concentrations.

(d) Records shall be kept of all temperature measurements required in this permit, as well as a description of any corrective actions taken pursuant to this permit.

(e) Records shall be kept of all pressure drop measurements required in this permit, as well as a description of any corrective actions taken pursuant to this permit.

(f) Records shall be kept of all required testing and monitoring in this permit. The records shall include the following:

(i) The date, place, and time of sampling or measurements;
(ii) The date(s) analyses were performed;
(iii) The company or entity that performed the analyses;
(iv) The analytical techniques or methods used;
(v) The results of such analyses or measurements; and
(vi) The operating conditions as existing at the time of sampling or measurement.

(g) Records shall be kept of all catalyst replacements or repairs, engine rebuilds and engine replacements.

(h) Records shall be kept of each rebuilt or replaced engine break-in period, pursuant to the requirements of this permit, where an existing engine that has been rebuilt or replaced resumes operation without the catalyst control system, for a period not to exceed 200 operating hours.

(i) Records shall be kept of each time the engine is shut down due to a deviation of the inlet temperature to the catalyst bed or pressure drop across the catalyst bed. The Permittee shall include in the record the cause of the problem, the corrective action taken, and the timeframe for bringing the pressure drop and inlet temperature range into compliance.

D. Requirements for Pneumatic Controllers

1. The Permittee shall install, maintain, and operate pneumatic controllers that meet one or more of the following emission control technologies:

(a) Air actuated controllers;

(b) Electronically actuated controllers;

(c) Low-bleed natural gas actuated controllers (no more than 6 standard cubic feet per hour of natural gas); or

(d) No-bleed natural gas actuated controllers.

2. Each controller shall be operated and maintained according to manufacturer or vendor specifications or equivalent procedures developed by the Permittee or vendor.

3. Beginning with the effective date of this permit, records shall be kept of the date of installation of the controllers, the manufacturer or vendor specifications of the controllers or equivalent specifications developed by the Permittee or vendor, and all scheduled maintenance and repairs on the controllers.

E. Requirements for Leak Detection and Repair (LDAR)

1. The Permittee shall implement a LDAR monitoring program for detecting emissions of volatile organic compound (VOC) emissions due to leaking equipment.

2. The Permittee shall develop a written LDAR protocol that , at a minimum, specifies the following:

   (a) The use of an infrared camera for the detection of VOC leaks;

   (b) The technical procedures for monitoring with the infrared camera;

   (c) A schedule for conducting semiannual monitoring;

   (d) Monitoring of "equipment" per the approved LDAR protocol;

   (e) A definition of when a "leak" is detected;

   (f) A repair schedule for leaking equipment (including delay of repair); and

   (g) A recordkeeping format.

3. The Permittee shall submit the LDAR protocol to the EPA at the following address for approval at least 45 calendar days prior to the date of initial monitoring:

   U.S. Environmental Protection Agency, Region 8
   Office of Enforcement, Compliance & Environmental Justice
   Air Toxics and Technical Enforcement Program, 8ENF-AT
   1595 Wynkoop Street
   Denver, Colorado 80202

4. LDAR protocols that have already been approved by the EPA may be used in lieu of new protocols unless the EPA requires the submittal and approval of a new LDAR protocol.

5. The Permittee may submit a revised LDAR protocol at any time for EPA approval. The existing LDAR protocol will remain in effect until a revised LDAR protocol is approved by the EPA.

6. In the event that the EPA determines that the LDAR monitoring program is not meeting its intended goals, the Permittee shall submit a revised LDAR protocol upon request by the EPA.

7. Leak detection monitoring shall commence upon approval of the LDAR protocol by the EPA.

8. LDAR monitoring shall be conducted at least semi-annually in accordance with an approved LDAR protocol and shall be conducted a minimum of 5 calendar months apart.

9. The Permittee shall notify the EPA in writing at least 30 calendar days prior to any LDAR monitoring conducted. If monitoring cannot be performed on the scheduled date, the Permittee shall notify EPA at least 1 week prior to the scheduled date and reschedule the monitoring to satisfy the monitoring frequency requirements.

10. The Permittee shall maintain a record of all EPA approved LDAR protocols.

11. The Permittee shall maintain a record of the results of all LDAR monitoring and any necessary equipment repairs due to VOC leaks.

F. Requirements for Records Retention

1. The Permittee shall retain all records required by this permit for a period of at least 5 years from the date the record was created.

2. Records shall be kept in the vicinity of the facility, such as at the facility, the location that has day-to-day operational control over the facility, or the location that has day-to-day responsibility for compliance of the facility.

G. Requirements for Reporting

1. Annual Emission Reports

   (a) The Permittee shall submit a written annual report of the actual annual emissions from all emission units at the facility covered under this permit; including emissions from start-ups, shutdowns, and malfunctions, each year no later than April 1st. The annual report shall cover the period for the previous calendar year. All reports shall be certified to truth and accuracy by the person primarily responsible for Clean Air Act compliance for the Permittee.

   (b) The report shall be submitted to:

   U.S. Environmental Protection Agency, Region 8
   Office of Partnerships and Regulatory Assistance
   Tribal Air Permitting Program, 8P-AR
   1595 Wynkoop Street
   Denver, Colorado 80202

   The report may be submitted via electronic mail to r8AirPermitting@epa.gov.

2. All other documents required to be submitted under this permit, with the exception of the Annual Emission Reports, shall be submitted to:

   U.S. Environmental Protection Agency, Region 8
   Office of Enforcement, Compliance & Environmental Justice
   Air Toxics and Technical Enforcement Program, 8ENF-AT
   1595 Wynkoop Street
   Denver, Colorado 80202

   All documents may be submitted electronically to r8airreportenforcement@epa.gov.

3. The Permittee shall submit a written LDAR monitoring report each year no later than April 1st. The annual report shall include the semi-annual LDAR monitoring results for the previous calendar year.

4. The Permittee shall promptly submit to the EPA a written report of any deviations of permit requirements and a description of the probable cause of such deviations and any corrective actions or preventative measures taken. A "prompt" deviation report is one that is post marked or submitted via electronic mail to r8airreportenforcement@epa.gov as follows:

(a) Within 30 days from the discovery of any deviation of the emission or operational limits that is left un-corrected for more than 5 days after discovering the deviation;

(b) Within 30 days from the discovery of an equipment leak as a result of the semi-annual LDAR monitoring that is left un-corrected for more than 5 days after discovering the leak; and

(c) By April 1st for the discovery of a deviation of recordkeeping or other permit conditions during the preceding calendar year that do not affect the Permittee's ability to meet the emission limits.

5. The Permittee shall submit a written report for any required performance tests to the EPA Regional Office within 60 days after completing the tests.

6. The Permittee shall submit any record or report required by this permit upon EPA request.

II. General Provisions

A. Conditional Approval:

Pursuant to the authority of 40 CFR 49.151, the EPA hereby conditionally grants this permit. This authorization is expressly conditioned as follows:

1. *Document Retention and Availability:* This permit and any required attachments shall be retained and made available for inspection upon request at the location set forth herein.

2. *Permit Application:* The Permittee shall abide by all representations, statements of intent and agreements contained in the application submitted by the Permittee. The EPA shall be notified 10 days in advance of any significant deviation from the permit application as well as any plans, specifications or supporting data furnished.

3. *Permit Deviations:* The issuance of this permit may be suspended or revoked if the EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been or is to be made. If the proposed source is constructed, operated, or modified not in accordance with the terms of this permit, the Permittee will be subject to appropriate enforcement action.

4. *Compliance with Permit:* The Permittee shall comply with all conditions of this permit, including emission limitations that apply to the affected emissions units at the permitted facility/source. Noncompliance with any permit term or condition is a violation of this permit and may constitute a violation of the Clean Air Act and is grounds for enforcement action and for a permit termination or revocation.

5. *Fugitive Emissions:* The Permittee shall take all reasonable precautions to prevent and/or minimize fugitive emissions during the construction period.

6. *National Ambient Air Quality Standard and PSD Increment:* The permitted source shall not cause or contribute to a National Ambient Air Quality Standard violation or a PSD increment violation.

7. *Compliance with Federal and Tribal Rules, Regulations, and Orders:* Issuance of this permit does not relieve the Permittee of the responsibility to comply fully with all other applicable federal and tribal rules, regulations, and orders now or hereafter in effect.

8. *Enforcement:* It is not a defense, for the Permittee, in an enforcement action, to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

9. *Facility/Source Modifications:* For proposed modifications, as defined at §49.152(d), that would increase an emissions unit allowable emissions of pollutants above its existing permitted annual allowable emissions limit, the Permittee shall first obtain a permit modification pursuant to the MNSR regulations approving the increase. For a proposed modification that is not otherwise subject to review under the PSD or MNSR regulations, such proposed increase in the annual allowable emissions limit shall be approved through an administrative permit revision as provided at §49.159(f).

10. *Relaxation of Legally and Practically Enforceable Limits:* At such time that a new or modified source within the permitted facility/source or modification of this permitted facility/source becomes a major stationary source or major modification solely by virtue of a relaxation in any legally and practically enforceable limitation which was established after August 7, 1980, on the capacity of this permitted facility/source to otherwise emit a pollutant, such as a restriction on hours of operation, then the requirements of the PSD regulations shall apply to the source or modification as though construction had not yet commenced on the source or modification.

11. *Revise, Reopen, Revoke and Reissue, or Terminate for Cause:* This permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee, for a permit revision, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. The EPA may reopen a permit for a cause on its own initiative, e.g., if this permit contains a material mistake or the Permittee fails to assure compliance with the applicable requirements.

12. *Severability Clause:* The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force.

13. *Property Rights:* This permit does not convey any property rights of any sort or any exclusive privilege.

14. *Information Requests:* The Permittee shall furnish to the EPA, within a reasonable time, any information that the EPA may request in writing to determine whether cause exists for revising, revoking and reissuing, or terminating this permit or to determine compliance with this permit.

    For any such information claimed to be confidential, you shall also submit a claim of confidentiality in accordance with 40 CFR Part 2, Subpart B.

15. *Inspection and Entry:* The EPA or its authorized representatives may inspect this permitted facility/source during normal business hours for the purpose of ascertaining compliance with all conditions of this permit. Upon presentation of proper credentials, the Permittee shall allow the EPA or its authorized representative to:

(a) Enter upon the premises where a permitted facility/source is located or emissions-related activity is conducted, or where records are required to be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of this permit;

(c) Inspect, during normal business hours or while the permitted facility/source is in operation, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or other applicable requirements; and

(e) Record any inspection by use of written, electronic, magnetic and photographic media.

16. *Permit Effective Date:* This permit is effective immediately upon issuance unless comments resulted in a change in the proposed permit, in which case this permit is effective 30 days after issuance. The Permittee may notify the EPA, in writing, that this permit or a term or condition of it is rejected. Such notice should be made within 30 days of receipt of this permit and should include the reason or reasons for rejection.

17. *Permit Transfers:* Permit transfers shall be made in accordance with 40 CFR 49.159(f). The Air Program Director shall be notified in writing at the address shown below if the company is sold or changes its name.

U.S. Environmental Protection Agency, Region 8
Office of Partnerships and Regulatory Assistance
Tribal Air Permitting Program, 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202

18. *Invalidation of Permit:* This permit becomes invalid if construction is not commenced within 18 months after the effective date of the permit, construction is discontinued for 18 months or more, or construction is not completed within a reasonable time. The EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between the construction of the approved phases of a phased construction project. The Permittee shall commence construction of each such phase within 18 months of the projected and approved commencement date.

19. *Notification of Start-Up*: The Permittee shall submit a notification of the anticipated date of initial start-up of the permitted source to the EPA within 60 days of such date, unless the source permitted under this action is an existing source.

B. Authorization:

Authorized by the United States Environmental Protection Agency, Region 8

Callie A. Videtich 9/15/14

Callie A. Videtich | Date

Acting Assistant Regional Administrator

Office of Partnerships and Regulatory Assistance

Public Notice: Request For Comments

Proposed Air Quality Permits to Construct
ConocoPhillips Company
Ute Compressor Station

Notice issued: May 12, 2014

Written comments due:
5 p.m., June 11, 2014

Where are the facilities located?
Southern Ute Indian Reservation
Ute Compressor Station
~17 miles south of Durango at Sections 14 and 15, Township 32N, Range 11W
Latitude 37.12944 N
Longitude -107.93722W

What is being proposed?
This permit action will apply to an existing facility operating on the Southern Ute Indian Reservation in Colorado.

The facility is an existing natural gas compressor station. The facility is currently subject to a September 30, 2011 Consent Agreement, Docket No. CAA-08-2011-0032, between the EPA and the ConocoPhillips Company. The attainment of this permit is a required element of the Consent Agreement. The Consent Agreement requires that the ConocoPhillips Company control carbon monoxide (CO), volatile organic compound (VOC), and formaldehyde (CH2O) emissions engines, storage tanks, and pneumatic devices operating at the facility.

Upon promulgation of the Tribal New Source Review Program at 40 CFR Part 49 (MNSR), implemented by Federal government, and the approval of the Southern Ute Indian Tribe's Title V Permit to Operate Program (Part 70) implemented by the Southern Ute Indian Tribe, it is now necessary to transfer these limits to the appropriate MNSR permits before the Southern Ute Indian Tribe issues an initial Part 70 operating permit.

Proposed Permit Requirements:
The permit proposes requirements to use air pollution controls and limit the emissions of CO and CH_2O for a 1,478 horsepower lean-burn natural gas-fired engine operating at the facility. In addition, the permit proposes to require the development and implementation of a leak detection and repair program to monitor volatile organic compound (VOC) emissions from leaking equipment and to retrofit or replace all existing high-bleed pneumatic devices operating at the facility with low-bleed or no-bleed devices. ConocoPhillips will be required to submit protocols that require the use of an infrared camera for the detection of leaks.

What are the effects on air quality?
These actions will have no adverse air quality impacts. The emissions at this existing facility will not be increasing due to this permit action. In addition, this action does not authorize the construction of any new emission sources, or emission increases from existing sources, nor does it otherwise authorize any other physical modifications to the facility or its operations.

Where can I send comments?
EPA accepts comments by mail, fax and e-mail.

US EPA Region 8 Air Program, 8P-AR
Attn: Federal Minor NSR Coordinator
1595 Wynkoop Street,
Denver, CO 80202
R8AirPermitting@epa.gov
Fax: 303-312-6064

How can I review documents?
You can review an electronic copy of the proposed permits and related documents at the following locations:

Southern Ute Indian Tribe
Environmental Programs Office
151 County Road 517
Ignacio, Colorado 81137
Attn: Brenda Jarrell, Air Quality Program Manager

and

US EPA Region 8 Office:
1595 Wynkoop Street, Denver, CO 80202
(Please call Claudia Smith at 303-312-6520 in advance of your visit.)

US EPA Region 8 Website:
http://www2.epa.gov/region8/air-permit-public-comment-opportunities

Permit number:
Ute Compressor Station:
SMNSR-SU-000054-2012.001

What happens next?
EPA will review and consider all comments received during the comment period. Following this review, the EPA may issue the permits as proposed, issue modified permits based on comments, or deny the permits.

Tribal Minor New Source Review in Indian Country

United States Environmental Protection Agency

Region 8
Air Program
1595 Wynkoop Street
Denver, CO 80202
Phone 800-227-8917

United States Environmental Protection Agency
Region 8 Air Program
1595 Wynkoop Street
Denver, CO 80202

Air Pollution Control
Synthetic Minor Source Permit to Construct

40 CFR 49.151

 # SMNSR-SU-000054-2012.001

Permit to Construct to establish legally and practically enforceable limitations and requirements on sources at an existing facility.

<u>Permittee</u>:

ConocoPhillips Company

<u>Permitted Facility</u>:

Ute Compressor Station
Southern Ute Indian Reservation
La Plata County, Colorado

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I. Conditional Permit to Construct

A. General Information

Facility:	ConocoPhillips Ute Compressor Station
Permit Number:	SMNSR-SU-000054-2012.001
SIC Code and SIC Description:	1311- Crude Petroleum and Natural Gas Production

Site Location:	Corporate Office Location
Ute Compressor Station	ConocoPhillips Company
SW ¼, SE ¼ Sec 14 and 15 T32N R11W	San Juan Business Unit
Southern Ute Indian Reservation	P.O. Box 4289
La Plata County, CO	Farmington, NM 87499

The equipment listed in this permit shall be operated by the ConocoPhillips Company at the following location:

Latitude 37.0173N, Longitude -108.0201W

B. Background

On July 1, 2011, the EPA promulgated the Tribal Minor New Source Review Permit Program at 40 CFR 49.151 (MNSR). The rule became effective on August 30, 2011. The purpose of the rule is to establish a preconstruction permitting program for new and modified minor sources and minor modifications at existing major sources. In addition, the rule provides a mechanism to create legally and practically enforceable restrictions upon request to recognize emission controls, limits in hours of operation, limits on throughputs, etc. creating synthetic minor sources. In other words, an otherwise major stationary source may receive restrictions on its total potential to emit to become a synthetic minor source for purposes of the Prevention of Significant Deterioration permit Program at 40 CFR 52 (PSD) and/or the Title V Operating Permit Program at 40 CFR Part 71 (Part 71). This mechanism is voluntary and may also be used to establish an otherwise major source of hazardous air pollutants (HAPs) as a synthetically minor source of HAPs.

Pursuant to §§49.151(c)(1)(ii)(C) and (D) of the rule, existing sources whose limits were established through mechanisms such as a consent decree, are required to apply for a permit under MNSR to transfer the limits to a MNSR permit. This permit does not approve any new construction.

C. Proposal

Through this permit action, the EPA is incorporating legally and practically enforceable emission limits established in a September 30, 2011 Consent Agreement (CA), #CAA-08-2011-0032. The CA requires that ConocoPhillips control the carbon monoxide (CO) and formaldehyde (CH_2O) emissions from a lean-burn engine rated at 1,478 horsepower (hp). In addition, the CA requires that ConocoPhillips implement a leak detection and repair (LDAR) program for tanks at the facility, and retrofit or replace all existing high-bleed pneumatics with low-bleed or no-bleed pneumatics.

The CA also requires the Permittee to comply with the National Emission Standards for Hazardous Air Pollutants (NESHAP) from Oil and Natural Gas Production Facilities at 40 CFR Part 63, Subpart HH for the dehydration system. However, this is a separately enforceable requirement of the NESHAP for Source Categories at 40 CFR Part 63 and is not included in this permit.

D. Applicability

1. This permit is being issued under the authority of the MNSR permitting program.

2. The requirements in this permit have been created, at the Permittee's request and pursuant to CA #CAA-08-2011-0032, to establish legally and practically enforceable requirements for limiting NO_X, CO, and CH_2O engine emissions, upgrading pneumatic controls, and implementing an LDAR program.

3. Any conditions established for this facility or any specific units at this facility pursuant to any permit issued under the authority of the PSD Permit Program at 40 CFR Part 52 or MNSR shall continue to apply.

4. By issuing this permit, EPA does not assume any risk of loss which may occur as a result of the operation of the permitted facility by the Permittee, Owner, and/or Operator, if the conditions of this permit are not met by the Permittee, Owner, and/or Operator.

E. Requirements for Engines

1. Construction and Operational Limits:

   The Permittee shall install and operate emission controls as specified in this permit on one (1) reciprocating internal combustion engine meeting the following specifications:

   (a) Operated as a 4-stroke lean-burn;

   (b) Fired with natural gas; and

   (c) Limited to a maximum site rating of 1,478 hp.

2. Emission Limits

   (a) Emissions from the engine shall not exceed the following:

      (i) NO_x: 5.5 pounds per hour (lb/hr);

      (ii) CO: 2.7 lb/hr; and

      (iii) CH_2O: 0.22 lb/hr.

   (b) Emission limits shall apply at all times, unless otherwise specified in this permit.

3. Control and Operational Requirements

(a) The Permittee shall ensure that the engine is equipped with a catalytic control system capable of reducing the uncontrolled emissions of CO and CH_2O to meet the emission limits specified in this permit.

(b) The Permittee shall install, operate, and maintain a temperature sensing device (i.e., thermocouple or resistance temperature detectors) before the catalytic control system on the engine in order to continuously monitor the exhaust temperature at the inlet of the catalyst bed. The temperature sensing device shall be calibrated and operated by the Permittee according to manufacturer and/or vendor specifications or specifications developed by the Permittee or vendor.

(c) Except during startups, not to exceed 30 minutes, the engine exhaust temperature of the engine, at the inlet to the catalyst bed, shall be maintained at all times the engine operates with an inlet temperature of at least 450° F and no more than 1,350°F.

(d) During operation, the pressure drop across the catalyst bed on the engine shall be maintained to within ± 2 inches of water from the baseline pressure drop measured during the most recent performance test. The baseline pressure drop for the catalyst bed shall be determined at 100% ± 10% of the engine load measured during the most recent performance test.

(e) The Permittee shall only fire the engine with natural gas. The natural gas shall be pipeline-quality in all respects except that the carbon dioxide (CO_2) concentration in the gas is not required to be within pipeline-quality.

(f) The Permittee shall follow, for the engine and its respective catalytic control system, the manufacturer and/or recommended maintenance schedule and procedures or equivalent maintenance schedule and procedures developed by the Permittee or vendor to ensure optimum performance of the engine and its respective catalytic control system.

(g) The Permittee may rebuild the existing permitted engine or replace the existing permitted engine with an engine of the same horsepower rating, and configured to operate in the same manner as the engine being rebuilt or replaced. Any emission limits, requirements, control technologies, testing or other provisions that apply to the permitted engine that is rebuilt or replaced shall also apply to the rebuilt and replaced engine.

(h) The Permittee may resume operation without the catalytic control system during an engine break-in period, not to exceed 200 operating hours, for rebuilt and replaced engines.

4. Performance Testing Requirements

(a) Performance tests shall be conducted on the engine for measuring NO_X, CO, and CH_2O emissions to demonstrate compliance with each emission limitation in this permit. The performance tests shall be conducted in accordance with appropriate reference methods specified in 40 CFR Part 63, Appendix A and 40 CFR Part 60, Appendix A, or an EPA approved American Society for Testing and Materials (ASTM) method. The Permittee may submit to the EPA a written request for approval of an alternate test method, but shall only use that alternate test method after obtaining approval from the EPA.

(i) The initial performance test for the engine shall be conducted within 90 calendar days of startup of a new engine.

(ii) Subsequent performance tests for CH_2O emissions shall be conducted within 12 months of the most recent performance test.

(iii) Performance tests shall be conducted within 90 calendar days of each catalyst replacement.

(iv) Performance tests shall be conducted within 90 calendar days of startup of all rebuilt and replaced engines.

(b) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, or processes or operational parameters the day of the engine testing or during the engine testing. Any such tuning or adjustments may result in a determination by the EPA that the test is invalid. Artificially increasing the engine load to meet testing requirements is not considered engine tuning or adjustments.

(c) The Permittee shall not abort any engine test that demonstrates non-compliance with the emission limits in this permit.

(d) All performance tests conducted on the engine shall meet the following requirements:

(i) The pressure drop across the catalyst bed and the inlet temperature to the catalyst bed shall be measured and recorded at least once during each performance test.

(ii) All tests for NO_X and CO emissions shall be performed simultaneously.

(iii) All tests shall be performed at a maximum operating rate (90% to 110% of the maximum achievable engine load available on the day of the test). The Permittee may submit to the EPA a written request for approval of an alternate load level for testing, but shall only test at that alternate load level after obtaining approval from the EPA.

(iv) During each test run, data shall be collected on all parameters necessary to document how emissions were measured and calculated (such as test run length, minimum sample volume, volumetric flow rate, moisture and oxygen corrections, etc.).

(v) Each test shall consist of at least three 1-hour or longer valid test runs. Emission results shall be reported as the arithmetic average of all valid test runs and shall be in terms of the emission limits in this permit.

(vi) Performance test plans shall be submitted to the EPA for approval 60 calendar days prior to the date the test is planned.

(vii) Performance test plans that have already been approved by the EPA for the emission unit approved in this permit may be used in lieu of new test plans unless the EPA requires the submittal and approval of new test plans. The Permittee may submit new plans for EPA approval at any time.

(viii) The test plans shall include and address the following elements:

(A) Purpose of the test;
(B) Engines and catalytic control systems to be tested;
(C) Expected engine operating rate(s) during the test;
(D) Sampling and analysis procedures (sampling locations, test methods, laboratory identification);
(E) Quality assurance plan (calibration procedures and frequency, sample recovery and field documentation, chain of custody procedures); and
(F) Data processing and reporting (description of data handling and quality control procedures, report content).

(e) The Permittee shall notify the EPA at least 30 calendar days prior to scheduled performance testing. The Permittee shall notify the EPA at least 1 week prior to scheduled performance testing if the testing cannot be performed.

(f) If the permitted engine is not operating, the Permittee does not need to start up the engine solely to conduct a performance test. The Permittee may conduct the performance test when the engine is started up again.

5. <u>Monitoring Requirements</u>

(a) The Permittee shall continuously monitor the engine exhaust temperature at the inlet to the catalyst bed.

(b) Except during startups, not to exceed 30 minutes, if the engine's exhaust temperature at the inlet to the catalyst bed deviates from the acceptable ranges specified in this permit then the following actions shall be taken. The Permittee's completion of any or all of these actions shall not constitute, nor qualify as, an exemption from any other emission limits in this permit.

(i) Within 24 hours of determining a deviation of the engine exhaust temperature at the inlet to the catalyst bed, the Permittee shall investigate. The investigation shall include testing the temperature sensing device, inspecting the engine for performance problems and assessing the catalytic control system for possible damage that could affect catalytic system effectiveness (including, but not limited to, catalyst housing damage, and fouled, destroyed or poisoned catalyst).

(ii) If the engine exhaust temperature at the inlet to the catalyst bed can be corrected by following the engine manufacturer and/or recommended procedures or equivalent procedures developed by the Permittee or vendor, and the catalytic control system has not been damaged, then the Permittee shall correct the engine exhaust temperature at the inlet to the catalyst bed within 24 hours of inspecting the engine and catalytic control system.

(iii) If the engine exhaust temperature at the inlet to the catalyst bed cannot be corrected using the engine manufacturer and/or recommended procedures or equivalent procedures developed by the Permittee or vendor, or the catalytic control system has been damaged, then the affected engine shall cease operating immediately and shall not be returned to routine service until the following has been met:

(A) The engine exhaust temperature at the inlet to the catalyst bed is measured and found to be within the acceptable temperature range for that engine; and

(B) The catalytic control system has been repaired or replaced, if necessary.

(c) The Permittee shall monitor the pressure drop across the catalyst bed on the engine every 30 days using pressure sensing devices before and after the catalyst bed to obtain a direct reading of the pressure drop (also referred to as the differential pressure). *[Note to Permittee: Differential pressure measurements, in general, are used to show the pressure across the filter elements. This information will determine when the elements of the catalyst bed are fouling, blocked or blown out and thus require cleaning or replacement.]*

(d) The Permittee shall perform the first measurement of the pressure drop across the catalyst bed on the engine no more than 30 days from the date of the initial performance test. Thereafter, the Permittee shall measure the pressure drop across the catalyst bed, at a minimum, every 30 days. Subsequent performance tests, as required in this permit, can be used to meet the periodic pressure drop monitoring requirements provided it occurs within the 30-day window. The pressure drop reading can be a one-time measurement on that day, the average of performance test runs conducted on that day, or an average of all the measurements taken on that day if continuous readings are taken.

(e) If the pressure drop reading exceeds ± 2 inches of water from the baseline pressure drop established during the most recent performance test, then the following actions shall be taken. The Permittee's completion of any or all of these actions shall not constitute, nor qualify as, an exemption from any other emission limits in this permit:

(i) Within 24 hours of determining a deviation of the pressure drop across the catalyst bed, the Permittee shall investigate. The investigation shall include testing the pressure transducers and assessing the catalytic control system for possible damage that could affect catalytic system effectiveness (including, but not limited to, catalyst housing damage, and plugged, fouled, destroyed or poisoned catalyst).

(ii) If the pressure drop across the catalyst bed can be corrected by following the catalytic control system manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, and the catalytic control system has not been damaged, then the Permittee shall correct the problem within 24 hours of inspecting the catalytic control system.

(iii) If the pressure drop across the catalyst bed cannot be corrected using the catalytic control system manufacturer and/or vendor recommended procedures or equivalent procedures developed by the Permittee or vendor, or the catalytic control system is damaged, then the Permittee shall do one of the following:

(A) Conduct a performance test within 90 calendar days, as specified in this permit, to ensure that the NO_X, CO, and CH_2O emission limits are being met and to re-establish the pressure drop across the catalyst bed. The Permittee shall measure CO and NO_X emissions using a portable analyzer and a monitoring protocol approved by the EPA to establish a new temporary pressure drop baseline until a performance test can be scheduled and completed; or

(B) Cease operating the affected engine immediately. The engine shall not be returned to routine service until the pressure drop is measured and found to be within the acceptable pressure range for that engine as determined from the most recent performance test. Corrective action may include removal and cleaning of the catalyst or replacement of the catalyst.

(f) The Permittee shall measure NO_X and CO emissions from the engine at least quarterly to demonstrate compliance with the engine's emission limits in this permit. To meet this requirement, the Permittee shall:

(i) Measure NO_X and CO emissions at the normal operating load using a portable analyzer and a monitoring protocol approved by the EPA or conduct a performance test as specified in this permit;

(ii) Measure the NO_X and CO emissions simultaneously; and

(iii) Commence monitoring for NO_X and CO emissions within 6 months of the Permittee's submittal of the initial performance test results for NO_X and CO emissions to the EPA.

(g) The Permittee shall not perform engine tuning or make any adjustments to engine settings, catalytic control system settings, or processes or operational parameters on the day of or during measurements. Any such tuning or adjustments may result in a determination by the EPA that the result is invalid. Artificially increasing an engine load to meet the testing requirements is not considered engine tuning or adjustments.

(h) If the results of 2 consecutive quarterly portable analyzer measurements demonstrate compliance with the NO_X and CO emission limits, the required monitoring frequency may change from quarterly to semi-annually.

(i) If the results of any subsequent portable analyzer measurements demonstrate non-compliance with the NO_X or CO emission limits, required monitoring frequency shall change from semi-annually to quarterly.

(j) The Permittee shall submit portable analyzer specifications and monitoring protocols for NO_X and CO to the EPA at the following address for approval at least 45 calendar days prior to the date of initial portable analyzer monitoring:

U.S. Environmental Protection Agency, Region 8
Office of Enforcement, Compliance & Environmental Justice
Air Toxics and Technical Enforcement Program, 8ENF-AT
1595 Wynkoop Street
Denver, Colorado 80202

(k) Portable analyzer specifications and monitoring protocols that have already been approved by the EPA for the emission units approved in this permit may be used in lieu of new protocols unless the EPA requires the submittal and approval of a new protocol. The Permittee may submit a new protocol for EPA approval at any time.

(l) The Permittee is not required to conduct emissions monitoring of NO_X, CO, and CH_2O emissions and parametric monitoring of exhaust temperature and catalyst differential pressure on engines that have not operated during the monitoring period. The Permittee shall certify that the engine did not operate during the monitoring period in the annual report specified in this permit.

6. Recordkeeping Requirements

(a) Records shall be kept of manufacturer and/or vendor specifications or equivalent specifications developed by the Permittee or vendor, and maintenance requirements for the engine, catalytic control system, temperature-sensing device, and pressure-measuring device.

(b) Records shall be kept of all calibration and maintenance conducted for the engine, catalytic control system, temperature-sensing device, and pressure-measuring device.

(c) Records shall be kept that are sufficient to demonstrate that the fuel used for the engine is pipeline-quality natural gas in all respects, with the exception of CO_2 concentrations.

(d) Records shall be kept of all temperature measurements required in this permit, as well as a description of any corrective actions taken pursuant to this permit.

(e) Records shall be kept of all pressure drop measurements required in this permit, as well as a description of any corrective actions taken pursuant to this permit.

(f) Records shall be kept of all required testing and monitoring in this permit. The records shall include the following:

(i) The date, place, and time of sampling or measurements;
(ii) The date(s) analyses were performed;
(iii) The company or entity that performed the analyses;
(iv) The analytical techniques or methods used;
(v) The results of such analyses or measurements; and
(vi) The operating conditions as existing at the time of sampling or measurement.

(g) Records shall be kept of all catalyst replacements or repairs, engine rebuilds and engine replacements.

(h) Records shall be kept of each rebuilt or replaced engine break-in period, pursuant to the requirements of this permit, where an existing engine that has been rebuilt or replaced resumes operation without the catalyst control system, for a period not to exceed 200 operating hours.

(i) Records shall be kept of each time the engine is shut down due to a deviation of the inlet temperature to the catalyst bed or pressure drop across the catalyst bed. The Permittee shall include in the record the cause of the problem, the corrective action taken, and the timeframe for bringing the pressure drop and inlet temperature range into compliance.

F. Requirements for Pneumatic Controllers

1. The Permittee shall install, maintain, and operate pneumatic controllers that meet one or more of the following emission control technologies:

   (a) Air actuated controllers;

   (b) Electronically actuated controllers;

   (c) Low-bleed natural gas actuated controllers (no more than 6 standard cubic feet per hour of natural gas); or

   (d) No-bleed natural gas actuated controllers.

2. Each controller shall be operated and maintained according to manufacturer or vendor specifications or equivalent procedures developed by the Permittee or vendor.

3. Beginning with the effective date of this permit, records shall be kept of the date of installation of the controllers, the manufacturer or vendor specifications of the controllers or equivalent specifications developed by the Permittee or vendor, and all scheduled maintenance and repairs on the controllers.

G. Requirements for Leak Detection and Repair (LDAR)

1. The Permittee shall implement a LDAR monitoring program for detecting emissions of volatile organic compound (VOC) emissions due to leaking equipment.

2. The Permittee shall develop a written LDAR protocol that , at a minimum, specifies the following:

   (a) The use of an infrared camera for the detection of VOC leaks;

   (b) The technical procedures for monitoring with the infrared camera;

   (c) A schedule for conducting semiannual monitoring;

   (d) Monitoring of "equipment" per the approved LDAR protocol;

   (e) A definition of when a "leak" is detected;

(f) A repair schedule for leaking equipment (including delay of repair); and

(g) A recordkeeping format.

3. The Permittee shall submit the LDAR protocol to the EPA at the following address for approval at least 45 calendar days prior to the date of initial monitoring:

   U.S. Environmental Protection Agency, Region 8
   Office of Enforcement, Compliance & Environmental Justice
   Air Toxics and Technical Enforcement Program, 8ENF-AT
   1595 Wynkoop Street
   Denver, Colorado 80202

4. LDAR protocols that have already been approved by the EPA may be used in lieu of new protocols unless the EPA requires the submittal and approval of a new LDAR protocol.

5. The Permittee may submit a revised LDAR protocol at any time for EPA approval. The existing LDAR protocol will remain in effect until a revised LDAR protocol is approved by the EPA.

6. In the event that the EPA determines that the LDAR monitoring program is not meeting its intended goals, the Permittee shall submit a revised LDAR protocol upon request by the EPA.

7. Leak detection monitoring shall commence upon approval of the LDAR protocol by the EPA.

8. LDAR monitoring shall be conducted at least semi-annually in accordance with an approved LDAR protocol and shall be conducted a minimum of 5 calendar months apart.

9. The Permittee shall notify the EPA in writing at least 30 calendar days prior to any LDAR monitoring conducted. If monitoring cannot be performed on the scheduled date, the Permittee shall notify EPA at least 1 week prior to the scheduled date and reschedule the monitoring to satisfy the monitoring frequency requirements.

10. The Permittee shall maintain a record of all EPA approved LDAR protocols.

11. The Permittee shall maintain a record of the results of all LDAR monitoring and any necessary equipment repairs due to VOC leaks.

H. Requirements for Records Retention

1. The Permittee shall retain all records required by this permit for a period of at least 5 years from the date the record was created.

2. Records shall be kept in the vicinity of the facility, such as at the facility, the location that has day-to-day operational control over the facility, or the location that has day-to-day responsibility for compliance of the facility.

I. Requirements for Reporting

1. Annual Emission Reports

(a) The Permittee shall submit a written annual report of the actual annual emissions from all emission units at the facility covered under this permit; including emissions from start-ups, shutdowns, and malfunctions, each year no later than April 1st. The annual report shall cover the period for the previous calendar year. All reports shall be certified to truth and accuracy by the person primarily responsible for Clean Air Act compliance for the Permittee.

(b) The report shall be submitted to:

U.S. Environmental Protection Agency, Region 8
Office of Partnerships and Regulatory Assistance
Tribal Air Permitting Program, 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202

The report may be submitted via electronic mail to r8AirPermitting@epa.gov.

2. All other documents required to be submitted under this permit, with the exception of the Annual Emission Reports, shall be submitted to:

U.S. Environmental Protection Agency, Region 8
Office of Enforcement, Compliance & Environmental Justice
Air Toxics and Technical Enforcement Program, 8ENF-AT
1595 Wynkoop Street
Denver, Colorado 80202

All documents may be submitted electronically to r8airreportenforcement@epa.gov.

3. The Permittee shall submit a written LDAR monitoring report each year no later than April 1st. The annual report shall include the semi-annual LDAR monitoring results for the previous calendar year.

4. The Permittee shall promptly submit to the EPA a written report of any deviations of permit requirements and a description of the probable cause of such deviations and any corrective actions or preventative measures taken. A "prompt" deviation report is one that is post marked or submitted via electronic mail to r8airreportenforcement@epa.gov as follows:

(a) Within 30 days from the discovery of any deviation of the emission or operational limits that is left un-corrected for more than 5 days after discovering the deviation;

(b) Within 30 days from the discovery of an equipment leak as a result of the semi-annual LDAR monitoring that is left un-corrected for more than 5 days after discovering the leak; and

(c) By April 1st for the discovery of a deviation of recordkeeping or other permit conditions during the preceding calendar year that do not affect the Permittee's ability to meet the emission limits.

5. The Permittee shall submit a written report for any required performance tests to the EPA Regional Office within 60 days after completing the tests.

6. The Permittee shall submit any record or report required by this permit upon EPA request.

II. General Provisions

A. Conditional Approval:

Pursuant to the authority of 40 CFR 49.151, the EPA hereby conditionally grants this permit. This authorization is expressly conditioned as follows:

1. *Document Retention and Availability:* This permit and any required attachments shall be retained and made available for inspection upon request at the location set forth herein.

2. *Permit Application:* The Permittee shall abide by all representations, statements of intent and agreements contained in the application submitted by the Permittee. The EPA shall be notified 10 days in advance of any significant deviation from the permit application as well as any plans, specifications or supporting data furnished.

3. *Permit Deviations:* The issuance of this permit may be suspended or revoked if the EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been or is to be made. If the proposed source is constructed, operated, or modified not in accordance with the terms of this permit, the Permittee will be subject to appropriate enforcement action.

4. *Compliance with Permit:* The Permittee shall comply with all conditions of this permit, including emission limitations that apply to the affected emissions units at the permitted facility/source. Noncompliance with any permit term or condition is a violation of this permit and may constitute a violation of the Clean Air Act and is grounds for enforcement action and for a permit termination or revocation.

5. *Fugitive Emissions:* The Permittee shall take all reasonable precautions to prevent and/or minimize fugitive emissions during the construction period.

6. *National Ambient Air Quality Standard and PSD Increment:* The permitted source shall not cause or contribute to a National Ambient Air Quality Standard violation or a PSD increment violation.

7. *Compliance with Federal and Tribal Rules, Regulations, and Orders:* Issuance of this permit does not relieve the Permittee of the responsibility to comply fully with all other applicable federal and tribal rules, regulations, and orders now or hereafter in effect.

8. *Enforcement:* It is not a defense, for the Permittee, in an enforcement action, to claim that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

9. *Facility/Source Modifications:* For proposed modifications, as defined at §49.152(d), that would increase an emissions unit allowable emissions of pollutants above its existing permitted annual allowable emissions limit, the Permittee shall first obtain a permit modification pursuant to the MNSR regulations approving the increase. For a proposed modification that is not otherwise subject to review under the PSD or MNSR regulations, such proposed increase in the annual allowable emissions limit shall be approved through an administrative permit revision as provided at §49.159(f).

10. *Relaxation of Legally and Practically Enforceable Limits:* At such time that a new or modified source within the permitted facility/source or modification of this permitted facility/source becomes a major stationary source or major modification solely by virtue of a relaxation in any legally and practically enforceable limitation which was established after August 7, 1980, on the capacity of this permitted facility/source to otherwise emit a pollutant, such as a restriction on hours of operation, then the requirements of the PSD regulations shall apply to the source or modification as though construction had not yet commenced on the source or modification.

11. *Revise, Reopen, Revoke and Reissue, or Terminate for Cause:* This permit may be revised, reopened, revoked and reissued, or terminated for cause. The filing of a request by the Permittee, for a permit revision, revocation and reissuance, or termination, or of a notification of planned changes or anticipated noncompliance does not stay any permit condition. The EPA may reopen a permit for a cause on its own initiative, e.g., if this permit contains a material mistake or the Permittee fails to assure compliance with the applicable requirements.

12. *Severability Clause:* The provisions of this permit are severable, and in the event of any challenge to any portion of this permit, or if any portion is held invalid, the remaining permit conditions shall remain valid and in force.

13. *Property Rights:* This permit does not convey any property rights of any sort or any exclusive privilege.

14. *Information Requests:* The Permittee shall furnish to the EPA, within a reasonable time, any information that the EPA may request in writing to determine whether cause exists for revising, revoking and reissuing, or terminating this permit or to determine compliance with this permit. For any such information claimed to be confidential, you shall also submit a claim of confidentiality in accordance with 40 CFR Part 2, Subpart B.

15. *Inspection and Entry:* The EPA or its authorized representatives may inspect this permitted facility/source during normal business hours for the purpose of ascertaining compliance with all conditions of this permit. Upon presentation of proper credentials, the Permittee shall allow the EPA or its authorized representative to:

    (a) Enter upon the premises where a permitted facility/source is located or emissions-related activity is conducted, or where records are required to be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that are required to be kept under the conditions of this permit;

(c) Inspect, during normal business hours or while the permitted facility/source is in operation, any facilities, equipment (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or other applicable requirements; and

(e) Record any inspection by use of written, electronic, magnetic and photographic media.

16. *Permit Effective Date:* This permit is effective immediately upon issuance unless comments resulted in a change in the proposed permit, in which case this permit is effective 30 days after issuance. The Permittee may notify the EPA, in writing, that this permit or a term or condition of it is rejected. Such notice should be made within 30 days of receipt of this permit and should include the reason or reasons for rejection.

17. *Permit Transfers:* Permit transfers shall be made in accordance with 40 CFR 49.159(f). The Air Program Director shall be notified in writing at the address shown below if the company is sold or changes its name.

    U.S. Environmental Protection Agency, Region 8
    Office of Partnerships and Regulatory Assistance
    Tribal Air Permitting Program, 8P-AR
    1595 Wynkoop Street
    Denver, Colorado 80202

18. *Invalidation of Permit:* This permit becomes invalid if construction is not commenced within 18 months after the effective date of the permit, construction is discontinued for 18 months or more, or construction is not completed within a reasonable time. The EPA may extend the 18-month period upon a satisfactory showing that an extension is justified. This provision does not apply to the time period between the construction of the approved phases of a phased construction project. The Permittee shall commence construction of each such phase within 18 months of the projected and approved commencement date.

19. *Notification of Start-Up*: The Permittee shall submit a notification of the anticipated date of initial start-up of the permitted source to the EPA within 60 days of such date, unless the source permitted under this action is an existing source.

B. Authorization:

Authorized by the United States Environmental Protection Agency, Region 8

____

Debra H. Thomas Date
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

United States Environmental Protection Agency
Region 8 Air Program
Air Pollution Control Synthetic Minor Source Permit to Construct
Technical Support Document for
Proposed Permit #SMNSR-SU-000054-2012.001

ConocoPhillips Company
Ute Compressor Station
Southern Ute Indian Reservation
La Plata County, Colorado

In accordance with the requirements of the Tribal Minor New Source Review Permit Program at 40 CFR Part 49 (MNSR), this Federal permit to construct is being issued under authority of the Clean Air Act (CAA). The EPA has prepared this technical support document describing the conditions of this permit and presents information that is germane to this permit action.

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I. Introduction

On August 29, 2012, we received an application from ConocoPhillips Company (ConocoPhillips) requesting a synthetic minor permit for the Ute Compressor Station under the Tribal Minor New Source Review Permit Program at 40 CFR part 49 (MNSR).

This permit action applies to an existing facility operating on the Southern Ute Indian Reservation in Colorado.

This permit does not authorize the construction of any new emission sources or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations. This permit is intended only to incorporate required emission limits and provisions from the following documents:

A. A September 30, 2011, Consent Agreement, Docket No. CAA-08-2011-0032 (Consent Agreement). This permit reflects the incorporation of the required emissions limits and provisions of a Consent Agreement between the EPA and ConocoPhillips. The attainment of this permit is a required element of the Consent Agreement. The requirement in the Consent Agreement to comply with National Emission Standards for Hazardous Air Pollutants (NESHAP) from Oil and Natural Gas Production Facilities at 40 CFR Part 63, Subpart HH for the dehydration system is a separately enforceable requirement of the NESHAP for Source Categories at 40 CFR Part 63 and is not included in this permit.

   The Consent Agreement requires that ConocoPhillips control the carbon monoxide (CO) and formaldehyde (CH_2O) emissions from one (1) lean-burn engine rated at 1,478 horsepower (hp). In addition, the Consent Agreement requires that ConocoPhillips implement a leak detection and repair (LDAR) program for tanks at the facility, and retrofit or replace all existing high-bleed pneumatics with low-bleed or no-bleed pneumatics.

B. An August 29, 2012, application from ConocoPhillips requesting a synthetic minor permit for the Ute Compressor Station to transfer the requirements of the Consent Agreement to a federally enforceable non-Title V permit where they will become applicable requirements under this permit.

Upon compliance with this permit, the legally and practically enforceable reductions in emissions can be used when determining the applicability of other CAA requirements, such as PSD and Part 71.

II. Facility Description

The Ute Compressor Station, owned and operated by ConocoPhillips, dehydrates and compresses natural gas prior to custody transfer. The natural gas entering the compressor station flows through suction scrubbers where most of the water is removed. The natural gas condensate produced by this step is transferred to on-site condensate storage tanks. The natural gas is further dried in a glycol dehydration system before leaving the facility.

The emission units identified in Table 1 are currently installed and/or operating at the facility. The information provided in this table is for informational purposes only and is not intended to be viewed as enforceable restrictions or open for public comment. Table 2 summarizes the uncontrolled and the practically enforceable controlled emissions at the facility based on the information provided by ConocoPhillips.

Table 1. Existing Emission Units

Unit Description	Controls	Original Preconstruction Approval Date & Permit Number
Natural gas-fired, 4-stroke lean-burn reciprocating internal combustion engine with a maximum site rating of 1,478 hp	Oxidation Catalyst	No pre-construction approval required for the installation of the engine. Installed prior to the promulgation of the MNSR permit program. CO and CH_2O control requirements established in the September 30, 2011 Consent Agreement # CAA-08-2011-0032 and transferred to MNSR permit #SMNSR-SU-000054-2012.001
Natural gas-fired, 4-stroke lean-burn reciprocating internal combustion engine with a maximum site rating of 1,215 hp	None	No pre-construction approval required for the installation of the engine. Installed prior to the promulgation of the MNSR permit program.
Tri-ethylene glycol dehydration unit with a natural gas processing capacity of 14.4 MMscfd * and a glycol recirculation rate of 3.0 gallons per pound of water removed.	Condenser	No pre-construction approval required for the installation of the dehydration unit. Installed prior to the promulgation of the MNSR permit program. VOC control required pursuant to the NESHAP From Oil and Natural Gas Production Facilities.
3- 300 bbl* Condensate Tanks	None	No pre-construction approval required for the installation of the organic liquid storage tanks. Installed prior to the promulgation of the MNSR permit program.
Truck Loadout	None	No pre-construction approval required for loadout operations. Installed prior to the promulgation of the MNSR permit program.
1 – 30 kW Combustion Turbine	None	No pre-construction approval required for the installation of the turbines. Installed prior to the promulgation of the MNSR permit program.
1 – 65 kW* Combustion Turbine	None	No pre-construction approval required for the installation of the turbines. Installed prior to the promulgation of the MNSR permit program.
Miscellaneous Storage Tanks	None	No pre-construction approval required for the installation of the tanks. Installed prior to the promulgation of the MNSR permit program.
Heaters: 1 – 0.014MMbtu/hr* Dehydrator Reboiler 1 – 0.014MMbtu/hr Auxiliary Heater 1 – 0.012MMbtu/hr Auxiliary Heater	None	No pre-construction approval required for the installation of the heaters. Installed prior to the promulgation of the MNSR permit program.

*Mscfd = million standard cubic feet per day; MMBtu/hr = million British thermal units per hour; bbl = barrel; kW = kilowatt.

Table 2. Facility-wide Emissions

Criteria Pollutants	Uncontrolled Potential Emissions (tons per year)	Controlled Potential Emissions (tons per year)
PM	0.48	0.48
PM_{10}	0.48	0.48
$PM_{2.5}$	0.48	0.48
SO_x	1.45	1.45
NO_x	24.23	24.23
CO	49.45	0.50
VOC	156.01	28.85
Hazardous Air Pollutants (HAPs)		
Acetaldehyde	0.37	0.37
Acrolein	0.22	0.22
Benzene	10.46	0.59
Ethyl-Benzene	2.78	0.14
Formaldehyde	3.85	0.96
2,2,4 Trimethylpentane	0.19	0.04
Toluene	33.35	1.74
n-Hexane	1.95	0.27
Xylene	19.02	0.98
Total HAPs	**72.19**	**5.31**

PM – Particulate Matter
PM_{10} – Particulate Matter less than 10 microns in size
$PM_{2.5}$ – Particulate Matter less than 2.5 microns in size
SO_x – Sulfur Oxides
NO_x – Nitrogen Oxides
CO – Carbon Monoxide
VOC – Volatile Organic Compounds

III. Permit Requirements

The conditions in the permit ensure that the operation will meet the relevant regulations and be consistent with applicable guidance.

A. Engine Requirements

The natural gas industry uses engines to compress natural gas as it is processed and prior to further pipeline distribution. ConocoPhillips operates a natural gas-fired, 4-stroke lean-burn reciprocating internal combustion engine for natural gas compression. Lean-burn engines produce NO_X, CO, VOC and HAP emissions. The HAP emissions consist primarily of CH_2O.

1. Controls and Emission Limits

The primary form of emission control for 4-stroke lean-burn engines is an oxidation catalyst. An oxidation catalyst is effective for CO, VOC (including HAPs that are VOCs), and CH_2O. These catalysts do not typically control NO_X emissions. However, lean-burn engines are designed to operate with more dilute natural gas streams (a higher air-to-fuel ratio). Because they operate on more dilute natural gas streams, lean-burn engines also operate at lower combustion temperatures producing less NO_X emissions.

We are requiring the use of an oxidation catalyst on the 1,478 hp lean-burn engine. In addition, we are requiring NO_X, CO, and CH_2O pound per hour (lb/hr) emissions limits on the engine. The CO and CH_2O limits are based on the required 75% catalytic reduction efficiency as specified in the Consent Agreement. The NO_X emission limits are based on manufacturer performance specifications of 1.8 grams per horsepower hours (g/hp-hr) for the engine. According to the application, this is an uncontrolled limit. The emission limits are as follows:

NO_X: 5.5 lb/hr;
CO: 2.7 lb/hr; and
CH_2O: 0.22 lb/hr.

2. Operational Requirements

EPA has determined that certain operational requirements are necessary for the practical enforceability of the engine's NO_X, CO, and HAP emission limits. EPA is requiring work practice and operational requirements that include, but are not limited to:

(a) The installation and operation of a temperature-sensing device before the catalyst bed in order to continuously monitor the inlet exhaust temperature. The inlet to each catalyst bed must be at least 450°F but not more than 1,350°F to ensure the emissions are controlled according to the manufacture's specifications.

(b) The use of a pressure measuring device before and after the catalyst bed to ensure that the catalyst is not clogged or blown out. During differential pressure measurements, the pressure drop across the catalyst bed must not exceed ± 2 inches of water from the baseline pressure drop reading taken during the most recent engine performance test.

(c) Approved a period of 200 operating hours for which rebuilt and replaced engines can operate without the catalytic control system. This provision takes into account the time needed for engine "break-in" before putting it into full-time, continuous operation. Engine "break-in" can damage the catalyst.

3. Testing and Monitoring Requirements

EPA has also determined that certain testing and monitoring requirements are necessary for the practical enforceability of the emission limits. EPA is requiring testing and monitoring requirements that include, but are not limited to the following:

(a) Performance tests are to be conducted for measuring NO_X, CO, and CH_2O emissions to demonstrate compliance with each limit. Tests are required annually and for the start-up of any new, rebuilt, and replaced engine. In addition, a performance test is required for any catalyst replacement.

(b) Performances tests for both CO and NO_X emissions are to be done simultaneously and the adjustment of the engine prior to and during emission testing is prohibited. This provision has been added to ensure that both CO and NO_X emission limits in the permit are being met under normal operating conditions. In general, there is a fundamental relationship between engine operating parameters and exhaust emissions. Engine parameter changes (engine tuning) during engine testing to decrease NO_X emissions can increase CO emissions. Likewise, tuning an engine to decrease CO emissions can increase NO_X emissions.

(c) The monitoring of engine exhaust temperature at the inlet to the catalyst control system is to be done continuously. Catalyst operating efficiency is greatly affected by the temperature of the engine exhaust to be controlled. The monitoring of the pressure drop across the catalyst is to be measured monthly to ensure that there is not a complete failure of the catalytic control system due to plugging, fouling, destruction, poisoning, etc. In the event of a deviation from the temperature and/or pressure drop range, the required actions begin with equipment inspections and end with the possible removal and cleaning of the catalyst or catalyst replacement.

(d) Portable analyzer monitoring of NO_X and CO is to be performed quarterly. If the quarterly monitoring indicate compliance then the quarterly monitoring can be extended to semi-annual monitoring. However, portable monitoring of NO_X and CO emissions is to return to quarterly if semi-annual monitoring results indicate an exceedance. These changes help ensure continual compliance with the synthetic minor status of the facility.

B. Pneumatics Control Requirements

The following discussion is paraphrased from an EPA October 2006 Natural Gas STAR Partners lessons learned document entitled "Options for Reducing Methane Emissions from Pneumatic Devices in The Natural Gas Industry." It can be found at http://www.epa.gov/gasstar/documents/ll_pneumatics.pdf.

The natural gas industry uses a variety of control devices to automatically operate valves and control pressure, flow, temperature or liquid levels. For example, in crude oil and natural gas transmission, controls are used to isolate actuation valves, and to regulate pressure at compressor stations, in pipelines, and at storage facilities.

These control devices can be powered by electricity or compressed air. However, in the vast majority of applications, pneumatic controllers that employ energy from pressurized natural gas are used. Emissions from these devices can be significant.

The Consent Agreement requires that ConocoPhillips retrofit or replace all existing high-bleed pneumatic controllers with low-bleed, no-bleed, or electric pneumatic controllers.

C. Leak Detection and Repair (LDAR) Requirements

The Consent Agreement requires that ConocoPhillips develop an LDAR program to monitor for and repair leaks at each pump, thief hatch, pressure release device, open-ended valve or line, flange, and compressor operating at the facility. ConocoPhillips is required to submit a protocol that requires the use of an infrared camera for the detection of leaks. In addition, the EPA is requiring that LDAR monitoring be performed and reported semi-annually.

IV. Air Quality Review

The Federal MNSR regulations at 40 CFR 49.154(d) require that an Air Quality Impact Assessment (AQIA) modeling analysis be performed if there is reason to be concerned that new construction would cause or contribute to a National Ambient Air Quality Standard (NAAQS) or PSD increment violation. If an AQIA reveals that the proposed construction could cause or contribute to a NAAQS or PSD increment violation, such impacts must be addressed before a pre-construction permit can be issued.

The emissions at this existing facility will not be increasing due to this permit. In addition, this action does not authorize the construction of any new emission sources, or emission increases from existing units, nor does it otherwise authorize any other physical modifications to the facility or its operations and the substantive requirements of the Consent Agreement (emission controls and reductions) have already been fulfilled at this facility. In short, this action will have no adverse air quality impacts; therefore, we have determined that an AQIA modeling analysis is not required for this permit.

V. Tribal Consultations and Communications

We offer Tribal Government Leaders an opportunity to consult on each permit action. We ask the Tribal Government Leaders to respond to our offer to consult within 30 days. We offered the Chairman of the Southern Ute Tribe an opportunity to consult on this action via letter dated September 25, 2012. To date, the EPA has not received a response to our offer to consult on this permit action.

All minor source applications (synthetic minor, modification to an existing facility, new true minor or general permit) are submitted to both the Tribe and EPA per the application instructions (see http://www2.epa.gov/region8/tribal-minor-new-source-review-permitting). The Tribe has 10 business days from the receipt of the application to respond to EPA with questions and comments on the application. In the event an AQIA is triggered, we email a copy of that document to the Tribe within 5 business days from the date that we receive it.

Additionally, we notify the Tribe of the public comment period for the proposed permit and provide copies of the notice of public comment opportunity to post in various locations of their choosing on the Reservation. We also notify the Tribe of the issuance of the final permit.

VI. Environmental Justice

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by “identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations.”

The EPA defines “Environmental Justice” to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices. The EPA’s goal is to address the needs of overburdened populations or communities to participate in the permitting process. *Overburdened* is used to describe the minority, low-income, tribal and indigenous populations or communities in the United States that potentially experience disproportionate environmental harms and risks due to exposures or cumulative impacts or greater vulnerability to environmental hazards.

This discussion describes our efforts to identify overburdened communities and assess potential effects in connection with issuing this permit in La Plata County, Colorado within the exterior boundaries of the Southern Ute Indian Reservation.

A. Environmental Impacts to Potentially Overburdened Communities

This permit action does not authorize the construction of any new air emission sources, or air emission increases from existing units, nor does it otherwise authorize any other physical modifications to the associated facility or its operations. The air emissions at the existing facility will not increase due to the associated action and the emissions will continue to be well controlled at all times. This action will have no adverse air quality impacts.

Furthermore, the permit contains a provision stating, "*The permitted source must not cause or contribute to a National Ambient Air Quality Standard violation or a PSD increment violation.*" Noncompliance with this permit provision is a violation of the permit and is grounds for enforcement action and for permit termination or revocation. As a result, we conclude that issuance of this permit will not have disproportionately high or adverse human health effects on communities in the vicinity of the Southern Ute Indian Reservation.

B. Enhanced Public Participation

Given the presence of potentially overburdened communities in the vicinity of the facility, we are providing an enhanced public participation process for this permit.

1. Interested parties can subscribe to an EPA listserve that notifies them of public comment opportunities on the Southern Ute Indian Reservation for draft air pollution control permits via email at http://www2.epa.gov/region8/air-permit-public-comment-opportunities.

2. All minor source permit applications (synthetic minor, modification to an existing facility, new true minor or general permit) are submitted to both the Tribe and EPA per the application instructions (see http://www2.epa.gov/region8/tribal-minor-new-source-review-permitting).

3. The Tribe has 10 business days to respond to EPA with questions and comments on the application.

4. In the event an AQIA is triggered, we email a copy of that document to the Tribe within 5 business days from the date we receive it.

5. We notify the Tribe of the public comment period for the proposed permit and provide copies of the notice of public comment opportunity to post in various locations on the Reservation that they deem fit. We also notify the Tribe of the issuance of the final permit.

6. We offer the Tribal Government Leaders an opportunity to consult on each proposed permit action. The Tribal Government Leaders are asked to respond to our offer to consult within 30 days.

VII. Authority

Requirements under §49.151 to obtain a permit apply to new and modified minor stationary sources and minor modifications at existing major stationary sources ("major" as defined in §52.21).

In addition, the permit program provides a mechanism for an otherwise major stationary source to voluntarily accept restrictions on its potential to emit to become a synthetic minor source. The EPA is charged with direct implementation of these provisions where there is no approved Tribal implementation plan for implementation of the MNSR regulations. Pursuant to Section 301(d)(4) of the CAA (42 U.S.C. §7601(d)), the EPA is authorized to implement the MNSR regulations at §49.151 in Indian country. The ConocoPhillips Ute Compressor Station is located within the exterior boundaries of the Southern Ute Indian Reservation in the southwestern part of the State of Colorado. The exact location is Latitude 37.12944, Longitude -107.93722, in La Plata County, Colorado.

VIII. Public Notice

A. Public Comment Period

In accordance with Section 49.157, we must provide public notice and a 30-day public comment period to ensure that the affected community and the general public have reasonable access to the application and proposed permit information. The application, the proposed permit, this technical support document, and all supporting materials for the proposed permit are available at:

Southern Ute Indian Tribe
Environmental Programs Office
151 County Road 517
Ignacio, Colorado 81137

and

U.S. EPA Region 8
Air Program Office
1595 Wynkoop Street (8P-AR)
Denver, Colorado 80202-1129

All documents are available for review at our office Monday through Friday from 8:00 a.m. to 4:00 p.m. (excluding Federal holidays). Additionally, the proposed permit and technical support document can be reviewed on our website at: http://www2.epa.gov/region8/air-permit-public-comment-opportunities.

Any person may submit written comments on the proposed permit and may request a public hearing during the public comment period. These comments must raise any reasonably ascertainable issues with supporting arguments by the close of the public comment period (including any public hearing). Comment may be sent to us at the address above, or sent via an email to r8airpermitting@epa.gov, with the topic "Comment on MNSR Permit for ConocoPhillips Ute Compressor Station".

B. Public Hearing

A request for a public hearing must be in writing and must state the nature of the issues proposed to be raised at the hearing. We will hold a hearing whenever there is, on the basis of requests, a significant degree of public interest in a proposed permit. We may also hold a public hearing at our discretion, whenever, for instance, such a hearing might clarify one or more issues involved in the permit decision.

C. Final Permit Action

In accordance with Section 49.159, a final permit becomes effective 30 days after permit issuance, unless: (1) a later effective date is specified in the permit; (2) appeal of the final permit is made as detailed in the next section; or (3) we may make the permit effective immediately upon issuance if no comments resulted in a change or a denial of the proposed permit. We will send notice of the final permit action to any individual who commented on the proposed permit during the public comment period. In addition, we will add the source to a list of final permit actions which is posted on our website at: http://www2.epa.gov/region8/nsr-and-psd-permits-issued-region-8. Anyone may request a copy of the final permit at any time by contacting the Tribal Air Permit Program at (800) 227–8917 or sending an email to r8airpermitting@epa.gov.

D. Appeals to the Environmental Appeals Board

In accordance with Section 49.159, within 30 days after a final permit decision has been issued, any person who filed comments on the proposed permit or participated in the public hearing may petition the Environmental Appeals Board (EAB) to review any condition of the permit decision. The 30-day period within which a person may request review under this section begins when we have fulfilled the notice requirements for the final permit decision. Motions to reconsider a final order by the EAB must be filed within 10 days after service of the final order. A petition to the EAB is under Section 307(b) of the CAA, a prerequisite to seeking judicial review of the final agency action. For purposes of judicial review, final agency action occurs when we issue or deny a final permit and agency review procedures are exhausted.

MEMO TO FILE

DATE: November 12, 2013

SUBJECT: Southern Ute Indian Reservation Natural Gas Production Facilities
Endangered Species Act

FROM: Victoria Parker-Christensen, EPA Region 8 Air Program

TO: Source Files:
205c AirTribal SU ConocoPhillips Sunnyside Compressor Station
SMNSR-SU-000032-2011.001
FRED # 84740

205c AirTribal SU ConocoPhillips Argenta CDP Compressor Facility
SMNSR-SU-000030-2011.001
FRED # 84741

205c AirTribal SU ConocoPhillips Ute Compressor Station
SMNSR-SU-000054-2012.001
FRED # 99955

Pursuant to Section 7 of the Endangered Species Act (ESA), 16 U.S.C. §1536, and its implementing regulations at 50 CFR, part 402, the EPA is required to ensure that any action authorized, funded, or carried out by the Agency is not likely to jeopardize the continued existence of any Federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat. Under ESA, those agencies that authorize, fund, or carry out the federal action are commonly known as "action agencies." If an action agency determines that its federal action "may affect" listed species or critical habitat, it must consult with the U.S. Fish and Wildlife Service (FWS). If an action agency determines that the federal action will have no effect on listed species or critical habitat, the agency will make a "no effect" determination. In that case, the action agency does not initiate consultation with the FWS and its obligations under Section 7 are complete.

In complying with its duty under ESA, the EPA, as the action agency, examined the potential effects on listed species and designated critical habitat relating to issuing these Clean Air Act (CAA) synthetic minor New Source Review (NSR) permits.

Region 8 Air Program Determination

The EPA has concluded that the proposed synthetic minor NSR permit actions will have "*No effect*" on listed species or critical habitat. These proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. Because the EPA has determined that the federal action will have no effect, the agency made a "*No effect*" determination, did not initiate consultation with the FWS and its obligations under Section 7 are complete.

Permit Request

The EPA has received CAA permit applications from ConocoPhillips Company (COP) requesting approval to transfer enforceable emission restrictions previously established in their title V permits to synthetic minor NSR permits for existing natural gas production facilities on the Southern Ute Indian Reservation in La Plata County, Colorado. These permits are intended only to incorporate allowable and requested emission limits and provisions from the following documents:

1. Associated Part 71 Permit to Operate issued by the EPA to COP for the specified facility,
2. Federal Compliance Agreement and Final Order (CAFO) between the EPA and COP,
3. Associated application from COP requesting a synthetic minor NSR permit for the specified facility in accordance the requirements of the "Review of New Sources and Modifications in Indian Country; Final Rule," at 40 CFR Parts 49 and 51.

The net effect of the incorporation of these documents into a single synthetic minor NSR permit is a facility that is an area source with regard to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for Source Categories at 40 CFR Part 63, and a minor source with regard to the PSD permitting program. Approval of these actions will establish each permit as the source of the legally and practically enforceable requirements previously created in the associated Part 71 permit and the Federal CAFO.

The creation of the limits in the Part 71 permits was a temporary, gap-filling measure for those sources operating in Indian country that did not have the ability to obtain these limits through other programs, such as exists in state jurisdictions. Upon promulgation of the minor new source review permitting program in Indian Country, this gap-filling measure is no longer needed. 40 CFR §49.153(a)(3)(iv) provides the EPA with the authority to transfer such limits to a synthetic minor NSR permit, effectively creating legally and practically enforceable requirements without the use of the Part 71 permit. These requirements would be similar to those requirements in New Source Performance Standards at 40 CFR Part 60, NESHAP at 40 CFR Part 63, and limits established in PSD permits.

The following table lists the facility, associated Title V permit, applicable CAFO and location.

Facility/ Title V Permit/CAFO	**Location**
Sunnyside Compressor Station, SMNSR-SU-000032-2011.001 CAA-08-2010-0007 dated February 4, 2010	 S9, T33N, R9W Lat. 37.1194, Long. -107.8372
Argenta CDP Compressor Facility, SMNSR-SU-000030-2011.001 CAA-08-2010-0007 dated February 4, 2010	 SW ¼, SE ¼ S4, T33N, R10W Lat. 37.1294, Long. -107.9372
Ute Compressor Station, SMNSR-SU-000054-2012.001 CAA-08-2011-0032 dated September 20, 2011	 S14-15,T32N, R11W Lat. 37.0173, Long. -108.0201

Process and Construction Information

These proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times.

Threatened and Endangered Species

The EPA accessed U.S. Fish and Wildlife Service (FWS) websites for information on threatened and endangered species and designated critical habitat for those species. FWS maintains a website titled *Environmental Conservation Online System* (ECOS, http://ecos.fws.gov/ecos/indexPublic.do) that provides access to databases for threatened and endangered species that may be present within the proposed project area and designated critical habitat for threatened and endangered species.

The EPA accessed the FWS Information, Planning, and Conservation System (IPaC) database (http://ecos.fws.gov/ipac) to identify species listed as threatened and endangered that have been documented as being present in La Plata County, Colorado, and received an official species list from the FWS Western Colorado Ecological Services Field Office on November 12, 2013. Information on critical habitat is available on-line at http://criticalhabitat.fws.gov/crithab/. The following threatened or endangered species may be found in La Plata County:

Birds

Mexican Spotted owl (*Strix occidentalis lucida*)
Threatened
Final designated critical habitat

Southwestern Willow flycatcher (*Empidonax traillii extimus*)
Endangered

Yellow-Billed Cuckoo (Coccyzus americanus)
Proposed Threatened

Butterfly

Uncompahge Fritillary butterfly (*Boloria acronema*)
Endangered

Fishes

Bonytail chub (*Gila elegans*)
Endangered

Humpback chub (*Gila cypha*)
Endangered
Final designated critical habitat

Colorado pikeminnow (*Ptychocheilus lucius*)
Endangered
Final designated critical habitat

Razorback sucker (*Xyrauchen texanus*)
Endangered
Final designated critical habitat

Mammals

Black-Footed ferret (*Mustela nigripes*)
Experimental Population, Non-Essential

Canada Lynx (*Lynx canadensis*)
Threatened

New Mexican meadow jumping mouse
(Zapus hudsonius luteus)
Proposed Endangered

North American Wolverine (Gulo gulo luscus)
Proposed Threatened

Plants

Knowlton’s cactus (*Pediocactus knowltonii*)
Endangered

Conclusion

The EPA has concluded that the proposed synthetic minor NSR permit actions will have “*No effect*” on listed species or critical habitat. These proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times. Because the EPA has determined that the federal action will have no effect, the agency will make a “*No effect*” determination. In that case, the EPA does not initiate consultation with the FWS and its obligations under Section 7 are complete.

Attachments:
Map of Facilities Located on the Southern Ute Indian Reservation and FWS Designated Critical Habitat
FWS Official Species List

United States Department of the Interior

FISH AND WILDLIFE SERVICE
WESTERN COLORADO ECOLOGICAL SERVICES FIELD OFFICE
764 HORIZON DRIVE, BUILDING B
GRAND JUNCTION, CO 81506
PHONE: (970)243-2778 FAX: (970)245-6933
URL: www.fws.gov/mountain-prairie/es/Colorado/;
www.fws.gov/platteriver/

Consultation Tracking Number: 06E24100-2014-SLI-0018 November 12, 2013
Project Name: SUIT Oil and Gas T% to SMNSR Permits

Subject: List of threatened and endangered species that may occur in your proposed project location, and/or may be affected by your proposed project.

To Whom It May Concern:

The enclosed species list identifies threatened, endangered, and proposed species, designated critical habitat, and candidate species that may occur within the boundary of your proposed project and/or may be affected by your proposed project. The species list fulfills the requirements of the U.S. Fish and Wildlife Service (Service) under section 7(c) of the Endangered Species Act (Act) of 1973, as amended (16 U.S.C. 1531 *et seq.*).

New information based on updated surveys, changes in the abundance and distribution of species, changed habitat conditions, or other factors could change this list. Please feel free to contact us if you need more current information or assistance regarding the potential impacts to federally proposed, listed, and candidate species and federally designated and proposed critical habitat. Please note that under 50 CFR 402.12(e) of the regulations implementing section 7 of the Act, the accuracy of this species list should be verified after 90 days. This verification can be completed formally or informally as desired. The Service recommends that verification be completed by visiting the ECOS-IPaC website at regular intervals during project planning and implementation for updates to species lists and information. An updated list may be requested through the ECOS-IPaC system by completing the same process used to receive the enclosed list.

The purpose of the Act is to provide a means whereby threatened and endangered species and the ecosystems upon which they depend may be conserved. Under sections 7(a)(1) and 7(a)(2) of the Act and its implementing regulations (50 CFR 402 *et seq.*), Federal agencies are required to utilize their authorities to carry out programs for the conservation of threatened and endangered species and to determine whether projects may affect threatened and endangered species and/or designated critical habitat.

A Biological Assessment is required for construction projects (or other undertakings having similar physical impacts) that are major Federal actions significantly affecting the quality of the human environment as defined in the National Environmental Policy Act (42 U.S.C. 4332(2)(c)). For projects other than major construction activities, the Service suggests that a biological evaluation similar to a Biological Assessment be prepared to determine whether the project may affect listed or proposed species and/or designated or proposed critical habitat. Recommended contents of a Biological Assessment are described at 50 CFR 402.12.

If a Federal agency determines, based on the Biological Assessment or biological evaluation, that listed species and/or designated critical habitat may be affected by the proposed project, the agency is required to consult with the Service pursuant to 50 CFR 402. In addition, the Service recommends that candidate species, proposed species and proposed critical habitat be addressed within the consultation. More information on the regulations and procedures for section 7 consultation, including the role of permit or license applicants, can be found in the "Endangered Species Consultation Handbook" at:

http://www.fws.gov/endangered/esa-library/pdf/TOC-GLOS.PDF

Please be aware that bald and golden eagles are protected under the Bald and Golden Eagle Protection Act (16 U.S.C. 668 *et seq.*), and projects affecting these species may require development of an eagle conservation plan (http://www.fws.gov/windenergy/eagle_guidance.html). Additionally, wind energy projects should follow the wind energy guidelines (http://www.fws.gov/windenergy/) for minimizing impacts to migratory birds and bats.

Guidance for minimizing impacts to migratory birds for projects including communications towers (e.g., cellular, digital television, radio, and emergency broadcast) can be found at: http://www.fws.gov/migratorybirds/CurrentBirdIssues/Hazards/towers/towers.htm; http://www.towerkill.com; and http://www.fws.gov/migratorybirds/CurrentBirdIssues/Hazards/towers/comtow.html.

We appreciate your concern for threatened and endangered species. The Service encourages Federal agencies to include conservation of threatened and endangered species into their project planning to further the purposes of the Act. Please include the Consultation Tracking Number in the header of this letter with any request for consultation or correspondence about your project that you submit to our office.

Attachment

United States Department of Interior
Fish and Wildlife Service

Project name: SUIT Oil and Gas T% to SMNSR Permits

Official Species List

Provided by:

WESTERN COLORADO ECOLOGICAL SERVICES FIELD OFFICE
764 HORIZON DRIVE, BUILDING B
GRAND JUNCTION, CO 81506
(970) 243-2778
http://www.fws.gov/mountain-prairie/es/Colorado/
http://www.fws.gov/platteriver/

Consultation Tracking Number: 06E24100-2014-SLI-0018
Project Type: Oil Or Gas
Project Description: US EPA syn minor NSR permits for previously T5 permits in La Plata County in the Soutern Ute Indian Reservation

Project Counties: La Plata, CO

Endangered Species Act Species List

Species lists are not entirely based upon the current range of a species but may also take into consideration actions that affect a species that exists in another geographic area. For example, certain fish may appear on the species list because a project could affect downstream species. Please contact the designated FWS office if you have questions.

Black-Footed ferret *(Mustela nigripes)*

Population: entire population, except where EXPN

Listing Status: Endangered

Bonytail chub *(Gila elegans)*

Population: Entire

Listing Status: Endangered

Canada Lynx *(Lynx canadensis)*

Population: (Contiguous U.S. DPS)

Listing Status: Threatened

Colorado pikeminnow *(Ptychocheilus lucius)*

Population: except Salt and Verde R. drainages, AZ

Listing Status: Endangered

Humpback chub *(Gila cypha)*

Population: Entire

Listing Status: Endangered

Knowlton's cactus *(Pediocactus knowltonii)*

Listing Status: Endangered

Mexican Spotted owl *(Strix occidentalis lucida)*

Population: Entire

Listing Status: Threatened

New Mexico meadow jumping mouse *(Zapus hudsonius luteus)*

Listing Status: Proposed Endangered

North American wolverine *(Gulo gulo luscus)*

Listing Status: Proposed Threatened

Razorback sucker *(Xyrauchen texanus)*

Population: Entire

Listing Status: Endangered

Schmoll milk-vetch *(Astragalus schmolliae)*

Listing Status: Candidate

Southwestern Willow flycatcher *(Empidonax traillii extimus)*

Population: Entire

Listing Status: Endangered

Critical Habitat: Final designated

Uncompahgre Fritillary butterfly *(Boloria acrocnema)*

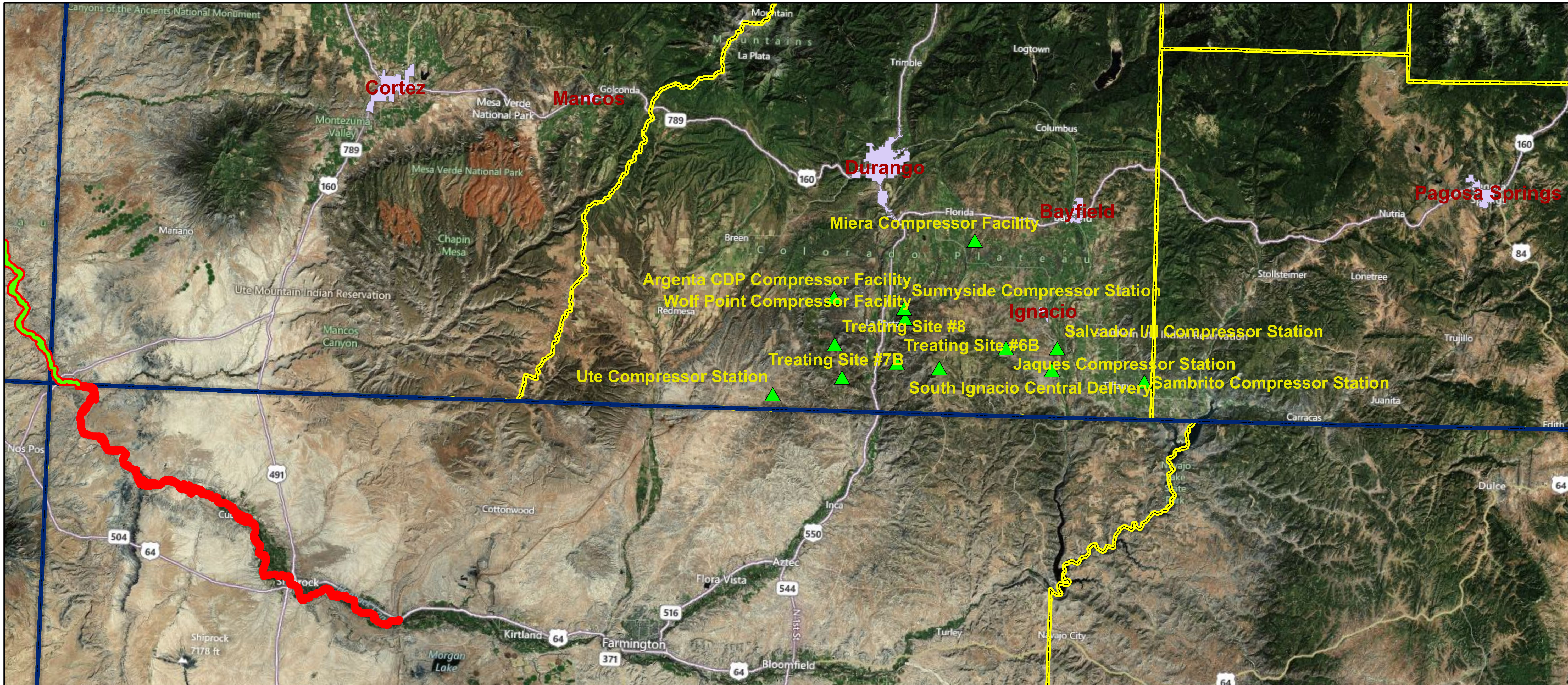
Population: Entire

Listing Status: Endangered

Yellow-Billed Cuckoo *(Coccyzus americanus)*

Population: Western U.S. DPS

Listing Status: Proposed Threatened



Southern Ute Indian Reservation

Clean Air Act, New Source Review Permit Program

N

Disclaimer: EPA makes no claim regarding the accuracy or precision of these data. Questions concerning the data should be referred to the source agency. This map does not necessarily represent EPA's position on any Indian Country boundaries or the jurisdictional status of any specific location.

Date: October 22, 2012

Map Projection: UTM, Meters, Zone 13N,NAD83.

Data Sources:

Reservations - U.S. Census Bureau (2009);

Base - Microsoft Bing web service (2012).

0 3.5 7 14 21 Miles

0 5 10 20 Kilometers

- Synthetic Minor NSR Permit Applicants
- City Boundary
- Colorado Pikeminnow - FWS Critical Habitat
- Razorback Sucker- FWS Critical Habitat
- State Boundary
- County Boundary

Area Enlarged

EPA United States Environmental Protection Agency

REGION 8 serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota

MEMO TO FILE

DATE: November 2, 2012

SUBJECT: Southern Ute Indian Reservation Natural Gas Production Facilities
National Historic Preservation Act

FROM: Victoria Parker-Christensen, EPA Region 8 Air Program

TO: Source Files:
205c AirTribal SU ConocoPhillips Sunnyside Compressor Station
SMNSR-SU-000032-2011.001
FRED # 84740

205c AirTribal SU ConocoPhillips Argenta CDP Compressor Facility
SMNSR-SU-000030-2011.001
FRED # 84741

205c AirTribal SU ConocoPhillips Ute Compressor Station
SMNSR-SU-000054-2012.001
FRED # 99955

Section 106 of the National Historic Preservation Act (NHPA) requires federal agencies to take into account the effects of their undertakings on historic properties and afford the Advisory Council on Historic Preservation (ACHP) a reasonable opportunity to comment with regard to such undertakings. Under the ACHP's implementing regulations at 36 C.F.R. Part 800, Section 106 consultation is generally with state and tribal historic preservation officials in the first instance, with opportunities for the ACHP to become directly involved in certain cases. An "undertaking" is "a project, activity, or program funded in whole or in part under the direct or indirect jurisdiction of a Federal agency, including those carried out by or on behalf of a Federal agency; those carried out with Federal financial assistance; and those requiring a Federal permit, license or approval." 36 C.F.R. § 800.16(y).

If an undertaking is a type of activity that does not have the potential to cause effects on historic properties, assuming such historic properties were present, the federal agency has no further obligations under 36 C.F.R. § 800.3(a)(1). Because this permit will authorize new construction and related activities at an existing site, this undertaking does have the potential to cause effects on historic properties.

Under the NHPA Section 106 implementing regulations, federal agencies consult with relevant historic preservation partners to determine the area of potential effect (APE) of the undertaking, to identify historic properties that may exist in that area, and to assess and address any adverse effects that may be caused on such properties by the undertaking. Specifically, 36 C.F.R. § 800.4(b)(1) of the regulations states that federal agency officials shall make a "reasonable and good faith effort" to identify historic properties.

This memorandum describes EPA's efforts to identify historic properties and assess potential effects in connection with issuing draft synthetic minor New Source Review (NSR) permits for existing oil and gas production facilities located within the exterior boundaries of the Southern Ute Indian Reservation in La Plata County, Colorado.

Region 8, Air Program Determination

The EPA has reviewed the proposed action for potential impacts on historic properties in the APE. These proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times. Because the EPA has determined that the federal action will have no effect, the agency is making the finding of "*No historic properties affected*" for the APE.

Area of Potential Effects (APE)

The APE for the existing facilities are the locations within the areas currently occupied by each facility.

Regulation 36 C.F.R. 800.16(d) defines "area of potential effects" - as:

> "… the geographic area or areas within which an undertaking may directly or indirectly cause alterations in the character or use of historic properties, if any such properties exist. The area of potential effects is influenced by the scale and nature of an undertaking and may be different for different kinds of effects caused by the undertaking."

Permit Request

The EPA has received CAA permit applications from ConocoPhillips Company (COP) requesting approval to transfer enforceable emission restrictions previously established in their title V permits to synthetic minor NSR permits for existing natural gas production facilities on the Southern Ute Indian Reservation in La Plata County, Colorado. These permits are intended only to incorporate allowable and requested emission limits and provisions from the following documents:

1. Associated Part 71 Permit to Operate issued by the EPA to COP for the specified facility,
2. Federal Compliance Agreement and Final Order (CAFO) between the EPA and COP,
3. Associated application from COP requesting a synthetic minor NSR permit for the specified facility in accordance the requirements of the "Review of New Sources and Modifications in Indian Country; Final Rule," at 40 CFR Parts 49 and 51.

The net effect of the incorporation of these documents into a single synthetic minor NSR permit is a facility that is an area source with regard to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for Source Categories at 40 CFR Part 63, and a minor source with regard to the PSD permitting program. Approval of these actions will establish each permit as the source of the legally and practically enforceable requirements previously created in the associated Part 71 permit and the Federal CAFO.

The creation of the limits in the Part 71 permits was a temporary, gap-filling measure for those sources operating in Indian country that did not have the ability to obtain these limits through other programs, such as exists in state jurisdictions. Upon promulgation of the minor new source review permitting program in Indian Country, this gap-filling measure is no longer needed. 40 CFR §49.153(a)(3)(iv) provides the EPA with the authority to transfer such limits to a synthetic minor NSR permit, effectively creating legally and practically enforceable requirements without the use of the Part 71 permit. These requirements would be similar to those requirements in New Source Performance Standards at 40 CFR Part 60, NESHAP at 40 CFR Part 63, and limits established in PSD permits.

The following table lists the facility, associated Title V permit, applicable CAFO and location.

Facility/ Title V Permit/CAFO	**Location**
Sunnyside Compressor Station, SMNSR-SU-000032-2011.001 CAA-08-2010-0007 dated February 4, 2010	 S9, T33N, R9W Lat. 37.1194, Long. -107.8372
Argenta CDP Compressor Facility, SMNSR-SU-000030-2011.001 CAA-08-2010-0007 dated February 4, 2010	 SW ¼, SE ¼ S4, T33N, R10W Lat. 37.1294, Long. -107.9372
Ute Compressor Station, SMNSR-SU-000054-2012.001 CAA-08-2011-0032 dated September 20, 2011	 S14-15,T32N, R11W Lat. 37.0173, Long. -108.0201

Process and Construction Information

These proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times. This is an administrative action with no physical changes to the existing facilities or surrounding area.

Registered Historic Places

The National Park Service maintains an internet resource that was can be used to determine whether any registered historic places are within the area of potential effect. The resource is:

1. National Register of Historic Places database, http://www.nps.gov/history/nr/research/index.htm

An additional site is available to provide additional information on these historic places. The resource is:

2. National Register of Historic Places, http://www.nationalregisterofhistoricplaces.com/
    a. County information, http://www.nationalregisterofhistoricplaces.com/ut/Uintah/state.html

b. Historic Districts within a county, http://www.nationalregisterofhistoricplaces.com/ut/Uintah/districts.html

A search of registered historic places or districts was not undertaken because this is an administrative action with no physical changes to the existing facilities or surrounding area.

State and Tribal Consultation

To comply with our obligations under Section 106 of the NHPS, we consulted with the Colorado State Historic Preservation Officer (SHPO) and requested any information the SHPO had regarding any historic properties within the APE. The EPA sent a letter to the Colorado SHPO on November 2, 2012 requesting concurrence with our determination of “No historic properties affected”. The Colorado SHPO concurred in writing with our determination in a letter dated November 9, 2012 and received on November 14, 2012.

We also consulted with the tribal government by sending a letter to the Tribal Chairman with cc: to the Environmental Programs Division Head and Air Quality Program Manager inviting them to consult with us and provide information concerning historic properties relating to these proposed permits and our determination of “No historic properties affected” for the APE. The EPA sent the letter on November 9, 2012 and is waiting for the Tribe’s response.

Attachment:

Map of Facilities Located on the Southern Ute Indian Reservation
Letter to Colorado State Historic Preservation Officer dated November 2, 2012
Letter from Colorado State Historic Preservation Officer dated November 9, 2012
Letter to Chairman Newton Southern Ute Indian Tribe dated November 9, 2012

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

NOV 02 2012

Ref: P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Edward Nichols, President and CEO
History Colorado
1200 Broadway
Denver, CO 80203

RE: Section 106 of the National Historic Preservation Act regarding Proposed Synthetic Minor New Source Review Permits on the Southern Ute Indian Reservation

Dear Mr. Nichols:

The Environmental Protection Agency Region 8 (EPA) has received federal Clean Air Act (CAA) permit applications and is preparing draft synthetic minor New Source Review (NSR) air pollution control permits for several existing oil production facilities within the exterior boundary of the Southern Ute Indian Reservation in La Plata County, Colorado. To comply with our obligations under Section 106 of the National Historic Preservation Act and its implementing regulations at 36 C.F.R. Part 800, we are consulting with you concerning our finding as to the potential effects and we are seeking any information you may have as to whether there are any historic properties within the area of potential effects for these facilities.

The permit applications request approval to transfer previously issued CAA Part 71 permits to synthetic minor NSR permits. The synthetic minor NSR permits are intended only to incorporate allowable and requested emission limits and provisions from the associated Part 71 permit, Federal Compliance Agreement and Final Order (if applicable) and associated permit applications.

The EPA has made the finding "*No historic properties affected*" for the proposed synthetic minor NSR permit actions. The proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times. This is an administrative action with no physical changes to the existing facilities or surrounding area. A map showing the locations of the facilities is enclosed with this letter.

The following table lists the companies, facilities and locations affected by the proposed permit actions.

Company and Facility	Section, Township, Range	Latitude / Longitude
BP America Production Company		
Treating Site 6B	S5, T32N, R9W	37.0571028 / -107.8457361
Treating Site 7	S3, T32N, R10W	37.0388778 / -107.9223722
Treating Site 8	S28, T33N, R10W	37.076025 / -107.9342472
Miera Compressor Facility	SE S8, T34N, R8W	37.1988 / -107.739683
Salvador I/II Compressor Station	S28, T33N, R7W	37.07905247 / -107.6182899
Wolf Point Compressor Facility	NW S16, T33N, R9W	37.10743378 / -107.8353513
ConocoPhillips Company		
Sunnyside Compressor Station,	S9, T33N, R9W	37.1194 / -107.8372
Argenta CDP Compressor Facility,	SW, SE S4, T33N, R10W	37.1294 / -107.9372
Ute Compressor Station,	S14-15,T32N, R11W	37.0173 / -108.0201
Red Cedar Gathering Company		
Arkansas Loop & Simpson Treating Plants	S1, T32N, R9W	37.052783 / -107.784875
Sambrito Compressor Station	SW S3, T32N, R6W	37.043769 / -107.493169
Samson Resources Company		
Jacques Compressor Station	NWS26, T33N, R8W	37.077944 / -107.691
South Ignacio Central Delivery	SE S32, T33N, R7W	37.0539167 / -107.6252222

The EPA has made the finding "*No historic properties affected*" for the proposed synthetic minor NSR permit actions. If you have any concerns regarding our determination, please notify me in writing within the 30 day time period described at 36 C.F.R. § 800.3(c)(4). If we haven't heard back from you within 30 days, we will assume you concur with our finding. In addition, please send any comments or information concerning historic properties within the project areas to me within 30 days, so as to ensure that we will have ample time to review them. You can reach me by phone at (303) 312-6441 or email at parker-christensen.victoria@epa.gov. Thank you for your assistance.

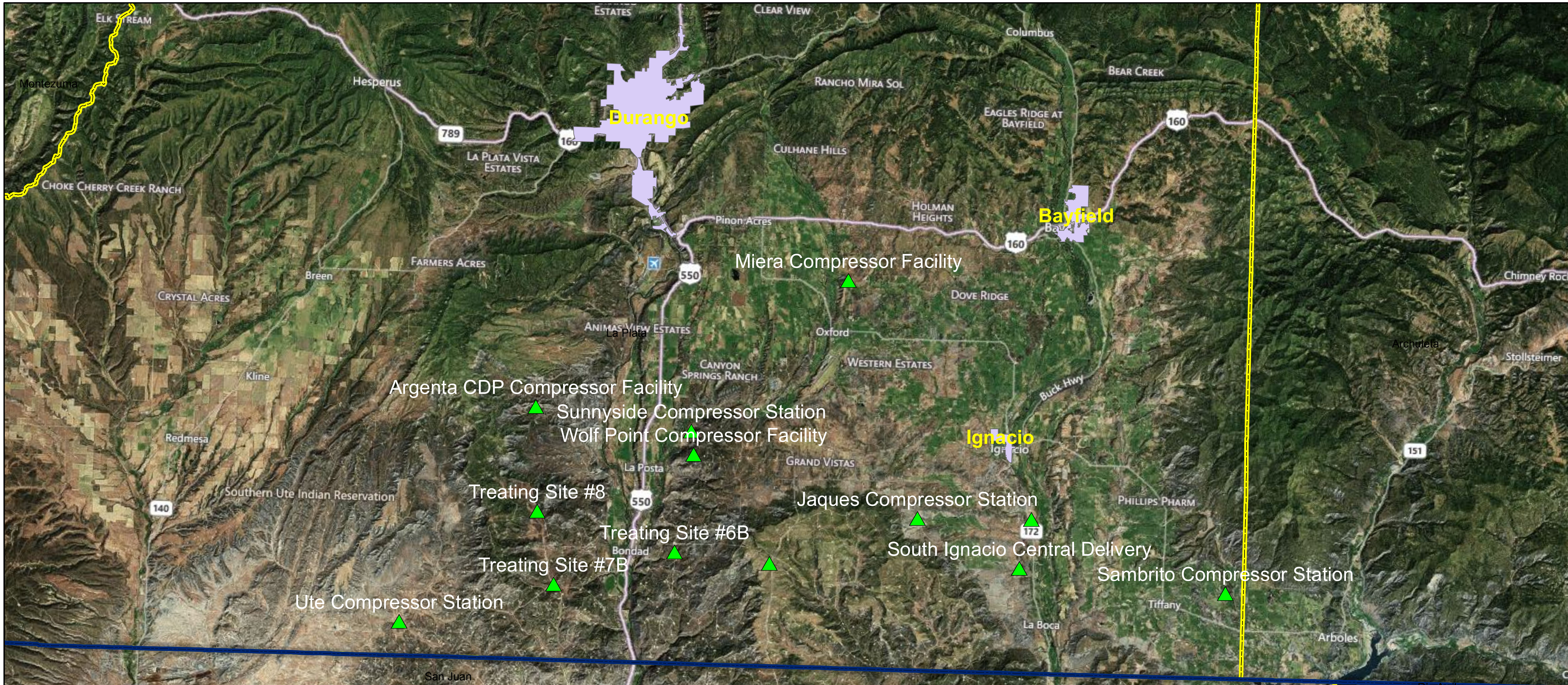
Sincerely,

Victoria Parker-Christensen

Victoria Parker-Christensen
Environmental Engineer
Air Program

Enclosure

cc: Mark Tobias, Section 106 Compliance Manager



Southern Ute Indian Reservation, Clean Air Act New Source Review (NSR) Permit Program

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Disclaimer: EPA makes no claim regarding the accuracy or precision of these data. Questions concerning the data should be referred to the source agency. This map does not necessarily represent EPA's position on any Indian Country boundaries or the jurisdictional status of any specific location.

EPA United States Environmental Protection Agency — REGION 8 serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota

Date: November 2, 2012

Map Projection: UTM, Meters, Zone 13N,NAD83.

Data Sources:

City Boundary - NAVTEQ (2011);
County Boundary - U.S. Census Bureau (2010);
State Boundary - U.S. Census Bureau (2010);
Base - Microsoft Bing web service (2012).

0 1.5 3 6 9 Miles

0 3.25 6.5 13 Kilometers

Synthetic Minor NSR PermitFacility

City Boundary

State Boundary

County Boundary

Area Enlarged

Southern Ute Indian Reservation, Clean Air Act New Source Review (NSR) Permit Program

N

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EPA United States Environmental Protection Agency
REGION 8 serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota

Date: November 2, 2012

Map Projection: UTM, Meters, Zone 13N,NAD83.

Data Sources:
City Boundary - NAVTEQ (2011);
County Boundary - U.S. Census Bureau (2010);
State Boundary - U.S. Census Bureau (2010);
Base - Microsoft Bing web service (2012).

0 1 2 4 6 Miles
0 2.25 4.5 9 Kilometers

Synthetic Minor NSR PermitFacility
City Boundary
State Boundary
County Boundary

Area Enlarged

HISTORY Colorado

RECEIVED
NOV 14 2012

November 9, 2012

Victoria Parker-Christensen
Environmental Engineer
Air Program
U.S. Environmental Protection Agency, Region 8
1595 Wynkoop Street
Denver, Colorado 80202-1129

Re: Section 106 of the National Historic Preservation Act regarding Proposed Synthetic Minor New Source Review Permits on the Southern Ute Indian Reservation, La Plata County, Colorado (CHS #62996)

Dear Ms. Parker-Christensen:

Thank you for your correspondence dated November 2, 2012 (received by our office on November 6, 2012) regarding the subject project.

Following our review of the documentation provided, we concur that a finding of no historic properties affected is appropriate for the proposed undertaking pursuant to 36 CFR 800.4(d)(1). This finding assumes that "no physical changes to the existing [thirteen] facilities or surrounding areas" will result from the implementation of this program.

Please remember that the consultation process does involve other consulting parties such as local governments and Tribes, which as stipulated in 36 CFR 800.3 are required to be notified of the undertaking. Additional information provided by the local government, Tribes or other consulting parties may cause our office to re-evaluate our comments and recommendations.

Should unidentified archaeological resources be discovered in the course of the projects, work must be interrupted until the resources have been evaluated in terms of the National Register of Historic Places eligibility criteria (36 CFR 60.4) in consultation with our office.

Thank you for the opportunity to comment. If we may be of further assistance please contact Mark Tobias, Section 106 Compliance Manager, at (303) 866-4674 or mark.tobias@state.co.us.

Sincerely,

for Edward C. Nichols
State Historic Preservation Officer
ECN/MAT

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

NOV 0 9 2012

Ref: 8P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Honorable Jimmy Newton Jr., Chairman
Southern Ute Indian Tribe
P.O. Box 737
Ignacio, Colorado 84026

RE: Notice to Consult – Section 106 of the National Historic Preservation Act regarding Proposed Synthetic Minor New Source Review Permits on the Southern Ute Indian Reservation

Dear Chairman Newton:

The U.S. Environmental Protection Agency Region 8 (EPA) is initiating consultation and coordination with the Southern Ute Indian Tribe regarding potential impacts to historic, religious or cultural properties covered by section 106 of the National Historic Preservation Act (NHPA) and its implementing regulations at 36 C.F.R. Part 800.

The EPA has received federal Clean Air Act (CAA) permit applications, as detailed in the enclosure, and is preparing draft synthetic minor New Source Review (NSR) air pollution control permits for 13 existing natural gas production facilities within the exterior boundary of the Southern Ute Indian Reservation in La Plata County, Colorado. As required by the NHPA, we are assessing whether approving the permits would cause any impacts on these properties. The EPA permit issuance process includes public notice of a draft permit, opportunity for public comment, as well as administrative and judicial review provisions. A copy of the draft permit document and technical support document will be available on the internet during the public comment period at www.epa.gov/region8/air/permitting/pubcomment.html.

The permit applications request approval to transfer previously issued CAA Part 71 permits to synthetic minor NSR permits. The synthetic minor NSR permits are intended only to incorporate allowable and requested emission limits and provisions from the associated Part 71 permit, Federal Compliance Agreement and Final Order (if applicable) and associated permit applications.

The EPA is proposing a finding of "*No historic properties affected*" for the proposed synthetic minor NSR permit actions. The proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times. This is an administrative action with no physical changes to the existing facilities or surrounding area. A map showing the locations of the facilities is enclosed with this letter.

We seek consultation with you concerning 1) how the Southern Ute Indian Tribe wishes us to address the NHPA consultation process, 2) the presence of historic properties within the areas of potential effects (APE) and 3) our proposed determination as to the potential effects of these proposed permit actions.

We want to ensure that we fulfill our obligations under the NHPA and that we are working with the appropriate representatives of the Tribe on air permitting matters. If a tribe does not have a federally designated Tribal Historic Preservation Officer (THPO), which is the case for the Southern Ute Indian Tribe, then federal agencies consult directly with the State Historic Preservation Officer (SHPO) concerning undertakings that may affect historic properties on tribal lands. The EPA initiated consultation with the Colorado SHPO on November 2, 2012. The enclosed letter to the Colorado SHPO describes the specific information for the facilities and seeks their concurrence with our proposed determination.

In addition, the NHPA and its implementing regulations require that the agencies consult with federally recognized tribes to ensure that tribes attaching religious or cultural significance to historic properties that may be affected by an undertaking have a reasonable opportunity to participate in the process. Therefore, please advise us as to the Tribe's preference for the process we should follow for the NHPA. Would you prefer that we communicate only with the SHPO, do you have a NHPA designated representative for the Tribe, or would you prefer that we communicate with the Tribal government as well as the SHPO and/or NHPA designated representative concerning any NHPA matters on the Reservation?

Also, to ensure that we are considering all relevant information, we would appreciate your assistance in identifying any historic properties of traditional religious or cultural importance to the Southern Ute Indian Tribe that may be located within the APE that may be directly or indirectly affected by these proposed permit actions. If the Tribe has any information concerning such properties, please contact us.

We understand that the Southern Ute Indian Tribe may not wish to divulge information about historic properties that have religious or cultural significance. The NHPA and its regulations provide a means to consider protecting information about a historic property if public disclosure might cause harm to the property, a significant invasion of privacy or impediments to traditional religious practices. We are open to working with the Tribe to seek to address any concerns that you may have regarding the sensitivity of information. If any properties are determined to be historic properties under the NHPA, the EPA would propose to consult with you on possible measures to avoid or minimize potential adverse effects.

As noted above, based on the administrative nature of the permit actions, we are proposing a finding of *"No historic properties affected"* as a result of issuing these permits. If you have any concerns regarding our determination or additional information about historic properties related to this permit, please notify me in writing within the 30 day time period described at 36 C.F.R. § 800.3(c)(4). If we haven't heard back from you within 30 days, we will assume you concur with our finding.

If you have questions or comments, please contact me directly at (303) 312-6308 or your staff can contact Victoria Parker-Christensen, Air Program, at (303) 312-6441 or parker-christensen.victoria@epa.gov. We are available to meet with you or your representatives to consult further regarding these permit actions.

Sincerely,

Howard M. Cantor, for
Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures

cc: Thomas Johnson, Southern Ute Indian Tribe, Environmental Programs Division Head
Brenda Jarrell, Southern Ute Indian Tribe, Air Quality Program Manager

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

NOV 02 2012

Ref: P-AR

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Edward Nichols, President and CEO
History Colorado
1200 Broadway
Denver, CO 80203

RE: Section 106 of the National Historic Preservation Act regarding Proposed Synthetic Minor New Source Review Permits on the Southern Ute Indian Reservation

Dear Mr. Nichols:

The Environmental Protection Agency Region 8 (EPA) has received federal Clean Air Act (CAA) permit applications and is preparing draft synthetic minor New Source Review (NSR) air pollution control permits for several existing oil production facilities within the exterior boundary of the Southern Ute Indian Reservation in La Plata County, Colorado. To comply with our obligations under Section 106 of the National Historic Preservation Act and its implementing regulations at 36 C.F.R. Part 800, we are consulting with you concerning our finding as to the potential effects and we are seeking any information you may have as to whether there are any historic properties within the area of potential effects for these facilities.

The permit applications request approval to transfer previously issued CAA Part 71 permits to synthetic minor NSR permits. The synthetic minor NSR permits are intended only to incorporate allowable and requested emission limits and provisions from the associated Part 71 permit, Federal Compliance Agreement and Final Order (if applicable) and associated permit applications.

The EPA has made the finding "*No historic properties affected*" for the proposed synthetic minor NSR permit actions. The proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times. This is an administrative action with no physical changes to the existing facilities or surrounding area. A map showing the locations of the facilities is enclosed with this letter.

The following table lists the companies, facilities and locations affected by the proposed permit actions.

Company and Facility	Section, Township, Range	Latitude / Longitude
BP America Production Company		
Treating Site 6B	S5, T32N, R9W	37.0571028 / -107.8457361
Treating Site 7	S3, T32N, R10W	37.0388778 / -107.9223722
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Miera Compressor Facility	SE S8, T34N, R8W	37.1988 / -107.739683
Salvador I/II Compressor Station	S28, T33N, R7W	37.07905247 / -107.6182899
Wolf Point Compressor Facility	NW S16, T33N, R9W	37.10743378 / -107.8353513
ConocoPhillips Company		
Sunnyside Compressor Station,	S9, T33N, R9W	37.1194 / -107.8372
Argenta CDP Compressor Facility,	SW, SE S4, T33N, R10W	37.1294 / -107.9372
Ute Compressor Station,	S14-15,T32N, R11W	37.0173 / -108.0201
Red Cedar Gathering Company		
Arkansas Loop & Simpson Treating Plants	S1, T32N, R9W	37.052783 / -107.784875
Sambrito Compressor Station	SW S3, T32N, R6W	37.043769 / -107.493169
Samson Resources Company		
Jacques Compressor Station	NWS26, T33N, R8W	37.077944 / -107.691
South Ignacio Central Delivery	SE S32, T33N, R7W	37.0539167 / -107.6252222

The EPA has made the finding "*No historic properties affected*" for the proposed synthetic minor NSR permit actions. If you have any concerns regarding our determination, please notify me in writing within the 30 day time period described at 36 C.F.R. § 800.3(c)(4). If we haven't heard back from you within 30 days, we will assume you concur with our finding. In addition, please send any comments or information concerning historic properties within the project areas to me within 30 days, so as to ensure that we will have ample time to review them. You can reach me by phone at (303) 312-6441 or email at parker-christensen.victoria@epa.gov. Thank you for your assistance.

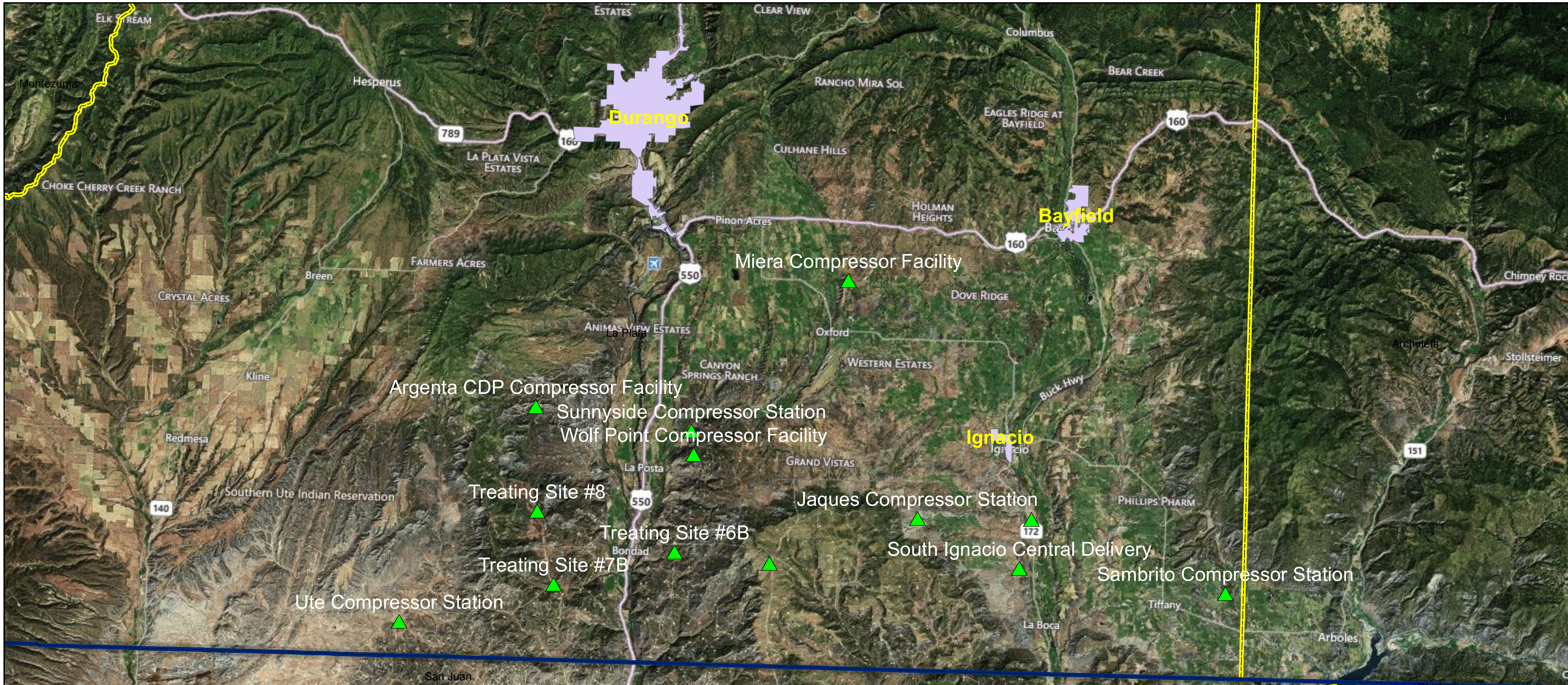
Sincerely,

Victoria Parker-Christensen

Victoria Parker-Christensen
Environmental Engineer
Air Program

Enclosure

cc: Mark Tobias, Section 106 Compliance Manager



Southern Ute Indian Reservation, Clean Air Act New Source Review (NSR) Permit Program

N

0 1.5 3 6 9 Miles

0 3.25 6.5 13 Kilometers

Synthetic Minor NSR PermitFacility

City Boundary

State Boundary

County Boundary

Area Enlarged

Disclaimer: EPA makes no claim regarding the accuracy or precision of these data. Questions concerning the data should be referred to the source agency. This map does not necessarily represent EPA's position on any Indian Country boundaries or the jurisdictional status of any specific location.

EPA United States Environmental Protection Agency REGION 8 serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota

Date: November 2, 2012

Map Projection: UTM, Meters, Zone 13N,NAD83.

Data Sources:
City Boundary - NAVTEQ (2011);
County Boundary - U.S. Census Bureau (2010);
State Boundary - U.S. Census Bureau (2010);
Base - Microsoft Bing web service (2012).

Southern Ute Indian Reservation, Clean Air Act New Source Review (NSR) Permit Program

N

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EPA United States Environmental Protection Agency
REGION 8 serving the states & tribes of Colorado, Montana, Wyoming, Utah, North Dakota & South Dakota

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0 1 2 4 6 Miles
0 2.25 4.5 9 Kilometers

- Synthetic Minor NSR PermitFacility
- City Boundary
- State Boundary
- County Boundary

Area Enlarged

MEMO TO FILE

DATE: October 24, 2012

SUBJECT: Southern Ute Indian Reservation Natural Gas Production Facilities
Environmental Justice

FROM: Victoria Parker-Christensen, EPA Region 8 Air Program

TO: Source Files:
205c AirTribal SU ConocoPhillips Sunnyside Compressor Station
SMNSR-SU-000032-2011.001
FRED # 84740

205c AirTribal SU ConocoPhillips Argenta CDP Compressor Facility
SMNSR-SU-000030-2011.001
FRED # 84741

205c AirTribal SU ConocoPhillips Ute Compressor Station
SMNSR-SU-000054-2012.001
FRED # 99955

On February 11, 1994, the President issued Executive Order 12898, entitled "Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations." The Executive Order calls on each federal agency to make environmental justice a part of its mission by "identifying and addressing, as appropriate, disproportionately high and adverse human health or environmental effects of its programs, policies and activities on minority populations and low-income populations."

EPA defines "Environmental Justice" to include meaningful involvement of all people regardless of race, color, national origin, or income with respect to the development, implementation, and enforcement of environmental laws, regulations, and polices.

On June 10, 2011, the EPA promulgated a final Clean Air Act (CAA) Federal Implementation Plan (FIP) that implements New Source Review (NSR) preconstruction air pollution control requirements in Indian country. The FIP includes two NSR rules for the protection of air quality in Indian country. One of those rules, known as the minor NSR Rule, applies to new industrial facilities or modifications at existing industrial facilities with the potential to emit (PTE) certain pollutants equal to or more than the minor NSR thresholds but less than the major NSR thresholds, generally 100 to 250 tons per year. The EPA permit issuance process includes public notice of a draft permit, opportunity for public comment, as well as administrative and judicial review provisions.

This memorandum describes EPA's efforts to identify environmental justice communities and assess potential effects in connection with issuing CAA synthetic minor NSR permits in La Plata County within the exterior boundaries of the Southern Ute Indian Reservation (SUIR).

Permit Request

The EPA has received CAA permit applications from ConocoPhillips Company (COP) requesting approval to transfer enforceable emission restrictions previously established in their title V permits to synthetic minor NSR permits for existing natural gas production facilities on the Southern Ute Indian Reservation in La Plata County, Colorado. These permits are intended only to incorporate allowable and requested emission limits and provisions from the following documents:

1. Associated Part 71 Permit to Operate issued by the EPA to COP for the specified facility,
2. Federal Compliance Agreement and Final Order (CAFO) between the EPA and COP,
3. Associated application from COP requesting a synthetic minor NSR permit for the specified facility in accordance the requirements of the "Review of New Sources and Modifications in Indian Country; Final Rule," at 40 CFR Parts 49 and 51.

The net effect of the incorporation of these documents into a single synthetic minor NSR permit is a facility that is an area source with regard to the National Emission Standard for Hazardous Air Pollutants (NESHAP) for Source Categories at 40 CFR Part 63, and a minor source with regard to the PSD permitting program. Approval of these actions will establish each permit as the source of the legally and practically enforceable requirements previously created in the associated Part 71 permit and the Federal CAFO.

The creation of the emission limits in the Part 71 permits was a temporary, gap-filling measure for those sources operating in Indian country that did not have the ability to obtain these limits through other programs, such as exists in state jurisdictions. Upon promulgation of the minor new source review permitting program in Indian Country, this gap-filling measure is no longer needed. 40 CFR §49.153(a)(3)(iv) provides the EPA with the authority to transfer such limits to a synthetic minor NSR permit, effectively creating legally and practically enforceable requirements without the use of the Part 71 permit. These requirements would be similar to those requirements in New Source Performance Standards at 40 CFR Part 60, NESHAP at 40 CFR Part 63, and limits established in PSD permits.

The following table lists the facility, associated Title V permit, applicable CAFO and location.

Facility/ Title V Permit/CAFO	Location
Sunnyside Compressor Station, SMNSR-SU-000032-2011.001 CAA-08-2010-0007 dated February 4, 2010	S9, T33N, R9W Lat. 37.1194, Long. -107.8372
Argenta CDP Compressor Facility, SMNSR-SU-000030-2011.001 CAA-08-2010-0007 dated February 4, 2010	SW ¼, SE ¼ S4, T33N, R10W Lat. 37.1294, Long. -107.9372
Ute Compressor Station, SMNSR-SU-000054-2012.001 CAA-08-2011-0032 dated September 20, 2011	S14-15,T32N, R11W Lat. 37.0173, Long. -108.0201

Environmental Impacts to Potential Environmental Justice Communities

Air Emissions

These proposed permit actions do not authorize the construction of any new emission sources, or emission increases from existing units, nor do they otherwise authorize any other physical modifications to the associated facility or its operations. The emissions, approved at present, from each existing facility will not increase due to the associated permit action and the emissions will continue to be well controlled at all times.

Air Quality Review

The Federal Minor New Source Review Regulations at 40 CFR 49.154(d) require that an Air Quality Impact Assessment (AQIA) modeling analysis be performed if there is reason to be concerned that new construction would cause or contribute to a National Ambient Air Quality Standard (NAAQS) or PSD increment violation. If an AQIA reveals that the proposed construction could cause or contribute to a NAAQS or PSD increment violation, such impacts must be addressed before a pre-construction permit can be issued.

The emissions, approved at present, from these existing facilities will not be increasing due to these permit actions and the emissions will continue to be well controlled at all times. These permit actions will have no air quality impacts; therefore, the EPA has determined that an AQIA modeling analysis is not required for any of the proposed permits.

Furthermore, each permit contains a provision stating, "*The permitted source shall not cause or contribute to a NAAQS violation or, in an attainment area, shall not cause or contribute to a PSD increment violation.*" Noncompliance with this permit provision is a violation of the permit and is grounds for enforcement action and for permit termination or revocation. As a result, the EPA concludes that issuance of the aforementioned synthetic minor NSR permits will not have disproportionately high and adverse human health effects on communities in the vicinity of the SUIR.

Tribal Consultation and Public Participation

The EPA offers the Tribal Government Leaders an opportunity to consult on each proposed permit action. The Tribal Government Leaders are asked to respond to the EPA's offer to consult within 30 days and if no response is received within that time, the EPA notifies the Tribal Government Leaders that the consultation period has closed. The Chairman of the Southern Ute Tribe has been offered an opportunity to consult on this permit action via letter dated September 25, 2012. To date, the EPA has not received a response to our offer to consult on this permit action and the Chairman will be notified when the consultation period has closed.

All minor source applications (synthetic minor, modification to an existing facility, new true minor or general permit) are submitted to both the EPA and the Tribal Environmental Director per the application instructions (see http://epa.gov/region8/air/permitting/tmnsr.html). The Tribal Environmental Office has 10 business days to respond to the EPA with questions and comments on the application. In the event an

Air Quality Impact Assessment (AQIA) is triggered, a copy of that document is emailed to the tribe within 5 business days of receipt by the EPA.

Given the presence of potential environmental justice communities in the vicinity of the facilities, the EPA is providing an enhanced public participation process for this permit. Interested parties can subscribe to an EPA listserve that notifies them of public comment opportunities on the Southern Ute Indian Reservation for draft air pollution control permits via email at http://epa.gov/region8/air/permitting/pubcomment.html.

Additionally, the Tribe's Environmental Director is notified of the public comment period for the proposed permit and provided copies of the notice of public comment opportunity to post in various locations on the Reservation that they deem fit. The Tribe is also notified of the issuance of the final permit.

ConocoPhillips

San Juan Business Unit
P.O. Box 4289
Farmington, NM 87499-4289
(505) 326-9700

VIA UPS

June 6, 2013

Ms. Kathleen Paser
US EPA Region 8
Mail Code 8P-AR
1595 Wynkoop Street
Denver, Colorado 80202

RE: **Part 49 Permit Application Modification**
Ute CDP

Dear Ms. Paser:

ConocoPhillips Company (COP) is submitting the enclosed revision to the Part 49 permit application for Ute Compressor Station. COP completed a like-kind replacement of unit E-2, a 1,375 horsepower (hp) Waukesha L7042GL compressor engine, with serial number C-115672/1 on May 8, 2013 as part of its regular maintenance program. The serial number of the new unit is C-13014/1.

COP requests that the enclosed updated EPA Form 5900-80 for Unit E-2 replace the same form previously submitted. Emission estimates and all other information in the permit application are unchanged. A regulatory determination for the new engine is detailed as follows:

- NSPS, Subpart JJJJ: The new unit was manufactured prior to January 1, 2008 (April 6, 2000) and is not an affected source under §60.4230(a)(4)(ii).
- NESHAPs, Subpart ZZZZ: The new unit was constructed prior to December 19, 2002 (April 6, 2000) and, as such, is an existing 4-stroke lean burn engine greater than 500 hp, Under §63.6590(b)(3)(ii) the unit has no applicable requirements under Subpart ZZZZ or Subpart A.

Please contact me at (505) 326-9822 or by email at lori.r.marquez@cop.com if you have questions.

Sincerely,

Lori Marquez

Lori Marquez
Environmental Coordinator

Enclosure
cc: Brenda Jarrell, Southern Ute Indian Tribe Air Quality Program Manager

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID E-2 Description Waukesha L7042GL 4SLB RICE

SIC Code (4-digit) E-2 SCC Code 20200202

B. Emissions Unit Description

Primary use Gas Compression Temporary Source ___Yes X No

Manufacturer Waukesha Model No. L7042GL

Serial Number C-13014/1 Installation Date May 8, 2013 (planned)

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) Natural gas compressor engine

Boiler horsepower rating 1,478 hp (1,375 hp altitude derated) Boiler steam flow lb/hr) ______

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input 9.83 MM BTU/hr Max. Design Heat Input 10.58 MM BTU/hr

C. Fuel Data

Primary fuel type(s) Natural Gas   Standby fuel type(s) N/A

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0	0	950 Btu/scf

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas		10.4 Mscf	90.7 mmscf

E. Associated Air Pollution Control Equipment

Emissions unit ID E-2   Device type Oxidation catalyst

Air pollutant(s) Controlled CO, Formaldehyde

Manufacturer TBD

Model No. TBD   Serial No. TBD

Installation date 05/08/13 (planned)   Control efficiency (%) 75% CO, 75% CH2O

Efficiency estimation method Manufacturer's guaranteed rates

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) N/A	Inside stack diameter (ft) N/A
Stack temp(°F) N/A	Design stack flow rate (ACFM) N/A
Actual stack flow rate (ACFM) N/A	Velocity (ft/sec) N/A

ConocoPhillips

RECEIVED
AUG 14 2013
ECEJ-AT

San Juan Business Unit
P.O. Box 4289
Farmington, NM 87499-4289
(505) 326-9700

VIA UPS

August 13, 2013

Mr. Adam Eisele
U.S. EPA Region 8 (8ENF-AT)
Enforcement Program
1595 Wynkoop Street
Denver, CO 80202-1129

Re: Request for NESHAP, Subpart HH Applicability Determination
Ute Compressor Station

Dear Mr Eisele:

On August 12, 2013, Ms. Kathy Pasar requested ConocoPhillips Company (COP) seek an applicability determination from EPA Region 8 Enforcement regarding its claim in its Part 49 application for Ute Compressor Station that the dehydrator at this location is subject to only limited requirements within NESHAP, Subpart HH. Rationale for this claim follows.

ConocoPhillips believes the condenser at the Ute CDP is not a "control device" as defined in 40 CFR 63.761. The definition of "control device" includes the following statement:

> *For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of a combustion device), returned back to the process or sold, then the recovery system used, including piping, connections and flow inducing devices, is not considered to be control devices or closed vent systems.*

This definition leads to the conclusion that piping from the glycol dehydration unit still vent to the condenser and the condenser itself at Ute CDP are not subject to General Standards in 40 CFR 63.764 or the Glycol Dehydration Unit Process Vent Standards at 40 CFR 63.765. In addition, 40 CFR 63.771, 40 CFR 63.772, 40 CFR 63.773, 40 CFR 63.774 and 40 CFR 63.775 would not apply.

To demonstrate the condenser at Ute CDP is not a control device for purposes of 40 CFR Part 63, Subpart HH, we must show the gas/vapor streams routed through the dehydration unit are used as fuel, returned to the process or sold. The dehydration unit has a flash tank. Vapors from the flash tank are routed to the reboiler and used as fuel. All vapors from the still vent are routed to the condenser via piping with a pressure relief valve set at 1.5 psi. The liquid stream resulting from the condensed vapors drains into the condensate tank located adjacent to the condenser. Any non-condensable vapors remain in the condenser and the condensate tank unless the pressure in the condensate tank exceeds four ounces. In this case, the non-condensable vapors would be vented to atmosphere. However, the condenser still achieves 95 percent control efficiency.

Liquids contained in the condensate tank adjacent to the condenser are transferred via truck to a condensate sales tank located on-site at Ute CDP. The sales tank operates with a safety valve setting of four ounces. Liquids in the sales tank are sold to a third party. The transport truck is a vacuum truck that draws the liquids out of the condensate tank. Relief settings on the vacuum truck operate at 18 psi.

Please contact me at (505) 326-9822 or lori.r.marquez@cop.com with any questions or if you need additional information.

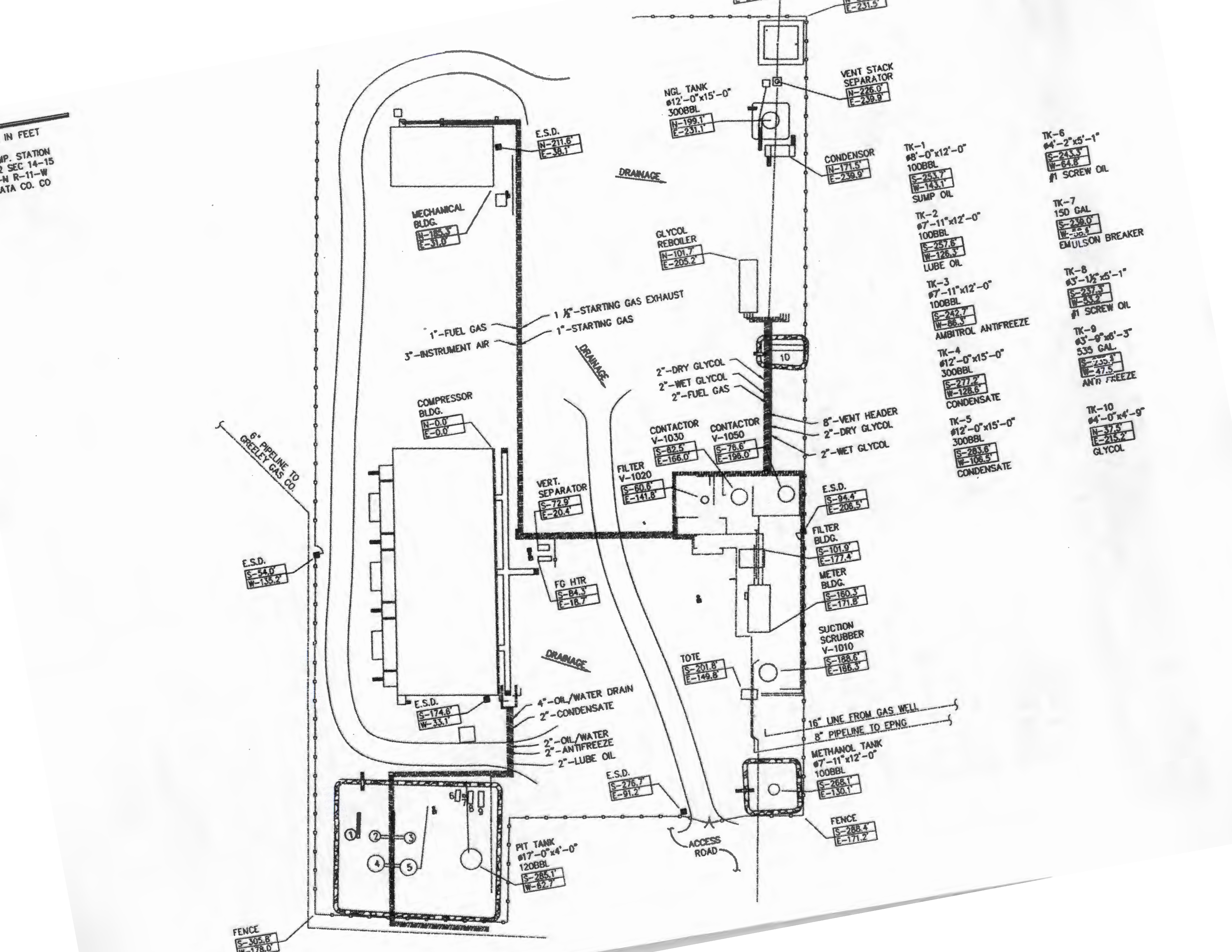
Sincerely,

Lori Marquez

Lori Marquez
Environmental Coordinator

Attachments

cc: Ms. Kathy Pasar, Environmental Protection Agency



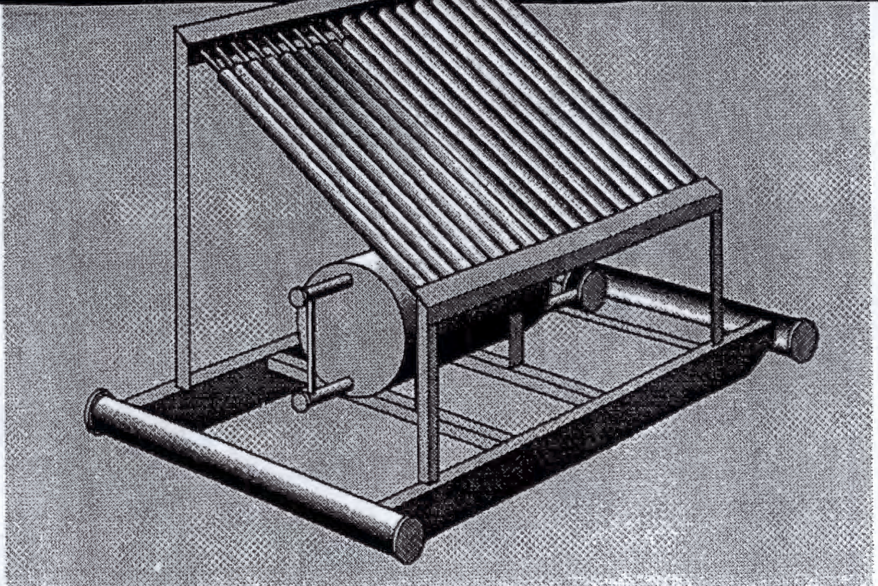
IN FEET
MP. STATION
2 SEC 14-15
-N R-11-W
ATA CO. CO
E-231.5'
VENT STACK
SEPARATOR
N-226.0'
E-239.9'
NGL TANK
ø12'-0"x15'-0"
300BBL
N-199.1'
E-231.1'
E.S.D.
N-211.6'
E-38.1'
CONDENSOR
N-171.5'
E-239.9'
DRAINAGE
MECHANICAL
BLDG.
N-185.3'
E-31.0'
GLYCOL
REBOILER
N-101.7'
E-205.2'
TK-1
ø8'-0"x12'-0"
100BBL
S-253.7'
W-143.1'
SUMP OIL
TK-2
ø7'-11"x12'-0"
100BBL
S-257.6'
W-126.3'
LUBE OIL
TK-3
ø7'-11"x12'-0"
100BBL
S-242.7'
W-86.3'
AMBITROL ANTIFREEZE
TK-4
ø12'-0"x15'-0"
300BBL
S-277.2'
W-128.6'
CONDENSATE
TK-5
ø12'-0"x15'-0"
300BBL
S-283.6'
W-106.5'
CONDENSATE
TK-6
ø4'-2"x5'-1"
S-243.3'
W-64.8'
#1 SCREW OIL
TK-7
150 GAL
S-238.0'
EMULSON BREAKER
TK-8
ø3'-1½"x5'-1"
S-237.3'
W-53.9'
#1 SCREW OIL
TK-9
ø3'-9"x6'-3"
535 GAL
W-47.5'
ANTI FREEZE
TK-10
ø4'-0"x4'-9"
N-37.5'
E-215.2'
GLYCOL
1 ½"-STARTING GAS EXHAUST
1"-STARTING GAS
1"-FUEL GAS
3"-INSTRUMENT AIR
DRAINAGE
10
2"-DRY GLYCOL
2"-WET GLYCOL
2"-FUEL GAS
8"-VENT HEADER
2"-DRY GLYCOL
2"-WET GLYCOL
COMPRESSOR
BLDG.
N-0.0'
E-0.0'
6" PIPELINE TO
GREELEY GAS CO.
CONTACTOR
V-1030
S-82.5'
E-166.0'
CONTACTOR
V-1050
S-76.6'
E-198.0'
FILTER
V-1020
S-60.6'
E-141.8'
VERT.
SEPARATOR
S-72.9'
E-20.4'
E.S.D.
S-94.4'
E-206.5'
FILTER
BLDG.
S-101.9'
E-177.4'
E.S.D.
S-54.0'
W-135.2'
FG HTR
S-84.3'
E-18.7'
METER
BLDG.
S-160.3'
E-171.8'
SUCTION
SCRUBBER
V-1010
S-188.6'
E-186.3'
DRAINAGE
TOTE
S-201.8'
E-149.8'
E.S.D.
S-174.8'
W-33.1'
4"-OIL/WATER DRAIN
2"-CONDENSATE
2"-OIL/WATER
2"-ANTIFREEZE
2"-LUBE OIL
16" LINE FROM GAS WELL
8" PIPELINE TO EPNG
METHANOL TANK
ø7'-11"x12'-0"
100BBL
S-268.1'
E-130.1'
E.S.D.
S-276.7'
E-91.2'
1
2
3
4
5
6
7
8
9
PIT TANK
ø17'-0"x4'-0"
120BBL
S-285.1'
W-62.7'
ACCESS
ROAD
FENCE
S-288.4'
E-171.2'
FENCE
S-305.8'
W-178.0'

NATCO

BTEX BUSTER™

Achieves 99.7%+ BTEX and VOC Removal Efficiency!

The Cost Effective Answer To Your Compliance Problems



Space saving skid mounted NATCO BTEX BUSTER is the cost effective answer to your compliance problems.

The NATCO BTEX BUSTER provides a removal efficiency greater than 99.7%, helps recover and collect saleable liquid hydrocarbons and prevents the loss of expensive fuel gas.

Field-proven, the NATCO BTEX BUSTER is now available through our 30 NATCO Sales and Service locations worldwide.

The unit was designed using the EPA approved GRI-GlyCalc™ computer simulation program with a flash-gas separator in the glycol regeneration process. Under common operating conditions, BTEX (Benzene, Toluene, Ethylbenzene and Xylene) as well as other volatile organic compounds (VOC's) are emitted to the atmosphere during the glycol regeneration process. The rates are usually proportional to the glycol circulation rate.

Meets Federal Regulation 40 CFR Part 63

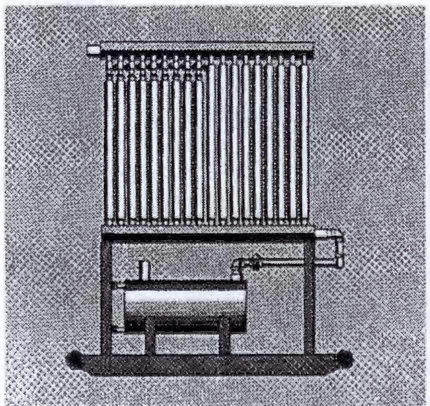
This cost efficient system is designed to assist operators in reducing BTEX and VOC emissions below the accepted levels and comply with Federal and State environmental regulations.

Economics of NATCO's BTEX BUSTER show that it can pay for itself by recovering saleable hydrocarbon liquids and fuel gas. By condensing troublesome glycol reconcentrator vapors and routing flash gas back to the reconcentrator fuel gas inlet for burning, the unit minimizes emissions during glycol plant dehydration processing.

The BTEX BUSTER incorporates field-proven NATCO burner accessories to help prevent sooting and back pressure on your regeneration system.

The BTEX BUSTER also features a design to eliminate potential freeze-up problems when operating in severe cold climates.

NATCO offers the BTEX BUSTER in standard sizes to accommodate most customer needs. Our units are backed by NATCO replacement parts, technical assistance and service available 24 hours a day.

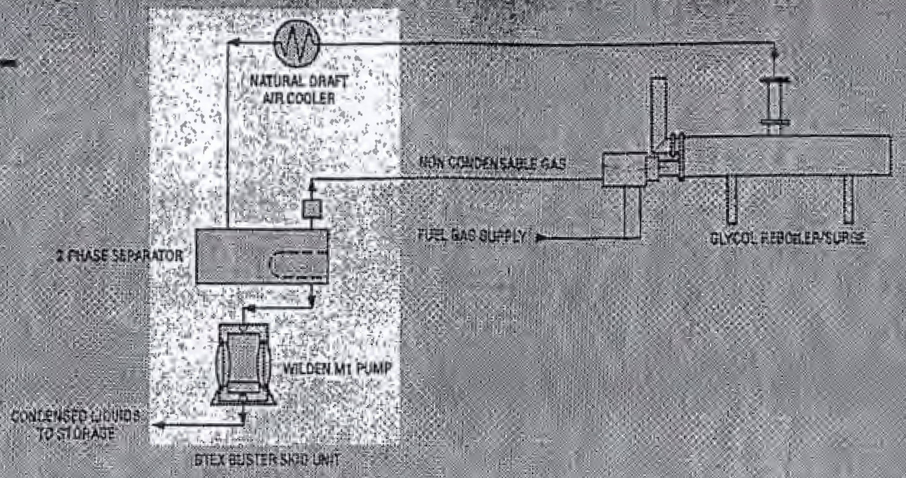


NATCO BTEX BUSTER units are designed and engineered for safe operation and meet today's environmental regulations

Features	Benefits
• Efficient	• Removal efficiency greater than 99.7%
• Environmentally Correct	• Meets Federal Regulation 40 CFR part 63 Meets or exceeds most stringent state regulations LAC:111.2116 and LAC 33:111, chapter 51
• Reduces Operating Costs	• Reduces fuel gas consumption Recovers saleable liquid hydrocarbons
• Safe	• In-line flash arrestor, high level switch, pressure safety valve, gas shutdown valves
• Designed For The Oilfield	• Includes NATCO field proven burner products Reduces freeze problems in most cold climates Pneumatic pump handles aromatic hydrocarbons
• NATCO Service	• Experienced staff, 30 locations, 24 hrs/day

NATCO

Flow Diagram – BTEX BUSTER Skid Package



Standard BTEX Size (1)	Reconcentrator Duty BTU/Hr	Glycol Pump Gallons/Hour	Maximum Capacity # Water/Day (2)	Non Condensable Vapor #/Day (3)	Cooler Duty BTU/Hr (4)
150	75,000	40	273	7	30,000
160	150,000	40	273	10	30,000
250	250,000	90	1216	27	51,000
375	375,000	210	1807	45	76,000
550	550,000	210	2650	60	112,000
750	750,000	450	3615	100	152,000

(1) Standard BTEX
Performance of unit is based on a non-condensable vapor HHV greater than 400 Btu/scf and less than 1800 Btu/scf and a glycol circulation rate of no more than 3 gallons per pound of water removed.

(2) Maximum Capacity # Water/Day
Represents the maximum capacity of water in pounds per day for each standard NATCO reboiler size based on a glycol circulation rate of 2 gallons of glycol per pound of water removed.

(3) Non-Condensable Vapor #/Day
Maximum non-condensable vapor rate was calculated with the GRI-GlyCalc computer simulation program with a flash gas separator used in the glycol regeneration process and a BTEX concentration in the inlet gas stream of no more than 700 ppm. Using adiabatic combustion calculations, a minimum of 99.7% of these non-condensable vapors are destroyed.

(4) Cooler Duty Btu/Hr
Cooler duty was calculated based on a prevailing windspeed of 3 mph and a maximum ambient temperature of 100°F.

Note: NATCO is not responsible for the disposal of any condensed liquids associated with its BTEX BUSTER units.

How It Works – The NATCO BTEX BUSTER is a relatively simple process that is designed to maintain greater than 99.7% removal of BTEX and VOC emissions.

The vapors emitted from the glycol still column are cooled in the natural draft air cooler to temperatures below 120°F (48.9°C).

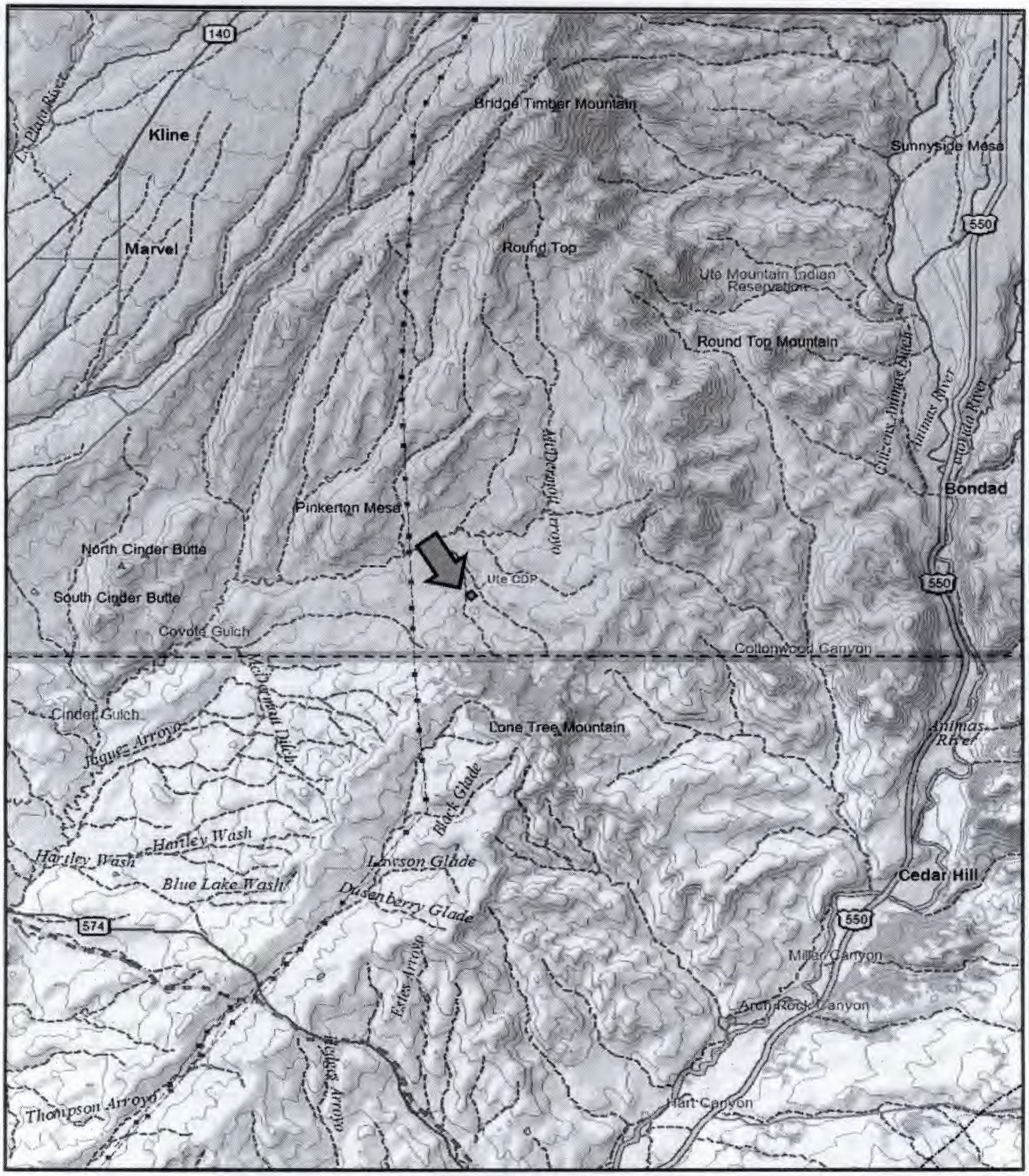
The condensed liquids are collected in a small two-phase separator and pumped to customer storage. Non-condensable gases from the separator are piped through an in-line flash arrestor and then burned in the glycol reboiler firebox to achieve an overall minimum destruction efficiency of 99.7% plus.

Built-In Safety Features – NATCO BTEX BUSTER units are engineered with proper controls for safe operation and long in-service life. These include an in-line flash arrestor, separator high level switch, pressure safety valve and gas shut-down valves for high reboiler bath temperatures. It also incorporates field-proven NATCO burner accessories that help to prevent typical sooting and back pressures on your regeneration system.

NATCO –
Your Single Source For:
- Design
- Engineering
- Procurement
- Fabrication
- Start-up
- Commissioning
- Operations Maintenance
- Education and Training
- Strategic Alliances

NATCO

NATCO
2950 North Loop West
Houston, Texas 77092 USA
Phone: (713) 683-9292
Fax: (713) 683-6768
www.natco_us.com



KEY: SOURCE: USGS 7.5 Minute Quadrangle (Topographic)

PROJECT	13704.01
PREPARED FOR	CONOCOPHILLIPS
LOCATION	37.0173N, 108.0201W

SHEET	DRAWN BY	REVIEWED BY	DATE

PEI

GENERAL VICINITY MAP
Ute CDP

Paser, Kathleen

From: Paser, Kathleen
Sent: Wednesday, September 18, 2013 7:53 AM
To: Ostrand, Laurie
Cc: Eisele, Adam; Paser, Kathleen
Subject: FW: ConocoPhillips Ute CS and MACT HH Applicable requirements
Attachments: Document.pdf

I've attached the cover letter to the application and the portion of the application where they discuss the dehydration process. The portion of the application is the piece they did not bother to send to you guys.

The process they are using is a combination of a control device (condenser) and a "process modification."

Is what they say they are doing a process modification pursuant to 63.771(e)?

1. Flash tank vent emissions are diverted to the Reboiler as fuel.
2. Process vent (still vent) emissions are captured in the control device (condenser).
3. The vapors and liquids from the condenser are sent to the condensate tanks.
4. The liquids from the condenser are saved as product and trucked off.
5. The vapors from the condenser remain in the condenser and condensate tank or are vented to the atmosphere in the event of excess pressure in the tanks.
6. According to ConocoPhillips, the overall control efficiency of the condenser is 95% when vapors from the process vent/condensate tank/condenser are vented to the atmosphere in the event of a pressure overload.

I've cut and paste relevant sections of MACT HH below.

****

MACT HH

63.761: DEFINITIONS

Control device means any equipment used for recovering or oxidizing HAP or volatile organic compound (VOC) vapors. Such equipment includes, but is not limited to, absorbers, carbon adsorbers, condensers, incinerators, flares, boilers, and process heaters. For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of an enclosed combustion device), returned back to the process, or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be a control device or closed-vent system.

63.765: GLYCOL DEHYDRATOR CONTROL REQUIREMENTS

(a) This section applies to each glycol dehydration unit subject to this subpart that must be controlled for air emissions as specified in either paragraph (c)(1)(i) or paragraph (d)(1)(i) of § 63.764.

(b) Except as provided in paragraph (c) of this section, an owner or operator of a glycol dehydration unit process vent shall comply with the requirements specified in paragraphs (b)(1) and (b)(2) of this section.

(1) For each glycol dehydration unit process vent, the owner or operator shall control air emissions by either paragraph (b)(1)(i), (ii), or (iii) of this section.

(i) The owner or operator of a large glycol dehydration unit, as defined in § 63.761, shall connect the process vent to a control device or a combination of control devices through a closed-vent system. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d).

(ii) The owner or operator of a large glycol dehydration unit shall connect the process vent to a control device or combination of control devices through a closed-vent system and the outlet benzene emissions from the control device(s) shall be reduced to a level less than 0.90 megagrams per year. The closed-vent system shall be designed and operated in accordance with the requirements of § 63.771(c). The control device(s) shall be designed and operated in accordance with the requirements of § 63.771(d), except that the performance levels specified in § 63.771(d)(1)(i) and (ii) do not apply.

(iii) You must limit BTEX emissions from each existing small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 1 of this section. You must limit BTEX emissions from each new small glycol dehydration unit process vent, as defined in § 63.761, to the limit determined in Equation 2 of this section. The limits determined using Equation 1 or Equation 2 must be met in accordance with one of the alternatives specified in paragraphs (b)(1)(iii)(A) through (D) of this section.

(c) (referenced in 63.765 (b) above.) As an alternative to the requirements of paragraph (b) of this section, the owner or operator may comply with one of the requirements specified in paragraphs (c)(1) through (3) of this section.

(1) The owner or operator shall control air emissions by connecting the process vent to a process natural gas line.

(2) The owner or operator shall demonstrate, to the **Administrator's satisfaction,** that the total HAP emissions to the atmosphere from the large glycol dehydration unit process vent are reduced by 95.0 percent through process modifications, or a combination of process modifications and one or more control devices, in accordance with the requirements specified in § 63.771(e). **←-have they done this? See 63.771(e) below.**

(3) Control of HAP emissions from a GCG separator (flash tank) vent is not required if the owner or operator demonstrates, to the Administrator's satisfaction, that total emissions to the atmosphere from the glycol dehydration unit process vent are reduced by one of the levels specified in paragraph (c)(3)(i) through (iv) of this section, through the installation and operation of controls as specified in paragraph (b)(1) of this section.

(i) For any large glycol dehydration unit, HAP emissions are reduced by 95.0 percent or more.

(ii) For any large glycol dehydration unit, benzene emissions are reduced to a level less than 0.90 megagrams per year.

(iii) For each existing small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 1 of paragraph (b)(1)(iii) of this section.

(iv) For each new small glycol dehydration unit, BTEX emissions are reduced to a level less than the limit calculated by Equation 2 of paragraph (b)(1)(iii) of this section.

63.771: Control Equipment Requirements (referenced in 63.765(c), above.)

(a) This section applies to each cover, closed-vent system, and control device installed and operated by the owner or operator to control air emissions as required by the provisions of this subpart. Compliance with paragraphs (b), (c), and (d) of this section will be determined by review of the records required by § 63.774 and the reports required by § 63.775, by review of performance test results, and by inspections.

(b) ***Cover requirements.***

(1) The cover and all openings on the cover (e.g., access hatches, sampling ports, and gauge wells) shall be designed to form a continuous barrier over the entire surface area of the liquid in the storage vessel.

(2) Each cover opening shall be secured in a closed, sealed position (e.g., covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system to a control device designed and operated in accordance with the requirements of paragraphs (c) and (d) of this section.

(c) ***Closed-vent system requirements.***

(1) The closed-vent system shall route all gases, vapors, and fumes emitted from the material in an emissions unit to a control device that meets the requirements specified in paragraph (d) of this section.

(2) The closed-vent system shall be designed and operated with no detectable emissions.

(3) If the closed-vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, the owner or operator shall meet the requirements specified in paragraphs (c)(3)(i) and (c)(3)(ii) of this section.

(i) For each bypass device, except as provided for in paragraph (c)(3)(ii) of this section, the owner or operator shall either:

(A) At the inlet to the bypass device that could divert the stream away from the control device to the atmosphere, properly install, calibrate, maintain, and operate a flow indicator that is capable of taking periodic readings and sounding an alarm when the bypass device is open such that the stream is being, or could be, diverted away from the control device to the atmosphere; or

(B) Secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

(d) ***Control device requirements for sources except small glycol dehydration units.*** Owners and operators of small glycol dehydration units, shall comply with the control device requirements in paragraph (f) of this section.

(1) The control device used to reduce HAP emissions in accordance with the standards of this subpart shall be one of the control devices specified in paragraphs (d)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated in accordance with one of the following performance requirements:

(A) Reduces the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e); or

(B) Reduces the concentration of either TOC or total HAP in the exhaust gases at the outlet to the device to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.772(e); or

(C) Operates at a minimum temperature of 760 degrees C, provided the control device has demonstrated, under § 63.772(e), that combustion zone temperature is an indicator of destruction efficiency.

(D) If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(ii) A vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of either TOC or total HAP in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) [Reserved]

(3) The owner or operator shall demonstrate that a control device achieves the performance requirements of paragraph (d)(1) of this section as specified in § 63.772(e).

(4) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (d)(4)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times when gases, vapors, and fumes are vented from the HAP emissions unit or units through the closed-vent system to the control device, as required under § 63.765, § 63.766, and § 63.769. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of § 63.772(f) or (g), as applicable.

(5) For each carbon adsorption system used as a control device to meet the requirements of paragraph (d)(1) of this section, the owner or operator shall manage the carbon as follows:

(i) Following the initial startup of the control device, all carbon in the control device shall be replaced with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established for the carbon adsorption system. Records identifying the schedule for replacement and records of each carbon replacement shall be maintained as required in § 63.774(b)(7)(ix). The schedule for replacement shall be submitted with the Notification of Compliance Status Report as specified in § 63.775(d)(5)(iv). Each carbon replacement must be reported in the Periodic Reports as specified in § 63.772(e)(2)(xii).

(ii) The spent carbon removed from the carbon adsorption system shall be either regenerated, reactivated, or burned in one of the units specified in paragraphs (d)(5)(ii)(A) through (d)(5)(ii)(G) of this section.

(A) Regenerated or reactivated in a thermal treatment unit for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(B) Regenerated or reactivated in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(C) Regenerated or reactivated in a thermal treatment unit equipped with and operating organic air emission controls in accordance with a national emissions standard for HAP under another subpart in 40 CFR part 61 or this part.

(D) Burned in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(E) Burned in a hazardous waste incinerator which the owner or operator has designed and operates in accordance with the requirements of 40 CFR part 265, subpart O.

(F) Burned in a boiler or industrial furnace for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(G) Burned in a boiler or industrial furnace which the owner or operator has designed and operates in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(e) ***Process modification requirements.*** Each owner or operator that chooses to comply with § 63.765(c)(2) shall meet the requirements specified in paragraphs (e)(1) through (e)(3) of this section.

(1) The owner or operator shall determine glycol dehydration unit baseline operations (as defined in § 63.761). Records of glycol dehydration unit baseline operations shall be retained as required under § 63.774(b)(10).

(2) The owner or operator shall document, to the **Administrator's satisfaction**, the conditions for which glycol dehydration unit baseline operations shall be modified to achieve the 95.0 percent overall HAP emission reduction, or BTEX limit determined in § 63.765(b)(1)(iii), as applicable, either through process modifications or through a combination of process modifications and one or more control devices. If a combination of process modifications and one or more control devices are used, the owner or operator shall also establish the emission reduction to be achieved by the control device to achieve an overall HAP emission reduction of 95.0 percent for the glycol dehydration unit process vent or, if applicable, the BTEX limit determined in § 63.765(b)(1)(iii) for the small glycol dehydration unit process vent. Only modifications in glycol dehydration unit operations directly related to process changes, including but not limited to changes in glycol circulation rate or glycol-HAP absorbency, shall be allowed. Changes in the inlet gas characteristics or natural gas throughput rate shall not be considered in determining the overall emission reduction due to process modifications.

(3) The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using process modifications alone shall comply with paragraph (e)(3)(i) of this section. The owner or operator that achieves a 95.0 percent HAP emission reduction or meets the BTEX limit determined in § 63.765(b)(1)(iii), as applicable, using a combination of process modifications and one or more control devices shall comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) The owner or operator shall maintain records, as required in § 63.774(b)(11), that the facility continues to operate in accordance with the conditions specified under paragraph (e)(2) of this section.

(ii) The owner ~~or operator shall~~ comply with the control device requirements specified in paragraph (d) or (f) of this section, as applicable, except that the emission reduction or limit achieved shall be the emission reduction or limit specified for the control device(s) in paragraph (e)(2) of this section.

(f) ***Control device requirements for small glycol dehydration units.***

(1) The control device used to meet BTEX the emission limit calculated in § 63.765(b)(1)(iii) shall be one of the control devices specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) An enclosed combustion device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) that is designed and operated to meet the levels specified in paragraphs (f)(1)(i)(A) or (B) of this section. If a boiler or process heater is used as the control device, then the vent stream shall be introduced into the flame zone of the boiler or process heater.

(A) The mass content of BTEX in the gases vented to the device is reduced as determined in accordance with the requirements of § 63.772(e).

(B) The concentration of either TOC or total HAP in the exhaust gases at the outlet of the device is reduced to a level equal to or less than 20 parts per million by volume on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 63.772(e).

(ii) A vapor recovery device (e.g., carbon adsorption system or condenser) or other non-destructive control device that is designed and operated to reduce the mass content of BTEX in the gases vented to the device as determined in accordance with the requirements of § 63.772(e).

(iii) A flare, as defined in § 63.761, that is designed and operated in accordance with the requirements of § 63.11(b).

(2) The owner or operator shall operate each control device in accordance with the requirements specified in paragraphs (f)(2)(i) and (ii) of this section.

(i) Each control device used to comply with this subpart shall be operating at all times. An owner or operator may vent more than one unit to a control device used to comply with this subpart.

(ii) For each control device monitored in accordance with the requirements of § 63.773(d), the owner or operator shall demonstrate compliance according to the requirements of either § 63.772(f) or (h).

(3) For each carbon adsorption system used as a control device to meet the requirements of paragraph (f)(1)(ii) of this section, the owner or operator shall manage the carbon as required under (d)(5)(i) and (ii) of this section.

SmNSR-SU-000054-2012.001

ConocoPhillips

San Juan Business Unit
P.O. Box 4289
Farmington, NM 87499-4289
(505) 326-9700

RECEIVED
SEP 27 2012
8P-AR

VIA UPS

August 28, 2012

Part 49 Lead – Air Permitting
U.S. EPA Region 8
1595 Wynkoop Street, 8P-AR
Denver, CO 80202-1129

RE: Part 49 Permit Application
Ute Compressor Station

Dear Sir or Madam:

ConocoPhillips Company ("COP") is submitting the enclosed Part 49 permit application for the Ute Compressor Station. This application fulfills the requirement for synthetic minor sources under 40 CFR Part 49.153(a)(3)(v). The Ute Compressor Station achieved synthetic minor status via Consent Agreement CAA-08-2011-0032 on September 30, 2011.

In this application, COP is requesting that the terms and conditions of the Consent Agreement referenced above be included in a permit issued under 40 CFR Part 49.158. Although the requirement to operate a condenser that achieves 95 percent control efficiency is listed as an applicable requirement in this application, ConocoPhillips has presented information in Section 3.4 of the application in support of a determination that the condenser is not a "control device" as defined in 40 CFR 63.761. Consequently, ConocoPhillips requests EPA Region 8 find that §63.764, §63.765, §63.771, §63.772, §63.773, §63.774 and §63.775 are not applicable requirements with respect to the glycol dehydrator (see C.2 of the referenced Consent Agreement).

Once the Part 49 permit has been issued, COP understands that a Title V permit will not be necessary for the Ute Compressor Station because the Potential to Emit will be less than Major Source thresholds.

If you have any questions or comments regarding this Part 49 permit application, please contact me at 505-326-9811.

Sincerely,

Randy Poteet

Randy Poteet
Principal Environmental Consultant

Enclosure

cc: Brenda Jarrell, Air Program Manager, SUIT
Evan Tullos, PEI w/o enclosure

SMNSR-SU-000054-2012.001

ConocoPhillips

RECEIVED
AUG 29 2012
8P - AR

San Juan Business Unit
P.O. Box 4289
Farmington, NM 87499-4289
(505) 326-9700

VIA UPS

August 28, 2012

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Sincerely,

Randy Poteet

Randy Poteet
Principal Environmental Consultant

Enclosure

cc: Brenda Jarrell, Air Program Manager, SUIT
Evan Tullos, PEI w/o enclosure

Part 49 Permit Application

ConocoPhillips Company
Ute CDP
La Plata County, Colorado

Prepared for
Air & Radiation Program, 8P-AR
United States Environmental Protection Agency
Region 8

Prepared by

PEI

Providing Environmental Solutions Worldwide
Compliance · Engineering · Remediation · Mercury & Toxic Metals

P.O. Box 1415
Aztec, New Mexico 87410

On behalf of
ConocoPhillips Company
P.O. Box 4289
Farmington, New Mexico 87499-4289

August 2012

TABLE OF CONTENTS

List of Appendices

1.0 INTRODUCTION

ConocoPhillips Company (COP) is submitting this application to request a Part 49 Permit for the Ute CDP located in La Plata County, Colorado on Southern Ute Tribal Land. The Ute CDP is a natural gas compressor station that dehydrates and compresses natural gas prior to custody transfer to a pipeline system. This application represents proposed changes made at the facility in response to the 2011 Consent Agreement (CAA-08-2011-0032), which includes the installation of a condenser to control emissions from the glycol dehydrator as required by 40 CFR 63, Subpart HH and the installation of a catalyst on the Waukesha L7042GL (Emission Unit E-2).

General contact information for the facility can be found in Form REG and the General Information and Summary (GIS) form in Appendix A. The remainder of the application forms is presented in Appendix A. Supporting documents, emission calculations, and figures are included as noted in the Table of Contents.

1.1 Facility Description

The Ute CDP is located in Sections 14 and 15, Township 32N, Range 11W, approximately 17 miles south of Durango in La Plata County, Colorado. A topographic map illustrating the location of the facility is included in Appendix B.1 of the application. The surrounding land use category is rural.

Operation at the site is conducted under the Standard Industrial Classification (SIC) Code 1311 – Crude oil and natural gas exploration and production. The facility can dehydrate and compress up to 14.4 million standard cubic feet per day (mmscfd) of natural gas. Operations at the facility are conducted 24 hours per day, 7 days per week, 365 days per year.

The facility currently operates one 4-stroke, lean burn (4SLB) Waukesha L5790GL rated at 1,215 hp (Emission Unit E-1), one 4SLB Waukesha L7042GL rated at 1,478 hp (Emission Unit E-2), a triethylene glycol dehydrator (DEHY-1) and three condensate tanks (TK-5080, TK-5081, and TK-8094A). Other emission units operated at the location include combustion turbines, heated separators, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks. All combustion units are gas-fired units fueled with natural gas (NG) supplied from the surrounding wells. A process flow diagram is included in Appendix B.2.

1.2 Process Description

The inlet gas from the field enters the suction scrubber at $\pm$ 49 psig and $\pm$ 53° F. The pressure and temperature is the same through the suction header and the suction scrubbers on the compressor skids. The liquids collected in the suction scrubber, suction header and the compressor suction scrubbers are sent via a closed drain system to either of the two condensate tanks (TK-5080 and TK-5081) on site. Approximately 90% of the condensate produced from the scrubbers is generated on the suction side.

Once the gas is compressed, the pressure in the discharge scrubber is $\pm$188 psig and $\pm$75° F. The temperature and pressure remains consistent in the compressor discharge scrubbers, discharge filter, and dehydration contactor until the gas leaves the facility. The liquids collected in the compressor discharge scrubbers and discharge filter are also discharged to one of the two condensate tanks (TK-

5080 and TK-5081). The remaining 10% of the condensate produced from the scrubbers is generated on the discharge side. These sources are referenced in the E&P Tank summary report (Appendix G) as *Inlet Scrubber to Condensate Tanks* and *Discharge Scrubber to Condensate Tanks*. None of the scrubbers, headers, or separators has an atmospheric vent.

The gas is dehydrated before leaving the site. Emissions from the still vent are condensed and collected in a storage tank (TK-8094A).

The facility operates two open-top pit tanks. One of the pit tanks is used to drain water from the condensate tanks prior to shipping. The second tank is used to temporarily store water from the glycol reboiler and water from the fuel gas scrubber. Various vertical fixed roof tanks are also used to store process fluids. All of these tanks are insignificant emissions units.

2.0 EMISSION CALCULATION METHODOLOGY

Manufacturer's data were used to estimate carbon monoxide (CO), nitrogen oxides (NOx), volatile organic compound (VOC), and formaldehyde emissions from the Waukesha engines, while AP-42 factors were used for particulate matter (PM) and sulfur dioxide (SO_2). AP-42 emission factors were used to estimate emissions of all pollutants from the heaters. The Environmental Protection Agency's Tanks 4.09d software was used to estimate emissions from storage tanks, while E&P Tank Version 2.0 was used for the condensate tanks. GRI-GLYCalc 4.0 was used to estimate emissions from the glycol dehydrator. A summary of emissions for the CDP, as well as detailed calculations, is provided in Appendix C.

3.0 REGULATORY APPLICABILITY

3.1 National Ambient Air Quality Standards (NAAQS)

La Plata County, Colorado is designated as unclassifiable/attainment for all pollutants.

3.2 Prevention of Significant Deterioration (PSD)

Compressor stations are not identified as one of the 28 source categories subject to the 100 tons per year thresholds. Additionally, the facility's potential emissions do not exceed the 250 ton PSD source threshold for other sources.

3.3 New Source Performance Standards (NSPS)

NSPS are codified in 40 CFR Part 60. The regulatory review identified four potentially applicable NSPS categories: standards applicable to petroleum/organic liquid storage tanks (K, Ka, Kb), standards applicable to stationary gas turbines (GG), standards applicable to equipment leaks at natural gas processing plants (KKK), and standards applicable to spark ignition internal combustion engines (JJJJ).

The NSPS subparts applicable to petroleum/organic liquid storage tanks include Subparts K, Ka, and Kb. TK-5080 and TK-5081 were constructed in the 1950's and storage capacities are less than 75 cubic meters (m^3); therefore, these subparts are not applicable. Though TK-8094A was recently constructed, the storage capacity is less than 75 m^3 and the tank is exempt from the requirements of Subpart Kb.

NSPS Subpart GG is not applicable since the gas turbines have a capacity of less than 10 million British thermal units (Btu) per hour.

The Ute CDP is not a natural gas processing facility because it does not extract natural gas liquids from gas or fractionate mixed natural gas liquids to natural gas products. Therefore, NSPS Subpart KKK is not applicable.

NSPS Subpart JJJJ applies to spark ignition internal combustion engines that are constructed, modified, or reconstructed after applicability dates specified in the rule. The Waukesha L5790GL (E-1) was modified in 2011. Per 40 CFR 60.4233(f)(4)(i), this engine will be subject to the emission limitations of Subpart JJJJ. The Waukesha L7042GL (E-2) was constructed prior to July 1, 2007 and is therefore not subject to Subpart JJJJ.

NSPS Subpart OOOO applies to certain sources at oil and natural gas production facilities. The facility has only one unit constructed after August 23, 2011. The reciprocating compressor on Unit E-2 was installed on September 15, 2011 and is subject to Subpart OOOO. The glycol dehydrator is not subject to Subpart OOOO since the average annual gas flow rate is greater than 3 mmscfd.

3.4 National Emission Standards for Hazardous Air Pollutants (NESHAP)

NESHAP for source categories are codified in 40 CFR Part 63. Based on the "Once In, Always In" policy, the Ute CDP is classified as a major source of HAP emissions when determining the applicable NESHAP regulations. The regulatory review identified four NESHAP categories potentially applicable to the compressor station operations: standards applicable to oil and natural gas production facilities (HH), standards applicable to natural gas storage and transmission facilities (HHH), standards applicable to organic liquids distribution facilities (EEEE), and standards applicable to spark ignition internal combustion engines (ZZZZ).

Since the facility is a major source of uncontrolled HAP emissions, 40 CFR 63 Subpart HH for Oil and Gas Production Facilities is applicable per 40 CFR 63.760(a)(1). DEHY-1 is subject to the control requirements of Subpart HH. A condenser is used to control emissions from the dehydrator. Since throughput is less than 75,900 liters per day (21,000 gallons per day), the condensate tanks (TK-5080, TK-5081, and TK-8094A) are not subject to Subpart HH. In addition, since the Ute CDP is not a natural gas processing plant, ancillary equipment and compressors are not subject to Subpart HH.

ConocoPhillips believes the condenser at the Ute CDP is not a "control device" as defined in 40 CFR 63.761. The definition of "control device" includes the statement "For the purposes of this subpart, if gas or vapor from regulated equipment is used, reused (i.e., injected into the flame zone of a combustion device), returned back to the process or sold, then the recovery system used, including piping, connections, and flow inducing devices, is not considered to be control devices or closed-vent systems." The consequence of this conclusion would be that the piping from the glycol dehydration unit still vent to the condenser and the condenser itself at the Ute CDP are not subject to the General Standards at 40 CFR 63.764 or the Glycol Dehydration Unit Process Vent Standards at

40 CFR 63.765. Other sections that would not be applicable include 40 CFR 63.771 and40 CFR 63.772. Additionally, the monitoring, recordkeeping and reporting requirements at 40 CFR 63.773, 40 CFR 63.774 and 40 CFR 63.775 would not apply.

In order to demonstrate that the condenser at the Ute CDP is not a control device for the purposes of 40 CFR Part 63, Subpart HH, we must show that the gas/vapor streams routed through the dehydration unit are used as fuel, returned to the process or sold. The dehydration unit does have a flash tank. Vapors off the flash tank are routed to the reboiler and used as fuel. All vapors from the still vent are routed to the condenser via piping with a pressure relief valve set at 1.5 psi. The liquid stream resulting from the condensed vapors drains into the condensate tank located adjacent to the condenser. Any non-condensable vapors remain in the condenser and the condensate tank unless the pressure in the condensate tank exceeds four ounces. In this case, the non-condensable vapors would be vented to atmosphere. However, the condenser still achieves 95 percent control efficiency.

Liquids contained in the condensate tank adjacent to the condenser are transferred via truck to a condensate sales tank located on-site at the Ute CDP. The sales tank operates with a safety valve setting of four ounces. Liquids in the sales tank are sold to a third party. The transport truck is a vacuum track which draws the liquids out of the condensate tank. Relief settings on the vacuum truck operate at 18 psi.

Since the Ute CDP is not a natural gas storage and transmission facility; therefore, Subpart EEEE is not applicable. Subpart EEEE does not apply to the Ute CDP since the regulation contains an exemption for oil and gas production facilities.

The Waukesha L5790GL (E-1) and the Waukesha L7042GL (E-2) are exempt from Subpart ZZZZ per 40 CFR 63.6590(b)(3)(ii) since both are 4-stroke, lean burn engines located at a major source.

3.5 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, requires monitoring for certain emission units at major sources. Though the glycol dehydrator (DEHY-1) has uncontrolled emissions greater than 100 tpy, the CAM rule does not apply to sources subject to Sections 111 (NSPS) or 112 (NESHAP) of the Clean Air Act (CAA).

3.6 Consent Agreement

Consent Agreement CAA-08-2011-0032 was signed on September 30, 2011. The agreement contains federally-enforceable requirements for the facility as follows:

1. Equip the Waukesha L7042GL (E-2) with a catalyst to reduce CO and formaldehyde emissions by at least 75%.
2. Control emissions from the glycol dehydrator (DEHY-1) by at least 95%.
3. Replace or retrofit all high-bleed pneumatic controllers with low-bleed controllers.
4. Implement a leak detection and repair program.

Items 1 and 2 have been incorporated into this application and have been used to limit the facility's potential-to-emit (PTE).

4.0 AIR QUALITY IMPACT ANALYSIS

Even though the Ute CDP is an existing facility and a process modification is not being permitted, discussions with Ms. Kathleen Paser of the Environmental Protection Agency's Region 8 office indicated that screening level modeling must be conducted to evaluate potential air quality impacts. ConocoPhillips has contracted the modeling and will provide the results as soon as they are available.

APPENDIX A

EPA Forms
(Part 71 forms were used to provide emission unit data.)

OMB Control No. 2060-0003
Approval expires 04/30/2012

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
FEDERAL MINOR NEW SOURCE REVIEW PROGRAM IN INDIAN COUNTRY
40 CFR 49.151

Registration for Existing Sources
(FORM REG)

Please submit information to following two entities:

Federal Minor NSR Permit Coordinator
U.S. EPA, Region 8
1595 Wynkoop Street, 8P-AR
Denver, CO 80202-1129
R8airpermitting@epa.gov

For more information, visit:
http://www.epa.gov/region08/air/permitting/tmnsr.html

The Tribal Environmental Contact for the specific reservation:

If you need assistance in identifying the appropriate Tribal Environmental Contact and address, please contact: R8airpermitting@epa.gov

A. GENERAL SOURCE INFORMATION

1. Company Name ConocoPhillips Company		**2. Source Name** Ute CDP	
3. Type of Operation Natural gas compressor Station		**4. Portable Source?** ☐ Yes X No **5. Temporary Source?** ☐ Yes X No	
6. NAICS Code 211111		**7. SIC Code** 1311	
8. Physical Address (home base for portable sources)			
9. Reservation* Southern Ute	**10. County*** La Plata	**11a. Latitude*** 37.0173N	**11b. Longitude*** 108.0201W
12a. Quarter-Quarter Section* NWSW and NESE	**12b. Section*** 14 and 15	**12c. Township*** 32N	**12d. Range*** 11W

* Provide all locations of operation for portable sources

B. CONTACT INFORMATION

1. Owner Name ConocoPhillips Company – Randy Poteet	Title Principal Environmental Consultant
Mailing Address P.O. Box 4289; Farmington, NM 87499-4289	
Email Address randy.poteet@conocophillips.com	
Telephone Number (505) 326-9811	Facsimile Number (505) 599-4005
2. Operator Name (if different from owner)	Title
Mailing Address	
Email Address	
Telephone Number	Facsimile Number
3. Source Contact ConocoPhillips Company – Cory Minton	Title Compression Supervisor
Mailing Address P.O. Box 4289; Farmington, NM 87499-4289	
Email Address cory.j.minton@conocophillips.com	
Telephone Number (505) 599-3430	Facsimile Number
Compliance Contact Randy Poteet	Title Principal Environmental Consultant
Mailing Address P.O. Box 4289; Farmington, NM 87499-4289	
Email Address randy.poteet@conocophillips.com	
Telephone Number (505) 326-9811	Facsimile Number (505) 599-4005

C. ATTACHMENTS

Include all of the following information as attachments to this form

X Narrative description of the operations **(See Section 1.1)**

X Identification and description of all emission units and air pollution generating activities (with the exception of the exempt emissions units and activities listed in §49.153(c) **(See Appendix A)**

X Identification and description of any existing air pollution control equipment and compliance monitoring devices or activities **(See Appendix A – Form GIS, Section I)**

X Type and amount of each fuel used **(See Appendix A – Form EUD-1 for Units E-1 and E-2)**

X Type raw materials used **(See Section 1.1)**

X Production Rates **(See Section 1.1)**

X Operating Schedules **(See Section 1.1)**

X Any existing limitations on source operations affecting emissions or any work practice standards, where applicable, for all regulated NSR pollutants at your source. **(See Appendix C.)**

X Total allowable (potential to emit if there are no legally and practically enforceable restrictions) emissions from the air pollution source for the following air pollutants: particulate matter, PM_{10}, $PM_{2.5}$, sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), volatile organic compound (VOC), lead (Pb) and lead compounds, fluorides (gaseous and particulate), sulfuric acid mist (H_2SO_4), hydrogen sulfide (H_2S), total reduced sulfur (TRS) and reduced sulfur compounds, including all calculations for the estimates. **(See Appendix C.)**

X Estimates of the total actual emissions from the air pollution source for the following air pollutants: particulate matter, PM_{10}, $PM_{2.5}$, sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon monoxide (CO), volatile organic compound (VOC), lead (Pb) and lead compounds, fluorides (gaseous and particulate), sulfuric acid mist (H_2SO_4), hydrogen sulfide (H_2S), total reduced sulfur (TRS) and reduced sulfur compounds, including all calculations for the estimates. **(See Appendix L.)**

X Other **(Greenhouse gas emissions – See Appendix M.)**

The public reporting and recordkeeping burden for this collection of information is estimated to average 6 hours per response. Send comments on the Agency's need for this information, the accuracy of the provided burden estimates, and any suggested methods for minimizing respondent burden, including through the use of automated collection techniques to the Director, Collection Strategies Division, U.S. Environmental Protection Agency (2822T), 1200 Pennsylvania Ave., NW, Washington, D.C. 20460. Include the OMB control number in any correspondence. Do not send the completed form to this address.

D. TABLE OF ESTIMATED EMISSIONS

The following estimates of the total emissions in tons/year for all pollutants contained in your worksheet stated above should be provided.

Pollutant	Total Actual Emissions (tpy) (2011)	Total Allowable or Potential Emissions (TPY)	
PM	0.84	0.84	PM - Particulate Matter
PM_{10}	0.84	0.84	PM_{10} - Particulate Matter less than 10 microns in size
$PM_{2.5}$	0.84	0.84	$PM_{2.5}$ - Particulate Matter less than 2.5 microns in size
SO_x	1.99	1.99	SOx - Sulfur Oxides
NO_x	31.57	56.94	NOx - Nitrogen Oxides
CO	50.81	57.24	CO - Carbon Monoxide
VOC	98.26	46.98	VOC - Volatile Organic Compound
Pb	-	-	Pb - Lead and lead compounds
Fluorides	-	-	Fluorides - Gaseous and particulates
H_2SO_4	-	-	H_2SO_4 - Sulfuric Acid Mist
H_2S	-	-	H_2S - Hydrogen Sulfide
TRS	-	-	TRS - Total Reduced Sulfur
RSC	-	-	RSC - Reduced Sulfur Compounds

Emissions calculations must include fugitive emissions if the source is one the following listed sources, pursuant to CAA Section 302(j):

(a) Coal cleaning plants (with thermal dryers);
(b) Kraft pulp mills;
(c) Portland cement plants;
(d) Primary zinc smelters;
(e) Iron and steel mills;
(f) Primary aluminum ore reduction plants;
(g) Primary copper smelters;
(h) Municipal incinerators capable of charging more than 250 tons of refuse per day;
(i) Hydrofluoric, sulfuric, or nitric acid plants;
(j) Petroleum refineries;
(k) Lime plants;
(l) Phosphate rock processing plants;
(m) Coke oven batteries;
(n) Sulfur recovery plants;
(o) Carbon black plants (furnace process);
(p) Primary lead smelters;
(q) Fuel conversion plants;
(r) Sintering plants;
(s) Secondary metal production plants;
(t) Chemical process plants
(u) Fossil-fuel boilers (or combination thereof) totaling more than 250 million British thermal units per hour heat input;
(v) Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels;
(w) Taconite ore processing plants;
(x) Glass fiber processing plants;
(y) Charcoal production plants;
(z) Fossil fuel-fired steam electric plants of more that 250 million British thermal units per hour heat input, and
(aa) Any other stationary source category which, as of August 7, 1980, is being regulated under section 111 or 112 of the Act.

EPA United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

GENERAL INFORMATION AND SUMMARY (GIS)

A. Mailing Address and Contact Information

Facility name Ute CDP

Mailing address: Street or P.O. Box P.O. Box 4289

City Farmington State NM ZIP 87499-4289

Contact person: Randy Poteet Title Principal Environmental Consultant

Telephone (505) 326 - 9811 Ext. ________

Facsimile (505) 599 - 4005

B. Facility Location

Temporary source? ___Yes X No Plant site location Sections14 and 15, T32N, R11W 37.0173N, 108.0201W

Drive north from Aztec, NM for 10.7 miles on US 550 to CR 2300 and turn left. Travel 9.8 miles to Ute CDP on right.

City Not Applicable (N/A) State CO County La Plata EPA Region 8

Is the facility located within:

Indian lands? X YES ___ NO OCS waters? ___YES X NO

Non-attainment area? ___ YES X NO If yes, for what air pollutants? ________

Within 50 miles of affected State? X YES __ NO If yes, What State(s)? CO, NM

C. Owner

Name ConocoPhillips Company Street/P.O. Box PO Box 2197

City Houston State TX ZIP 77252 - 2197

Telephone (281) 293 – 1000 Ext ________

D. Operator

Name ConocoPhillips Company Street/P.O. Box PO Box 4289 (3401 E. 30th Street)

City Farmington State NM ZIP 87499-4289

Telephone (505) 326 – 9700 Ext ________

E. Application Type

Mark only one permit application type and answer the supplementary question appropriate for the type marked.

X Initial Permit (Part 49) ___ Renewal ___ Significant Mod ___ Minor Permit Mod(MPM)

___ Group Processing, MPM ___ Administrative Amendment

For initial permits, when did operations commence? 1988

For permit renewal, what is the expiration date of current permit? _____/____/_____

F. Applicable Requirement Summary

Mark all types of applicable requirements that apply.

___ SIP ___ FIP/TIP ___ PSD ___Non-attainment NSR

X Minor source NSR X Section 111 ___ Phase I acid rain ___Phase II acid rain

___ Stratospheric ozone ___ OCS regulations X NESHAP ___ Sec. 112(d) MACT

___ Sec. 112(g) MACT ___ Early reduction of HAP ___ Sec 112(j) MACT ___ RMP [Sec.112(r)]

___ Tank Vessel requirements, sec. 183(f)) ___ Section 129 Standards/Requirement

___ Consumer / comm.. products, ϶ 183(e) ___ NAAQS, increments or visibility (temp. sources)

Has a risk management plan been registered? ___YES X NO Regulatory agency ____________

Phase II acid rain application submitted? ___YES X NO If yes, Permitting authority ____________

G. Source-Wide PTE Restrictions and Generic Applicable Requirements

Cite and describe any emissions-limiting requirements and/or facility-wide "generic" applicable requirements.

See Section 3.0 of the application.

H. Process Description

List processes, products, and SIC codes for the facility.

Process	Products	SIC
Oil and Natural Gas Exploration and Production	Natural Gas	1311

I. Emission Unit Identification

Assign an emissions unit ID and describe each emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
E-1	1,215 Waukesha L5790GL - 4SLB natural gas-fueled compressor engine
E-2	1,478 hp Waukesha L7042GL - 4SLB natural gas-fueled compressor engine
DEHY-1	14.4 MMscf/day glycol dehydrator (The capacity of DEHY-1 was obtained using the methodology of 40 CFR 63.760(a)(1)(i)(A) for declining gas fields, which uses the maximum 5 year gas throughput multiplied by a 20% contingency factor.)
TK-5080	300-barrel Condensate Tank
TK-5081	300-barrel Condensate Tank
TK-8094A	300-barrel Condensate Tank

J. Facility Emissions Summary

Enter potential to emit (PTE) for the facility as a whole for each air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information.

NOx 56.94 tons/yr VOC 46.98 tons/yr SO2 1.99 tons/yr

PM-10 0.84 tons/yr CO 57.24 tons/yr Lead Negligible tons/yr

Total HAP 9.56 tons/yr

Single HAP emitted in the greatest amount Formaldehyde PTE 4.13 tons/yr

* In accordance with 40 CFR 63, Subpart HH and the Consent Agreement, this application includes the requirement to operate a condenser at all times on the dehydrator (DEHY-1) and use a catalyst with 75% control of CO and formaldehyde emissions on the Waukesha 7042GL (E-2).

K. Existing Federally-Enforceable Permits

Permit number(s) ________ Permit type ________ Permitting authority ________

Permit number(s) ________ Permit type ________ Permitting authority ________

L. Emission Unit(s) Covered by General Permits

Emission unit(s) subject to general permit ________

Check one: ___ Application made ___ Coverage granted

General permit identifier ________ Expiration Date ___/___/___

M. Cross-referenced Information

Does this application cross-reference information? ___YES X NO (If yes, see instructions)

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

POTENTIAL TO EMIT (PTE)

For each unit with emissions that count towards applicability, list the emissions unit ID and the PTE for the air pollutants listed below and sum them up to show totals for the facility. You may find it helpful to complete form **EMISS** before completing this form. Show other pollutants not listed that are present in major amounts at the facility on attachment in a similar fashion. You may round values to the nearest tenth of a ton. Also report facility totals in section **J** of form **GIS**.

Emissions Unit ID	Regulated Air Pollutants and Pollutants for which the Source is Major (tons/yr)						
	NOx	VOC	SO2	PM10	CO	Lead	HAP
E-1	32.73	10.91	0.54	0.36	43.64	-	3.68
E-2	23.89	13.27	0.65	0.43	11.95	-	1.57
DEHY-1	0.05	6.36	0.01	0.01	0.04	-	3.30
TK-5080	-	6.90	-	-	-	-	0.49
TK-5081	-	6.90	-	-	-	-	0.49
TK-8094A	-	0.52	-	-	-	-	0.04
Insignificant Activities	0.27	2.11	0.79	0.05	1.61	-	-
FACILTY TOTALS	56.94	46.98	1.99	0.84	57.24	-	9.56

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID __E-1__ Description Waukesha L5790GL 4SLB RICE

SIC Code (4-digit) __1311__ SCC Code __20200202__

B. Emissions Unit Description

Primary use Gas Compression ______ Temporary Source ___Yes _X_ No

Manufacturer __Waukesha__ Model No. L5790GL

Serial Number __240747__ Installation Date __1/10/12__

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) Natural gas compressor engine

Boiler horsepower rating__1,215 hp (1,130 hp altitude derated)__Boiler steam flow lb/hr)______

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input __8.3__MM BTU/hr Max. Design Heat Input __8.9__MM BTU/hr
(Site Derated)

C. Fuel Data

Primary fuel type(s) Natural Gas   Standby fuel type(s) N/A

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0	0	950 Btu/scf

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	Did not operate in 2012	8.7 Mscf	76.1 mmscf

E. Associated Air Pollution Control Equipment

Emissions unit ID__________ Device type

Air pollutant(s) Controlled

Manufacturer

Model No.__   Serial No.

Installation date__/____/_________ Control efficiency (%)

Efficiency estimation method

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) 25	Inside stack diameter (ft) 0.67
Stack temp(°F) 900	Design stack flow rate (ACFM) N/A
Actual stack flow rate (ACFM) 2500	Velocity (ft/sec) 119.4

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID E-1

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	NA	7.47	32.73	
CO	NA	9.96	43.64	
VOC	NA	2.49	10.91	
PM	NA	0.08	0.36	
SO2	NA	0.12	0.54	
Formaldehyde	NA	0.72	3.16	50-00-0
Acetaldehyde	NA	0.07	0.31	75-07-0
Acrolein	NA	0.04	0.19	107-02-8
Benzene	NA	0.004	0.02	71-43-2

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID __E-2__ Description Waukesha L7042GL 4SLB RICE

SIC Code (4-digit) __1311__ SCC Code __20200202__

B. Emissions Unit Description

Primary use Gas Compression Temporary Source ___Yes X No

Manufacturer Waukesha Model No. L7042GL

Serial Number C-11672/1 Installation Date 10/20/2011

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) Natural gas compressor engine

Boiler horsepower rating 1,478 hp (1,375 hp altitude derated) Boiler steam flow lb/hr)______

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input __9.83__ MM BTU/hr Max. Design Heat Input __10.58__ MM BTU/hr

C. Fuel Data

Primary fuel type(s) Natural Gas   Standby fuel type(s) N/A

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0	0	950 Btu/scf

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas	18.1 mmscf (2011)	10.4 Mscf	90.7 mmscf

E. Associated Air Pollution Control Equipment

Emissions unit ID E-2   Device type Oxidation catalyst

Air pollutant(s) Controlled CO, Formaldehyde

Manufacturer Miratech

Model No. ZXS-RF-Full-354XH   Serial No. RE-7129

Installation date 9 /15 / 2011   Control efficiency (%) 75% CO, 75% CH2O

Efficiency estimation method Manufacturer's guaranteed rates

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) 27	Inside stack diameter (ft) 0.67
Stack temp(°F) 900	Design stack flow rate (ACFM) N/A
Actual stack flow rate (ACFM) 2967	Velocity (ft/sec) 141.7

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID ____E-2

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	4.78	5.45	23.89	
CO	2.39	2.73	11.95	
VOC	2.65	3.03	13.27	
PM	0.09	0.10	0.43	
SO2	0.13	0.15	0.65	
Formaldehyde	0.19	0.22	0.96	50-00-0
Acetaldehyde	0.07	0.08	0.37	75-07-0
Acrolein	0.04	0.05	0.22	107-02-8
Benzene	0.004	0.004	0.02	71-43-2

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID DEHY-1 Description Glycol Dehydrator

SIC Code (4-digit) 1311 SCC Code 31000227

B. Emissions Unit Description

Primary use or equipment type Natural Gas Dehydration

Manufacturer Pesco Model No. N/A

Serial No. 10413 Installation date 1988

Raw materials Natural gas

Finished products Dehydrated Natural Gas

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.38 MMscf (9.2/day)	3.36 Bscf
Maximum rate	0.6 MMscf (14.4/day)	5.3 Bscf

D. Associated Air Pollution Control Equipment

Emissions unit ID DEHY-1 Device Type Condenser

Manufacturer Natco Model No NC 36-6

Serial No. 3GPA8 Installation date 10/30/11

Control efficiency (%) > 95% Capture efficiency (%) N/A

Air pollutant(s) controlled VOC/Organic HAP Efficiency estimation method Manufacturer

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 09/30/2010

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID DEHY-1 (includes reboiler emissions)

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx	0.05	0.01	0.05	
CO	0.04	0.009	0.04	
VOC	62.05	1.89	8.28	
SO_2	0.007	0.002	0.007	
$PM_{10}/PM_{2.5}$	0.004	0.001	0.004	
Benzene	5.24	0.09	0.39	71-43-2
n-Hexane	0.34	0.02	0.08	110-54-3
Toluene	17.15	0.09	0.38	108-88-3
Xylenes	15.25	0.02	0.08	1330-20-7
Ethylbenzene	1.46	0.002	0.009	100-41-4

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(°F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID TK-5080 Description 300-barrel Condensate Storage Tank

SIC Code (4-digit) 1311 SCC Code 40400311

B. Emissions Unit Description

Primary use or equipment type Condensate Storage

Manufacturer Graver Model No. N/A

Serial No. 3935-4 Installation date 1988

Raw materials Natural Gas Condensate

Finished products Natural Gas Condensate

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.14 barrels	1,250 barrels
Maximum rate	0.29 barrels	2,500 barrels

D. Associated Air Pollution Control Equipment

Emissions unit ID N/A Device Type N/A

Manufacturer N/A Model No N/A

Serial No. N/A Installation date ____/___/____

Control efficiency (%) N/A Capture efficiency (%) N/A

Air pollutant(s) controlled N/A Efficiency estimation method N/A

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(°F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID TK-5080

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC	6.90	1.58	6.90	
n-Hexane	0.26	0.06	0.26	110-54-3
Benzene	0.07	0.02	0.07	71-43-2
Toluene	0.11	0.03	0.11	108-88-3
Ethylbenzene	0.005	0.001	0.005	100-41-4
Xylene	0.04	0.01	0.04	1330-20-7

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID TK-5081 Description 300-barrel Condensate Storage Tank

SIC Code (4-digit) 1311 SCC Code 40400311

B. Emissions Unit Description

Primary use or equipment type Condensate Storage

Manufacturer Graver Model No. N/A

Serial No. 976-2 Installation date 1988

Raw materials Natural Gas Condensate

Finished products Natural Gas Condensate

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.14 barrels	1,250 barrels
Maximum rate	0.29 barrels	2,500 barrels

D. Associated Air Pollution Control Equipment

Emissions unit ID N/A Device Type N/A

Manufacturer N/A Model No N/A

Serial No. N/A Installation date ___/___/______

Control efficiency (%) N/A Capture efficiency (%) N/A

Air pollutant(s) controlled N/A Efficiency estimation method N/A

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID TK-5081

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC	6.90	1.58	6.90	
n-Hexane	0.26	0.06	0.26	110-54-3
Benzene	0.07	0.02	0.07	71-43-2
Toluene	0.11	0.03	0.11	108-88-3
Ethylbenzene	0.005	0.001	0.005	100-41-4
Xylene	0.04	0.01	0.04	1330-20-7

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(°F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID TK-8094A Description 300-barrel Condensate Storage Tank

SIC Code (4-digit) 1311 SCC Code 40400311

B. Emissions Unit Description

Primary use or equipment type Condensate Storage

Manufacturer Pesco Model No. N/A

Serial No. None Installation date 2011

Raw materials Natural Gas Condensate

Finished products Natural Gas Condensate

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.21 barrels	1,825 barrels
Maximum rate	0.34 barrels	3,000 barrels

D. Associated Air Pollution Control Equipment

Emissions unit ID N/A Device Type N/A

Manufacturer N/A Model No N/A

Serial No. N/A Installation date ____/___/____

Control efficiency (%) N/A Capture efficiency (%) N/A

Air pollutant(s) controlled N/A Efficiency estimation method N/A

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(°F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID TK-8094A

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC	NA	0.12	0.52	
n-Hexane	NA	0.004	0.02	110-54-3
Benzene	NA	0.001	0.005	71-43-2
Toluene	NA	0.002	0.008	108-88-3
Ethylbenzene	NA	0.000	0.000	100-41-4
Xylene	NA	0.001	0.003	1330-20-7

Federal Operating Permit Program (40 CFR Part 71)

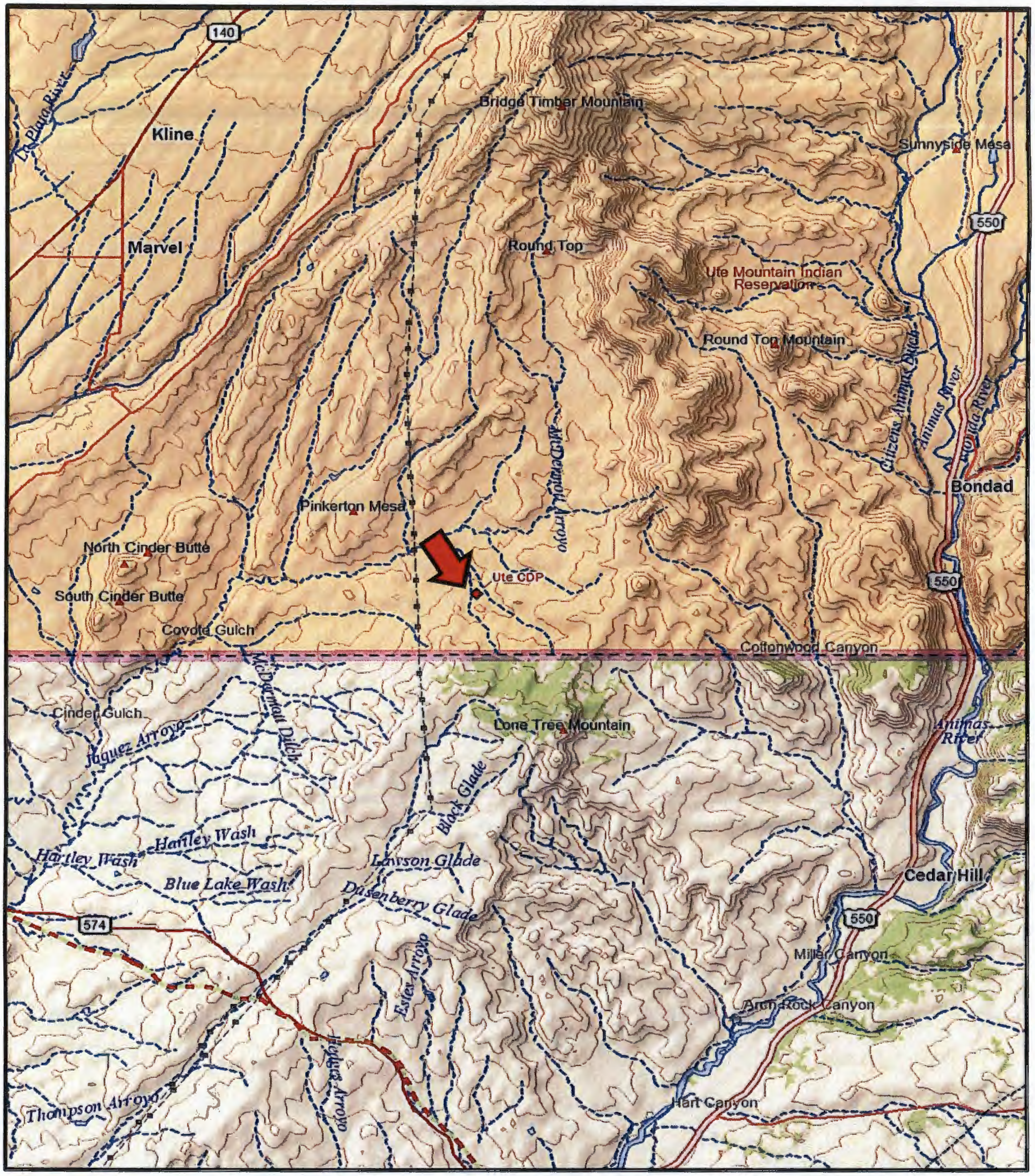
INSIGNIFICANT EMISSIONS (IE)

List each insignificant activity or emission unit. In the "number" column, indicate the number of units in this category. Descriptions should be brief but unique. Indicate which emissions criterion of part 71 is the basis for the exemption.

Number	Description of Activities or Emissions Units	RAP, except HAP	HAP
2	100-barrel Oil Tanks (TK-1, TK-2)	X	X
1	100-barrel Coolant Tank (TK-3)	X	X
1	250-gallon Compressor Oil Tank (TK-6)	No Vent	No Vent
1	150-gallon Emulsion Breaker Tank (TK-7)	No Vent	No Vent
1	300-gallon Compressor Oil Tank (TK-8)	No Vent	No Vent
1	535-gallon Ethylene Glycol Tank (TK-9)	No Vent	No Vent
1	1,130-gallon Triethylene Glycol Tank (TK-10)	X	X
1	100-barrel methanol tank (TK-4040)	X	X
1	5,040-gallon below-grade pit sump liquids tank (BGT-1)	X	X
1	5,040-gallon below-grade pit sump liquids tank (BGT-2)	X	X
1	30 kW Turbine (T-1)	X	X
1	65 kW Turbine (T-2)	X	X
1	Fugitive Emissions	X	X
1	Truck Loading of Condensate	X	X

APPENDIX B.1

Site Location Map



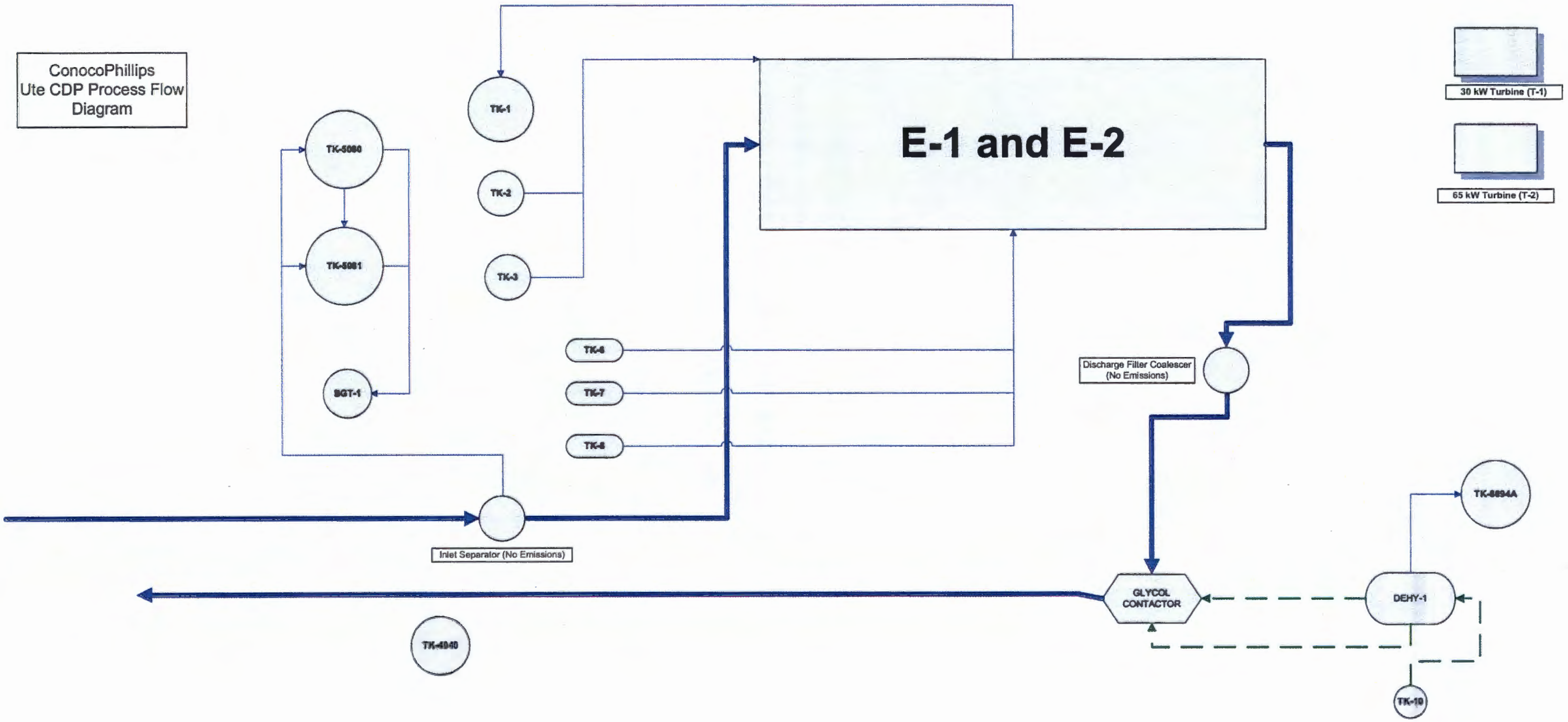
KEY: SOURCE: USGS 7.5 Minute Quadrangle (Topographic)	PROJECT	13704.01		PEI
	PREPARED FOR	CONOCOPHILLIPS		
	LOCATION	37.0173N, 108.0201W		GENERAL VICINITY MAP Ute CDP
	SHEET 1 of 1	DRAWN BY ET	REVIEWED BY TLJ	DATE 4/28/10

(The Ute CDP is on the Southern Ute Reservation.)

APPENDIX B.2

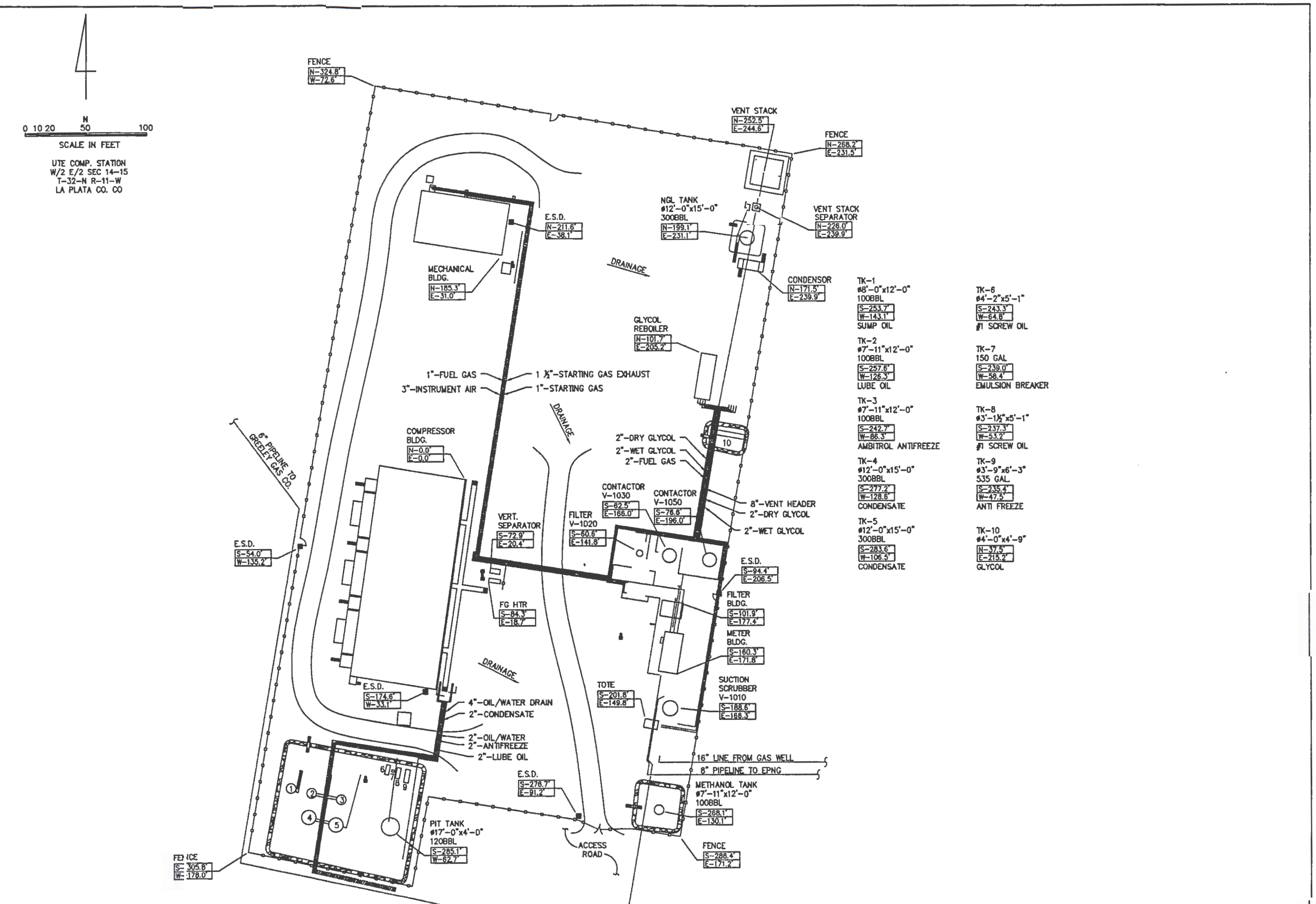
Process Flow Diagram

ConocoPhillips
Ute CDP Process Flow
Diagram



APPENDIX B.3

Site Plot Plan



NOTE:
ALL PIPING SHOWN IS UNDERGROUND
AND POSITIONS ARE APPROXIMATE.

FORM: DSIZEPD

REFERENCE DWG NO/SHT NO.	REV	DATE	REVISIONS	BY	CHK	JOB ENGR	PROJ ENGR	CUST APP
X								
	2	2/12	AS-BUILT REVISIONS	WCB	WCB			
	1	07/11	AS BUILT	RWW	RWW			

ORIGINATOR:
ORIGINATOR DWG NO:
SCALE: AS SHOWN
DATE: 07/11

ConocoPhillips
San Juan Business Unit

DRAWN: RWW
DESIGN:
CHECKED: WCB
APPROVAL:

SJBU UTE CDP
(UTE GATHERING SYSTEM)
PLOT PLAN

DRAWING NO. PLO-UTEG-2702
SHEET 001 OF 001
REV. 2

ConocoPhillips Company - San Juan Basin

Ute CDP

Potential Facility Emissions

Unit ID	E-1	E-2	DEHY-1	TK-5080	TK-5081	TK-8094A	Insignificant Emission Units[3]	Total by Pollutant
Description	Waukesha L5790GL	Waukesha L7042GL	Dehydrator[1]	Condensate Tank[2]	Condensate Tank[2]	Condensate Tank[2]	-	
Rated Capacity (horsepower)	1,215	1,478	-	-	-	-	-	
Rated Capacity (MMBtu/hr)	-	-	0.100	-	-	-	-	
Hourly Emission Rate								
NO_x	7.47	5.45	0.01	-	-	-	0.04	**12.98**
CO	9.96	2.73	0.009	-	-	-	0.35	**13.05**
VOC[4]	2.49	3.03	1.45	1.58	1.58	0.12	0.36	**10.60**
SO_2	0.12	0.15	0.002	-	-	-	0.18	**0.45**
PM/PM_{10}	0.08	0.10	0.001	-	-	-	0.01	**0.19**
Formaldehyde	0.72	0.22	-	-	-	-	-	**0.94**
Acetaldehyde	0.07	0.08	-	-	-	-	-	**0.16**
Acrolein	0.04	0.05	-	-	-	-	-	**0.09**
Hexane	-	-	0.01	0.06	0.06	0.004	-	**0.14**
Benzene	0.004	0.004	0.12	0.02	0.02	0.001	-	**0.16**
Toluene	-	-	0.38	0.03	0.03	0.002	-	**0.43**
Ethylbenzene	-	-	0.032	0.001	0.001	0.000	-	**0.034**
Xylene	-	-	0.22	0.01	0.01	0.001	-	**0.24**
Annual PTE								
NO_x	32.73	23.89	0.05	-	-	-	0.27	**56.94**
CO	43.64	11.95	0.04	-	-	-	1.61	**57.24**
VOC	10.91	13.27	6.36	6.90	6.90	0.52	2.11	**46.98**
SO_2	0.54	0.65	0.007	-	-	-	0.79	**1.99**
PM/PM_{10}	0.36	0.43	0.004	-	-	-	0.05	**0.84**
Formaldehyde	3.16	0.96	-	-	-	-	-	**4.13**
Acetaldehyde	0.31	0.37	-	-	-	-	-	**0.68**
Acrolein	0.19	0.22	-	-	-	-	-	**0.41**
n-Hexane	-	-	0.06	0.26	0.26	0.02	-	**0.59**
Benzene	0.02	0.02	0.51	0.07	0.07	0.005	-	**0.69**
Toluene	-	-	1.65	0.11	0.11	0.008	-	**1.88**
Ethylbenzene	-	-	0.14	0.005	0.005	0.000	-	**0.15**
Xylene	-	-	0.94	0.04	0.04	0.003	-	**1.04**

Notes:

[1] The dehydrator includes VOC/HAP emissions from the still vent and the reboiler. Reboiler criteria pollutant emissions, except SO2, are based on AP-42, Ch. 1.4, Natural Gas Combustion. SO2 emissions are based on a sulfur content of 50 gr/Mscf. 40 CFR 63, Subpart HH requires the use of controls to minimize VOC/HAP emissions.

[2] Emissions from condensate tanks TK-5080 and TK-5081 were estimated using E&P Tank and an annual throughput of 5,000 barrels. Total emissions were split equally between the 2 tanks and include working, breathing, and flashing losses. Emissions from TK-8094A were estimated using Tanks 4.09d since there are no flashing emissions.

[3] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutants. IA include 2 combustion turbines, 2 auxiliary heaters, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks. Details of these emissions are included in the applicable Appendix to the application.

[4] Startup, shutdown, and maintenance emissions will not exceed any hourly or annual limits established in the permit.

APPENDIX C

Emissions Calculations

ConocoPhillips Company - San Juan Basin

Ute CDP

2011 Actual Emissions

Unit ID				DEHY-1	TK-1	TK-2	Insignificant Emission Units[3]	Total by Pollutant
Description	Waukesha L5108GL A	Waukesha L5108GL B	Waukesha L7042GL	Dehydrator[1]	Condensate Tank[2]	Condensate Tank[2]	-	
Rated Capacity (horsepower)	1,072	1,072	1,478	-	-	-	-	
Rated Capacity (MMBtu/hr)	-	-	-	0.125	-	-	-	
Hourly Emission Rate								
NO_x	3.30	3.30	5.45	0.01	-	-	0.04	**12.10**
CO	5.82	5.82	2.73	0.01	-	-	0.35	**14.73**
VOC[4]	2.20	2.20	3.03	14.17	1.58	1.58	0.36	**25.10**
SO_2	0.13	0.13	0.15	0.002	-	-	0.18	**0.60**
PM/PM_{10}	0.09	0.09	0.10	0.001	-	-	0.01	**0.29**
Formaldehyde	0.64	0.64	0.22	-	-	-	-	**1.49**
Acetaldehyde	0.08	0.08	0.08	-	-	-	-	**0.24**
Acrolein	0.05	0.05	0.05	-	-	-	-	**0.14**
Hexane	-	-	-	0.08	0.06	0.06	-	**0.20**
Benzene	0.004	0.004	0.004	1.20	0.02	0.02	-	**1.24**
Toluene	-	-	-	3.92	0.03	0.03	-	**3.97**
Ethylbenzene	-	-	-	0.33	0.001	0.001	-	**0.33**
Xylene	-	-	-	3.48	0.01	0.01	-	**3.50**
Annual Emissions (tpy)								
NO_x	12.03	14.44	4.78	0.05	-	-	0.27	**31.57**
CO	21.26	25.51	2.39	0.04	-	-	1.61	**50.81**
VOC	8.02	9.63	2.65	62.05	6.90	6.90	2.11	**98.26**
SO_2	0.48	0.58	0.13	0.007	-	-	0.79	**1.99**
PM/PM_{10}	0.32	0.38	0.09	0.004	-	-	0.05	**0.84**
Formaldehyde	2.33	2.79	0.19	-	-	-	-	**5.31**
Acetaldehyde	0.28	0.33	0.07	-	-	-	-	**0.68**
Acrolein	0.17	0.20	0.04	-	-	-	-	**0.41**
n-Hexane	-	-	-	0.34	0.26	0.26	-	**0.85**
Benzene	0.01	0.02	0.004	5.24	0.07	0.07	-	**5.42**
Toluene	-	-	-	17.15	0.11	0.11	-	**17.37**
Ethylbenzene	-	-	-	1.46	0.005	0.005	-	**1.47**
Xylene	-	-	-	15.25	0.04	0.04	-	**15.34**

Notes:

[1] The dehydrator includes VOC/HAP emissions from the still vent and the reboiler. Reboiler criteria pollutant emissions, except SO2, are based on AP-42, Ch. 1.4, Natural Gas Combustion. SO2 emissions are based on a sulfur c of 50 gr/Mscf. The condenser was assumed to be operational on October 1, with uncontrolled emissions prior to that date.

[2] Emissions from condensate tanks were estimated using E&P Tank and an annual throughput of 5,000 barrels. Total emissions were split equally between the 2 tanks and include working, breathing, and flashing losses. Potential throughput was assumed to be actual throughput for purposes of the application.

[3] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutants. IA include 2 combustion turbines, 2 auxiliary heaters, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks. Details of these emissions are included in the applicable Appendix to the application.

[4] Startup, shutdown, and maintenance emissions will not exceed any hourly or annual limits established in the permit.

ConocoPhillips Company - San Juan Basin

Ute CDP

2011 Actual Waukesha L5108GL Emissions

Source Description	Waukesha 5108GL (Serial # 399990)	
Type	Turbocharged 4SLB engine	
Rated Output	1,072	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	997	hp
Fuel Use Rate	8850	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.82	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	9.29	Mscf/hr, site derated
Annual Fuel Consumption	67.8	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	7300	hrs/year

No longer

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	°F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency (%)	Emission Rate Uncontrolled (lb/hr)	Emission Rate Uncontrolled (tpy)	Emission Rate Controlled (lb/hr)	Emission Rate Controlled (tpy)	Notes
Criteria Pollutants	NO_x	1.50	g/hp-hr		3.30	12.03	3.30	12.03	1
	CO	2.65	g/hp-hr		5.82	21.26	5.82	21.26	1
	VOC	1.00	g/hp-hr		2.20	8.02	2.20	8.02	1
	SO_2	14.29	lb/MMscf		0.13	0.48	0.13	0.48	2
	PM_{10}	9.91E-03	lb/MMBtu		0.09	0.32	0.09	0.32	3
HAP	Formaldehyde	0.29	g/hp-hr		0.64	2.33	0.64	2.33	1
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.28	0.08	0.28	3
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.17	0.05	0.17	3
	Benzene	4.40E-04	lb/MMBtu		0.004	0.01	0.004	0.01	3

[1] Manufacturer engine specification

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

2011 ~~Actual~~ Potential Waukesha L5108GL Emissions

Source Description	Waukesha 5108GL (Serial # 240747)	
Type	Turbocharged 4SLB engine	
Rated Output	1,072	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	997	hp
Fuel Use Rate	8850	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.82	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	9.29	Mscf/hr, site derated
Annual Fuel Consumption	81.4	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	8760	hrs/year

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	°F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency (%)	Emission Rate Uncontrolled (lb/hr)	Uncontrolled (tpy)	Controlled (lb/hr)	Controlled (tpy)	Notes
Criteria Pollutants	NO_x	1.50	g/hp-hr		3.30	14.44	3.30	14.44	1
	CO	2.65	g/hp-hr		5.82	25.51	5.82	25.51	1
	VOC	1.00	g/hp-hr		2.20	9.63	2.20	9.63	1
	SO_2	14.29	lb/MMscf		0.13	0.58	0.13	0.58	2
	PM_{10}	9.91E-03	lb/MMBtu		0.09	0.38	0.09	0.38	3
HAP	Formaldehyde	0.29	g/hp-hr		0.64	2.79	0.64	2.79	1
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.33	0.08	0.33	3
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.20	0.05	0.20	3
	Benzene	4.40E-04	lb/MMBtu		0.004	0.02	0.004	0.02	3

[1] Manufacturer engine specification

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

2011 Actual Waukesha L5790GL Emissions

Source Description	Waukesha L5790GL	
Type	Turbocharged 4SLB engine	
Rated Output	1,215	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	1,130	hp
Fuel Use Rate	7305	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.25	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	8.69	Mscf/hr, site derated
Annual Fuel Consumption	0.0	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	0	hrs/year - Did not being operation until 2012.

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	°F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency (%)	Emission Rate Uncontrolled (lb/hr)	Uncontrolled (tpy)	Controlled (lb/hr)	Controlled (tpy)	Notes
Criteria Pollutants	NO_x	3.00	g/hp-hr		0.00	0.00	0.00	0.00	1
	CO	4.00	g/hp-hr		0.00	0.00	0.00	0.00	1
	VOC	1.00	g/hp-hr		0.00	0.00	0.00	0.00	1
	SO_2	14.29	lb/MMscf		0.00	0.00	0.00	0.00	2
	PM_{10}	9.91E-03	lb/MMBtu		0.00	0.00	0.00	0.00	3
HAP	Formaldehyde	0.29	g/hp-hr		0.00	0.00	0.00	0.00	4
	Acetaldehyde	8.60E-03	lb/MMBtu		0.00	0.00	0.00	0.00	3
	Acrolein	5.14E-03	lb/MMBtu		0.00	0.00	0.00	0.00	3
	Benzene	4.40E-04	lb/MMBtu		0.00	0.00	0.00	0.00	3

[1] Based on NSPS Subpart JJJJ

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

[4] Based on manufacturer's data, See Appendix D

ConocoPhillips Company - San Juan Basin

Ute CDP

Waukesha L5790GL Emissions - Potential

Emission Unit Designation	E-1	
Source Description	Waukesha L5790GL	
Type	Turbocharged 4SLB engine	
Rated Output	1,215	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	1,130	hp
Fuel Use Rate	7305	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.25	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	8.7	Mscf/hr, site derated
Annual Fuel Consumption	76.1	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	8760	hrs/year

Stack Height	25	ft
Exhaust Gas Velocity	119.4	ft/sec
Exhaust Temp	900	°F, estimated
Stack Inside Diameter	0.67	ft
Exhaust Gas Flow	2500	cfm, estimated based on E-2 flow

	Pollutant	Emission Factor		Control Efficiency (%)	Emission Rate Uncontrolled (lb/hr)	Uncontrolled (tpy)	Controlled (lb/hr)	Controlled (tpy)	Notes
Criteria Pollutants	NO_x	3.00	g/hp-hr		7.47	32.73	7.47	32.73	1
	CO	4.00	g/hp-hr		9.96	43.64	9.96	43.64	1
	VOC	1.00	g/hp-hr		2.49	10.91	2.49	10.91	1
	SO_2	14.29	lb/MMscf		0.12	0.54	0.12	0.54	2
	PM_{10}	9.91E-03	lb/MMBtu		0.08	0.36	0.08	0.36	3
HAP	Formaldehyde	0.29	g/hp-hr		0.72	3.16	0.72	3.16	4
	Acetaldehyde	8.60E-03	lb/MMBtu		0.07	0.31	0.07	0.31	3
	Acrolein	5.14E-03	lb/MMBtu		0.04	0.19	0.04	0.19	3
	Benzene	4.40E-04	lb/MMBtu		0.004	0.02	0.004	0.02	3

[1] Based on 40 CFR 60, Subpart JJJJ

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

[4] Based on manufacturer's data, See Appendix D

ConocoPhillips Company - San Juan Basin

Ute CDP

Waukesha L7042GL Emissions - Potential

Emission Unit Designation	E-2	
Source Description	Waukesha L7042GL	
Type	Turbocharged 4SLB engine with oxidation catalyst	
Rated Output	1,478	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	1,375	hp
Fuel Use Rate	7155	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	9.83	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	10.4	Mscf/hr, site derated
Annual Fuel Consumption	90.7	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	8760	hrs/year

Stack Height	27	ft
Exhaust Gas Velocity	141.7	ft/sec
Exhaust Temp	900	°F, estimated
Stack Inside Diameter	0.67	ft
Exhaust Gas Flow	2967	cfm, obtained from stack test

	Pollutant	Emission Factor		Control Efficiency (%)	Emission Rate Uncontrolled (lb/hr)	Uncontrolled (tpy)	Controlled (lb/hr)	Controlled (tpy)	Notes
Criteria Pollutants	NO_x	1.80	g/hp-hr		5.45	23.89	5.45	23.89	1
	CO	3.60	g/hp-hr	75%	10.91	47.78	2.73	11.95	1,2
	VOC	1.00	g/hp-hr		3.03	13.27	3.03	13.27	1
	SO_2	14.29	lb/MMscf		0.15	0.65	0.15	0.65	3
	PM_{10}	9.91E-03	lb/MMBtu		0.10	0.43	0.10	0.43	4
HAP	Formaldehyde	0.29	g/hp-hr	75%	0.88	3.85	0.22	0.96	1,2
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.37	0.08	0.37	4
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.22	0.05	0.22	4
	Benzene	4.40E-04	lb/MMBtu		0.004	0.02	0.004	0.02	4

[1] Manufacturer engine specifications plus a 20% flexibility factor for NOx and CO; see Appendix D

[2] 75% CO and Formaldehyde Control Efficiency per Consent Agreement; see Appendix D for manufacturer's data

[3] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[4] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

2011 Actual Waukesha L7042GL Emissions

Source Description	Waukesha L7042GL	
Type	Turbocharged 4SLB engine with oxidation catalyst	
Rated Output	1,478	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	1,375	hp
Fuel Use Rate	7155	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	9.83	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	10.35	Mscf/hr, site derated
Annual Fuel Consumption	18.1	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	1752	hrs/year - Assumed continuous operation since October 20, 2011.

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	°F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency (%)	Emission Rate Uncontrolled (lb/hr)	Uncontrolled (tpy)	Controlled (lb/hr)	Controlled (tpy)	Notes
Criteria Pollutants	NO_x	1.80	g/hp-hr		5.45	4.78	5.45	4.78	1
	CO	3.60	g/hp-hr	75%	10.91	9.56	2.73	2.39	1,2
	VOC	1.00	g/hp-hr		3.03	2.65	3.03	2.65	1
	SO_2	14.29	lb/MMscf		0.15	0.13	0.15	0.13	3
	PM_{10}	9.91E-03	lb/MMBtu		0.10	0.09	0.10	0.09	4
HAP	Formaldehyde	0.29	g/hp-hr	75%	0.88	0.77	0.22	0.19	1,2
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.07	0.08	0.07	4
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.04	0.05	0.04	4
	Benzene	4.40E-04	lb/MMBtu		0.004	0.004	0.004	0.00	4

[1] Manufacturer engine specifications plus a 20% flexibility factor for NOx and CO; see Appendix D

[2] 75% CO and Formaldehyde Control Efficiency per specifications; see Appendix D

[3] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[4] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

TEG Dehydrator Still Vent Emissions – Actual

Emission Unit	DEHY-1	
Source Description	Triethylene Glycol Dehydrator Still Vent	
Manufacturer	Pesco	
Glycol Pump	Electric	
Maximum Flowrate	9.2 MMscfd	Average 2011 Gas Flow Rate
Outlet Gas Dewpoint	7 lb H20/MMscf	
Glycol Recirculation Rate	3 gallons glycol/pound water	

Stack Height	22	ft, per site inspection
Exhaust Gas Velocity	5	ft/sec, estimated
Exhaust Gas Flow	14.7	cfm, estimated
Exhaust Temperature	100	°F, estimated
Stack Inside Diameter	0.25	ft, per site inspection
Operating Time	8760	(hrs/year)

Source Description	Glycol Regenerator
Control Device	Condenser

Pollutant		Control Efficiency	Emission Rate				Notes
			Uncontrolled Days		Controlled Days		
		(%)	(lb/day)	(tons)	(lb/day)	(tons)	
VOC			404.21	61.64	13.36	0.40	1,2,3
HAP	n-Hexane		2.16	0.33	0.25	0.008	1,3
HAP	Benzene		34.21	5.22	0.93	0.03	1,3
HAP	Toluene		112.26	17.12	1.03	0.03	1,3
HAP	Ethylbenzene		9.55	1.46	0.03	0.001	1,3
HAP	Xylenes		99.98	15.25	0.25	0.007	1,3
Total HAP			-	39.37	-	0.07	

Notes:

1 GRI GlyCalc v4.0 Calculations (Appendix E) based on extended gas analysis (Appendix I)

2 VOC emissions from the reboiler are shown on the Potential Heater Emissions calculation sheet.

3 Emissions were not controlled for 305 days. The condenser was installed and emissions were controlled for 60 days.

ConocoPhillips Company - San Juan Basin

Ute CDP

30 kW Capstone Turbine Emissions

Unit ID	T-1	Units, Data Source
Description	Capstone Turbine	
Rated Output	30	kW, manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.79	NMED AQB Deration for Turbines
Altitude Derated Output	24	kW, derated to site elevation
Engine Type	Turbine	manufacturer
Fuel Type	NG	manufacturer
Operating hr/yr	8,760	Maximum actual hours
Stack Information		
Stack Height	7.5	ft, for each turbine
Exhaust Gas Velocity	14.6	ft/sec
Exhaust Temp	588	°F, per manufacturer specification sheet
Stack Inside Diameter	0.67	ft
Exhaust Gas Flow	305	cfm, per manufacturer specification sheet
Emission Factor (EF)[1]		
NO_x	0.64	lb/MWhe, per manufacturer's specifications
CO	1.70	lb/MWhe, per manufacturer's specifications
VOC	0.22	lb/MWhe, per manufacturer's specifications
SO_2	50.0	g/mscf pipeline specification
PM/PM_{10}	0.0066	lb/MMBtu, AP-42 Tbl 3.1-2a
Hourly Emission Rate		
NO_x	0.02	lb/hr, calc'd from EF data; derated to site elevation
CO	0.04	lb/hr, calc'd from EF data; derated to site elevation
VOC	0.005	lb/hr, calc'd from EF data; derated to site elevation
SO_2	0.09	lb/hr, calc'd from EF data; derated to site elevation
PM/PM_{10}	0.01	lb/hr, calc'd from EF data; derated to site elevation
Annual PTE		
NO_x	0.07	tpy, calc'd from lb/hr data
CO	0.18	tpy, calc'd from lb/hr data
VOC	0.02	tpy, calc'd from lb/hr data
SO_2	0.39	tpy, calc'd from lb/hr data
PM/PM_{10}	0.02	tpy, calc'd from lb/hr data
Fuel Flowrates		
Fuel Use Rated Capacity	0.77	MMBtu/hr; derated to site elevation
Fuel LHV	950	Btu/scf, estimated
Fuel Use Rate	765,000	Btu/hr, per manufacturer
Fuel Use Rate	805.3	scf/hr
Fuel Use Rate	7.1	MMscf/yr

Notes:

[1] USEPA AP-42 Ch. 3.1, Stationary Gas Turbines

ConocoPhillips Company - San Juan Basin

Ute CDP

Potential TEG Dehydrator Still Vent Emissions

Emission Unit	DEHY-1	
Source Description	Triethylene Glycol Dehydrator Still Vent	
Manufacturer	Pesco	
Glycol Pump	Electric	
Maximum Flowrate	14.4 MMscfd	Maximum flow rate since 1994 multiplied by 1.2
Outlet Gas Dewpoint	7 lb H20/MMscf	
Glycol Recirculation Rate	3 gallons glycol/pound water	

Stack Height	22	ft, per site inspection
Exhaust Gas Velocity	5	ft/sec, estimated
Exhaust Gas Flow	14.7	cfm, estimated
Exhaust Temperature	100	°F, estimated
Stack Inside Diameter	0.25	ft, per site inspection
Operating Time	8760	(hrs/year)

Source Description	Glycol Regenerator
Control Device	Condenser

	Pollutant	Control Efficiency	Emission Rate				Notes
			Uncontrolled		Controlled		
		(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
VOC		95%	29.03	127.16	1.45	6.36	1,2
HAP	n-Hexane	95%	0.25	1.11	0.01	0.06	1,2
HAP	Benzene	95%	2.33	10.21	0.12	0.51	1,2
HAP	Toluene	95%	7.53	33.00	0.38	1.65	1,2
HAP	Ethylbenzene	95%	0.63	2.77	0.03	0.14	1,2
HAP	Xylenes	95%	4.31	18.88	0.22	0.94	1,2
	Total HAP		-	65.97	-	3.30	

Notes:

[1] GRI GlyCalc v4.0 Calculations (Appendix E) based on extended gas analysis (Appendix I). A condenser is used to comply with 40 CFR 63, Subpart HH. 95% control is required by the Consent Agreement.

ConocoPhillips Company - San Juan Basin

Ute CDP

Potential Heater Emissions

← 0.04 mmBtu/hr → 0.12 mmBtu/hr

Unit ID	DEHY-1	H-1	H-2	Units, Data Source
Description	Reboiler	Auxiliary Heater	Auxiliary Heater	
Fuel Type	NG	NG	NG	manufacturer
Operating hr/yr	8,760	8,760	8,760	Maximum actual hours
Stack Information				
Stack Height	22	22	22	ft
Exhaust Gas Velocity	5	5	5	ft/sec, estimated
Exhaust Temp	100	100	100	°F, estimated
Stack Inside Diameter	0.67	0.67	0.67	ft, site inspection
Exhaust Gas Flow	104.7	104.7	104.7	cfm
Emission Factor (EF)[1]				
NO_x	100	100	100	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
CO	84	84	84	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
VOC	5.5	5.5	5.5	lb/MMscf, AP-42 Tbl 1.4-2 (07/98)
SO_2	14.3	14.3	14.3	lb/MMscf (50 grains S/Mscf assumed), AP-42 Tbl 1.4-2 (07/98)
PM/PM_{10}	7.6	7.6	7.6	lb/MMscf [total assumed], AP-42 Tbl 1.4-2 (07/98)
Formaldehyde	0.08	0.08	0.08	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hexane	1.8	1.8	1.8	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hourly Emission Rate in pounds per hour				
NO_x	0.01	0.01	0.01	lb/hr, calc'd from EF data
CO	0.01	0.01	0.01	lb/hr, calc'd from EF data
VOC	0.001	0.001	0.001	lb/hr, calc'd from EF data
SO_2[2]	0.002	0.002	0.002	lb/hr, calc'd from EF data
PM/PM_{10}	0.001	0.001	0.001	lb/hr, calc'd from EF data
Formaldehyde	0.000	0.000	0.000	lb/hr, calc'd from EF data
Hexane	0.000	0.000	0.000	lb/hr, calc'd from EF data
Annual Potential To Emit (PTE) in tons per year				
NO_x	0.06	0.06	0.05	tpy, calc'd from lb/hr data
CO	0.05	0.05	0.04	tpy, calc'd from lb/hr data
VOC	0.003	0.003	0.003	tpy, calc'd from lb/hr data
SO_2	0.008	0.008	0.007	tpy, calc'd from lb/hr data
PM/PM_{10}	0.004	0.004	0.004	tpy, calc'd from lb/hr data
Formaldehyde	0.000	0.000	0.000	tpy, calc'd from lb/hr data
Hexane	0.001	0.001	0.001	tpy, calc'd from lb/hr data
Fuel Flowrates				
Rated Input Capacity	0.125	0.125	0.100	MMBtu/hr, per manufacturer
Fuel LHV	950	950	950	Btu/scf, estimated
Fuel Use Rate	131.6	131.6	105.3	scfh @ 950 Btu/scf (LHV)
Fuel Use Rate	1.2	1.2	0.9	MMscf/yr @ 950 Btu/scf (LHV)

Notes:

[1] USEPA AP-42 Ch. 1.4 Natural Gas Combustion

[2] Fuel Sulfur Content (gr/Mscf) * (lb/7000 gr) * (1000 Mscf/MMscf) * (64 lb/lb-mol SO_2/32 lb/lb-mol S)

ConocoPhillips Company - San Juan Basin

Ute CDP

65 kW Capstone Turbine Emissions

Unit ID	**T-2**	**Units, Data Source**
Description	Capstone Turbine	
Rated Output	65	kW, manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.79	NMED AQB Deration for Turbines
Altitude Derated Output	51	kW, derated to site elevation
Engine Type	Turbine	manufacturer
Fuel Type	NG	manufacturer
Operating hr/yr	8,760	Maximum actual hours
Stack Information		
Stack Height	7.5	ft, for each turbine
Exhaust Gas Velocity	14.6	ft/sec
Exhaust Temp	588	^{o}F, per manufacturer specification sheet
Stack Inside Diameter	0.67	ft
Exhaust Gas Flow	305	cfm, per manufacturer specification sheet
Emission Factor (EF)[1]		
NO_x	0.46	lb/MWhe, per manufacturer's specifications
CO	6.00	lb/MWhe, per manufacturer's specifications
VOC	0.10	lb/MWhe, per manufacturer's specifications
SO_2	50.0	g/mscf pipeline specification
PM/PM_{10}	0.0066	lb/MMBtu, AP-42 Tbl 3.1-2a
Hourly Emission Rate		
NO_x	0.02	lb/hr, calc'd from EF data; derated to site elevation
CO	0.31	lb/hr, calc'd from EF data; derated to site elevation
VOC	0.005	lb/hr, calc'd from EF data; derated to site elevation
SO_2	0.09	lb/hr, calc'd from EF data; derated to site elevation
PM/PM_{10}	0.01	lb/hr, calc'd from EF data; derated to site elevation
Annual PTE		
NO_x	0.10	tpy, calc'd from lb/hr data
CO	1.35	tpy, calc'd from lb/hr data
VOC	0.02	tpy, calc'd from lb/hr data
SO_2	0.39	tpy, calc'd from lb/hr data
PM/PM_{10}	0.02	tpy, calc'd from lb/hr data
Fuel Flowrates		
Fuel Use Rated Capacity	0.77	MMBtu/hr; derated to site elevation
Fuel LHV	950	Btu/scf, estimated
Fuel Use Rate	765,000	Btu/hr, per manufacturer
Fuel Use Rate	805.3	scf/hr
Fuel Use Rate	7.1	MMscf/yr

Notes:

[1] USEPA AP-42 Ch. 3.1, Stationary Gas Turbines

ConocoPhillips Company - San Juan Basin

Ute CDP

2011 Actual Heater Emissions

Unit ID	DEHY-1	H-1	H-2	Units, Data Source
Description	Reboiler	Auxiliary Heater	Auxiliary Heater	
Fuel Type	NG	NG	NG	manufacturer
Operating hr/yr	8,760	8,760	8,760	Maximum actual hours
Stack Information				
Stack Height	22	22	22	ft
Exhaust Gas Velocity	5	5	5	ft/sec, estimated
Exhaust Temp	100	100	100	°F, estimated
Stack Inside Diameter	0.67	0.67	0.67	ft, site inspection
Exhaust Gas Flow	104.7	104.7	104.7	cfm
Emission Factor (EF)[1]				
NO_x	100	100	100	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
CO	84	84	84	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
VOC	5.5	5.5	5.5	lb/MMscf, AP-42 Tbl 1.4-2 (07/98)
SO_2	14.3	14.3	14.3	lb/MMscf (50 grains S/Mscf assumed), AP-42 Tbl 1.4-2 (07/98)
PM/PM_{10}	7.6	7.6	7.6	lb/MMscf [total assumed], AP-42 Tbl 1.4-2 (07/98)
Formaldehyde	0.08	0.08	0.08	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hexane	1.8	1.8	1.8	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hourly Emission Rate in pounds per hour				
NO_x	0.01	0.01	0.01	lb/hr, calc'd from EF data
CO	0.01	0.01	0.01	lb/hr, calc'd from EF data
VOC	0.001	0.001	0.001	lb/hr, calc'd from EF data
SO_2[2]	0.002	0.002	0.002	lb/hr, calc'd from EF data
PM/PM_{10}	0.001	0.001	0.001	lb/hr, calc'd from EF data
Formaldehyde	0.000	0.000	0.000	lb/hr, calc'd from EF data
Hexane	0.000	0.000	0.000	lb/hr, calc'd from EF data
Annual Emission Rate in tons per year				
NO_x	0.06	0.06	0.05	tpy, calc'd from lb/hr data
CO	0.05	0.05	0.04	tpy, calc'd from lb/hr data
VOC	0.003	0.003	0.003	tpy, calc'd from lb/hr data
SO_2	0.008	0.008	0.007	tpy, calc'd from lb/hr data
PM/PM_{10}	0.004	0.004	0.004	tpy, calc'd from lb/hr data
Formaldehyde	0.000	0.000	0.000	tpy, calc'd from lb/hr data
Hexane	0.001	0.001	0.001	tpy, calc'd from lb/hr data
Fuel Flowrates				
Rated Input Capacity	0.125	0.125	0.100	MMBtu/hr, per manufacturer
Fuel LHV	950	950	950	Btu/scf, estimated
Fuel Use Rate	131.6	131.6	105.3	scfh @ 950 Btu/scf (LHV)
Fuel Use Rate	1.2	1.2	0.9	MMscf/yr @ 950 Btu/scf (LHV)

Notes:

[1] USEPA AP-42 Ch. 1.4 Natural Gas Combustion

[2] Fuel Sulfur Content (gr/Mscf) * (lb/7000 gr) * (1000 Mscf/MMscf) * (64 lb/lb-mol SO_2/32 lb/lb-mol S)

ConocoPhillips Company - San Juan Basin

Ute CDP

Summary of Potential Emissions for Insignificant Activities

Unit ID	Turbine 1	Turbine 2	Truck Loading of Condensate	Fugitive Emissions	Miscellaneous Storage Tanks	Auxiliary Heaters	Total by Pollutant
Description	Capstone 30 kW	Capstone 65 kW	-	-	-	-	
Hourly Emission Rate							
NO_x	0.02	0.02	-	-	-	0.02	**0.04**
CO	0.04	0.31	-	-	-	0.02	**0.35**
VOC	0.01	0.01	-	0.19	0.15	0.001	**0.36**
SO_2	0.09	0.09	-	-	-	0.003	**0.18**
PM/PM_{10}	0.01	0.01	-	-	-	0.002	**0.01**
Annual PTE							
NO_x	0.07	0.10	-	-	-	0.10	**0.27**
CO	0.18	1.35	-	-	-	0.09	**1.61**
VOC	0.02	0.02	0.55	0.85	0.66	0.006	**2.11**
SO_2	0.39	0.39	-	-	-	0.01	**0.79**
PM/PM_{10}	0.02	0.02	-	-	-	0.008	**0.05**

Notes:

[1] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutant IA include 2 combustion turbines, 2 auxiliary heaters, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks.

ConocoPhillips Company - San Juan Basin

Ute CDP

Potential Condensate/Oil Truck Loading Emissions

Condensate/Oil Throughput for 3 Tanks = 336,000 gallons

Condensate/Oil Loading Emissions

L_L = 12.46 (SPM/T)

where L_L = loading loss, lb/10^3gal loaded

S = saturation factor

P = true vapor pressure

M = molecular weight of vapors (lb/lb-mole)

T = temperature (ºR)

S (Saturation Factor) = 0.6 per AP-42

P (Pressure) = 4.97 using an RVP of 9.85 at 65º

M (Vapor molecular weight, lb/lb-mole) = 46.75 per E&P Output

T (Vapor temperature) = 530 per Tanks Output

L_L = 12.46 * (0.6*4.97*46.75/530)

= 3.277 lbs/1,000 gallons

= 1101.21 lbs/year

= 0.55 tons/year

NOTES:

1) Unless otherwise noted, equation is taken from U.S. EPA document AP-42, "Compilation of Air Pollutant Emission Factors Volume I: Stationary and Area Sources, Section 5.2," Office of Air Quality Planning and Standards, Research Triangle Park, NC.

ConocoPhillips Company - San Juan Basin

Ute CDP

Summary of Potential Emissions for Insignificant Activities

Unit ID	Turbine 1	Turbine 2	Truck Loading of Condensate	Fugitive Emissions	Miscellaneous Storage Tanks	Auxiliary Heaters	Total by Pollutant
Description	Capstone 30 kW	Capstone 65 kW	-	-	-	-	
Hourly Emission Rate							
NO_x	0.02	0.02	-	-	-	0.02	**0.04**
CO	0.04	0.31	-	-	-	0.02	**0.35**
VOC	0.01	0.01	-	0.19	0.15	0.001	**0.36**
SO_2	0.09	0.09	-	-	-	0.003	**0.18**
PM/PM_{10}	0.01	0.01	-	-	-	0.002	**0.01**
Annual PTE							
NO_x	0.07	0.10	-	-	-	0.10	**0.27**
CO	0.18	1.35	-	-	-	0.09	**1.61**
VOC	0.02	0.02	0.55	0.85	0.66	0.006	**2.11**
SO_2	0.39	0.39	-	-	-	0.01	**0.79**
PM/PM_{10}	0.02	0.02	-	-	-	0.008	**0.05**

Notes:

[1] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutants. IA include 2 combustion turbines, 2 auxiliary heaters, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks.

APPENDIX D

Manufacturer's Emissions Data

POWER RATINGS: L7042GL VHP SERIES GAS ENGINES

Model	I.C. Water Inlet Temp. °F (°C) (Tcra)	C.R.	Brake Horsepower (kWb Output) 800 rpm	900 rpm	1000 rpm	1100 rpm	1200 rpm
High Speed Turbo[1]	85° (29°)	10.5:1	928 (692)	1160 (865)	1289 (961)	1418 (1057)	1547 (1154)
High Speed Turbo[1]	130° (54°)	10.5:1	886 (661)	1108 (826)	1232 (919)	1355 (1010)	1478 (1102)
Low Speed Turbo[2]	85° (29°)	10.5:1	1031 (769)	1160 (865)	1289 (961)	— —	— —
Low Speed Turbo[2]	130° (54°)	10.5:1	985 (735)	1108 (826)	1232 (919)	— —	— —

[1]High speed turbocharger match – 1001-1200 rpm

[2]Low speed turbocharger match – 700-1000 rpm

Rating Standard: All models: Ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and auxiliary water temperature Tcra (clause 10.1) as specified above limited to ± 10° F (± 5° C). Ratings are also valid for SAE J1349, BS5514, DIN6271 and AP17B-11C standard atmospheric conditions.

ISO Standard Power/Continuous Power Rating: The highest load and speed which can be applied 24 hours a day, seven days a week, 365 days per year except for normal maintenance. It is permissible to operate the engine at up to 10% overload, or maximum load indicated by the intermittent rating, whichever is lower, for two hours in each 24 hour period.

All natural gas engine ratings are based on a fuel of 900 Btu/ft³ (35.3 MJ/nm³) SLHV value, with a 91 Waukesha Knock Index®.

For conditions or fuels other than standard, the Waukesha Engine Sales Engineering Department.

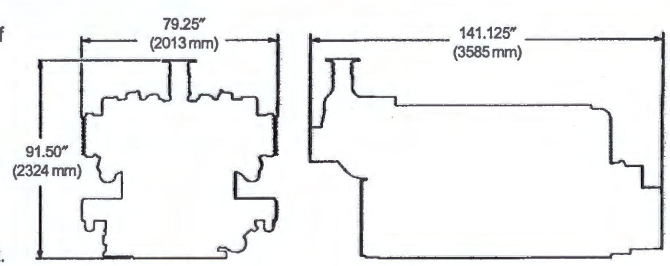
PERFORMANCE: L7042GL VHP SERIES GAS ENGINES

	English	130° F ICW		85° F ICW	
	RPM	1200	1000	1200	1000
	Power (Bhp)	1478	1232	1547	1289
Low NO_x Settings	BSFC (Btu/bhp-hr)	7155	6815	7180	6840
Low NO_x Settings	NOx (grams/bhp-hr)	0.90	0.90	0.70	0.70
Low NO_x Settings	CO (grams/bhp-hr)	2.75	2.65	2.65	2.55
Low NO_x Settings	NMHC (grams/bhp--hr)	1.00	1.00	1.10	1.10
Low Fuel Consumption Settings	BSFC (Btu/bhp-hr)	6910	6615	6935	6640
Low Fuel Consumption Settings	NOx (grams/bhp-hr)	1.50	1.60	1.30	1.40
Low Fuel Consumption Settings	CO (grams/bhp-hr)	3.00	2.75	2.90	2.65
Low Fuel Consumption Settings	NMHC (grams/bhp--hr)	0.70	1.00	0.80	1.10

	Metric	54° C ICW		29° C ICW	
	RPM	1200	1000	1200	1000
	Power (kWb)	1103	919	1154	962
Low NO_x Settings	BSFC (kJ/kW-hr)	10124	9643	10160	9679
Low NO_x Settings	NOx (g/nm³)	0.37	0.37	0.29	0.29
Low NO_x Settings	CO (g/nm³)	1.14	1.10	1.10	1.05
Low NO_x Settings	NMHC (g/nm³)	0.41	0.41	0.45	0.45
Low Fuel Consumption Settings	BSFC (kJ/kW-hr)	9778	9360	9813	9396
Low Fuel Consumption Settings	NOx (g/nm³)	0.62	0.66	0.54	0.58
Low Fuel Consumption Settings	CO (g/nm³)	1.24	1.14	1.20	1.10
Low Fuel Consumption Settings	NMHC (g/nm³)	0.29	0.41	0.33	0.45

NOTES:

1) Performance ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and Tcra limited to ± 10° F.
2) Fuel consumptions based on ISO 3046/1-1995 with a +5% tolerance for commercial quality natural gas having a 900 Btu/ft³ saturated low heat value.
3) Data based on standard conditions of 77° F (25° C) ambient temperature, 29.53 inches Hg (100kPa) barometric pressure, 30% relative humidity (0.3 inches Hg / 1 kPa water vapor pressure).
4) Data will vary due to variations in site conditions. For conditions and/or fuels other than standard, consult the Waukesha Engine Sales Engineering Department.



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Bulletin 7005 0102

POWER RATINGS: L5790GL VHP SERIES GAS ENGINES

Model	I.C. Water Inlet Temp. °F (°C) (Tcra)	C.R.	Brake Horsepower (kWb Output) 800 rpm	900 rpm	1000 rpm	1100 rpm	1200 rpm
High Speed Turbo[1]	85° (29°)	10:1	795 (593)	954 (711)	1060 (790)	1166 (869)	1272 (949)
High Speed Turbo[1]	130° (54°)	10:1	762 (568)	911 (679)	1013 (755)	1114 (831)	1215 (906)
Low Speed Turbo[2]	85° (29°)	10:1	848 (632)	954 (711)	1060 (790)	— —	— —
Low Speed Turbo[2]	130° (54°)	10:1	810 (604)	911 (679)	1013 (755)	— —	— —

[1]High speed turbocharger match – 1001-1200 rpm

[2]Low speed turbocharger match – 700-1000 rpm

Rating Standard: All models: Ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and auxiliary water temperature Tcra (clause 10.1) as specified above limited to ± 10° F (± 5° C). Ratings are also valid for SAE J1349, BS5514, DIN6271 and AP17B-11C standard atmospheric conditions.

ISO Standard Power/Continuous Power Rating: The highest load and speed which can be applied 24 hours a day, seven days a week, 365 days per year except for normal maintenance. It is permissible to operate the engine at up to 10% overload, or maximum load indicated by the intermittent rating, whichever is lower, for two hours in each 24 hour period.

All natural gas engine ratings are based on a fuel of 900 Btu/ft³ (35.3 MJ/nm³) SLHV value, with a 91 Waukesha Knock Index®.

For conditions or fuels other than standard, the Waukesha Engine Sales Engineering Department.

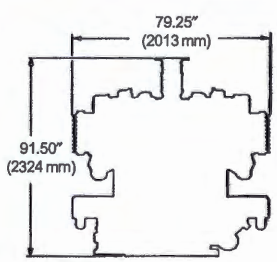
PERFORMANCE: L5790GL VHP SERIES GAS ENGINES

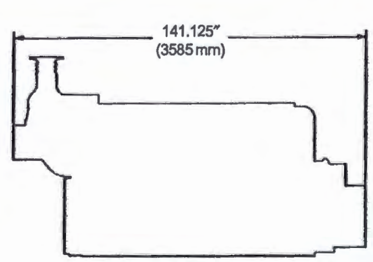
	English	130° F ICW		85° F ICW	
Low NO_x Settings	RPM	1200	1000	1200	1000
	Power (Bhp)	1215	1013	1272	1060
	BSFC (Btu/bhp-hr)	7305	7085	7330	7105
	NOx (grams/bhp-hr)	0.90	0.90	0.75	0.75
	CO (grams/bhp-hr)	2.75	2.70	2.65	2.60
	NMHC (grams/bhp–hr)	0.90	0.90	0.90	0.90
Low Fuel Consumption Settings	BSFC (Btu/bhp-hr)	7010	6815	7010	6790
	NOx (grams/bhp-hr)	2.15	2.35	2.00	2.20
	CO (grams/bhp-hr)	3.05	3.00	2.95	2.90
	NMHC (grams/bhp–hr)	0.80	0.80	0.80	0.80

	Metric	54° C ICW		29° C ICW	
Low NO_x Settings	RPM	1200	1000	1200	1000
	Power (kWb)	906	756	949	791
	BSFC (kJ/kW-hr)	10337	10025	10372	10054
	NOx (g/nm³)	0.37	0.37	0.31	0.31
	CO (g/nm³)	1.14	1.12	1.10	1.07
	NMHC (g/nm³)	0.37	0.37	0.37	0.37
Low Fuel Consumption Settings	BSFC (kJ/kW-hr)	9919	9643	9919	9608
	NOx (g/nm³)	0.89	0.97	0.83	0.91
	CO (g/nm³)	1.26	1.24	1.22	1.20
	NMHC (g/nm³)	0.33	0.33	0.33	0.33

NOTES:

1) Performance ratings are based on ISO 3046/1-1995 with mechanical efficiency of 90% and Tcra limited to ± 10° F.
2) Fuel consumptions based on ISO 3046/1-1995 with a +5% tolerance for commercial quality natural gas having a 900 Btu/ft³ saturated low heat value.
3) Data based on standard conditions of 77° F (25° C) ambient temperature, 29.53 inches Hg (100kPa) barometric pressure, 30% relative humidity (0.3 inches Hg / 1 kPa water vapor pressure).
4) Data will vary due to variations in site conditions. For conditions and/or fuels other than standard, consult the Waukesha Engine Sales Engineering Department.





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Bulletin 7004 0102

Consult your local Waukesha Distributor for system application assistance. The manufacturer reserves the right to change or modify without notice, the design or equipment specifications as herein set forth without incurring any obligation either with respect to equipment previously sold or in the process of construction except where otherwise specifically guaranteed by the manufacturer.

FORMALDEHYDE EMISSION LEVELS

The following table provides formaldehyde (CH_2O) levels that are valid for new engines for the duration of the standard warranty period and are attainable by an engine in good operating condition running on commercial quality natural gas of 900 BTU/ft^3 (35.38 MJ/m^3 [25, V(0; 101.325)]) SLHV, Waukesha Knock Index® of 91 or higher, 93% methane content by volume, and at ISO standard conditions. Values are based on standard engine timing at 91 WKI® with an absolute humidity of 42 grains/lb. Refer to engine specific WKI® Power & Timing curves for standard timing. Unless otherwise noted, these emission levels can be achieved across the continuous duty speed range at the load levels tabulated. ***Contact the local Waukesha representative or Waukesha's Sales Application Engineering Department for emission values which can be obtained on a case-by-case basis for specific ratings, fuels, and site conditions.***

MODEL	CARB. SETTING	CH_2O GRAMS/ BHP-HR PERCENT LOAD 100%	75%	% OBSERVED DRY CO	O_2	MASS AFR(2)	VOLUME AFR(2)	EXCESS AIR RATIO
275GL/AT27GL	Lean Burn	0.18	0.20	0.06	9.8	28.0:1	16.8:1	1.74
	Ultra Lean	0.18	0.20	0.05	11.2	32.0:1	19.2:1	2.00
12V220GL/APG2000 18V220GL/APG3000	Ultra Lean	0.23	0.29	0.09 – 0.15	12.3 – 13.4	32.1 – 35.3	19.3 – 21.2	2.03 – 2.20
16V150LTD/APG1000	Lean Burn	0.14	0.15	0.07	9.5 – 9.6	26.9 – 27.2	16.2 – 16.4	1.68 – 1.7
VHP G, GSI	Rich Burn	0.05	0.05	0.02 – 1.15	0.30 – 1.35	15.5:1 – 17.0:1	9.3:1 – 10.2:1	0.97 – 1.06
VHP Series 4 GSI	Rich Burn	0.05	0.05	0.02 – 0.45	0.30 – 1.35	15.85:1 – 17.0:1	9.5:1 – 10.2:1	0.99 – 1.06
L5774LT L5794LT	Lean Burn	0.22	0.25	0.04	7.8 – 8.0	24.5:1 – 24.7:1	14.7:1 – 14.8:1	1.52 – 1.54
VHP GL	Lean Burn	0.29	0.34	0.06	9.8	28.0:1	16.8:1	1.74
VGF G, GSID	Rich Burn	0.05	0.05	0.20 – 1.1	0.18 – 2.4	15.5:1 – 18.0:1	9.3:1 – 10.8:1	0.97 – 1.12
VGF GL, GLD, GLD/2	Lean Burn	0.19	0.22	0.03 – 0.04	7.8 – 9.0	21.5:1 – 25.4:1	13.9:1 – 15.2:1	1.53 – 1.65
VSG G, GSI, GSID	Rich Burn	0.05	0.05	0.02 – 1.15	0.29 – 2.10	15.5:1 – 17.7:1	9.3:1 – 10.6:1	0.97 – 1.10

Table 2: Summary of Results
Sunnyside Compressor Station Unit #E002

Company: ConocoPhillips Company
Location: Sunnyside CS
Source: Waukesha L7042GL SN: C-10664/2
Engine Site Rating: 1330 Hp @ 1200 RPM
Technician: CS, CS

Test Run Number	1	2	3	
Unit Number	E002	E002	E002	
Engine Number	2	2	2	
Date	8/26/08	8/26/08	8/26/08	
Start Time	9:51	10:59	12:06	
Stop Time	10:51	11:59	13:06	
Engine/Compressor Operation				
Engine Speed (rpm)	1155	1156	1163	
Load (%)	90	90	95	
Engine Horsepower (Hp)	1197	1197	1264	
Fuel Manifold Pressure (psig)	40	40	40	
Air Manifold Pressure (psig)	11	11	13	
Air Manifold Temperature (°F) (L/R)	122/123	129/124	139/131	
Compressor Suction Pressure (psig)	42	44	54	
1st Interstage Pressure (psig)	163	160	175	
Compressor Discharge Pressure (psig)	381	378	390	
Compressor Suction Temperature (°F)	88/233.5	84/233.5	82/231.5	
1st Interstage Temperature (°F)	97.5/233.5	102/236	110.5/235	
Compressor Discharge Temperature (°F)	96.5	102.5	106	
Average Exhaust Temperature (°F)	920	930	940	
Compressor Throughput (MMSCFD)	247.04	247.04	247.04	
Ignition Timing (°BTDC)	11	11	11	
Fuel Data				
Measured Fuel Consumption (SCFM)	261.77	262.72	259.73	
Calculated Fuel Consumption (SCFH)	10907	10947	10822	
O2 F-Factor (DSCF/MMBtu, HHV basis)	8687	8687	8687	
Fuel Heating Value (Btu/SCF, HHV basis)	952	952	952	
BHp Specific Fuel Rate (Btu/Hp-hr, HHV basis)	8675	8707	8154	
Ambient Conditions				
Pressure Altitude (MSL)	6100	6100	6100	
Atmospheric Pressure ("Hg)	23.91	23.91	23.91	
Ambient Temperature (°F)	75.4	79.5	83.7	
Wet Bulb Temperature (°F)	60.1	61.8	63.2	
Humidity (lb/lb air)	0.0101	0.0104	0.0105	
Measured Exhaust Emissions (Corrected)				**Average**
NOx (ppmv)	102.18	117.65	176.08	131.97
CO (ppmv)	680.51	702.23	746.37	709.70
O2 (vol %)	10.55	10.44	10.17	10.39
CO2 (vol %)	5.83	5.97	5.98	5.93
H2CO (ppmv)	4.86	4.34	4.74	4.65
Fo	1.77	1.75	1.79	1.77
Exhaust Flow Rates (EPA Methods 1-4)				
SCFH (dry basis, calc. from meas. stack velocity)	1.78E+05	1.71E+05	1.76E+05	1.75E+05
Exhaust Flow Rates (EPA Method 19)				
Dry SCFH (dry basis, calc. from Fuel Consump.)	1.82E+05	1.81E+05	1.74E+05	1.79E+05
Difference from Methods 1-4 Determination (%)	-2.44	-5.70	0.74	-2.46
Calculated Mass Emission Rates (EPA Methods 1-4)				
NOx (g/hp-hr)	0.82	0.91	1.33	1.02
CO (g/hp-hr)	3.34	3.32	3.42	3.36
H2CO (g/hp-hr)	0.026	0.022	0.023	0.024
NOx (lbs/hr)	2.17	2.41	3.69	2.76
CO (lbs/hr)	8.80	8.74	9.53	9.02
H2CO (lbs/hr)	0.067	0.058	0.065	0.063
NOx (tons/yr)	9.51	10.54	16.18	12.08
CO (tons/yr)	38.55	38.28	41.74	39.52
H2CO (tons/yr)	0.295	0.253	0.284	0.277

CONFIDENTIAL

MIRATECH Emissions Control Equipment Specification Summary

Proposal Number: RJ-11-1154 Rev(3)

Engine Data

Number of Engines:	1
Application:	Gas Compression
Engine Manufacturer:	Waukesha
Model Number:	L 7042 GL
Power Output:	1,478 bhp
Lubrication Oil:	0.6 wt% sulfated ash or less
Type of Fuel:	Natural Gas
Exhaust Flow Rate:	207,712 scfh
Exhaust Temperature:	709°F

System Details

System Pressure Loss:	5.0 inches of WC (Fresh)
Sound Attenuation:	22-29 dBA insertion loss
Exhaust Temperature Limits:	550 – 1250°F (catalyst inlet); 1350°F (catalyst outlet)

NSCR Housing & Catalyst Details

Model Number:	ZCS-30x31-12-XH2B1
Material:	Carbon Steel
Diameter:	30 inches
Inlet Pipe Size & Connection:	12 inch FF Flange, 150# ANSI standard bolt pattern
Outlet Pipe Size & Connection:	12 inch FF Flange, 150# ANSI standard bolt pattern
Overall Length:	105 inches
Weight Without Catalyst:	711 lbs
Weight Including Catalyst:	811 lbs
Instrumentation Ports:	2 inlet/2 outlet (1/2" NPT)

Emission Requirements

Exhaust Gases	Engine Outputs (g/ bhp-hr)	Reduction (%)	Warranted Converter Outputs (g/ bhp-hr)	Requested Emissions Targets
CO	3.36	75%	0.84	75 % Reduction
CH_2O	0.29	75%	0.07	75 % Reduction
Oxygen	9.8%			

MIRATECH warrants the performance of the converter, as stated above, per the MIRATECH General Terms and Conditions of Sale.

MIRATECH Corporation Scope of Supply

	Model Number	Quantity per Engine
NSCR Housing & Catalyst	**IQ-28-12-EL1**	**1**
NSCR Housing	IQ-28-12-HSG	1
Oxidation Catalyst	IQ-RE-28EL	1
Nut, Bolt, and Gasket Set	NBG-IQ28-1	1
NSCR Housing & Catalyst	**ZCS-30x31-12-XH2B1**	**1**
NSCR Housing	ZCS-30x31-12-HSG	1
Oxidation Catalyst	ZXS-RE-FULL354XH	2
Blind Catalyst	ZXS-RE-FULLBLIND	1
Nut, Bolt, and Gasket Set	NBG-ZXS3	1
Air/Fuel Ratio Controller	**MECL-22-FT-60**	**1**
Full Authority Control Valve	FT-60	2
Control Valve Cable	FT Cable-50	2
Flange Adapter	FLOTECH Flange Adaptor 2"	4
Engine Control Module	ECM-L	1
Terminal Connector Board	TCB	1
Enclosure	Enclosure-CSA	1
UEGO Sensor	UEGO Sensor	2
UEGO Cable	UEGO Cable-50	2
Magnetic Pick-Up	MAG PU	1
Magnetic Pick-Up Cable	MAG PU Cable-50	1
Manifold Absolute Pressure Sensor	MAP Sensor	1
Manifold Absolute Pressure Sensor Cable	MAP Cable-50	1
Manifold Air Temperature Sensor	MAT Sensor	1
Manifold Air Temperature Sensor Cable	MAT Cable-50	1
Oxygen Sensor Coupling	O2 NUT	2
Null Modem Cable	NM-10	1
Diagnostic Software and Manual CD	MECL-CD	1
Manual	MECL Manual	1

Customer Scope of Supply

Description
Support Structure
Attachment to Support Structure (Bolts, Nuts, Levels, etc.)
Expansion Joints
Exhaust Piping
Inlet Pipe Bolts, Nuts, & Gasket
Outlet Pipe Bolts, Nuts, & Gasket

Capstone

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Technical Reference

Capstone MicroTurbine™ Systems Emissions

Summary

Capstone MicroTurbine™ systems are inherently clean and can meet some of the strictest emissions standards in the world. This technical reference is to provide customers with information that may be requested by local air permitting organizations or to compare air quality impacts of different technologies for a specific project. The preferred units of measure are "output based"; meaning that the quantity of a particular exhaust emission is reported relative to the useable output of the microturbine – typically in pounds per megawatt hour for electrical generating equipment. This technical reference also provides the volumetric measurement in parts per million, which is still used by many people. A conversion between several common units is also provided.

Maximum Exhaust Emissions at ISO Conditions

Table 1 below summarizes the exhaust emissions at full power and ISO conditions for different Capstone microturbine models. Note that the fuel can have a significant impact on certain emissions. For example landfill and digester gas can be made up of a wide variety of fuel elements and impurities, and typically contains some percentage of carbon dioxide (CO_2). This CO_2 dilutes the fuel, makes complete combustion more difficult, and results in higher carbon monoxide emissions (CO) than for pipeline-quality natural gas.

Table 1. Emission for Different Capstone Microturbine Models in [lb/MWhe]

Model	Fuel	NOx	CO	VOC (5)
C30 NG	Natural Gas (1)	.64	1.7	.22
C30 MBTU	Landfill Gas (2)	.64	22	12.4
C30 MBTU	Digester Gas (3)	.64	22	12.4
C30 Liquid	Diesel #2 (4)	2.6	.41	.23
C65 NG Standard	Natural Gas (1)	.46	6.0	.10
C65 NG Low NOx	Natural Gas (1)	.17	6.0	.10
C65 NG CARB	Natural Gas (1)	.17	.24	.05
CR65 Landfill	Landfill Gas (2)	.50	6.0	.10
CR65 Digester	Digester Gas (3)	.50	6.0	.10
C200 NG	Natural Gas (1)	.43	.26	.10
C200 NG CARB	Natural Gas (1)	.14	.20	.04
CR200 Digester	Digester Gas (3)	.50	6.0	.10

Notes:

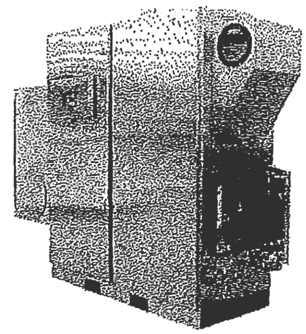
(1) Emissions for standard natural gas at 1,000 BTU/scf (HHV)
(2) Emissions for surrogate gas containing 42% natural gas, 39% CO2, and 19% Nitrogen
(3) Emissions for surrogate gas containing 63% natural gas and 37% CO2
(4) Emissions for Diesel #2 according to ASTM D975-07b
(5) Expressed as Hexane

C65 MicroTurbine
Oil & Gas

Capstone

33% smaller than equivalent generators. Offers ultra-low emissions and reliable electrical generation from raw natural gas.

- Patented air bearing: No lubricating oil or coolant
- One moving part: Minimal maintenance and downtime
- Low NOx and CO_2 emissions – better than tough global standards
- Immediate service available worldwide
- Remote monitoring and diagnostic capabilities
- Multiple units easily synchronized
- Electrical protective relays mean no external switchgear required
- Small, modular design allows for easy, low-cost installation
- Reliable: 16,000,000+ run hours and counting



Offshore C65 CID2

Electrical Performance	
Electrical Power Output	65 kW
Voltage	400 to 480 VAC
Electrical Service	3-Phase, 4 wire
Frequency	10 - 60 Hz
Maximum Output Current	127A, stand alone operation(2)
Electrical Efficiency LHV	29%

Fuel/Engine Characteristic	
Natural/Wellhead Gas HHV	825 to 1,275 BTU/scf
H2S Content	< 400 ppmv
Inlet Pressure	5.2 barg (75 psig)
Fuel Flow LHV	807 MJ/hr (765,000 BTU/hr)
Generator Heat Rate LHV	11.6 MJ/kWh (11,000 BTU/kWh)

Exhaust Characteristic	C65
Exhaust Gas Flow	0.49 kg/s (1.08 lb/sec)
Exhaust Gas Temperature	309°C (588°F)

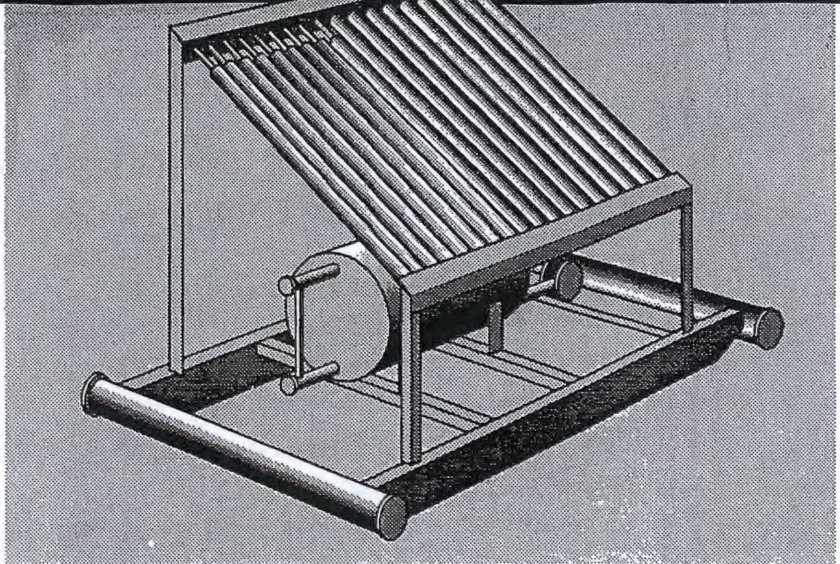
Power when and where you need it. Clean and simple.

NATCO

BTEX BUSTER™

Achieves 99.7%+ BTEX and VOC Removal Efficiency!

The Cost Effective Answer To Your Compliance Problems



Space saving skid mounted NATCO BTEX BUSTER is the cost effective answer to your compliance problems.

The NATCO BTEX BUSTER provides a removal efficiency greater than 99.7%, helps recover and collect saleable liquid hydrocarbons and prevents the loss of expensive fuel gas.

Field-proven, the NATCO BTEX BUSTER is now available through our 30 NATCO Sales and Service locations worldwide.

The unit was designed using the EPA approved GRI-GlyCalc™ computer simulation program with a flash-gas separator in the glycol regeneration process. Under common operating conditions, BTEX (Benzene, Toluene, Ethylbenzene and Xylene) as well as other volatile organic compounds (VOC's) are emitted to the atmosphere during the glycol regeneration process. The rates are usually proportional to the glycol circulation rate.

Meets Federal Regulation 40 CFR Part 63

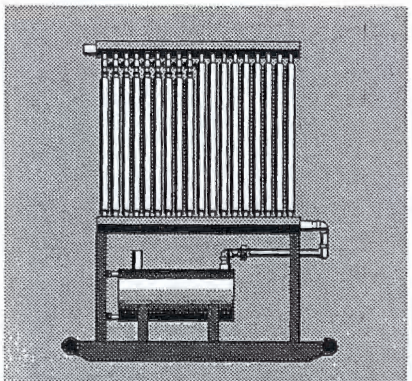
This cost efficient system is designed to assist operators in reducing BTEX and VOC emissions below the accepted levels and comply with Federal and State environmental regulations.

Economics of NATCO's BTEX BUSTER show that it can pay for itself by recovering saleable hydrocarbon liquids and fuel gas. By condensing troublesome glycol reconcentrator vapors and routing flash gas back to the reconcentrator fuel gas inlet for burning, the unit minimizes emissions during glycol plant dehydration processing.

The BTEX BUSTER incorporates field-proven NATCO burner accessories to help prevent sooting and back pressure on your regeneration system.

The BTEX BUSTER also features a design to eliminate potential freeze-up problems when operating in severe cold climates.

NATCO offers the BTEX BUSTER in standard sizes to accommodate most customer needs. Our units are backed by NATCO replacement parts, technical assistance and service available 24 hours a day.

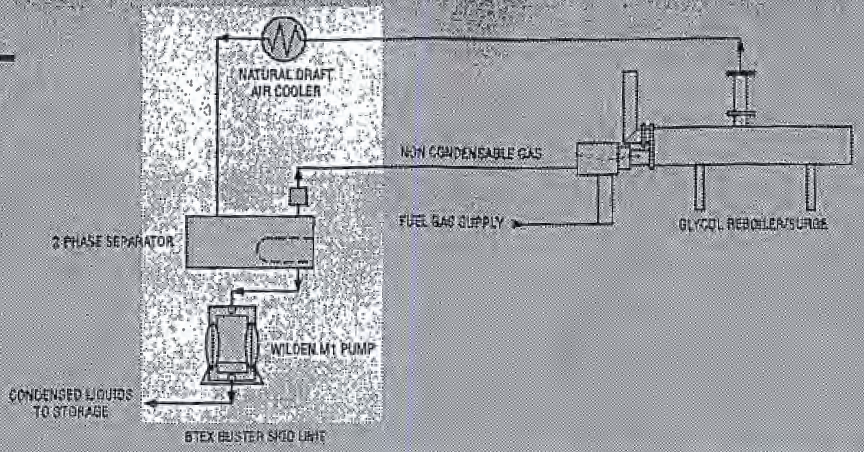


NATCO BTEX BUSTER units are designed and engineered for safe operation and meet today's environmental regulations

Features	Benefits
• Efficient	• Removal efficiency greater than 99.7%
• Environmentally Correct	• Meets Federal Regulation 40 CFR part 63 Meets or exceeds most stringent state regulations LAC:111.2116 and LAC 33:111, chapter 51
• Reduces Operating Costs	• Reduces fuel gas consumption Recovers saleable liquid hydrocarbons
• Safe	• In-line flash arrestor, high level switch, pressure safety valve, gas shutdown valves
• Designed For The Oilfield	• Includes NATCO field proven burner products Reduces freeze problems in most cold climates Pneumatic pump handles aromatic hydrocarbons
• NATCO Service	• Experienced staff, 30 locations, 24 hrs/day

NATCO

Flow Diagram – BTEX BUSTER Skid Package



Standard BTEX Size (1)	Reconcentrator Duty BTU/Hr	Glycol Pump Gallons/Hour	Maximum Capacity # Water/Day (2)	Non Condensable Vapor #/Day (3)	Cooler Duty BTU/Hr (4)
150	75,000	40	273	7	30,000
160	150,000	40	273	10	30,000
250	250,000	90	1216	27	51,000
375	375,000	210	1807	45	76,000
550	550,000	210	2650	60	112,000
750	750,000	450	3615	100	152,000

(1) Standard BTEX
Performance of unit is based on a non-condensable vapor HHV greater than 400 Btu/scf and less than 1800 Btu/scf and a glycol circulation rate of no more than 3 gallons per pound of water removed.

(2) Maximum Capacity # Water/Day
Represents the maximum capacity of water in pounds per day for each standard NATCO reboiler size based on a glycol circulation rate of 2 gallons of glycol per pound of water removed.

(3) Non-Condensable Vapor #/Day
Maximum non-condensable vapor rate was calculated with the GRI-GlyCalc computer simulation program with a flash gas separator used in the glycol regeneration process and a BTEX concentration in the inlet gas stream of no more than 700 ppm. Using adiabatic combustion calculations, a minimum of 99.7% of these non-condensable vapors are destroyed.

(4) Cooler Duty Btu/Hr
Cooler duty was calculated based on a prevailing windspeed of 3 mph and a maximum ambient temperature of 100°F.

Note: NATCO is not responsible for the disposal of any condensed liquids associated with its BTEX BUSTER units.

How It Works – The NATCO BTEX BUSTER is a relatively simple process that is designed to maintain greater than 99.7% removal of BTEX and VOC emissions.

The vapors emitted from the glycol still column are cooled in the natural draft air cooler to temperatures below 120°F (48.9°C).

The condensed liquids are collected in a small two-phase separator and pumped to customer storage. Non-condensable gases from the separator are piped through an in-line flash arrestor and then burned in the glycol reboiler firebox to achieve an overall minimum destruction efficiency of 99.7% plus.

Built-In Safety Features – NATCO BTEX BUSTER units are engineered with proper controls for safe operation and long in-service life. These include an in-line flash arrestor, separator high level switch, pressure safety valve and gas shut-down valves for high reboiler bath temperatures. It also incorporates field-proven NATCO burner accessories that help to prevent typical sooting and back pressures on your regeneration system.

NATCO – Your Single Source For:

- Design
- Engineering
- Procurement
- Fabrication
- Start-up
- Commissioning
- Operations Maintenance
- Education and Training
- Strategic Alliances

NATCO

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Fax: (713) 683-6768
www.natco_us.com

Specification Sheet

COOLER SERVICE COMPANY

PROPOSAL NO.	BTX
DATE	2/12/99
PAGE	1 OF 1

CUSTOMER	NATCO	
REF. NO.	750 Standard	
MODEL	NC 36-6	

PERFORMANCE OF ONE UNIT

1	SERVICE	Overhead Condenser
2	FLOW	5390 #/day
3	FLUID	Water vapor and HC vapor
4	TEMPERATURE IN, °F	220
5	TEMPERATURE OUT, °F	120
6	INLET PRESSURE, PSIA	14.9
7	PRESSURE DROP, PSI	0.2
8	DUTY, BTU/HOUR	152,000
9	CORRECTED MTD	58 wtd
10	BARE TUBE RATE	48.5 wtd
11	FOULING	.001
12	BARE TUBE SURFACE, SQ. FT.	54
13	TOTAL SURFACE, SQ. FT.	1170

CONSTRUCTION

14	NO SECTIONS	1
15	NO. TUBES/SECTION	36
16	LENGTH	6'
17	NO. ROWS	1
18	NO PASSES	1
19	COUNTERFLOW	
	TUBE O.D AND BWG	1" OD x 16 Bwg
	TUBE MATERIAL	SA214
22	DESIGN PRESSURE, PSI	15
23	DESIGN TEMPERATURE, °F	250
24	NOZZLES	2" NPT
25	HEADERS	CARBON STEEL BOX TYPE WITH REMOVABLE PLUGS
26	ASME CODE STAMP	
27		
28	GRVD TUBE SHEET	
29	CORROSION ALLOWANCE	
30	FINS	ALUMINUM, ANGLE BASE, MECHANICALLY BONDED
31	PLUGS, TYPE	
32	PLUGS, MATERIAL	
33	RETARDERS	
34	ACCELERATORS	

AIR DATA

35	INLET AIR, °F	100	ELEVATION, FT.	500
36	OUTLET AIR, °F		TOTAL SCFM	
37				

MECHANICAL EQUIPMENT

38	NO. FANS	HP/FAN	RPM	DIA.	NO. BLADES	MATERIAL	MAKE	
39	DRIVE							
40								
41	DRAFT TYPE		OVERALL WIDTH		LENGTH		HEIGHT	
42	EST. SHIPPING WEIGHT							
	ACCESSORIES	Mounted at 45 degree angle						
		Normal wind 5 mph						
		All welded construction						
46								
47								
48								

Form A4, 9/84

APPENDIX E

GRI-GLYCalc Output Report

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: Ute CDP
File Name: C:\Users\ETullos\Desktop\Work\137 - ConocoPhillips\ Title V\Ute CDP\Part 49 Application\Dehydrator Emissions_Ute CDP_ 2010-2012 Composite Samples_PTE_5 YR Max of 14.4 MMscf No Controls.ddf
Date: August 23, 2012

DESCRIPTION:

Description: 14.4 MMScf/Day per 5 YR Subpart HH maximum; Temperature/Pressure taken from the average values of gas analyses collected 2010-2012; Gas dewpoint is 7; Saturated gas; 3 gal TEG per lb H2O removed

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 81.90 deg. F
Pressure: 204.33 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	2.2610
Nitrogen	0.1680
Methane	85.4260
Ethane	7.3590
Propane	2.8500
Isobutane	0.5430
n-Butane	0.6170
Isopentane	0.2410
n-Pentane	0.1490
n-Hexane	0.0530
Cyclohexane	0.0280
Other Hexanes	0.1030
Heptanes	0.0700
Methylcyclohexane	0.0420
2,2,4-Trimethylpentane	0.0050
Benzene	0.0130
Toluene	0.0220
Ethylbenzene	0.0010
Xylenes	0.0080
C8+ Heavies	0.0400

DRY GAS:

Flow Rate: 14.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 3.0 gal/lb H2O

GRI-GLYCalc VERSION 4.0 - EMISSIONS SUMMARY

Case Name: Ute CDP
File Name: C:\Users\ETullos\Desktop\Work\137 - ConocoPhillips\ Title V\Ute CDP\Part 49 Application\Dehydrator Emissions_Ute CDP_ 2010-2012 Composite Samples_PTE_5 YR Max of 14.4 MMscf No Controls.ddf
Date: August 23, 2012

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1835	4.404	0.8038
Ethane	0.3053	7.327	1.3372
Propane	0.6191	14.857	2.7115
Isobutane	0.3008	7.220	1.3177
n-Butane	0.5144	12.346	2.2532
Isopentane	0.3156	7.575	1.3825
n-Pentane	0.2669	6.405	1.1688
n-Hexane	0.2504	6.009	1.0967
Cyclohexane	0.6017	14.442	2.6356
Other Hexanes	0.3407	8.178	1.4924
Heptanes	0.9296	22.309	4.0715
Methylcyclohexane	1.4301	34.322	6.2637
2,2,4-Trimethylpentane	0.0324	0.776	0.1417
Benzene	2.3296	55.909	10.2034
Toluene	7.5322	180.773	32.9910
Ethylbenzene	0.6333	15.199	2.7737
Xylenes	6.5933	158.239	28.8786
C8+ Heavies	6.2674	150.417	27.4512
Total Emissions	29.4461	706.707	128.9741
Total Hydrocarbon Emissions	29.4461	706.707	128.9741
Total VOC Emissions	28.9573	694.976	126.8332
Total HAP Emissions	17.3710	416.905	76.0851
Total BTEX Emissions	17.0883	410.119	74.8468

FLASH GAS EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.0602	1.446	0.2638
Ethane	0.0294	0.705	0.1287
Propane	0.0260	0.625	0.1141
Isobutane	0.0085	0.204	0.0372
n-Butane	0.0111	0.266	0.0486
Isopentane	0.0059	0.141	0.0257
n-Pentane	0.0040	0.097	0.0177
n-Hexane	0.0021	0.051	0.0093
Cyclohexane	0.0013	0.032	0.0059
Other Hexanes	0.0038	0.091	0.0166
Heptanes	0.0039	0.094	0.0172
Methylcyclohexane	0.0025	0.060	0.0109
2,2,4-Trimethylpentane	0.0003	0.006	0.0012
Benzene	0.0007	0.017	0.0031
Toluene	0.0015	0.036	0.0066
Ethylbenzene	0.0001	0.002	0.0003
Xylenes	0.0005	0.013	0.0023
C8+ Heavies	0.0025	0.060	0.0109

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Combustion device
Flash Control Efficiency: 95.00 %
Temperature: 131.0 deg. F
Pressure: 30.0 psig

Total Emissions	0.1644	3.946	0.7201
Total Hydrocarbon Emissions	0.1644	3.946	0.7201
Total VOC Emissions	0.0748	1.795	0.3276
Total HAP Emissions	0.0052	0.125	0.0228
Total BTEX Emissions	0.0028	0.068	0.0123

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	1.2048	28.915	5.2770
Ethane	0.5875	14.101	2.5734
Propane	0.5209	12.501	2.2814
Isobutane	0.1698	4.076	0.7439
n-Butane	0.2218	5.324	0.9717
Isopentane	0.1174	2.817	0.5142
n-Pentane	0.0809	1.942	0.3543
n-Hexane	0.0425	1.019	0.1860
Cyclohexane	0.0268	0.643	0.1173
Other Hexanes	0.0757	1.818	0.3318
Heptanes	0.0786	1.886	0.3442
Methylcyclohexane	0.0498	1.195	0.2180
2,2,4-Trimethylpentane	0.0053	0.128	0.0233
Benzene	0.0144	0.345	0.0630
Toluene	0.0301	0.723	0.1320
Ethylbenzene	0.0015	0.035	0.0064
Xylenes	0.0104	0.250	0.0457
C8+ Heavies	0.0499	1.197	0.2185
Total Emissions	3.2881	78.915	14.4019
Total Hydrocarbon Emissions	3.2881	78.915	14.4019
Total VOC Emissions	1.4958	35.899	6.5515
Total HAP Emissions	0.1042	2.500	0.4563
Total BTEX Emissions	0.0564	1.353	0.2470

COMBINED REGENERATOR VENT/FLASH GAS EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2438	5.850	1.0676
Ethane	0.3347	8.032	1.4658
Propane	0.6451	15.482	2.8256
Isobutane	0.3093	7.424	1.3549
n-Butane	0.5255	12.612	2.3018
Isopentane	0.3215	7.716	1.4082
n-Pentane	0.2709	6.502	1.1366
n-Hexane	0.2525	6.060	1.1060
Cyclohexane	0.6031	14.474	2.6415
Other Hexanes	0.3445	8.268	1.5090
Heptanes	0.9335	22.404	4.0887
Methylcyclohexane	1.4326	34.381	6.2746
2,2,4-Trimethylpentane	0.0326	0.783	0.1429
Benzene	2.3303	55.926	10.2066
Toluene	7.5337	180.809	32.9976
Ethylbenzene	0.6333	15.200	2.7740
Xylenes	6.5938	158.251	28.8809
C8+ Heavies	6.2699	150.477	27.4621

Total Emissions	29.6105	710.653	129.6942
Total Hydrocarbon Emissions	29.6105	710.653	129.6942
Total VOC Emissions	29.0321	696.771	127.1607
Total HAP Emissions	17.3762	417.030	76.1079
Total BTEX Emissions	17.0911	410.187	74.8591

APPENDIX F

GRI-HAPCalc Output Report

GRI-HAPCalc® 3.0
Fugitive Emissions Report

Facility ID:	**UTE CDP**	**Notes:**	**The number of components in light oil (condensate) service was estimated by assuming it is equivalent to 10% of the components in gas/vapor service.**
Operation Type:	**COMPRESSOR STATION**		
Facility Name:	**UTE CDP**		
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".

Fugitive Emissions

Calculation Method: EPA Average Factors

User Inputs

Component	Gas Service	Light Liquid Service	Heavy Liquid Service
Connections:	737	74	0
Flanges	120	12	0
Open-Ended Lines:	14	1	0
Pumps:	0	0	0
Valves:	257	26	0
Others:	30	3	0

Calculated Emissions (ton/yr)

Chemical Name	Emissions
HAPs	
Benzene	0.0039
Toluene	0.0070
Ethylbenzene	0.0005
Xylenes(m,p,o)	0.0020
Total	0.0134
Criteria Pollutants	
NMHC	1.6627
NMEHC	0.8516

APPENDIX G

E&P Tank Output Reports

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File                : C:\Users\ETullos\Desktop\Work\137 - ConocoPhillips\_Title V\Ute CDP\Part 49 Applicat
Flowsheet Selection         : Oil Tank with Separator
Calculation Method          : RVP Distillation
Control Efficiency          : 100.0%
Known Separator Stream      : Low Pressure Oil
Entering Air Composition    : No

Filed Name                  : San Juan Basin
Well Name                   : Ute CDP
Well ID                     : Inlet Scrubber to Condensate Tanks
Date                        : 2011.04.11

******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure          : 49.02[psig]
Separator Temperature       : 52.67[F]
Ambient Pressure            : 11.20[psia]
Ambient Temperature         : 52.10[F]
C10+ SG                     : 0.7522
C10+ MW                     : 172.356

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component            mol %
   1      H2S                  0.0000
   2      O2                   0.0000
   3      CO2                  1.0532
   4      N2                   0.0323
   5      C1                  15.2754
   6      C2                   2.8457
   7      C3                   2.2485
   8      i-C4                 0.8541
   9      n-C4                 1.3596
   10     i-C5                 1.4608
   11     n-C5                 1.1185
   12     C6                   3.1739
   13     C7                  16.5335
   14     C8                  10.1878
   15     C9                   7.4041
   16     C10+                22.2889
   17     Benzene              0.7645
   18     Toluene              3.9271
   19     E-Benzene            0.4620
   20     Xylenes              5.3035
   21     n-C6                 2.3908
   22     224Trimethylp        1.3158

-- Sales Oil -----------------------------------------------------------------------------
Production Rate             : 12.3[bbl/day]
Days of Annual Operation    : 365 [days/year]
API Gravity                 : 58.0
Reid Vapor Pressure         : 3.90[psia]

******************************************************************************************
*     Calculation Results                                                                *
******************************************************************************************

-- Emission Summary ----------------------------------------------------------------------
Item                 Uncontrolled   Uncontrolled
                     [ton/yr]       [lb/hr]
```

Total HAPs	0.860	0.196
Total HC	31.855	7.273
VOCs, C2+	17.448	3.984
VOCs, C3+	12.460	2.845

Uncontrolled Recovery Info.

Vapor	2.7800	[MSCFD]
HC Vapor	2.6500	[MSCFD]
GOR	226.02	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	2.724	0.622
4	N2	0.053	0.012
5	C1	14.407	3.289
6	C2	4.989	1.139
7	C3	4.390	1.002
8	i-C4	1.400	0.320
9	n-C4	1.769	0.404
10	i-C5	1.095	0.250
11	n-C5	0.630	0.144
12	C6	0.688	0.157
13	C7	1.288	0.294
14	C8	0.262	0.060
15	C9	0.067	0.015
16	C10+	0.011	0.003
17	Benzene	0.110	0.025
18	Toluene	0.171	0.039
19	E-Benzene	0.007	0.002
20	Xylenes	0.069	0.016
21	n-C6	0.407	0.093
22	224Trimethylp	0.096	0.022
	Total	34.633	7.907

-- 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	1.0532	0.0668	0.0005	4.5342	7.2967	4.6201
4	N2	28.01	0.0323	0.0002	0.0000	0.1457	0.0197	0.1417
5	C1	16.04	15.2754	0.3111	0.0000	68.0856	34.1986	67.0318
6	C2	30.07	2.8457	0.3489	0.0306	11.6571	35.0321	12.3840
7	C3	44.10	2.2485	0.8426	0.7187	7.2100	14.3413	7.4317
8	i-C4	58.12	0.8541	0.5892	0.5755	1.7891	2.0767	1.7980
9	n-C4	58.12	1.3596	1.1030	1.0902	2.2653	2.4887	2.2723
10	i-C5	72.15	1.4608	1.5541	1.5575	1.1315	1.1887	1.1333
11	n-C5	72.15	1.1185	1.2511	1.2563	0.6505	0.6820	0.6515
12	C6	86.16	3.1739	3.9004	3.9303	0.6101	0.6403	0.6110
13	C7	100.20	16.5335	20.9380	21.1206	0.9896	1.0458	0.9914
14	C8	114.23	10.1878	13.0248	13.1426	0.1757	0.1874	0.1761
15	C9	128.28	7.4041	9.4907	9.5774	0.0402	0.0462	0.0404
16	C10+	172.36	22.2889	28.6034	28.8658	0.0047	0.0052	0.0047
17	Benzene	78.11	0.7645	0.9514	0.9591	0.1048	0.1104	0.1050
18	Toluene	92.13	3.9271	5.0006	5.0452	0.1385	0.1472	0.1388
19	E-Benzene	106.17	0.4620	0.5915	0.5969	0.0049	0.0053	0.0049
20	Xylenes	106.17	5.3035	6.7926	6.8545	0.0482	0.0518	0.0483
21	n-C6	86.18	2.3908	2.9686	2.9924	0.3518	0.3700	0.3524
22	224Trimethylp	114.24	1.3158	1.6710	1.6857	0.0624	0.0659	0.0625
	MW		99.27	120.14	120.94	25.65	32.07	25.85
	Stream Mole Ratio		1.0000	0.7792	0.7721	0.2208	0.0071	0.2279
	Heating Value	[BTU/SCF]				1407.15	1685.86	1415.82
	Gas Gravity	[Gas/Air]				0.89	1.11	0.89
	Bubble Pt. @ 100F	[psia]	546.59	16.59	4.32			

RVP @ 100F	[psia]	101.27	6.52	3.83
Spec. Gravity @ 100F		0.665	0.689	0.690

Total HAPs	0.090	0.021
Total HC	3.551	0.811
VOCs, C2+	1.913	0.437
VOCs, C3+	1.345	0.307

Uncontrolled Recovery Info.

Vapor	314.4900 x1E-3	[MSCFD]
HC Vapor	299.4300 x1E-3	[MSCFD]
GOR	224.64	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.310	0.071
4	N2	0.006	0.001
5	C1	1.638	0.374
6	C2	0.569	0.130
7	C3	0.499	0.114
8	i-C4	0.153	0.035
9	n-C4	0.191	0.044
10	i-C5	0.115	0.026
11	n-C5	0.066	0.015
12	C6	0.070	0.016
13	C7	0.129	0.029
14	C8	0.026	0.006
15	C9	0.006	0.001
16	C10+	0.001	0.000
17	Benzene	0.011	0.003
18	Toluene	0.017	0.004
19	E-Benzene	0.001	0.000
20	Xylenes	0.007	0.002
21	n-C6	0.041	0.009
22	224Trimethylp	0.010	0.002
	Total	3.866	0.883

-- 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	1.0532	0.0697	0.0003	4.5639	6.9839	4.6468
4	N2	28.01	0.0323	0.0002	0.0000	0.1469	0.0182	0.1425
5	C1	16.04	15.2754	0.3192	0.0000	68.6620	32.1164	67.4103
6	C2	30.07	2.8457	0.3647	0.0202	11.7019	34.6908	12.4892
7	C3	44.10	2.2485	0.8816	0.7158	7.1276	17.4028	7.4795
8	i-C4	58.12	0.8541	0.6094	0.5942	1.7275	2.1269	1.7412
9	n-C4	58.12	1.3596	1.1343	1.1210	2.1637	2.4636	2.1740
10	i-C5	72.15	1.4608	1.5751	1.5796	1.0529	1.1260	1.0554
11	n-C5	72.15	1.1185	1.2638	1.2700	0.6000	0.6400	0.6014
12	C6	86.16	3.1739	3.9088	3.9421	0.5508	0.5887	0.5521
13	C7	100.20	16.5335	20.9195	21.1200	0.8775	0.9468	0.8799
14	C8	114.23	10.1878	12.9990	13.1278	0.1532	0.1674	0.1537
15	C9	128.28	7.4041	9.4687	9.5633	0.0345	0.0408	0.0347
16	C10+	172.36	22.2889	28.5320	28.8183	0.0039	0.0045	0.0039
17	Benzene	78.11	0.7645	0.9523	0.9608	0.0942	0.1012	0.0945
18	Toluene	92.13	3.9271	4.9930	5.0418	0.1222	0.1328	0.1225
19	E-Benzene	106.17	0.4620	0.5902	0.5961	0.0043	0.0047	0.0043
20	Xylenes	106.17	5.3035	6.7776	6.8451	0.0418	0.0461	0.0419
21	n-C6	86.18	2.3908	2.9721	2.9985	0.3159	0.3385	0.3167
22	224Trimethylp	114.24	1.3158	1.6689	1.6851	0.0553	0.0596	0.0554
	MW		99.27	120.00	120.88	25.28	32.55	25.53
	Stream Mole Ratio		1.0000	0.7812	0.7734	0.2188	0.0078	0.2266
	Heating Value	[BTU/SCF]				1387.13	1720.15	1398.54
	Gas Gravity	[Gas/Air]				0.87	1.12	0.88
	Bubble Pt. @ 100F	[psia]	546.59	17.08	4.29			

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File              : C:\Users\ETullos\Desktop\Work\137 - ConocoPhillips\_Title V\Ute CDP\Part 49 Applicat
Flowsheet Selection       : Oil Tank with Separator
Calculation Method        : RVP Distillation
Control Efficiency        : 100.0%
Known Separator Stream    : Low Pressure Oil
Entering Air Composition  : No

Filed Name                : San Juan Basin
Well Name                 : Ute CDP
Well ID                   : Discharge Scrubber to Condensate Tanks
Date                      : 2011.04.11

******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure        : 188.00[psig]
Separator Temperature     : 70.10[F]
Ambient Pressure          : 11.20[psia]
Ambient Temperature       : 52.10[F]
C10+ SG                   : 0.7522
C10+ MW                   : 172.356

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component          mol %
   1      H2S                0.0000
   2      O2                 0.0000
   3      CO2                1.0532
   4      N2                 0.0323
   5      C1                15.2754
   6      C2                 2.8457
   7      C3                 2.2485
   8      i-C4               0.8541
   9      n-C4               1.3596
   10     i-C5               1.4608
   11     n-C5               1.1185
   12     C6                 3.1739
   13     C7                16.5335
   14     C8                10.1878
   15     C9                 7.4041
   16     C10+              22.2889
   17     Benzene            0.7645
   18     Toluene            3.9271
   19     E-Benzene          0.4620
   20     Xylenes            5.3035
   21     n-C6               2.3908
   22     224Trimethylp      1.3158

-- Sales Oil -----------------------------------------------------------------------------
Production Rate           : 1.4[bbl/day]
Days of Annual Operation  : 365 [days/year]
API Gravity               : 58.0
Reid Vapor Pressure       : 3.90[psia]

******************************************************************************************
*     Calculation Results                                                                *
******************************************************************************************

-- Emission Summary ----------------------------------------------------------------------
Item                Uncontrolled   Uncontrolled
                    [ton/yr]       [lb/hr]
```

RVP @ 100F	[psia]	101.27	6.72	3.81
Spec. Gravity @ 100F		0.665	0.689	0.690

APPENDIX H

EPA Tanks 4.09d Output Report

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	BGT-1 (Pit Sump Tank)
City:	La Plata
State:	Colorado
Company:	ConocoPhillips Company
Type of Tank:	Vertical Fixed Roof Tank
Description:	120-barrel Pit Tank
Tank Dimensions	
Shell Height (ft):	5.00
Diameter (ft):	13.00
Liquid Height (ft) :	5.00
Avg. Liquid Height (ft):	2.50
Volume (gallons):	5,040.00
Turnovers:	20.00
Net Throughput(gal/yr):	100,800.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Red/Primer
Shell Condition	Poor
Roof Color/Shade:	Red/Primer
Roof Condition:	Poor
Roof Characteristics	
Type:	Dome
Height (ft)	0.50
Radius (ft) (Dome Roof)	13.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

BGT-1 (Pit Sump Tank) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	55.56	38.56	72.56	45.54	0.0061	0.0031	0.0098	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0074

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

BGT-1 (Pit Sump Tank) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations	
Standing Losses (lb):	2.4341
Vapor Space Volume (cu ft):	365.0792
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.1272
Vented Vapor Saturation Factor:	0.9991
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	365.0792
Tank Diameter (ft):	13.0000
Vapor Space Outage (ft):	2.7505
Tank Shell Height (ft):	5.0000
Average Liquid Height (ft):	2.5000
Roof Outage (ft):	0.2505
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2505
Dome Radius (ft):	13.0000
Shell Radius (ft):	6.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0061
Daily Avg. Liquid Surface Temp. (deg. R):	515.2302
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	505.2050
Tank Paint Solar Absorptance (Shell):	0.9100
Tank Paint Solar Absorptance (Roof):	0.9100
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1272
Daily Vapor Temperature Range (deg. R):	67.9997
Daily Vapor Pressure Range (psia):	0.0067
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0061
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0098
Daily Avg. Liquid Surface Temp. (deg R):	515.2302
Daily Min. Liquid Surface Temp. (deg R):	498.2303
Daily Max. Liquid Surface Temp. (deg R):	532.2301
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9991
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0061
Vapor Space Outage (ft):	2.7505

Working Losses (lb):	1.9071
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0061
Annual Net Throughput (gal/yr.):	100,800.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	5,040.0000
Maximum Liquid Height (ft):	5.0000
Tank Diameter (ft):	13.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	4.3412

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

BGT-1 (Pit Sump Tank) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1.91	2.43	4.34

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	BGT-2 (Pit Sump Liquids)	
City:	La Plata	
State:	Colorado	
Company:	ConocoPhillips Company	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	120-barrel Pit Tank	
Tank Dimensions		
Shell Height (ft):		5.00
Diameter (ft):		13.00
Liquid Height (ft) :		5.00
Avg. Liquid Height (ft):		2.50
Volume (gallons):		5,040.00
Turnovers:		20.00
Net Throughput(gal/yr):		100,800.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Red/Primer	
Shell Condition	Poor	
Roof Color/Shade:	Red/Primer	
Roof Condition:	Poor	
Roof Characteristics		
Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		13.00
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

BGT-2 (Pit Sump Liquids) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	55.56	38.56	72.56	45.54	0.0061	0.0031	0.0098	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0074

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

BGT-2 (Pit Sump Liquids) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations	
Standing Losses (lb):	2.4341
Vapor Space Volume (cu ft):	365.0792
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.1272
Vented Vapor Saturation Factor:	0.9991
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	365.0792
Tank Diameter (ft):	13.0000
Vapor Space Outage (ft):	2.7505
Tank Shell Height (ft):	5.0000
Average Liquid Height (ft):	2.5000
Roof Outage (ft):	0.2505
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2505
Dome Radius (ft):	13.0000
Shell Radius (ft):	6.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0061
Daily Avg. Liquid Surface Temp. (deg. R):	515.2302
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	505.2050
Tank Paint Solar Absorptance (Shell):	0.9100
Tank Paint Solar Absorptance (Roof):	0.9100
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1272
Daily Vapor Temperature Range (deg. R):	67.9997
Daily Vapor Pressure Range (psia):	0.0067
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0061
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0098
Daily Avg. Liquid Surface Temp. (deg R):	515.2302
Daily Min. Liquid Surface Temp. (deg R):	498.2303
Daily Max. Liquid Surface Temp. (deg R):	532.2301
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9991
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0061
Vapor Space Outage (ft):	2.7505

Working Losses (lb):	1.9071
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0061
Annual Net Throughput (gal/yr.):	100,800.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	5,040.0000
Maximum Liquid Height (ft):	5.0000
Tank Diameter (ft):	13.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	4.3412

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

BGT-2 (Pit Sump Liquids) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	1.91	2.43	4.34

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	T-8094A (Condenser Liquids Tank)
City:	La Plata
State:	Colorado
Company:	ConocoPhillips Company
Type of Tank:	Vertical Fixed Roof Tank
Description:	300-barrel Condensate Tank
Tank Dimensions	
Shell Height (ft):	15.00
Diameter (ft):	12.00
Liquid Height (ft) :	15.00
Avg. Liquid Height (ft):	7.50
Volume (gallons):	12,600.00
Turnovers:	10.00
Net Throughput(gal/yr):	126,000.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.50
Radius (ft) (Dome Roof)	12.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.25
Pressure Settings (psig)	0.25

Meterological Data used in Emissons Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

T-8094A (Condenser Liquids Tank) - Vertical Fixed Roof Tank
La Plata, Colorado

		Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp	Vapor Pressure (psia)			Vapor Mol.	Liquid Mass	Vapor Mass	Mol.	Basis for Vapor Pressure
Mixture/Component	Month	Avg.	Min.	Max.	(deg F)	Avg.	Min.	Max.	Weight.	Fract.	Fract.	Weight	Calculations
Crude oil (RVP 5)	All	51.76	37.44	66.07	44.16	2.4413	1.8110	3.2379	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

T-8094A (Condenser Liquids Tank) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations

Standing Losses (lb):	774.0548
Vapor Space Volume (cu ft):	876.5698
Vapor Density (lb/cu ft):	0.0222
Vapor Space Expansion Factor:	0.2179
Vented Vapor Saturation Factor:	0.4993
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	876.5698
Tank Diameter (ft):	12.0000
Vapor Space Outage (ft):	7.7506
Tank Shell Height (ft):	15.0000
Average Liquid Height (ft):	7.5000
Roof Outage (ft):	0.2506
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2506
Dome Radius (ft):	12.0000
Shell Radius (ft):	6.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0222
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2179
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.4269
Breather Vent Press. Setting Range(psia):	0.5000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.8110
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	3.2379
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.4993
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.4413
Vapor Space Outage (ft):	7.7506

Working Losses (lb):	274.6464
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Annual Net Throughput (gal/yr.):	126,000.0000
Annual Turnovers:	10.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	12,600.0000
Maximum Liquid Height (ft):	15.0000
Tank Diameter (ft):	12.0000
Working Loss Product Factor:	0.7500
Total Losses (lb):	1,048.7012

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

T-8094A (Condenser Liquids Tank) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	274.65	774.05	1,048.70

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	TK-1 (Sump Oil)
City:	La Plata
State:	Colorado
Company:	ConocoPhillips Company
Type of Tank:	Vertical Fixed Roof Tank
Description:	100-barrel Oil Tank

Tank Dimensions

Shell Height (ft):		12.00
Diameter (ft):		8.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		4,200.00
Turnovers:		20.00
Net Throughput(gal/yr):		84,000.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		8.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calcuations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

APPENDIX I

Gas and Liquid Analyses

TANKS 4.0.9d
Emissions Report - Detail Format
Total Emissions Summaries - All Tanks in Report

Emissions Report for: Annual

Tank Identification				Losses (lbs)
BGT-1 (Pit Sump Tank)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	4.34
BGT-2 (Pit Sump Liquids)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	4.34
T-8094A (Condenser Liquids Tank)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	1,048.70
TK-1 (Sump Oil)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	561.23
TK-10 (TEG)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	0.04
TK-2 (Lube Oil)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	561.23
TK-3 (AntifreezeTank)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	0.17
TK-4040 (Methanol)	ConocoPhillips Company	Vertical Fixed Roof Tank	La Plata, Colorado	185.38
Total Emissions for all Tanks:				2,365.43

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-4040 (Methanol) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	70.93	114.45	185.38

Working Losses (lb):	70.9301
Vapor Molecular Weight (lb/lb-mole):	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.1069
Annual Net Throughput (gal/yr.):	84,000.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,200.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	185.3806

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-4040 (Methanol) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations

Standing Losses (lb):	114.4505
Vapor Space Volume (cu ft):	314.2247
Vapor Density (lb/cu ft):	0.0065
Vapor Space Expansion Factor:	0.2111
Vented Vapor Saturation Factor:	0.7317
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	314.2247
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	6.2513
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.2513
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2513
Dome Radius (ft):	8.0000
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0065
Vapor Molecular Weight (lb/lb-mole):	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.1069
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2111
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.0595
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.1069
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.6820
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	1.7416
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.7317
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	1.1069
Vapor Space Outage (ft):	6.2513

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-4040 (Methanol) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	51.76	37.44	66.07	44.16	1.1069	0.6820	1.7416	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	TK-4040 (Methanol)	
City:	La Plata	
State:	Colorado	
Company:	ConocoPhillips Company	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	100-barrel Methanol Tank	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		8.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		4,200.00
Turnovers:		20.00
Net Throughput(gal/yr):		84,000.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		8.00
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-3 (AntifreezeTank) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Ethylene Glycol	0.08	0.09	0.17

Working Losses (lb):	0.0794
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0008
Annual Net Throughput (gal/yr.):	84,000.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,200.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	0.1679

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-3 (AntifreezeTank) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations	
Standing Losses (lb):	0.0885
Vapor Space Volume (cu ft):	314.2247
Vapor Density (lb/cu ft):	0.0000
Vapor Space Expansion Factor:	0.1067
Vented Vapor Saturation Factor:	0.9997
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	314.2247
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	6.2513
Tank Shell Height (ft):	12.0000
Average Lquid Height (ft):	6.0000
Roof Outage (ft):	0.2513
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2513
Dome Radius (ft):	8.0000
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0008
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1067
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	0.0010
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0008
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0001
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0012
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9997
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0008
Vapor Space Outage (ft):	6.2513

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-3 (AntifreezeTank) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Ethylene Glycol	All	51.76	37.44	66.07	44.16	0.0008	0.0001	0.0012	50.0000			50.00	Option 1: VP50 = .00072 VP60 = .00114

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	TK-3 (AntifreezeTank)	
City:	La Plata	
State:	Colorado	
Company:	ConocoPhillips Company	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	100-barrel AntifreezeTank (50% water)	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		8.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		4,200.00
Turnovers:		20.00
Net Throughput(gal/yr):		84,000.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		8.00
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-2 (Lube Oil) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	183.10	378.13	561.23

Working Losses (lb):	183.0976
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Annual Net Throughput (gal/yr.):	84,000.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,200.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	0.7500
Total Losses (lb):	561.2254

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-2 (Lube Oil) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations	
Standing Losses (lb):	378.1278
Vapor Space Volume (cu ft):	314.2247
Vapor Density (lb/cu ft):	0.0222
Vapor Space Expansion Factor:	0.2681
Vented Vapor Saturation Factor:	0.5528
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	314.2247
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	6.2513
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.2513
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2513
Dome Radius (ft):	8.0000
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0222
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2681
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.4269
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.8110
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	3.2379
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.5528
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.4413
Vapor Space Outage (ft):	6.2513

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-2 (Lube Oil) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	51.76	37.44	66.07	44.16	2.4413	1.8110	3.2379	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	TK-2 (Lube Oil)	
City:	La Plata	
State:	Colorado	
Company:	ConocoPhillips Company	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	100-barrel Oil Tank	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		8.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		4,200.00
Turnovers:		20.00
Net Throughput(gal/yr):		84,000.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		8.00
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-10 (TEG) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Ethylene Glycol	0.02	0.02	0.04

Working Losses (lb):	0.0214
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0008
Annual Net Throughput (gal/yr.):	22,600.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,130.0000
Maximum Liquid Height (ft):	5.0000
Tank Diameter (ft):	6.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	0.0433

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-10 (TEG) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations	
Standing Losses (lb):	0.0219
Vapor Space Volume (cu ft):	77.8199
Vapor Density (lb/cu ft):	0.0000
Vapor Space Expansion Factor:	0.1067
Vented Vapor Saturation Factor:	0.9999
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	77.8199
Tank Diameter (ft):	6.0000
Vapor Space Outage (ft):	2.7523
Tank Shell Height (ft):	5.0000
Average Liquid Height (ft):	2.5000
Roof Outage (ft):	0.2523
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2523
Dome Radius (ft):	6.0000
Shell Radius (ft):	3.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0000
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0008
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1067
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	0.0010
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0008
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0001
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0012
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9999
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0008
Vapor Space Outage (ft):	2.7523

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-10 (TEG) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Ethylene Glycol	All	51.76	37.44	66.07	44.16	0.0008	0.0001	0.0012	50.0000			50.00	Option 1: VP50 = .00072 VP60 = .00114

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	TK-10 (TEG)	
City:	La Plata	
State:	Colorado	
Company:	ConocoPhillips Company	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	1130-gallon Glycol Tank (for dehydrator)	
Tank Dimensions		
Shell Height (ft):		5.00
Diameter (ft):		6.00
Liquid Height (ft) :		5.00
Avg. Liquid Height (ft):		2.50
Volume (gallons):		1,130.00
Turnovers:		20.00
Net Throughput(gal/yr):		22,600.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		6.00
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

TK-1 (Sump Oil) - Vertical Fixed Roof Tank
La Plata, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	183.10	378.13	561.23

Working Losses (lb):	183.0976
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Annual Net Throughput (gal/yr.):	84,000.0000
Annual Turnovers:	20.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,200.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	0.7500
Total Losses (lb):	561.2254

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

TK-1 (Sump Oil) - Vertical Fixed Roof Tank
La Plata, Colorado

Annual Emission Calcaulations	
Standing Losses (lb):	378.1278
Vapor Space Volume (cu ft):	314.2247
Vapor Density (lb/cu ft):	0.0222
Vapor Space Expansion Factor:	0.2681
Vented Vapor Saturation Factor:	0.5528
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	314.2247
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	6.2513
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.2513
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2513
Dome Radius (ft):	8.0000
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0222
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2681
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.4269
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.8110
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	3.2379
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.5528
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.4413
Vapor Space Outage (ft):	6.2513

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

TK-1 (Sump Oil) - Vertical Fixed Roof Tank
La Plata, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F)			Liquid Bulk Temp (deg F)	Vapor Pressure (psia)			Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
		Avg.	Min.	Max.		Avg.	Min.	Max.					
Crude oil (RVP 5)	All	51.76	37.44	66.07	44.16	2.4413	1.8110	3.2379	50.0000			207.00	Option 4: RVP=5

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A	Description	Ute CDP Inlet to Dehy
Analysis Date/Time:	12/7/2010 5:06 PM	Field:	Farmington, NM
Analyst Initials:	AST	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Methoc	Quesbtex
Data File:	QPC24.D		
Date Sampled:	12/6/2010		

Component	Mol%	Wt%	LV%
Methane	85.3946	70.0552	79.0010
Ethane	7.3491	11.3004	10.7563
Propane	2.8593	6.4476	4.3028
Isobutane	0.5306	1.5771	0.9480
n-Butane	0.6218	1.8480	1.0706
Neopentane	0.0054	0.0200	0.0113
Isopentane	0.2346	0.8656	0.4690
n-Pentane	0.1546	0.5702	0.3057
2,2-Dimethylbutane	0.0069	0.0305	0.0158
2,3-Dimethylbutane	0.0193	0.0849	0.0431
2-Methylpentane	0.0539	0.2376	0.1222
3-Methylpentane	0.0308	0.1359	0.0687
n-Hexane	0.0585	0.2577	0.1313
Heptanes	0.1973	0.9322	0.4105
Octanes	0.0300	0.1756	0.0820
Nonanes	0.0155	0.0916	0.0392
Decanes plus	0.0021	0.0152	0.0070
Nitrogen	0.1550	0.2221	0.0928
Carbon Dioxide	2.2807	5.1326	2.1227
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1144.6	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1125.8	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6768	air=1
Avg Molecular Weight	19.556	gm/mole
Propane GPM	0.783627	gal/MCF
Butane GPM	0.368718	gal/MCF
Gasoline GPM	0.290145	gal/MCF
26# Gasoline GPM	0.487829	gal/MCF
Total GPM	1.444646	gal/MCF
Base Mol%	99.904	%v/v
Sample Temperature:	85	°F
Sample Pressure:	198	psig
H2SLength of Stain Tube	N/A	ppm

Summary of 2010-2012 Extended Gas Analyses
Ute Compressor Station
GRI GlyCalc Information

Component			
Carbon Dioxide	2.261	Sample Temperature:	81.9
Hydrogen Sulfide	0.000	Sample Pressure:	204.3333
Nitrogen	0.168		
Methane	85.426		
Ethane	7.359		
Propane	2.850		
Isobutane	0.543		
n-Butane	0.617		
Isopentane	0.241		
n-Pentane	0.149		
Cyclopentane	0.000		
n-Hexane	0.053		
Cyclohexane	0.028		
Other Hexanes	0.103		
Heptanes	0.070		
Methylcyclohexane	0.042		
2,2,4 Trimethylpentane	0.005		
Benzene	0.013		
Toluene	0.022		
Ethylbenzene	0.001		
Xylenes	0.008		
C8+ Heavies	0.040		
Subtotal	100.000		
Oxygen	0.000		
Total			

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A	Description	Ute CDP Inlet to Dehy
Analysis Date/Time:	12/9/2010 12:05 PM	Field:	Farmington, NM
Analyst Initials:	AST	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Methoc	Quesbtex
Data File:	QPC41.D		
Date Sampled:	12/7/2010		

Component	Mol%	Wt%	LV%
Methane	85.4429	69.9588	79.0389
Ethane	7.2336	11.1012	10.5864
Propane	2.8160	6.3375	4.2373
Isobutane	0.5418	1.6071	0.9678
n-Butane	0.6161	1.8277	1.0608
Neopentane	0.0055	0.0204	0.0116
Isopentane	0.2399	0.8834	0.4795
n-Pentane	0.1566	0.5766	0.3097
2,2-Dimethylbutane	0.0072	0.0318	0.0165
2,3-Dimethylbutane	0.0201	0.0883	0.0449
2-Methylpentane	0.0569	0.2501	0.1289
3-Methylpentane	0.0326	0.1432	0.0726
n-Hexane	0.0615	0.2706	0.1381
Heptanes	0.2172	1.0275	0.4530
Octanes	0.0386	0.2237	0.1049
Nonanes	0.0291	0.1738	0.0753
Decanes plus	0.0079	0.0572	0.0264
Nitrogen	0.1733	0.2478	0.1038
Carbon Dioxide	2.3032	5.1733	2.1436
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1146.1	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1126.9	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6780	air=1
Avg Molecular Weight	19.594	gm/mole
Propane GPM	0.771761	gal/MCF
Butane GPM	0.370581	gal/MCF
Gasoline GPM	0.306042	gal/MCF
26# Gasoline GPM	0.504322	gal/MCF
Total GPM	1.452927	gal/MCF
Base Mol%	100.118	%v/v

Sample Temperature:	85	°F
Sample Pressure:	230	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0151	0.0603	0.0231
Toluene	0.0238	0.1122	0.0435
Ethylbenzene	0.0008	0.0043	0.0017
M&P Xylene	0.0069	0.0374	0.0146
O-Xylene	0.0010	0.0055	0.0021
2,2,4-Trimethylpentane	0.0057	0.0334	0.0157
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0332	0.1428	0.0617
Methylcyclohexane	0.0473	0.2373	0.1037
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.2807	5.1326	2.1227
Hydrogen Sulfide	0	0.0000	0.0000
Nitrogen	0.155	0.2221	0.0928
Methane	85.3946	70.0552	79.0010
Ethane	7.3491	11.3004	10.7563
Propane	2.8593	6.4476	4.3028
Isobutane	0.5306	1.5771	0.9480
n-Butane	0.6218	1.8480	1.0706
Isopentane	0.2400	0.8856	0.4803
n-Pentane	0.1546	0.5702	0.3057
Cyclopentane	0	0.0000	0.0000
n-Hexane	0.0585	0.2577	0.1313
Cyclohexane	0.0332	0.1428	0.0617
Other Hexanes	0.1109	0.4889	0.2498
Heptanes	0.0722	0.3462	0.1628
Methylcyclohexane	0.0473	0.2373	0.1037
2,2,4 Trimethylpentane	0.0057	0.0334	0.0157
Benzene	0.0151	0.0603	0.0231
Toluene	0.0238	0.1122	0.0435
Ethylbenzene	0.0008	0.0043	0.0017
Xylenes	0.0079	0.0429	0.0167
C8+ Heavies	0.0389	0.2352	0.1098
Subtotal	100.0000	100.0000	100.0000
Oxygen	0	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Component	Mol%	Wt%	LV%
Benzene	0.0167	0.0667	0.0256
Toluene	0.0282	0.1326	0.0516
Ethylbenzene	0.0013	0.0069	0.0027
M&P Xylene	0.0115	0.0623	0.0243
O-Xylene	0.0018	0.0099	0.0038
2,2,4-Trimethylpentane	0.0062	0.0361	0.0170
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0350	0.1505	0.0651
Methylcyclohexane	0.0529	0.2650	0.1160
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.3032	5.1733	2.1436
Hydrogen Sulfide	0	0.0000	0.0000
Nitrogen	0.1733	0.2478	0.1038
Methane	85.4429	69.9588	79.0389
Ethane	7.2336	11.1012	10.5864
Propane	2.816	6.3375	4.2373
Isobutane	0.5418	1.6071	0.9678
n-Butane	0.6161	1.8277	1.0608
Isopentane	0.2454	0.9038	0.4911
n-Pentane	0.1566	0.5766	0.3097
Cyclopentane	0	0.0000	0.0000
n-Hexane	0.0615	0.2706	0.1381
Cyclohexane	0.035	0.1505	0.0651
Other Hexanes	0.1168	0.5134	0.2629
Heptanes	0.0782	0.3766	0.1777
Methylcyclohexane	0.0529	0.2650	0.1160
2,2,4 Trimethylpentane	0.0062	0.0361	0.0170
Benzene	0.0167	0.0667	0.0256
Toluene	0.0282	0.1326	0.0516
Ethylbenzene	0.0013	0.0069	0.0027
Xylenes	0.0133	0.0722	0.0281
C8+ Heavies	0.0610	0.3756	0.1758
Subtotal	100.0000	100.0000	100.0000
Oxygen	0	0.0000	0.0000
Total	100.0000	100.0000	100.0000

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A	Description	Ute CDP Inlet to Dehy
Analysis Date/Time:	12/14/2010 8:59 AM	Field:	Farmington, NM
Analyst Initials:	AST	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Methoc	Quesbtex
Data File:	QPC73.D		
Date Sampled:	12/8/2010		

Component	Mol%	Wt%	LV%
Methane	84.9797	69.3126	78.4038
Ethane	7.5525	11.5461	11.0241
Propane	2.9548	6.6243	4.4344
Isobutane	0.5609	1.6575	0.9993
n-Butane	0.6503	1.9216	1.1166
Neopentane	0.0058	0.0213	0.0121
Isopentane	0.2487	0.9125	0.4959
n-Pentane	0.1633	0.5989	0.3221
2,2-Dimethylbutane	0.0073	0.0319	0.0165
2,3-Dimethylbutane	0.0205	0.0897	0.0457
2-Methylpentane	0.0576	0.2525	0.1302
3-Methylpentane	0.0329	0.1440	0.0731
n-Hexane	0.0615	0.2693	0.1376
Heptanes	0.2176	1.0275	0.4580
Octanes	0.0282	0.1634	0.0764
Nonanes	0.0146	0.0868	0.0375
Decanes plus	0.0013	0.0091	0.0042
Nitrogen	0.1650	0.2350	0.0985
Carbon Dioxide	2.2775	5.0960	2.1140
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1150.6	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1131.8	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6808	air=1
Avg Molecular Weight	19.669	gm/mole
Propane GPM	0.809800	gal/MCF
Butane GPM	0.387570	gal/MCF
Gasoline GPM	0.311189	gal/MCF
26# Gasoline GPM	0.516731	gal/MCF
Total GPM	1.509610	gal/MCF
Base Mol%	99.898	%v/v

Sample Temperature:	79.4	°F
Sample Pressure:	195	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0162	0.0644	0.0247
Toluene	0.0246	0.1153	0.0449
Ethylbenzene	0.0007	0.0038	0.0015
M&P Xylene	0.0062	0.0334	0.0131
O-Xylene	0.0008	0.0043	0.0016
2,2,4-Trimethylpentane	0.0058	0.0334	0.0158
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0338	0.1447	0.0627
Methylcyclohexane	0.0474	0.2368	0.1038
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.2775	5.0960	2.1140
Hydrogen Sulfide	0	0.0000	0.0000
Nitrogen	0.165	0.2350	0.0985
Methane	84.9797	69.3126	78.4038
Ethane	7.5525	11.5461	11.0241
Propane	2.9548	6.6243	4.4344
Isobutane	0.5609	1.6575	0.9993
n-Butane	0.6503	1.9216	1.1166
Isopentane	0.2545	0.9338	0.5080
n-Pentane	0.1633	0.5989	0.3221
Cyclopentane	0	0.0000	0.0000
n-Hexane	0.0615	0.2693	0.1376
Cyclohexane	0.0338	0.1447	0.0627
Other Hexanes	0.1183	0.5181	0.2655
Heptanes	0.0898	0.4329	0.2061
Methylcyclohexane	0.0474	0.2368	0.1038
2,2,4 Trimethylpentane	0.0058	0.0334	0.0158
Benzene	0.0162	0.0644	0.0247
Toluene	0.0246	0.1153	0.0449
Ethylbenzene	0.0007	0.0038	0.0015
Xylenes	0.0070	0.0377	0.0147
C8+ Heavies	0.0364	0.2178	0.1019
Subtotal	100.0000	100.0000	100.0000
Oxygen	0	0.0000	0.0000
Total	100.0000	100.0000	100.0000

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A	Description	Ute CDP Inlet to Dehy
Analysis Date/Time:	1/14/2011 9:18 AM	Field:	Farmington, NM
Analyst Initials:	PRP	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Method	Quesbtex
Data File:	QPC63.D		
Date Sampled:	1/1/2011		

Component	Mol%	Wt%	LV%
Methane	84.6847	68.2306	77.8182
Ethane	7.5141	11.3474	10.9240
Propane	2.9795	6.5985	4.4536
Isobutane	0.5765	1.6828	1.0230
n-Butane	0.6552	1.9126	1.1206
Neopentane	0.0066	0.0238	0.0137
Isopentane	0.2630	0.9530	0.5222
n-Pentane	0.1758	0.6369	0.3453
2,2-Dimethylbutane	0.0082	0.0355	0.0186
2,3-Dimethylbutane	0.0242	0.1047	0.0538
2-Methylpentane	0.0696	0.3014	0.1567
3-Methylpentane	0.0406	0.1757	0.0899
n-Hexane	0.0806	0.3487	0.1797
Heptanes	0.3710	1.7460	0.7841
Octanes	0.0717	0.4097	0.1935
Nonanes	0.0401	0.2337	0.1013
Decanes plus	0.0027	0.0193	0.0090
Nitrogen	0.1796	0.2527	0.1068
Carbon Dioxide	2.2563	4.9870	2.0860
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1163.6	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1144.5	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9969	
Specific Gravity	0.6890	air=1
Avg Molecular Weight	19.912	gm/mole
Propane GPM	0.816570	gal/MCF
Butane GPM	0.394202	gal/MCF
Gasoline GPM	0.405945	gal/MCF
26# Gasoline GPM	0.614276	gal/MCF
Total GPM	1.619017	gal/MCF
Base Mol%	100.505	%v/v

Sample Temperature:	62	°F
Sample Pressure:	174	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0220	0.0862	0.0333
Toluene	0.0515	0.2384	0.0935
Ethylbenzene	0.0021	0.0112	0.0044
M&P Xylene	0.0176	0.0940	0.0370
O-Xylene	0.0024	0.0126	0.0049
2,2,4-Trimethylpentane	0.0097	0.0559	0.0265
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0502	0.2120	0.0926
Methylcyclohexane	0.0901	0.4441	0.1963
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.2563	4.9870	2.0860
Hydrogen Sulfide	0	0.0000	0.0000
Nitrogen	0.1796	0.2527	0.1068
Methane	84.6847	68.2306	77.8182
Ethane	7.5141	11.3474	10.9240
Propane	2.9795	6.5985	4.4536
Isobutane	0.5765	1.6828	1.0230
n-Butane	0.6552	1.9126	1.1206
Isopentane	0.2696	0.9768	0.5359
n-Pentane	0.1758	0.6369	0.3453
Cyclopentane	0	0.0000	0.0000
n-Hexane	0.0806	0.3487	0.1797
Cyclohexane	0.0502	0.2120	0.0926
Other Hexanes	0.1426	0.6173	0.3190
Heptanes	0.1475	0.7094	0.3419
Methylcyclohexane	0.0901	0.4441	0.1963
2,2,4 Trimethylpentane	0.0097	0.0559	0.0265
Benzene	0.022	0.0862	0.0333
Toluene	0.0515	0.2384	0.0935
Ethylbenzene	0.0021	0.0112	0.0044
Xylenes	0.0200	0.1066	0.0419
C8+ Heavies	0.0924	0.5449	0.2575
Subtotal	100.0000	100.0000	100.0000
Oxygen	0	0.0000	0.0000
Total	100.0000	100.0000	100.0000

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A	Description	Ute CDP Inlet to Dehy
Analysis Date/Time:	6/18/2012 3:14 PM	Field:	Farmington, NM
Analyst Initials:	PRP	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Methoc	Quesbtex
Data File:	QPC76.D		
Date Sampled:	6/7/2012		

Component	Mol%	Wt%	LV%
Methane	86.0212	71.7765	80.0689
Ethane	7.2401	11.3231	10.6618
Propane	2.7330	6.2681	4.1380
Isobutane	0.5185	1.5674	0.9320
n-Butane	0.5714	1.7274	0.9899
Neopentane	0.0047	0.0176	0.0099
Isopentane	0.2198	0.8248	0.4421
n-Pentane	0.1206	0.4525	0.2400
2,2-Dimethylbutane	0.0044	0.0199	0.0102
2,3-Dimethylbutane	0.0109	0.0487	0.0245
2-Methylpentane	0.0301	0.1347	0.0685
3-Methylpentane	0.0154	0.0690	0.0345
n-Hexane	0.0250	0.1119	0.0564
Heptanes	0.0351	0.1708	0.0757
Octanes	0.0027	0.0154	0.0073
Nonanes	0.0008	0.0049	0.0021
Decanes plus	0.0012	0.0086	0.0039
Nitrogen	0.1660	0.2419	0.1000
Carbon Dioxide	2.2791	5.2168	2.1343
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1127.1	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1108.6	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9972	
Specific Gravity	0.6654	air=1
Avg Molecular Weight	19.228	gm/mole
Propane GPM	0.749013	gal/MCF
Butane GPM	0.348920	gal/MCF
Gasoline GPM	0.174659	gal/MCF
26# Gasoline GPM	0.354507	gal/MCF
Total GPM	3.611891	gal/MCF
Base Mol%	99.573	%v/v

Sample Temperature:	90	°F
Sample Pressure:	214	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0038	0.0153	0.0058
Toluene	0.0021	0.0100	0.0038
Ethylbenzene	0.0000	0.0000	0.0000
M&P Xylene	0.0005	0.0030	0.0012
O-Xylene	0.0000	0.0000	0.0000
2,2,4-Trimethylpentane	0.0012	0.0069	0.0032
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0082	0.0361	0.0154
Methylcyclohexane	0.0065	0.0334	0.0144
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.2791	5.2168	2.1343
Hydrogen Sulfide	0	0.0000	0.0000
Nitrogen	0.166	0.2419	0.1000
Methane	86.0212	71.7765	80.0689
Ethane	7.2401	11.3231	10.6618
Propane	2.733	6.2681	4.1380
Isobutane	0.5185	1.5674	0.9320
n-Butane	0.5714	1.7274	0.9899
Isopentane	0.2245	0.8424	0.4520
n-Pentane	0.1206	0.4525	0.2400
Cyclopentane	0	0.0000	0.0000
n-Hexane	0.025	0.1119	0.0564
Cyclohexane	0.0082	0.0361	0.0154
Other Hexanes	0.0608	0.2723	0.1377
Heptanes	0.0133	0.0691	0.0331
Methylcyclohexane	0.0065	0.0334	0.0144
2,2,4 Trimethylpentane	0.0012	0.0069	0.0032
Benzene	0.0038	0.0153	0.0058
Toluene	0.0021	0.0100	0.0038
Ethylbenzene	0	0.0000	0.0000
Xylenes	0.0005	0.0030	0.0012
C8+ Heavies	0.0042	0.0259	0.0121
Subtotal	100.0000	100.0000	100.0000
Oxygen	0	0.0000	0.0000
Total	100.0000	100.0000	100.0000

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A	Description	Ute CDP Inlet to Dehy
Analysis Date/Time:	6/19/2012 8:44 AM	Field:	Farmington, NM
Analyst Initials:	PRP	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Methoc	Quesbtex
Data File:	QPC79.D		
Date Sampled:	6/7/2012		

Component	Mol%	Wt%	LV%
Methane	86.0335	71.7713	80.0262
Ethane	7.2647	11.3592	10.6907
Propane	2.7602	6.3293	4.1764
Isobutane	0.5288	1.5984	0.9499
n-Butane	0.5879	1.7768	1.0177
Neopentane	0.0056	0.0210	0.0118
Isopentane	0.2055	0.7711	0.4131
n-Pentane	0.1242	0.4659	0.2470
2,2-Dimethylbutane	0.0050	0.0223	0.0114
2,3-Dimethylbutane	0.0120	0.0539	0.0270
2-Methylpentane	0.0332	0.1486	0.0756
3-Methylpentane	0.0172	0.0769	0.0385
n-Hexane	0.0280	0.1255	0.0632
Heptanes	0.0475	0.2316	0.1031
Octanes	0.0038	0.0224	0.0103
Nonanes	0.0020	0.0113	0.0047
Decanes plus	0.0000	0.0000	0.0000
Nitrogen	0.1714	0.2497	0.1032
Carbon Dioxide	2.1695	4.9648	2.0302
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1129.8	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1111.5	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9971	
Specific Gravity	0.6656	air=1
Avg Molecular Weight	19.232	gm/mole
Propane GPM	0.756468	gal/MCF
Butane GPM	0.357470	gal/MCF
Gasoline GPM	0.180062	gal/MCF
26# Gasoline GPM	0.365324	gal/MCF
Total GPM	3.622044	gal/MCF
Base Mol%	100.069	%v/v

Sample Temperature:	90	°F
Sample Pressure:	215	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0046	0.0187	0.0071
Toluene	0.0032	0.0153	0.0059
Ethylbenzene	0.0000	0.0000	0.0000
M&P Xylene	0.0013	0.0069	0.0027
O-Xylene	0.0000	0.0000	0.0000
2,2,4-Trimethylpentane	0.0014	0.0080	0.0037
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0098	0.0429	0.0183
Methylcyclohexane	0.0083	0.0424	0.0183
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.1695	4.9648	2.0302
Hydrogen Sulfide	0	0.0000	0.0000
Nitrogen	0.1714	0.2497	0.1032
Methane	86.0335	71.7713	80.0262
Ethane	7.2647	11.3592	10.6907
Propane	2.7602	6.3293	4.1764
Isobutane	0.5288	1.5984	0.9499
n-Butane	0.5879	1.7768	1.0177
Isopentane	0.2111	0.7921	0.4249
n-Pentane	0.1242	0.4659	0.2470
Cyclopentane	0	0.0000	0.0000
n-Hexane	0.028	0.1255	0.0632
Cyclohexane	0.0098	0.0429	0.0183
Other Hexanes	0.0674	0.3017	0.1525
Heptanes	0.0202	0.1043	0.0498
Methylcyclohexane	0.0083	0.0424	0.0183
2,2,4 Trimethylpentane	0.0014	0.0080	0.0037
Benzene	0.0046	0.0187	0.0071
Toluene	0.0032	0.0153	0.0059
Ethylbenzene	0	0.0000	0.0000
Xylenes	0.0013	0.0069	0.0027
C8+ Heavies	0.0045	0.0268	0.0123
Subtotal	100.0000	100.0000	100.0000
Oxygen	0	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Sales oil analysis for E&P Tank

1210 D Street
Rock Springs, Wy. 82901
Ph: 307-352-7292
Fax: 307-352-7326

Questar Energy Services
Applied Technology Services

API Gravity
Reid Vapor Pressure

Producer:	**Conoco Phillips**
Well Name:	**Ute CDP**
Field:	**Farmington**
County and State:	**New Mexico**
Corrected API Gravity:	**58.0@60*f**
RVP:	**3.9#**
Date Sampled:	**4/14/11**
Date Analyzed:	**4/21/11**
Sampled By:	**Salyzar**
Analyzed By:	**Putnam**

*** This is a sample of the sales oil.**

Inlet liquids sample
for E&P Tank

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901
(307) 352-7292

LIMS ID:	N/A		Description:	Ute CDP Coalescing Scrubber
Analysis Date/Time:	4/20/2011	10:39 AM	Field:	Farmington, NM
Analyst Initials:	AST		ML#:	Conoco Phillips
Sample Temperature:	70.1 F		GC Method:	Quesliq1.M
Sample Pressure:	188		Data File:	QPC40.D
Date Sampled:	4/14/2011		Instrument ID:	1

Component	Mol%	Wt%	LV%
Methane	15.2754	2.4603	5.7886
Ethane	2.8457	0.8591	1.7019
Propane	2.2485	0.9954	1.3853
Isobutane	0.8541	0.4984	0.6250
n-Butane	1.3596	0.7934	0.9586
Neopentane	0.0015	0.0011	0.0013
Isopentane	1.4593	1.0571	1.1935
n-Pentane	1.1185	0.8102	0.9067
2,2-Dimethylbutane	0.1311	0.1134	0.1224
2,3-Dimethylbutane	0.5821	0.5036	0.5335
2-Methylpentane	1.5211	1.3161	1.4120
3-Methylpentane	0.9396	0.8129	0.8575
n-Hexane	2.3908	2.0685	2.1987
Heptanes	17.2980	16.5910	15.9630
Octanes	15.4307	16.8176	15.8602
Nonanes	13.1696	15.6794	14.3081
Decanes plus	22.2889	38.1475	35.7760
Nitrogen	0.0323	0.0091	0.0079
Carbon Dioxide	1.0532	0.4653	0.4019
Total	100.0000	100.0000	100.0000

Global Properties		**Units**
Avg Molecular Weight	99.6064	gm/mole
Pseudocritical Pressure	460.85	psia
Pseudocritical Temperatu	452.60	degF
Specific Gravity	0.70588	gm/ml
Liquid Density	5.8848	lb/gal
Liquid Density	247.16	lb/bbl
Specific Gravity	2.5602	air=1
SCF/bbl	944.95	SCF/bbl
SCF/gal	22.4989	SCF/gal
MCF/gal	0.0225	MCF/gal
gal/MCF	44.461	gal/MCF
Net Heating Value	4965.9	BTU/SCF at 60°F
Net Heating Value	18302.0	BTU/lb at 60°F
Gross Heating Value	5086.9	BTU/SCF at 60°F
Gross Heating Value	19671.5	BTU/lb at 60°F
Gross Heating Value	120893.1	BTU/gal at 60°F
API Gravity	68.95900153	
MON	53.7	
RON	55.2	
RVP	808.062	psia

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

Component	Mol%	Wt%	LV%
Benzene	0.7645	0.5996	0.4784
Toluene	3.9271	3.6329	2.9409
Ethylbenzene	0.4620	0.4925	0.3987
M&P Xylene	4.4878	4.7836	3.8863
O-Xylene	0.8157	0.8694	0.6937
2,2,4-Trimethylpentane	1.3158	1.5090	1.4789

Data File: Ute CDP Coalescing Scrubber Page #2

GRI E&P TANK INFORMATION

Component	Mol%	Wt%	LV%
H2S			
O2			
CO2	1.0532	0.4653	0.4019
N2	0.0323	0.0091	0.0079
C1	15.2754	2.4603	5.7886
C2	2.8457	0.8591	1.7019
C3	2.2485	0.9954	1.3853
IC4	0.8541	0.4984	0.6250
NC4	1.3596	0.7934	0.9586
IC5	1.4608	1.0582	1.1948
NC5	1.1185	0.8102	0.9067
Hexanes	3.1739	2.7460	2.9254
Heptanes	16.5335	15.9914	15.4846
Octanes	10.1878	11.6757	11.4404
Nonanes	7.4041	9.5339	9.3294
Benzene	0.7645	0.5996	0.4784
Toluene	3.9271	3.6329	2.9409
E-Benzene	0.4620	0.4925	0.3987
Xylene	5.3035	5.6530	4.5800
n-C6	2.3908	2.0685	2.1987
2,2,4-Trimethylpentane	1.3158	1.5090	1.4789
C10 Plus			
C10 Mole %	22.2889	38.1475	35.7760
Molecular Wt.	172.3562		
Specific Gravity	0.7522		
Total	100.00	100.00	100.00
Ethane (includes CO2, N2, and C1)	19.2066	3.7938	
C6+	73.75190	92.05000	

APPENDIX J

Air Quality Impact Analysis
(To be provided upon completion)

APPENDIX K

Endangered Species List

Group	Name	Population	Status	Lead Office	Recovery Plan Name	Recovery Plan Stage
Birds	Yellow-billed Cuckoo (Coccyzus	Western U.S. DPS	Candidate	Sacramento Fish And Wildlife		
Birds	Mexican spotted owl (Strix		Threatened	Arizona Ecological Services	Draft Recovery Plan for the	Draft Revision 1
Birds	Southwestern willow flycatcher		Endangered	Arizona Ecological Services	Final Recovery Plan for the	Final
Flowering Plants	Knowlton's cactus (Pediocactus		Endangered	New Mexico Ecological Services	Knowlton's (=Hedgehog) Cactus	Final
Insects	Uncompahgre fritillary butterfly		Endangered	Western Colorado Ecological	Uncompahgre Fritillary Butterfly	Final
Mammals	Black-footed ferret (Mustela	U.S.A. (specific portions of AZ,	Experimental Population, Non-	Office Of The Regional Director		
Mammals	Canada Lynx (Lynx canadensis)	(Contiguous U.S. DPS)	Threatened	Montana Ecological Services	Recovery Outline for the	Outline
Mammals	New Mexico meadow jumping		Candidate			
Mammals	North American wolverine (Gulo		Candidate	Montana Ecological Services		

APPENDIX L

2011 Actual Emissions

APPENDIX M

Greenhouse Gas Emissions

Instructions: This is the only sheet you input data. Please only enter in the highlighted areas. List facilities, fuel, and related operating data parameters for the equipment included in your permit or NOI. If necessary, add rows. All other pages do not require input and are password protected. Please note: fuel parameters are an average or representative across all sources included in this report and ideally from a recent fuel analysis. Throughput is the amount of gas produced or handled by the facility. If you only have engines at your facility as reflected by your permit/NOI, put zero in the facility throughput cell(s). Total GHG emissions are listed on the GHG summary page.

Facility Name	Fuel (MMSCF/Yr)	Throughput (MMSCF/YR)	Pneumatic Count	Compressor Starts	Compressor Blowdowns	Permit No.	AI NO.
UTE CDP	182.36	14.40	6	2	2		
For additional facilities, insert rows in highlighted range above this cell							
Total	182.36	14.4	6	2	2		

Fuel Parameters

Fuel MMBtu (HHV)	1147.00
Average or representative methane content mole %	86.00
Average or representative CO2 content mole %	2.00

Vented Emissions - Ute CDP (Potential to Emit)

Instructions: This is the only sheet you input data. Please only enter in the highlighted areas. List facilities, fuel, and related operating data parameters for the equipment included in your permit or NOI. If necessary, add rows. All other pages do not require input and are password protected. Please note: fuel parameters are an average or representative across all sources included in this report and ideally from a recent fuel analysis. Throughput is the amount of gas produced or handled by the facility. If you only have engines at your facility as reflected by your permit/NOI, put zero in the facility throughput cell(s). Total GHG emissions are listed on the GHG summary page.
Calculation Methodology: Uses API Table(s) 5.1, 5.3, 5-15 & 5-21 to calculate vented methane and CO2 emissions from glycol dehydrators, dehydrator pump(s) gas driven pneumatic devices and compressor starts and blowdown(s). The methods are reflected in the calculations listed below.

Dehydrator Emissions (including pumps)	
Emission Factor(s)	
CH4 emission factor (tonnes CH4/MMscf)	0.0053
Methane Gas Content Basis of Factor mole %	78.8
GRI/EPA Kimray Pump CH4 Emission factor (tonnes CH4/MMscf)	0.019
Dehydration Emissions Totals	
CH4 Kimray pump Emissions (Metric Tons)	0.3
CH4 Dehydration Emissions (Metric Tons)	0.1
CO2 Emissions (Metric Tons)	0.0
CH4 Total Emissions (Metric Tons)	0.4
CO2e Emissions (Metric Tons)	8.0
Pneumatic Devices Emissions	
Emission Factor(s)	
CH4 emission factor Production Average (tonnes/device-yr)	2.415
Methane Gas Content Basis of Factor mole %	78.8
Pneumatic Devices Emissions Totals	
CH4 Emissions (metric tons/yr)	15.8
CO2 Emissions (Metric Tons)	1.0
CO2e Total Emissions (metric tons/yr)	333.1
Maintenance and Upset Event Emissions	
Emission Factor(s)	
CH4 emission factor compressor starts (tonnes/compressor-yr)	0.1620
CH4 emission factor compressor blowdowns (tonnes/compressor-yr)	0.0724
Average or representative methane content mole %	78.8000
Maintenance & Upset Event Emissions Totals	
CH4 Emissions (metric tons) - Compressor Starts	0.4
CO2 Emissions (metric tons) Compressor Starts	0.0
CH4 Emissions (metric tons) - Compressor Blowdowns	0.2
CO2 Emissions (Metric Tons) - Compressor Blowdowns	0.0
CO2e Emissions (metric tons)	10.8
Vented Emissions Total (metric tons/yr)	351.9

Combustion Emissions - Ute CDP (Potential to Emit)

Instructions: This is the only sheet you input data. Please only enter in the highlighted areas. List facilities, fuel, and related operating data parameters for the equipment included in your permit or NOI. If necessary, add rows. All other pages do not require input and are password protected. Please note: fuel parameters are an average or representative across all sources included in this report and ideally from a recent fuel analysis. Throughput is the amount of gas produced or handled by the facility. If you only have engines at your facility as reflected by your permit/NOI, put zero in the facility throughput cell(s). Total GHG emissions are listed on the GHG summary page.
Calculation Methodology: (Fuel Consumption (MMSCF/YR) * Fuel HHV (btu/scf) * 53.02 kg CO2 /mmbtu * 0.001)

Emission Factor(s)

CO2 Emission Factor Kg/mmbtu	53.02
CH4 Emission Factor Kg/mmbtu	0.0009
Conversion to metric tons	0.001

Combustion Emissions Totals

CO2 Emissions (Metric Tons)	11090.0
CH4 Emissions (Metric Tons	0.2
CO2e Emissions (Metric Tons)	11094.0

Fugitive Emissions - Ute CDP (Potential to Emit)

Instructions: This is the only sheet you input data. Please only enter in the highlighted areas. List facilities, fuel, and related operating data parameters for the equipment included in your permit or NOI. If necessary, add rows. All other pages do not require input and are password protected. Please note: fuel parameters are an average or representative across all sources included in this report and ideally from a recent fuel analysis. Throughput is the amount of gas produced or handled by the facility. If you only have engines at your facility as reflected by your permit/NOI, put zero in the facility throughput cell(s). Total GHG emissions are listed on the GHG summary page. **Calculation Methodology:** Uses API's facility-level average fugitive emission factors provided in Table 6.1. Determine and enter on the inputs page annual gas production from each facility and using a representative gas analysis determine methane and CO2 content on a mole basis and enter also enter that data on the inputs page

Emission Factor(s)	
CH4 emission factor (tonnes CH4/MMscf) - API - 6.1.1	0.0259
Gas Content Basis of Factor mole %	78.8
Fugitive Emissions Totals	
CO2 Emissions (Metric Tons)	0.0
CH4 Emissions (Metric Tons	0.4
CO2e Emissions (Metric Tons)	8.6

Instructions: This is the only sheet you input data. Please only enter in the highlighted areas. List facilities, fuel, and related operating data parameters for the equipment included in your permit or NOI. If necessary, add rows. All other pages do not require input and are password protected. Please note: fuel parameters are an average or representative across all sources included in this report and ideally from a recent fuel analysis. Throughput is the amount of gas produced or handled by the facility. If you only have engines at your facility as reflected by your permit/NOI, put zero in the facility throughput cell(s). Total GHG emissions are listed on the GHG summary page.	Metric Tons
CO_2	11091.1
CH_4	17.3
CO_2e Combustion	11094.0
CO_2e Vented	351.9
CO_2e Fugitive	8.6
CO_2e	11454.5

Part 71 Title V Permit Application

ConocoPhillips Company
Ute CDP
La Plata County, Colorado

Prepared for
Air & Radiation Program, 8P-AR
United States Environmental Protection Agency
Region 8

Prepared by

PEI

Providing Environmental Solutions Worldwide
Compliance · Engineering · Remediation · Mercury & Toxic Metals

P.O. Box 1415
Aztec, New Mexico 87410

On behalf of
ConocoPhillips Company
P.O. Box 4289
Farmington, New Mexico 87499-4289

May 2011

TABLE OF CONTENTS

1.0 INTRODUCTION

ConocoPhillips Company (COP) is submitting this application to request a Part 71 Title V Operating Permit for the Ute CDP located in La Plata County, Colorado on Southern Ute Tribal Land. The Ute CDP is a natural gas compressor station that dehydrates and compresses natural gas prior to custody transfer in a pipeline system. General contact information for the facility can be found in the General Information and Summary (GIS) form in Appendix A.

Since potential emissions did not exceed 250 tons per year, the facility was not required to apply for a construction permit. As part of its internal environmental audit process, COP learned that the glycol dehydrator at its Ute CDP was emitting at major source levels for hazardous air pollutants (HAP), making the facility subject to permitting requirements. This application represents proposed changes to be made at the station, as well as proposed rates to be incorporated into a permit that will limit the potential to emit below major source thresholds.

The Application forms are presented in Appendix A. Supporting documents, emission calculations, and figures are included as noted in the Table of Contents.

1.1 Facility Description

The Ute CDP is located in Sections 14 and 15, Township 32N, Range 11W, approximately 17 miles south of Durango in La Plata County, Colorado. A topographic map illustrating the location of the well site is included in Appendix B of the application. The surrounding land use category is rural.

Operation at the site is conducted under the Standard Industrial Classification (SIC) Code 1311 – Crude oil and natural gas exploration and production. The facility currently operates two 4-stroke, lean burn Waukesha L5108GL engines rated at 1,072 horsepower (hp) each. A third L5108GL has been shut down for more than one year but remains onsite. Two of the L5108GL engines will be permanently removed from the location. The third unit is being modified and will be subject to 40 Code of Federal Regulations (CFR) 60.4233(f)(4). According to the manufacturer, once modified, the old L5108GL will be designated as an L5790GL rated at 1,215 hp (Emission Unit E-1). A 4-stroke, lean burn Waukesha L7042GL rated at 1,478 hp (Emission Unit E-2) will be brought onsite to replace the two Waukesha L5108GL engines that are being removed.

Significant emission units to be operated at the location will include two compressor engines (E-1 and E-2), a triethylene glycol dehydrator (DEHY-1), and condensate tanks (TK-1 and TK-2). Insignificant emission units include combustion turbines, heated separators, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks. All combustion units are gas-fired units fueled with natural gas (NG) supplied from the surrounding wells. A process flow diagram is included in Appendix B.2.

2.0 EMISSION CALCULATION METHODOLOGY

Manufacturer's data were used to estimate carbon monoxide (CO), nitrogen oxides (NOx), volatile organic compound (VOC), and formaldehyde emissions from the Waukesha engines, while AP-42 factors were used for particulate matter (PM) and sulfur dioxide (SO_2). AP-42 emission factors were used to estimate emissions of all pollutants from the heaters. The Environmental Protection

Agency's Tanks 4.09d software was used to estimate emissions from storage tanks, while E&P Tank Version 2.0 was used for the condensate tanks. GRI-GLYCalc 4.0 was used to estimate emissions from the glycol dehydrator. A summary of uncontrolled and controlled emissions for the CDP, as well as detailed calculations, is provided in Appendix C.

3.0 REGULATORY APPLICABILITY

3.1 National Ambient Air Quality Standards (NAAQS)

La Plata County, Colorado is designated as unclassifiable/attainment for all pollutants to which a NAAQS applies.

3.2 Title V

The facility's uncontrolled emissions exceed major source thresholds for criteria pollutants and HAP. ConocoPhillips is requesting federally-enforceable control requirements in a permit. The use of a condenser on the glycol dehydrator (DEHY-1) will limit VOC and HAP emissions to minor source levels.

3.3 Prevention of Significant Deterioration (PSD)

Compressor stations are not identified as one of the 28 source categories subject to the 100 tons per year thresholds. Additionally, the facility's potential emissions do not exceed the 250 ton PSD source threshold for other sources.

3.4 New Source Performance Standards (NSPS)

NSPS are codified in 40 CFR Part 60. The regulatory review identified four potentially applicable NSPS categories: standards applicable to petroleum/organic liquid storage tanks (K, Ka, Kb), standards applicable to stationary gas turbines (GG), standards applicable to equipment leaks at natural gas processing plants (KKK), and standards applicable to spark ignition internal combustion engines (JJJJ).

The NSPS subparts applicable to petroleum/organic liquid storage tanks include Subparts K, Ka, and Kb. Since the condensate tanks were constructed in the 1950's and storage capacities are less than 75 cubic meters, these subparts are not applicable.

NSPS Subpart GG is not applicable since the gas turbines have a capacity of less than 10 million British thermal units (Btu) per hour.

The Ute CDP is not a natural gas processing facility because it does not extract natural gas liquids from fuel gas or fractionate mixed natural gas liquids to natural gas products. Therefore, NSPS Subpart KKK is not applicable.

NSPS Subpart JJJJ applies to spark ignition internal combustion engines that are constructed, modified, or reconstructed after applicability dates specified in the rule. The Waukesha L5790GL (E-1) to be installed is being modified in 2011 from an L5108GL to an L5790GL. The L5108GL was manufactured prior to July 1, 2007. Per 40 CFR 60.4233(f)(4)(i), this engine will be subject to the emission limitations of Subpart JJJJ. The Waukesha L7042GL (E-2) was constructed prior to July 1, 2007 and is therefore not subject to Subpart JJJJ.

3.5 National Emission Standards for Hazardous Air Pollutants (NESHAP)

NESHAP for source categories are codified in 40 CFR Part 63. Based on the "Once In, Always In" policy, the Ute CDP is classified as a major source of HAP emissions when determining the applicable NESHAP regulations. The regulatory review identified four NESHAP categories potentially applicable to the compressor station operations: standards applicable to oil and natural gas production facilities (HH), standards applicable to natural gas storage and transmission facilities (HHH), standards applicable to organic liquids distribution facilities (EEEE), and standards applicable to spark ignition internal combustion engines (ZZZZ).

Since the facility was a major source of HAP emissions, 40 CFR 63 Subpart HH for Oil and Gas Production Facilities is applicable per 40 CFR 63.760(a)(1). DEHY-1 is subject to the control requirements of Subpart HH. A condenser will be used to control emissions from the dehydrator. Since throughput is less than 75,900 liters per day (21,000 gallons per day), the condensate tanks (TK-1 and TK-2) are not considered to be tanks with a potential for flashing emissions and are therefore not subject to Subpart HH. In addition, since the Ute CDP is not a natural gas processing plant, ancillary equipment and compressors are not subject to Subpart HH.

Since the Ute CDP is not a natural gas storage and transmission facility, Subpart EEEE is not applicable.

Subpart EEEE does not apply to the Ute CDP since the regulation contains an exemption for oil and gas production facilities.

The Waukesha L5790GL was constructed on August 8, 1988. Per 40 CFR 63.6590(a)(1)(i), engines constructed before December 19, 2002 are not subject to Subpart ZZZZ if located at a major source. The Waukesha L7042GL (E-2) is exempt from Subpart ZZZZ per 40 CFR 63.6590(b)(3)(ii) since it is a 4-stroke, lean burn engine located at a major source.

3.6 Compliance Assurance Monitoring

The Compliance Assurance Monitoring (CAM) Rule, 40 CFR Part 64, requires monitoring for certain emission units at major sources, assuring effective monitoring of air pollution control equipment. Though the glycol dehydrator (DEHY-1) has uncontrolled emissions greater than 100 tpy, the CAM rule does not apply to sources subject to Sections 111 (NSPS) or 112 (NESHAP) of the Clean Air Act (CAA). Therefore, the provisions of the CAM rule do not apply to the Ute CDP.

3.7 Permit Shield

COP is requesting a permit shield for non-applicable regulations pursuant to 40 CFR 71.6(f). A summary of the non-applicable regulations, or portions of non-applicable regulations requested for the permit shield are noted in the table below.

Summary of Permit Shield

Regulatory Standard	Emission Unit	Permit Shield Request	Regulatory Citation
40 CFR 60 Subparts K, Ka, Kb	TK-1, TK-2	These subparts do not apply to storage vessels for petroleum or condensate stored, processed, and/or treated at a drilling and production facility prior to custody transfer.	40 CFR 60.110(b), 110a(b), 110b(d)(4)
40 CFR 60 Subpart GG	T-1, T-2	Subpart GG is not applicable to the turbines since both have a capacity less than 10 MMBtu/hr.	40 CFR 60.330(a)
40 CFR 60 Subpart KKK	Fugitive Emissions	Since the Ute CDP is not a natural gas processing plant, Subpart KKK is not applicable.	40 CFR 60.4230(a)(4)(i)
40 CFR 60 Subpart JJJJ	E-2	Since the manufacture date of E-2 was 9/19/1995, it was constructed prior to the applicability date of the rule.	40 CFR 60.4230(a)(4)(i)
40 CFR 63 Subpart HH	TK-1, TK-2	Since each storage tank has an annual average throughput of less than 79,500 liters per day (21,000 gallons), TK-1 and TK-2 are not considered storage tanks with a potential for flashing emissions and are not subject to the control requirements of Subpart HH .	40 CFR 63.766(a) and 63.761.
40 CFR 63 Subpart HH	E-1, E-2, and Fugitive Emissions	Since the Ute CDP is not a natural gas processing plant, the equipment leak standards of Subpart HH are not applicable.	40 CFR 63.769 (a) and 63.761
40 CFR 63 Subpart HHH	DEHY-1	Subpart HHH does not apply since the Ute CDP is not a natural gas transmission and storage facility transporting or storing gas prior to entering the pipeline to a local distribution company or the final end user.	40 CFR 63.1270(a)
40 CFR 63 Subpart ZZZZ	E-1	E-1 is exempt from Subpart ZZZZ since it was constructed prior to 12/19/2002.	40 CFR 63.6590(a)(1)(i)
40 CFR 63 Subpart ZZZZ	E-2	E-2 is exempt from Subpart ZZZZ since it is a 4-stroke lean burn engine located at a major source.	40 CFR 63.6590(b)(3)(ii)
40 CFR 64	Entire Facility	DEHY-1 is exempt since it is subject to a NESHAP. None of the other units have uncontrolled emissions greater than 100 tpy.	40 CFR 64.2(a)(3) and 64.2(b)(1)(i)
40 CFR 68	Entire Facility	The facility does not store any hazardous chemicals in excess of threshold quantities as determined by 40 CFR 68.115.	40 CFR 68.10(a)

APPENDIX A

EPA Forms

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

GENERAL INFORMATION AND SUMMARY (GIS)

A. Mailing Address and Contact Information

Facility name Ute CDP

Mailing address: Street or P.O. Box P.O. Box 4289

City Farmington State NM ZIP 87499-4289

Contact person: Randy Poteet Title Principal Environmental Consultant

Telephone (505) 326 - 9811 Ext. _________

Facsimile (505) 599 - 4005

B. Facility Location

Temporary source? ___Yes X No Plant site location Sections14 and 15, T32N, R11W 37.0173N, 108.0201W

Drive north from Aztec, NM for 10.7 miles on US 550 to CR 2300 and turn left. Travel 9.8 miles to Ute CDP on right.

City Not Applicable (N/A) State CO County La Plata EPA Region 8

Is the facility located within:

Indian lands? X YES ___ NO OCS waters? ___YES X NO

Non-attainment area? ___ YES X NO If yes, for what air pollutants? _________

Within 50 miles of affected State? X YES __ NO If yes, What State(s)? CO, NM

C. Owner

Name ConocoPhillips Company Street/P.O. Box PO Box 2197

City Houston State TX ZIP 77252 - 2197

Telephone (281) 293 – 1000 Ext_________

D. Operator

Name ConocoPhillips Company Street/P.O. Box PO Box 4289 (3401 E. 30th Street)

City Farmington State NM ZIP 87499-4289

Telephone (505) 326 – 9700 Ext_________

E. Application Type

Mark only one permit application type and answer the supplementary question appropriate for the type marked.

X Initial Permit ___ Renewal ___ Significant Mod ___ Minor Permit Mod(MPM)

___ Group Processing, MPM ___ Administrative Amendment

For initial permits, when did operations commence? 1988

For permit renewal, what is the expiration date of current permit? _____/____/_____

F. Applicable Requirement Summary

Mark all types of applicable requirements that apply.

___ SIP ___ FIP/TIP ___ PSD ___Non-attainment NSR

___ Minor source NSR X Section 111 ___ Phase I acid rain ___Phase II acid rain

___ Stratospheric ozone ___ OCS regulations X NESHAP ___ Sec. 112(d) MACT

___ Sec. 112(g) MACT ___ Early reduction of HAP ___ Sec 112(j) MACT ___ RMP [Sec.112(r)]

___ Tank Vessel requirements, sec. 183(f)) ___ Section 129 Standards/Requirement

___ Consumer / comm.. products, ' 183(e) ___ NAAQS, increments or visibility (temp. sources)

Has a risk management plan been registered? ___YES X NO Regulatory agency _____________

Phase II acid rain application submitted? ___YES X NO If yes, Permitting authority _____________

G. Source-Wide PTE Restrictions and Generic Applicable Requirements

Cite and describe any emissions-limiting requirements and/or facility-wide "generic" applicable requirements.

The dehydrator (DEHY-1) must be operated with a condenser at all times.

H. Process Description

List processes, products, and SIC codes for the facility.

Process	Products	SIC
Oil and Natural Gas Exploration and Production	Natural Gas	1311

I. Emission Unit Identification

Assign an emissions unit ID and describe each emissions unit at the facility. Control equipment and/or alternative operating scenarios associated with emissions units should by listed on a separate line. Applicants may exclude from this list any insignificant emissions units or activities.

Emissions Unit ID	Description of Unit
E-1	1,215 Waukesha L5790GL - 4SLB natural gas-fueled compressor engine
E-2	1,478 hp Waukesha L7042GL - 4SLB natural gas-fueled compressor engine
DEHY-1	14.4 MMscf/day glycol dehydrator (The capacity of DEHY-1 was obtained using the methodology of 40 CFR 63.760(a)(1)(i)(A) for declining gas fields, which uses the maximum 5 year gas throughput multiplied by a 20% contingency factor.)
TK-1	300-barrel Condensate Tank
TK-2	300-barrel Condensate Tank

J. Facility Emissions Summary

Enter potential to emit (PTE) for the facility as a whole for each air pollutant listed below. Enter the name of the single HAP emitted in the greatest amount and its PTE. For all pollutants stipulations to major source status may be indicated by entering "major" in the space for PTE. Indicate the total actual emissions for fee purposes for the facility in the space provided. Applications for permit modifications need not include actual emissions information.

NOx _*_ tons/yr VOC _*_ tons/yr SO2 _*_ tons/yr

PM-10 _*_ tons/yr CO _*_ tons/yr Lead _Negligible_ tons/yr

Total HAP _*_ tons/yr

Single HAP emitted in the greatest amount _Formaldehyde_ PTE _*_ tons/yr

Total of regulated pollutants (for fee calculation), Sec. F, line 5 of form FEE _124_ tons/yr

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions. This application includes a request for a federally-enforceable permit requirement to operate a condenser at all times on the dehydrator (DEHY-1).

K. Existing Federally-Enforceable Permits

Permit number(s) __________ Permit type ________ Permitting authority ______

Permit number(s) __________ Permit type ________ Permitting authority ______

L. Emission Unit(s) Covered by General Permits

Emission unit(s) subject to general permit ____________________

Check one: ___ Application made ___ Coverage granted

General permit identifier ________________ Expiration Date ____/____/____

M. Cross-referenced Information

Does this application cross-reference information? ___ YES X NO (If yes, see instructions)

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

POTENTIAL TO EMIT (PTE)

For each unit with emissions that count towards applicability, list the emissions unit ID and the PTE for the air pollutants listed below and sum them up to show totals for the facility. You may find it helpful to complete form **EMISS** before completing this form. Show other pollutants not listed that are present in major amounts at the facility on attachment in a similar fashion. You may round values to the nearest tenth of a ton. Also report facility totals in section **J** of form **GIS**.

Emissions Unit ID	Regulated Air Pollutants and Pollutants for which the Source is Major (tons/yr)						
	NOx	VOC	SO2	PM10	CO	Lead	HAP
E-1	*	*	*	*	*	-	*
E-2	*	*	*	*	*	-	*
DEHY-1	*	*	*	*	*	-	*
TK-1	-	*	-	-	-	-	*
TK-2	-	*	-	-	-	-	*
FACILTY TOTALS	*	*	*	*	*	-	*

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions.

Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID E-1 Description Waukesha L5790GL 4SLB RICE

SIC Code (4-digit) 1311 SCC Code 20200202

B. Emissions Unit Description

Primary use Gas Compression Temporary Source ___Yes X No

Manufacturer Waukesha Model No. L5790GL

Serial Number 399989 Installation Date To be installed

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) Natural gas compressor engine

Boiler horsepower rating 1,215 hp (1,130 hp altitude derated) Boiler steam flow lb/hr)______

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input 10.0 MM BTU/hr Max. Design Heat Input 10.75 MM BTU/hr

C. Fuel Data

Primary fuel type(s)_ Natural Gas ___ Standby fuel type(s)__ N/A

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0	0	950 Btu/scf

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas		10.5 Mscf	92.2 mmscf

E. Associated Air Pollution Control Equipment

Emissions unit ID___________ Device type

Air pollutant(s) Controlled

Manufacturer

Model No.__ Serial No.

Installation date__/_____/_________ Control efficiency (%)

Efficiency estimation method

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) N/A	Inside stack diameter (ft) N/A
Stack temp(°F) N/A	Design stack flow rate (ACFM) N/A
Actual stack flow rate (ACFM) N/A	Velocity (ft/sec) N/A

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID E-1

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx		*	*	
CO		*	*	
VOC		*	*	
PM		*	*	
SO2		*	*	
Formaldehyde		*	*	50-00-0
Acetaldehyde		*	*	75-07-0
Acrolein		*	*	107-02-8
Benzene		*	*	71-43-2

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions.

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR FUEL COMBUSTION SOURCES (EUD-1)

A. General Information

Emissions unit ID E-2 Description Waukesha L7042GL 4SLB RICE

SIC Code (4-digit) E-2 SCC Code 20200202

B. Emissions Unit Description

Primary use Gas Compression Temporary Source ___Yes X No

Manufacturer Waukesha Model No. L7042GL

Serial Number C-11672/1 Installation Date To be installed

Boiler Type: ___ Industrial boiler ___ Process burner ___ Electric utility boiler

Other (describe) Natural gas compressor engine

Boiler horsepower rating 1,478 hp (1,375 hp altitude derated) Boiler steam flow lb/hr)______

Type of Fuel-Burning Equipment (coal burning only):

___ Hand fired ___Spreader stoker ___Underfeed stoker ___Overfeed stoker

___ Traveling grate ___Shaking grate ___Pulverized, wet bed ___ Pulverized, dry bed

Actual Heat Input 9.83 MM BTU/hr Max. Design Heat Input 10.58 MM BTU/hr

C. Fuel Data

Primary fuel type(s) Natural Gas   Standby fuel type(s) N/A

Describe each fuel you expected to use during the term of the permit.

Fuel Type	Max. Sulfur Content (%)	Max. Ash Content (%)	BTU Value (cf, gal., or lb.)
Natural Gas	0	0	950 Btu/scf

D. Fuel Usage Rates

Fuel Type	Annual Actual Usage	Maximum Usage	
		Hourly	Annual
Natural Gas		10.4 Mscf	90.7 mmscf

E. Associated Air Pollution Control Equipment

Emissions unit ID E-2   Device type Oxidation catalyst

Air pollutant(s) Controlled CO, Formaldehyde

Manufacturer Miratech

Model No. ZXS-RF-Full-354XH   Serial No. RE-7129

Installation date TBD / / Control efficiency (%) 75% CO, 75% CH2O

Efficiency estimation method Manufacturer's guaranteed rates

F. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (this is not common).

Stack height (ft) N/A	Inside stack diameter (ft) N/A
Stack temp(°F) N/A	Design stack flow rate (ACFM) N/A
Actual stack flow rate (ACFM) N/A	Velocity (ft/sec) N/A

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID E-2

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx		*	*	
CO		*	*	
VOC		*	*	
PM		*	*	
SO2		*	*	
Formaldehyde		*	*	50-00-0
Acetaldehyde		*	*	75-07-0
Acrolein		*	*	107-02-8
Benzene		*	*	71-43-2

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions.

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID DEHY-1 Description Glycol Dehydrator

SIC Code (4-digit) 1311 SCC Code 31000227

B. Emissions Unit Description

Primary use or equipment type Natural Gas Dehydration

Manufacturer Pesco Model No. N/A

Serial No. 10413 Installation date 1988

Raw materials Natural gas

Finished products Dehydrated Natural Gas

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.42 MMscf (10.16/day)	3.71 Bscf
Maximum rate	0.6 MMscf (14.4/day)	5.3 Bscf

D. Associated Air Pollution Control Equipment

Emissions unit ID DEHY-1 Device Type Condenser

Manufacturer Natco Model No NC 36-6

Serial No. TBD Installation date ___/___/ TBD

Control efficiency (%) > 95% Capture efficiency (%) N/A

Air pollutant(s) controlled VOC/Organic HAP Efficiency estimation method Manufacturer

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(^{o}F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID DEHY-1 (includes reboiler emissions)

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
NOx		*	*	
CO		*	*	
VOC		*	*	
SO_2		*	*	
$PM_{10}/PM_{2.5}$		*	*	
Benzene		*	*	71-43-2
n-Hexane		*	*	110-54-3
Toluene		*	*	108-88-3
Xylenes		*	*	1330-20-7
Ethylbenzene		*	*	100-41-4

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions.

United States Environmental Protection Agency

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID TK-1 Description 300-barrel Condensate Storage Tank

SIC Code (4-digit) 1311 SCC Code 40400311

B. Emissions Unit Description

Primary use or equipment type Condensate Storage

Manufacturer Graver Model No. N/A

Serial No. 3935-4 Installation date 1988

Raw materials Natural Gas Condensate

Finished products Natural Gas Condensate

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.14 barrels	1,250 barrels
Maximum rate	0.29 barrels	2,500 barrels

D. Associated Air Pollution Control Equipment

Emissions unit ID N/A Device Type N/A

Manufacturer N/A Model No N/A

Serial No. N/A Installation date _____/___/_________

Control efficiency (%) N/A Capture efficiency (%) N/A

Air pollutant(s) controlled N/A Efficiency estimation method N/A

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(^{o}F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID TK-1

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC		*	*	
n-Hexane		*	*	110-54-3
Benzene		*	*	71-43-2
Toluene		*	*	108-88-3
Ethylbenzene		*	*	100-41-4
Xylene		*	*	1330-20-7

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions.

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION UNIT DESCRIPTION FOR PROCESS SOURCES (EUD-3)

A. General Information

Emissions unit ID TK-2 Description 300-barrel Condensate Storage Tank

SIC Code (4-digit) 1311 SCC Code 40400311

B. Emissions Unit Description

Primary use or equipment type Condensate Storage

Manufacturer Graver Model No. N/A

Serial No. 976-2 Installation date 1988

Raw materials Natural Gas Condensate

Finished products Natural Gas Condensate

Temporary source: X No ___Yes

C. Activity or Production Rates

Activity or Production Rate	Amount/Hour	Amount/Year
Actual Rate	0.14 barrels	1,250 barrels
Maximum rate	0.29 barrels	2,500 barrels

D. Associated Air Pollution Control Equipment

Emissions unit ID N/A Device Type N/A

Manufacturer N/A Model No N/A

Serial No. N/A Installation date _____/___/_________

Control efficiency (%) N/A Capture efficiency (%) N/A

Air pollutant(s) controlled N/A Efficiency estimation method N/A

E. Ambient Impact Assessment

This information must be completed by temporary sources or when ambient impact assessment is an applicable requirement for this emissions unit (This is not common)).

Stack height (ft) N/A

Inside stack diameter (ft) N/A

Stack temp(^{o}F) N/A

Design stack flow rate (ACFM) N/A

Actual stack flow rate (ACFM) N/A

Velocity (ft/sec) N/A

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Federal Operating Permit Program (40 CFR Part 71)

EMISSION CALCULATIONS (EMISS)

Calculate potential to emit (PTE) for applicability purposes and actual emissions for fee purposes for each emissions unit, control device, or alternative operating scenario identified in section I of form **GIS**. If form **FEE** does not need to be submitted with the application, do not calculate actual emissions.

A. Emissions Unit ID TK-2

B. Identification and Quantification of Emissions

First, list each air pollutant that is either regulated at the unit or present in major amounts, then list any other regulated pollutant (for fee calculation) not already listed. HAP may be simply listed as "HAP." Next, calculate PTE for applicability purposes and actual emissions for fee purposes for each pollutant. Do not calculate PTE for air pollutants listed solely for fee purposes. Include all fugitives for fee purposes. You may round to the nearest tenth of a ton for yearly values or tenth of a pound for hourly values.

Air Pollutants	Emission Rates			CAS No.
	Actual Annual Emissions (tons/yr)	Potential to Emit		
		Hourly (lb/hr)	Annual (tons/yr)	
VOC		*	*	
n-Hexane		*	*	110-54-3
Benzene		*	*	71-43-2
Toluene		*	*	108-88-3
Ethylbenzene		*	*	100-41-4
Xylene		*	*	1330-20-7

* See Appendix C for a summary of requested allowable emissions and potential uncontrolled emissions.

Federal Operating Permit Program (40 CFR Part 71)

INSIGNIFICANT EMISSIONS (IE)

List each insignificant activity or emission unit. In the "number" column, indicate the number of units in this category. Descriptions should be brief but unique. Indicate which emissions criterion of part 71 is the basis for the exemption.

Number	Description of Activities or Emissions Units	RAP, except HAP	HAP
2	4,512-gallon oil tanks (UOT-1, OT-1)	X	X
1	3,454-gallon coolant storage tank (CT-1)	X	X
1	1,130-gallon triethylene glycol storage tank (GT-1)	X	X
1	3,454-gallon methanol tank (MT-1)	X	X
2	250-gallon oil tanks (OT-2, OT-3)	X	X
1	250-gallon antifreeze tank (AT-1)	X	X
1	5,040-gallon below-grade pit sump liquids tank (BGT-1)	X	X
1	5,040-gallon below-grade condenser liquids tank (BGT-2)	X	X
1	30 kW Turbine (T-1)	X	X
1	65 kW Turbine (T-2)	X	X
1	Fugitive Emissions	X	X
1	Truck Loading of Condensate	X	X

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Federal Operating Permit Program (40 CFR Part 71)

INITIAL COMPLIANCE PLAN AND COMPLIANCE CERTIFICATION (I-COMP)

SECTION A - COMPLIANCE STATUS AND COMPLIANCE PLAN

Complete this section for each unique combination of applicable requirements and emissions units at the facility. List all compliance methods (monitoring, recordkeeping and reporting) you used to determine compliance with the applicable requirement described above. Indicate your compliance status at this time for this requirement and compliance methods and check "YES" or "NO" to the follow-up question.

Emission Unit ID(s): A compliance plan will be developed for each applicable unit once the Consent Decree is final.

Applicable Requirement (Describe and Cite)

Compliance Methods for the Above (Description and Citation):

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

_X_ Future-Effective Requirement: Do you expect to meet this on a timely basis? _X_ Yes ____No

---

Emission Unit ID(s):

Applicable Requirement (Description and Citation):

Compliance Methods for the Above (Description and Citation):

Compliance Status:

___ In Compliance: Will you continue to comply up to permit issuance? ____Yes ____No

___ Not In Compliance: Will you be in compliance at permit issuance? ___Yes ___No

___ Future-Effective Requirement: Do you expect to meet this on a timely basis? ____Yes ____No

B. SCHEDULE OF COMPLIANCE

Complete this section if you answered "NO" to any of the questions in section A. Also complete this section if required to submit a schedule of compliance by an applicable requirement. Please attach copies of any judicial consent decrees or administrative orders for this requirement.

Unit(s)____________________ Requirement ____

Reason for Noncompliance. Briefly explain reason for noncompliance at time of permit issuance or that future-effective requirement will not be met on a timely basis:

Narrative Description of how Source Compliance Will be Achieved. Briefly explain your plan for achieving compliance:

Schedule of Compliance. Provide a schedule of remedial measures, including an enforceable sequence of actions with milestones, leading to compliance, including a date for final compliance.

Remedial Measure or Action	Date to be Achieved

C. SCHEDULE FOR SUBMISSION OF PROGRESS REPORTS

Only complete this section if you are required to submit one or more schedules of compliance in section B or if an applicable requirement requires submittal of a progress report. If a schedule of compliance is required, your progress report should start within 6 months of application submittal and subsequently, no less than every six months. One progress report may include information on multiple schedules of compliance.

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_______________

Contents of Progress Report (describe):

First Report____/____/___ Frequency of Submittal_______________

D. SCHEDULE FOR SUBMISSION OF COMPLIANCE CERTIFICATIONS

This section must be completed once by every source. Indicate when you would prefer to submit compliance certifications during the term of your permit (at least once per year).

Frequency of submittal______________________ Beginning____/____/____

E. COMPLIANCE WITH ENHANCED MONITORING & COMPLIANCE CERTIFICATION REQUIREMENTS

This section must be completed once by every source. To certify compliance with these, you must be able to certify compliance for every applicable requirement related to monitoring and compliance certification at every unit.

Enhanced Monitoring Requirements: ____ In Compliance ____ Not In Compliance

Compliance Certification Requirements: ____ In Compliance ____ Not In Compliance

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

CERTIFICATION OF TRUTH, ACCURACY, AND COMPLETENESS (CTAC)

This form must be completed, signed by the "Responsible Official" designated for the facility or emission unit, and sent with each submission of documents (i.e., application forms, updates to applications, reports, or any information required by a part 71 permit).

A. Responsible Official

Name: (Last) Elmer (First) Matt (MI) ___

Title Manager, San Juan Operations

Street or P.O. Box P.O. Box 4289 (3401 E. 30^{th} St)

City Farmington State NM ZIP 87499- 4289

Telephone (505) 326 – 9802 Ext. ______ Facsimile (505) 326 - 9880

B. Certification of Truth, Accuracy and Completeness (to be signed by the responsible official)

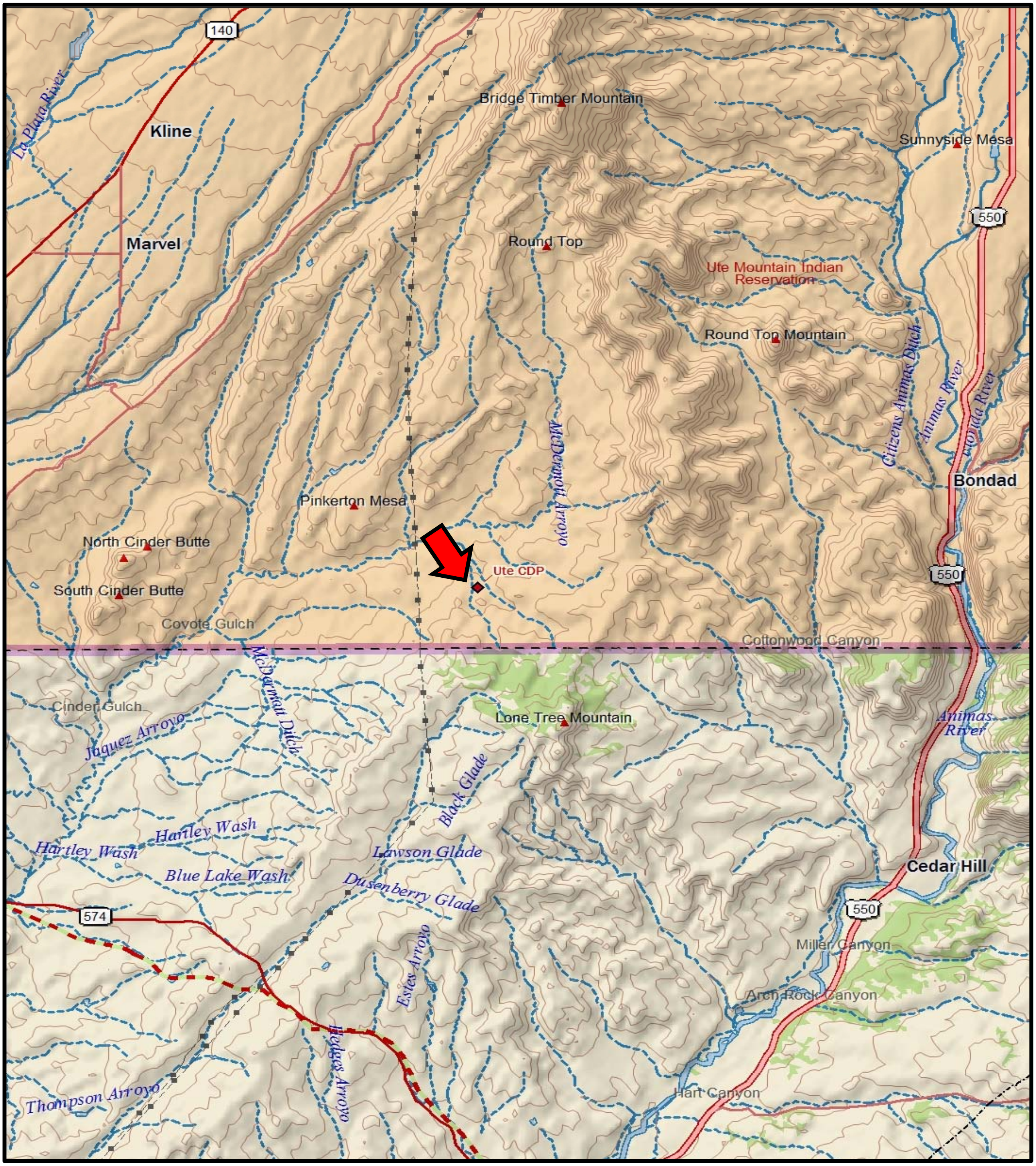
I certify under penalty of law, based on information and belief formed after reasonable inquiry, the statements and information contained in these documents are true, accurate and complete.

Name (signed) Matt Elmer

Name (typed) Matt Elmer Date: 5 / 11 / 11

APPENDIX B.1

Site Location Map



KEY: SOURCE: USGS 7.5 Minute Quadrangle (Topographic)

PROJECT	13704.01
PREPARED FOR	CONOCOPHILLIPS
LOCATION	37.0173N, 108.0201W

SHEET	***DRAWN BY***	***REVIEWED BY***	***DATE***
1 of 1	*ET*	*TLJ*	*4/28/10*

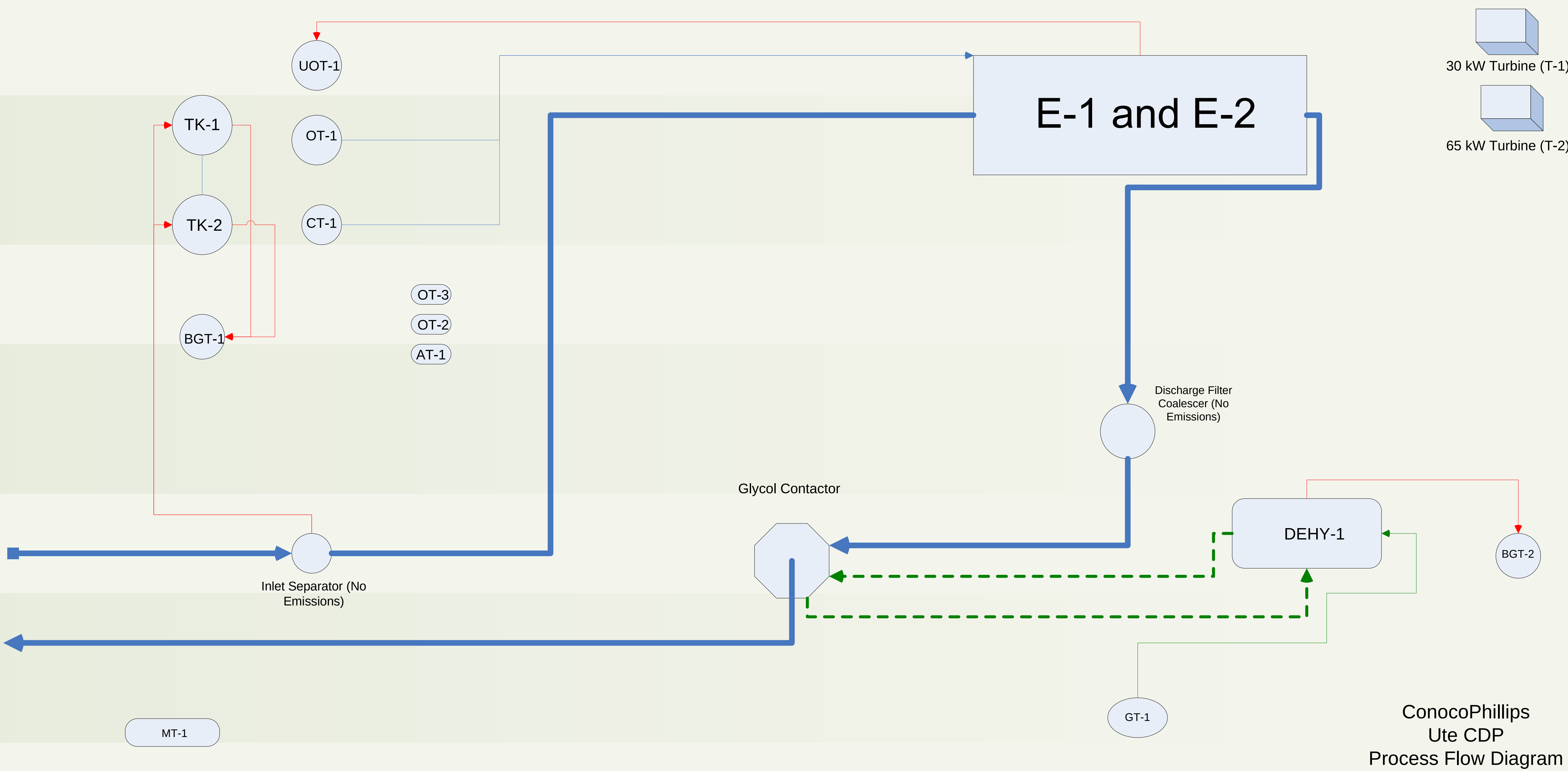
PEI

GENERAL VICINITY MAP
Ute CDP

(The Ute CDP is on the Southern Ute Reservation.)

APPENDIX B.2

Process Flow Diagram


UOT-1
TK-1
OT-1
TK-2
CT-1
BGT-1
OT-3
OT-2
AT-1
E-1 and E-2
30 kW Turbine (T-1)
65 kW Turbine (T-2)
Discharge Filter Coalescer (No Emissions)
Glycol Contactor
DEHY-1
BGT-2
Inlet Separator (No Emissions)
GT-1
MT-1
ConocoPhillips
Ute CDP
Process Flow Diagram

APPENDIX C

Emissions Calculations

ConocoPhillips Company - San Juan Basin

Ute CDP

Facility Emissions Requested in Permit (Controlled Emissions)

Unit ID	E-1	E-2	DEHY-1	TK-1	TK-2	Insignificant Emission Units[3]	Total by Pollutant
Description	Waukesha L5790GL	Waukesha L7042GL	Dehydrator[1]	Condensate Tank[2]	Condensate Tank[2]	-	
Rated Capacity (horsepower)	1,215	1,478	-	-	-	-	
Rated Capacity (MMBtu/hr)	-	-	0.125	-	-	-	
Hourly Emission Rate							
NO_x	7.47	6.06	0.01	-	-	0.04	**13.59**
CO	9.96	2.55	0.01	-	-	0.35	**12.87**
VOC[4]	2.49	3.03	1.78	1.72	1.72	0.50	**11.25**
SO_2	0.15	0.15	0.002	-	-	0.18	**0.48**
PM/PM_{10}	0.10	0.10	0.001	-	-	0.01	**0.21**
Formaldehyde	0.72	0.22	-	-	-	-	**0.94**
Acetaldehyde	0.09	0.08	-	-	-	-	**0.17**
Acrolein	0.05	0.05	-	-	-	-	**0.10**
Hexane	-	-	0.02	0.06	0.06	-	**0.14**
Benzene	0.004	0.004	0.13	0.02	0.02	-	**0.17**
Toluene	-	-	0.12	0.03	0.03	-	**0.17**
Ethylbenzene	-	-	0.002	0.001	0.001	-	**0.004**
Xylene	-	-	0.02	0.01	0.01	-	**0.04**
Annual PTE							
NO_x	32.73	26.55	0.06	-	-	0.17	**59.51**
CO	43.64	11.15	0.05	-	-	1.52	**56.36**
VOC	10.91	13.27	7.79	7.55	7.55	2.54	**49.60**
SO_2	0.66	0.65	0.008	-	-	0.78	**2.09**
PM/PM_{10}	0.43	0.43	0.004	-	-	0.04	**0.91**
Formaldehyde	3.16	0.96	-	-	-	-	**4.13**
Acetaldehyde	0.38	0.37	-	-	-	-	**0.75**
Acrolein	0.23	0.22	-	-	-	-	**0.45**
n-Hexane	-	-	0.11	0.26	0.26	-	**0.63**
Benzene	0.02	0.02	0.57	0.07	0.07	-	**0.75**
Toluene	-	-	0.52	0.11	0.11	-	**0.74**
Ethylbenzene	-	-	0.01	0.005	0.005	-	**0.02**
Xylene	-	-	0.11	0.04	0.04	-	**0.20**

Notes:

[1] The dehydrator includes VOC/HAP emissions from the still vent and the reboiler. Reboiler criteria pollutant emissions, except SO2, are based on AP-42, Ch. 1.4, Natural Gas Combustion. SO2 emissions are based on a sulfur content of 50 gr/Mscf.

[2] Emissions from condensate tanks were estimated using E&P Tank and an annual throughput of 5,000 barrels. Total emissions were split equally between the 2 tanks and include working, breathing, and flashing losses. Controls are not required on the condensate tanks.

[3] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutants. IA include 2 combustion turbines, 3 heated separators, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks. Details of these emissions are included in the applicable Appendix to the application.

[4] Startup, shutdown, and maintenance emissions will not exceed any hourly or annual limits established in the permit.

ConocoPhillips Company - San Juan Basin

Ute CDP

Uncontrolled Facility Potential to Emit

Unit ID	E-1	E-2	DEHY-1	TK-1	TK-2	Insignificant Emission Units[3]	Total by Pollutant
Description	Waukesha L5790GL	Waukesha L7042GL	Dehydrator[1]	Condensate Tank[2]	Condensate Tank[2]	-	
Rated Capacity (horsepower)	1,215	1,478	-	-	-	-	
Rated Capacity (MMBtu/hr)	-	-	0.125	-	-	-	
Hourly Emission Rate							
NO_x	7.47	6.06	0.01	-	-	0.04	**13.59**
CO	9.96	10.18	0.01	-	-	0.35	**20.51**
VOC[4]	2.49	3.03	32.78	1.72	1.72	0.50	**42.25**
SO_2	0.15	0.15	0.002	-	-	0.18	**0.48**
PM/PM_{10}	0.10	0.10	0.001	-	-	0.01	**0.21**
Formaldehyde	0.72	0.88	-	-	-	-	**1.60**
Acetaldehyde	0.09	0.08	-	-	-	-	**0.17**
Acrolein	0.05	0.05	-	-	-	-	**0.10**
Hexane	-	-	0.24	0.06	0.06	-	**0.36**
Benzene	0.004	0.004	2.88	0.02	0.02	-	**2.92**
Toluene	-	-	8.79	0.03	0.03	-	**8.84**
Ethylbenzene	-	-	0.57	0.001	0.001	-	**0.575**
Xylene	-	-	7.80	0.01	0.01	-	**7.82**
Annual PTE							
NO_x	32.73	26.55	0.06	-	-	0.17	**59.51**
CO	43.64	44.60	0.05	-	-	1.52	**89.81**
VOC	10.91	13.27	143.56	7.55	7.55	2.54	**185.37**
SO_2	0.66	0.65	0.008	-	-	0.78	**2.09**
PM/PM_{10}	0.43	0.43	0.004	-	-	0.04	**0.91**
Formaldehyde	3.16	3.85	-	-	-	-	**7.01**
Acetaldehyde	0.38	0.37	-	-	-	-	**0.75**
Acrolein	0.23	0.22	-	-	-	-	**0.45**
n-Hexane	-	-	1.06	0.26	0.26	-	**1.58**
Benzene	0.02	0.02	12.62	0.07	0.07	-	**12.80**
Toluene	-	-	38.48	0.11	0.11	-	**38.70**
Ethylbenzene	-	-	2.51	0.005	0.005	-	**2.52**
Xylene	-	-	34.15	0.04	0.04	-	**34.24**

Notes:

[1] The dehydrator includes VOC/HAP emissions from the still vent and the reboiler. Reboiler criteria pollutant emissions, except SO2, are based on AP-42, Ch. 1.4, Natural Gas Combustion. SO2 emissions are based on a sulfur content of 50 gr/Mscf.

[2] Emissions from condensate tanks were estimated using E&P Tank and an annual throughput of 5,000 barrels. Total emissions were split equally between the 2 tanks and include working, breathing, and flashing losses. Controls are not required on the condensate tanks.

[3] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutants. IA include 2 combustion turbines, 3 heated separators, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks. Details of these emissions are included in the applicable Appendix to the application.

[4] Startup, shutdown, and maintenance emissions will not exceed any hourly or annual limits established in the permit.

ConocoPhillips Company - San Juan Basin

Ute CDP

Waukesha L5790GL Emissions

Emission Unit Designation	E-1	
Source Description	Waukesha L5790GL	
Type	Turbocharged 4SLB engine	
Rated Output	1,215	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	1,130	hp
Fuel Use Rate	8850	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	10.00	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	10.53	Mscf/hr, site derated
Annual Fuel Consumption	92.2	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	8760	hrs/year

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	^{o}F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency	Emission Rate				Notes
					Uncontrolled		Controlled		
				(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
Criteria Pollutants	NO_x	3.00	g/hp-hr		7.47	32.73	7.47	32.73	1,4
	CO	4.00	g/hp-hr		9.96	43.64	9.96	43.64	1,4
	VOC	1.00	g/hp-hr		2.49	10.91	2.49	10.91	1,4
	SO_2	14.29	lb/MMscf		0.15	0.66	0.15	0.66	2,4
	PM_{10}	9.91E-03	lb/MMBtu		0.10	0.43	0.10	0.43	3,4
HAP	Formaldehyde	0.29	g/hp-hr		0.72	3.16	0.72	3.16	4,5
	Acetaldehyde	8.60E-03	lb/MMBtu		0.09	0.38	0.09	0.38	3,4
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.23	0.05	0.23	3,4
	Benzene	4.40E-04	lb/MMBtu		0.004	0.02	0.004	0.02	3,4

[1] Based on NSPS Subpart JJJJ

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

[4] Shaded emissions reflect those being requested as permitted emissions limits by ConocoPhillips.

[5] Based on manufacturer's data, See Appendix D

ConocoPhillips Company - San Juan Basin

Ute CDP

Waukesha L7042GL Emissions

Emission Unit Designation	E-2	
Source Description	Waukesha L7042GL	
Type	Turbocharged 4SLB engine with oxidation catalyst	
Rated Output	1,478	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	1,375	hp
Fuel Use Rate	7155	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	9.83	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	10.35	Mscf/hr, site derated
Annual Fuel Consumption	90.7	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	8760	hrs/year

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	^{o}F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

Pollutant		Emission Factor		Control Efficiency	Emission Rate				Notes
					Uncontrolled		Controlled		
				(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
Criteria Pollutants	NO_x	2.00	g/hp-hr		6.06	26.55	6.06	26.55	1,5
	CO	3.36	g/hp-hr	75%	10.18	44.60	2.55	11.15	1,2,5
	VOC	1.00	g/hp-hr		3.03	13.27	3.03	13.27	1,5
	SO_2	14.29	lb/MMscf		0.15	0.65	0.15	0.65	3,5
	PM_{10}	9.91E-03	lb/MMBtu		0.10	0.43	0.10	0.43	4,5
HAP	Formaldehyde	0.29	g/hp-hr	75%	0.88	3.85	0.22	0.96	1,2,5
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.37	0.08	0.37	4,5
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.22	0.05	0.22	4,5
	Benzene	4.40E-04	lb/MMBtu		0.004	0.02	0.004	0.02	4,5

[1] Manufacturer engine specifications plus a 33% flexibility factor for NOx and test data for CO; see Appendix D

[2] 75% CO and Formaldehyde Control Efficiency per specifications; see Appendix D

[3] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[4] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

[5] Shaded emissions reflect those being requested as permitted emissions limits by ConocoPhillips.

ConocoPhillips Company - San Juan Basin

Ute CDP

Potential TEG Dehydrator Still Vent Emissions

Emission Unit	DEHY-1	
Source Description	Triethylene Glycol Dehydrator Still Vent	
Manufacturer	Pesco	
Glycol Pump	Electric	
Maximum Flowrate	14.4 MMscfd	Maximum flow rate since 1994 multiplied by 1.2
Outlet Gas Dewpoint	7 lb H20/MMscf	
Glycol Recirculation Rate	3 gallons glycol/pound water	

Stack Height	22	ft, per site inspection
Exhaust Gas Velocity	5	ft/sec, estimated
Exhaust Gas Flow	14.7	cfm, estimated
Exhaust Temperature	100	^{o}F, estimated
Stack Inside Diameter	0.25	ft, per site inspection
Rated Input Capacity	0.125	MMBtu/hr, per manufacturer
Fuel Gas Heating Value	950	Btu/scf, estimated
Fuel Use Rate	131.58	scfh @ 950 Btu/scf
Fuel Use Rate	1.15	MMscf/yr @ 950 Btu/scf
Fuel Sulfur Content	50	(gr/Mscf)
Operating Time	8760	(hrs/year)

Source Description	Glycol Regenerator
Control Device	Condenser

Pollutant		Control Efficiency	Emission Rate				Notes
			Uncontrolled		Controlled		
		(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
VOC			32.78	143.56	1.78	7.79	1,2
HAP	n-Hexane		0.24	1.06	0.02	0.11	1,2
	Benzene		2.88	12.62	0.13	0.57	1,2
	Toluene		8.79	38.48	0.12	0.52	1,2
	Ethylbenze		0.57	2.51	0.002	0.01	1,2
	Xylenes		7.80	34.15	0.02	0.11	1,2
Total HAP		98.5%	-	88.82	-	1.32	

Notes:

[1] GRI GlyCalc v4.0 Calculations (Appendix E) based on extended gas analysis (Appendix I)

[2] Shaded emissions reflect those being requested as permitted emissions limits by ConocoPhillips.

ConocoPhillips Company - San Juan Basin

Ute CDP

Uncontrolled Facility Potential to Emit

Unit ID	**T-1**	**Units, Data Source**
Description	Capstone Turbine	
Rated Output	30	kW, manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.79	NMED AQB Deration for Turbines
Altitude Derated Output	24	kW, derated to site elevation
Engine Type	Turbine	manufacturer
Fuel Type	NG	manufacturer
Operating hr/yr	8,760	Maximum actual hours
Stack Information		
Stack Height	7.5	ft, for each turbine
Exhaust Gas Velocity	14.6	ft/sec
Exhaust Temp	588	^oF, per manufacturer specification sheet
Stack Inside Diameter	0.67	ft
Exhaust Gas Flow	305	cfm, per manufacturer specification sheet
Emission Factor (EF)		
NO_x	0.64	lb/MWhe, per manufacturer's specifications
CO	1.70	lb/MWhe, per manufacturer's specifications
VOC	0.22	lb/MWhe, per manufacturer's specifications
SO_2	50.0	g/mscf pipeline specification
PM/PM_{10}	0.0066	lb/MMBtu, AP-42 Tbl 3.1-2a
Hourly Emission Rate		
NO_x	0.02	lb/hr, calc'd from EF data; derated to site elevation
CO	0.04	lb/hr, calc'd from EF data; derated to site elevation
VOC	0.005	lb/hr, calc'd from EF data; derated to site elevation
SO_2	0.09	lb/hr, calc'd from EF data; derated to site elevation
PM/PM_{10}	0.01	lb/hr, calc'd from EF data; derated to site elevation
Annual PTE		
NO_x	0.07	tpy, calc'd from lb/hr data
CO	0.18	tpy, calc'd from lb/hr data
VOC	0.02	tpy, calc'd from lb/hr data
SO_2	0.39	tpy, calc'd from lb/hr data
PM/PM_{10}	0.02	tpy, calc'd from lb/hr data
Fuel Flowrates		
Fuel Use Rated Capacity	0.77	MMBtu/hr; derated to site elevation
Fuel LHV	950	Btu/scf, estimated
Fuel Use Rate	765,000	Btu/hr, per manufacturer
Fuel Use Rate	805.3	scf/hr
Fuel Use Rate	7.1	MMscf/yr

ConocoPhillips Company - San Juan Basin

Ute CDP

Uncontrolled Facility Potential to Emit

Unit ID	T-2	Units, Data Source
Description	Capstone Turbine	
Rated Output	65	kW, manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.79	NMED AQB Deration for Turbines
Altitude Derated Output	51	kW, derated to site elevation
Engine Type	Turbine	manufacturer
Fuel Type	NG	manufacturer
Operating hr/yr	8,760	Maximum actual hours
Stack Information		
Stack Height	7.5	ft, for each turbine
Exhaust Gas Velocity	14.6	ft/sec
Exhaust Temp	588	^{o}F, per manufacturer specification sheet
Stack Inside Diameter	0.67	ft
Exhaust Gas Flow	305	cfm, per manufacturer specification sheet
Emission Factor (EF)		
NO_x	0.46	lb/MWhe, per manufacturer's specifications
CO	6.00	lb/MWhe, per manufacturer's specifications
VOC	0.10	lb/MWhe, per manufacturer's specifications
SO_2	50.0	g/mscf pipeline specification
PM/PM_{10}	0.0066	lb/MMBtu, AP-42 Tbl 3.1-2a
Hourly Emission Rate		
NO_x	0.02	lb/hr, calc'd from EF data; derated to site elevation
CO	0.31	lb/hr, calc'd from EF data; derated to site elevation
VOC	0.005	lb/hr, calc'd from EF data; derated to site elevation
SO_2	0.09	lb/hr, calc'd from EF data; derated to site elevation
PM/PM_{10}	0.01	lb/hr, calc'd from EF data; derated to site elevation
Annual PTE		
NO_x	0.10	tpy, calc'd from lb/hr data
CO	1.35	tpy, calc'd from lb/hr data
VOC	0.02	tpy, calc'd from lb/hr data
SO_2	0.39	tpy, calc'd from lb/hr data
PM/PM_{10}	0.02	tpy, calc'd from lb/hr data
Fuel Flowrates		
Fuel Use Rated Capacity	0.77	MMBtu/hr; derated to site elevation
Fuel LHV	950	Btu/scf, estimated
Fuel Use Rate	765,000	Btu/hr, per manufacturer
Fuel Use Rate	805.3	scf/hr
Fuel Use Rate	7.1	MMscf/yr

Notes:

[1] USEPA AP-42 Ch. 3.1, Stationary Gas Turbines

ConocoPhillips Company - San Juan Basin

Ute CDP

Potential Heater Emissions

Unit ID	**DEHY-1**	**Units, Data Source**
Description	Reboiler	
Fuel Type	NG	manufacturer
Operating hr/yr	8,760	Maximum actual hours
Stack Information		
Stack Height	22	ft
Exhaust Gas Velocity	5	ft/sec, estimated
Exhaust Temp	100	^{o}F, estimated
Stack Inside Diameter	0.67	ft, site inspection
Exhaust Gas Flow	104.7	cfm
Emission Factor (EF)[1]		
NO_x	100	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
CO	84	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
VOC	5.5	lb/MMscf, AP-42 Tbl 1.4-2 (07/98)
SO_2	14.3	lb/MMscf (50 grains S/Mscf assumed), AP-42 Tbl 1.4-2 (07/98)
PM/PM_{10}	7.6	lb/MMscf [total assumed], AP-42 Tbl 1.4-2 (07/98)
Formaldehyde	0.08	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hexane	1.8	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hourly Emission Rate in pounds per hour		
NO_x	0.01	lb/hr, calc'd from EF data
CO	0.01	lb/hr, calc'd from EF data
VOC	0.001	lb/hr, calc'd from EF data
SO_2[2]	0.002	lb/hr, calc'd from EF data
PM/PM_{10}	0.001	lb/hr, calc'd from EF data
Formaldehyde	0.000	lb/hr, calc'd from EF data
Hexane	0.000	lb/hr, calc'd from EF data
Annual Potential To Emit (PTE) in tons per year		
NO_x	0.06	tpy, calc'd from lb/hr data
CO	0.05	tpy, calc'd from lb/hr data
VOC	0.003	tpy, calc'd from lb/hr data
SO_2	0.008	tpy, calc'd from lb/hr data
PM/PM_{10}	0.004	tpy, calc'd from lb/hr data
Formaldehyde	0.000	tpy, calc'd from lb/hr data
Hexane	0.001	tpy, calc'd from lb/hr data
Fuel Flowrates		
Rated Input Capacity	0.125	MMBtu/hr, per manufacturer
Fuel LHV	950	Btu/scf, estimated
Fuel Use Rate	131.6	scfh @ 950 Btu/scf (LHV)
Fuel Use Rate	1.2	MMscf/yr @ 950 Btu/scf (LHV)

Notes:

[1] USEPA AP-42 Ch. 1.4 Natural Gas Combustion

[2] Fuel Sulfur Content (gr/Mscf) * (lb/7000 gr) * (1000 Mscf/MMscf) * (64 lb/lb-mol SO_2/32 lb/lb-mol S)

ConocoPhillips Company - San Juan Basin

Ute CDP

Summary of Potential Emissions for Insignificant Activities

Unit ID	Turbine 1	Turbine 2	Truck Loading of Condensate	Fugitive Emissions	Miscellaneous Storage Tanks	Total by Pollutant
Description	Capstone 30 kW	Capstone 65 kW	-	-	-	
Hourly Emission Rate						
NO_x	0.02	0.02	-	-	-	**0.04**
CO	0.04	0.31	-	-	-	**0.35**
VOC	0.01	0.01	-	0.19	0.30	**0.50**
SO_2	0.09	0.09	-	-	-	**0.18**
PM/PM_{10}	0.01	0.01	-	-	-	**0.01**
Annual PTE						
NO_x	0.07	0.10	-	-	-	**0.17**
CO	0.18	1.35	-	-	-	**1.52**
VOC	0.02	0.02	0.34	0.85	1.30	**2.54**
SO_2	0.39	0.39	-	-	-	**0.78**
PM/PM_{10}	0.02	0.02	-	-	-	**0.04**

Notes:

[1] Insignificant activities (IA) include all emission units with a potential to emit less than 2 tpy of criteria pollutants or 0.5 tpy hazardous air pollutants. IA include 2 combustion turbines, 3 heated separators, truck loading of condensate, fugitive emissions, and miscellaneous storage tanks.

APPENDIX D

Manufacturer's Emissions Data

VHP EMISSIONS LEVELS

MODEL	CARBURETOR SETTING	GRAMS/BHP-HR				% OBSERVED DRY		MASS AFR (2)	VOLUME AFR (2)	EXCESS AIR RATIO
		NO_X (1)	CO	NMHC (4)	THC	CO	O_2			
G, GSI	Lowest Manifold (Best Power)	8.5	32.0	0.35	2.3	1.15	0.30	15.5:1	9.3:1	0.97
	Equal NOx & CO	12.0	12.0	0.35	2.3	0.45	0.30	15.9:1	9.6:1	0.99
	Catalytic Conv. Input (3-way3)	13.0	9.0	0.30	2.0	0.38	0.30	15.95:1	9.6:1	0.99
	Standard (Best Economy)	22.0	1.5	0.25	1.5	0.02	1.35	17.0:1	10.2:1	1.06
F3514GSI F3524GSI L7044GSI	Equal NOx & CO	14.0	14.0	0.25	1.1	0.45	0.30	15.85:1	9.5:1	0.99
	Catalytic Conv. Input (3-way3)	15.0	13.0	0.20	1.0	0.38	0.30	15.95:1	9.6:1	0.99
L5794GSI	Equal NOx & CO	13.5	13.5	0.45	3.0	0.45	0.30	15.85:1	9.5:1	0.99
	Catalytic Conv. Input (3-way3)	14.5	11.0	0.45	2.9	0.38	0.30	15.95:1	9.6:1	0.99
GL	Standard	1.5	2.65	1.0	5.5	0.06	9.8	28.0:1	16.8:1	1.74
L5774LT#	Standard	2.6	2.0	0.60	4.0	0.04	8.0	24.7:1	14.8:1	1.54
L5794LT#	Standard	2.6	2.0	0.60	4.0	0.04	7.8	24.5:1	14.7:1	1.52

L5774LT and L5794LT emission levels are based on 1000 – 1200 rpm operation. For information at all other speeds Contact Waukesha's Sales Application Engineering Department.

275GL/AT-GL EMISSION LEVELS ‡

MODEL	CARBURETOR SETTING	GRAMS/BHP-HR				% OBSERVED DRY		MASS AFR (2)	VOLUME AFR (2)	EXCESS AIR RATIO
		NO_X (1)	CO	NMHC (4)	THC	CO	O_2			
275GL/AT27GL	32:1	2.0	1.5	0.40	3.5	0.05	11.2	32.0:1	19.2:1	2.00
275GL+	34:1	0.5	1.6	0.6	6.0	0.04	11.6	34:1	20.4	2.12

‡ These AT-GL emission levels are based on 900 – 1000 rpm operation. For information at all other speeds contact Waukesha's Sales Application Engineering Department.

NOTE: The above table indicates emission levels that are valid for new engines for the duration of the standard warranty period and are attainable by an engine in good operating condition running on commercial quality natural gas of 900 BTU/ft^3 (35.38 MJ/m^3 [25, V(0; 101.325)]) SLHV, Waukesha Knock Index® of 91 or higher, 93% methane content by volume, and at ISO standard conditions. Emissions are based on standard engine timing at 91 WKI® with an absolute humidity of 42 grains/lb. Refer to engine specific WKI® Power & Timing curves for standard timing. Unless otherwise noted these emission levels can be achieved across the continuous duty speed range and from 75% to 110% of the ISO Standard Power (continuous duty) rating. ***Contact your local Waukesha representative or Waukesha's Sales Application Engineering Department for emission values which can be obtained on a case-by-case basis for specific ratings, fuels, and site conditions.***

FORMALDEHYDE EMISSION LEVELS

The following table provides formaldehyde (CH_2O) levels that are valid for new engines for the duration of the standard warranty period and are attainable by an engine in good operating condition running on commercial quality natural gas of 900 BTU/ft^3 (35.38 MJ/m^3 [25, V(0; 101.325)]) SLHV, Waukesha Knock Index® of 91 or higher, 93% methane content by volume, and at ISO standard conditions. Values are based on standard engine timing at 91 WKI® with an absolute humidity of 42 grains/lb. Refer to engine specific WKI® Power & Timing curves for standard timing. Unless otherwise noted, these emission levels can be achieved across the continuous duty speed range at the load levels tabulated. ***Contact the local Waukesha representative or Waukesha's Sales Application Engineering Department for emission values which can be obtained on a case-by-case basis for specific ratings, fuels, and site conditions.***

MODEL	CARB. SETTING	CH_2O GRAMS/ BHP-HR PERCENT LOAD 100%	75%	% OBSERVED DRY CO	O_2	MASS AFR(2)	VOLUME AFR(2)	EXCESS AIR RATIO
275GL/AT27GL	Lean Burn	0.18	0.20	0.06	9.8	28.0:1	16.8:1	1.74
	Ultra Lean	0.18	0.20	0.05	11.2	32.0:1	19.2:1	2.00
12V220GL/APG2000 18V220GL/APG3000	Ultra Lean	0.23	0.29	0.09 – 0.15	12.3 – 13.4	32.1 – 35.3	19.3 – 21.2	2.03 – 2.20
16V150LTD/APG1000	Lean Burn	0.14	0.15	0.07	9.5 – 9.6	26.9 – 27.2	16.2 – 16.4	1.68 – 1.7
VHP G, GSI	Rich Burn	0.05	0.05	0.02 – 1.15	0.30 – 1.35	15.5:1 – 17.0:1	9.3:1 – 10.2:1	0.97 – 1.06
VHP Series 4 GSI	Rich Burn	0.05	0.05	0.02 – 0.45	0.30 – 1.35	15.85:1 – 17.0:1	9.5:1 – 10.2:1	0.99 – 1.06
L5774LT L5794LT	Lean Burn	0.22	0.25	0.04	7.8 – 8.0	24.5:1 – 24.7:1	14.7:1 – 14.8:1	1.52 – 1.54
VHP GL	Lean Burn	0.29	0.34	0.06	9.8	28.0:1	16.8:1	1.74
VGF G, GSID	Rich Burn	0.05	0.05	0.20 – 1.1	0.18 – 2.4	15.5:1 – 18.0:1	9.3:1 – 10.8:1	0.97 – 1.12
VGF GL, GLD, GLD/2	Lean Burn	0.19	0.22	0.03 – 0.04	7.8 – 9.0	21.5:1 – 25.4:1	13.9:1 – 15.2:1	1.53 – 1.65
VSG G, GSI, GSID	Rich Burn	0.05	0.05	0.02 – 1.15	0.29 – 2.10	15.5:1 – 17.7:1	9.3:1 – 10.6:1	0.97 – 1.10

Table 2: Summary of Results
Sunnyside Compressor Station Unit #E002

Company: ConocoPhillips Company
Location: Sunnyside CS
Source: Waukesha L7042GL SN: C-10664/2
Engine Site Rating: 1330 Hp @ 1200 RPM
Technician: CS, CS

Test Run Number	1	2	3	
Unit Number	**E002**	**E002**	**E002**	
Engine Number	**2**	**2**	**2**	
Date	8/26/08	8/26/08	8/26/08	
Start Time	9:51	10:59	12:06	
Stop Time	10:51	11:59	13:06	
Engine/Compressor Operation				
Engine Speed (rpm)	1155	1156	1163	
Load (%)	90	90	95	
Engine Horsepower (Hp)	1197	1197	1264	
Fuel Manifold Pressure (psig)	40	40	40	
Air Manifold Pressure (psig)	11	11	13	
Air Manifold Temperature (°F) (L/R)	122/123	129/124	139/131	
Compressor Suction Pressure (psig)	42	44	54	
1st Interstage Pressure (psig)	163	160	175	
Compressor Discharge Pressure (psig)	381	378	390	
Compressor Suction Temperature (°F)	88/233.5	84/233.5	82/231.5	
1st Interstage Temperature (°F)	97.5/233.5	102/236	110.5/235	
Compressor Discharge Temperature (°F)	96.5	102.5	106	
Average Exhaust Temperature (°F)	920	930	940	
Compressor Throughput (MMSCFD)	247.04	247.04	247.04	
Ignition Timing (°BTDC)	11	11	11	
Fuel Data				
Measured Fuel Consumption (SCFM)	261.77	262.72	259.73	
Calculated Fuel Consumption (SCFH)	10907	10947	10822	
O2 F-Factor (DSCF/MMBtu, HHV basis)	8687	8687	8687	
Fuel Heating Value (Btu/SCF, HHV basis)	952	952	952	
BHp Specific Fuel Rate (Btu/Hp-hr, HHV basis)	8675	8707	8154	
Ambient Conditions				
Pressure Altitude (MSL)	6100	6100	6100	
Atmospheric Pressure ("Hg)	23.91	23.91	23.91	
Ambient Temperature (°F)	75.4	79.5	83.7	
Wet Bulb Temperature (°F)	60.1	61.8	63.2	
Humidity (lb/lb air)	0.0101	0.0104	0.0105	
Measured Exhaust Emissions (Corrected)				**Average**
NOx (ppmv)	102.18	117.65	176.08	**131.97**
CO (ppmv)	680.51	702.23	746.37	**709.70**
O2 (vol %)	10.55	10.44	10.17	**10.39**
CO2 (vol %)	5.83	5.97	5.98	**5.93**
H2CO (ppmv)	4.86	4.34	4.74	**4.65**
Fo	1.77	1.75	1.79	**1.77**
Exhaust Flow Rates (EPA Methods 1-4)				
SCFH (dry basis, calc. from meas. stack velocity)	1.78E+05	1.71E+05	1.76E+05	**1.75E+05**
Exhaust Flow Rates (EPA Method 19)				
Dry SCFH (dry basis, calc. from Fuel Consump.)	1.82E+05	1.81E+05	1.74E+05	**1.79E+05**
Difference from Methods 1-4 Determination (%)	-2.44	-5.70	0.74	**-2.46**
Calculated Mass Emission Rates (EPA Methods 1-4)				
NOx (g/hp-hr)	0.82	0.91	1.33	**1.02**
CO (g/hp-hr)	3.34	3.32	3.42	**3.36**
H2CO (g/hp-hr)	0.026	0.022	0.023	**0.024**
NOx (lbs/hr)	2.17	2.41	3.69	**2.76**
CO (lbs/hr)	8.80	8.74	9.53	**9.02**
H2CO (lbs/hr)	0.067	0.058	0.065	**0.063**
NOx (tons/yr)	9.51	10.54	16.18	**12.08**
CO (tons/yr)	38.55	38.28	41.74	**39.52**
H2CO (tons/yr)	0.295	0.253	0.284	**0.277**

Capstone

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Phone: (818) 734-5300 • Fax: (818) 734-5320 • Web: www.microturbine.com

Technical Reference

Capstone MicroTurbine™ Systems Emissions

Summary

Capstone MicroTurbine™ systems are inherently clean and can meet some of the strictest emissions standards in the world. This technical reference is to provide customers with information that may be requested by local air permitting organizations or to compare air quality impacts of different technologies for a specific project. The preferred units of measure are "output based"; meaning that the quantity of a particular exhaust emission is reported relative to the useable output of the microturbine – typically in pounds per megawatt hour for electrical generating equipment. This technical reference also provides the volumetric measurement in parts per million, which is still used by many people. A conversion between several common units is also provided.

Maximum Exhaust Emissions at ISO Conditions

Table 1 below summarizes the exhaust emissions at full power and ISO conditions for different Capstone microturbine models. Note that the fuel can have a significant impact on certain emissions. For example landfill and digester gas can be made up of a wide variety of fuel elements and impurities, and typically contains some percentage of carbon dioxide (CO_2). This CO_2 dilutes the fuel, makes complete combustion more difficult, and results in higher carbon monoxide emissions (CO) than for pipeline-quality natural gas.

Table 1. Emission for Different Capstone Microturbine Models in [lb/MWhe]

Model	Fuel	NOx	CO	VOC (5)
C30 NG	Natural Gas (1)	.64	1.7	.22
C30 MBTU	Landfill Gas (2)	.64	22	12.4
C30 MBTU	Digester Gas (3)	.64	22	12.4
C30 Liquid	Diesel #2 (4)	2.6	.41	.23
C65 NG Standard	Natural Gas (1)	.46	6.0	.10
C65 NG Low NOx	Natural Gas (1)	.17	6.0	.10
C65 NG CARB	Natural Gas (1)	.17	.24	.05
CR65 Landfill	Landfill Gas (2)	.50	6.0	.10
CR65 Digester	Digester Gas (3)	.50	6.0	.10
C200 NG	Natural Gas (1)	.43	.26	.10
C200 NG CARB	Natural Gas (1)	.14	.20	.04
CR200 Digester	Digester Gas (3)	.50	6.0	.10

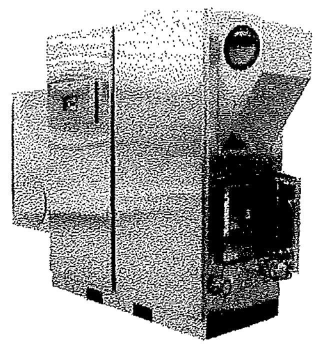
Notes:

(1) Emissions for standard natural gas at 1,000 BTU/scf (HHV)
(2) Emissions for surrogate gas containing 42% natural gas, 39% CO2, and 19% Nitrogen
(3) Emissions for surrogate gas containing 63% natural gas and 37% CO2
(4) Emissions for Diesel #2 according to ASTM D975-07b
(5) Expressed as Hexane

C65 MicroTurbine
Oil & Gas

33% smaller than equivalent generators. Offers ultra-low emissions and reliable electrical generation from raw natural gas.

- Patented air bearing: No lubricating oil or coolant
- One moving part: Minimal maintenance and downtime
- Low NOx and CO_2 emissions – better than tough global standards
- Immediate service available worldwide
- Remote monitoring and diagnostic capabilities
- Multiple units easily synchronized
- Electrical protective relays mean no external switchgear required
- Small, modular design allows for easy, low-cost installation
- Reliable: 16,000,000+ run hours and counting



Offshore C65 CID2

Electrical Performance	
Electrical Power Output	65 kW
Voltage	400 to 480 VAC
Electrical Service	3-Phase, 4 wire
Frequency	10 - 60 Hz
Maximum Output Current	127A, stand alone operation[1]
Electrical Efficiency LHV	29%

Fuel/Engine Characteristics	
Natural/Wellhead Gas HHV	825 to 1,275 BTU/scf
H2S Content	< 400 ppmv
Inlet Pressure	5.2 barg (75 psig)
Fuel Flow LHV	807 MJ/hr (765,000 BTU/hr)
Generator Heat Rate LHV	11.6 MJ/kWh (11,000 BTU/kWh)

Exhaust Characteristics	C65
Exhaust Gas Flow	0.49 kg/s (1.08 lb/sec)
Exhaust Gas Temperature	309°C (588°F)

Power when and where you need it. Clean and simple.

MIRATECH Corporation Scope of Supply

	Model Number	Quantity per Engine
NSCR Housing & Catalyst	**IQ-28-12-EL1**	**1**
NSCR Housing	IQ-28-12-HSG	1
Oxidation Catalyst	IQ-RE-28EL	1
Nut, Bolt, and Gasket Set	NBG-IQ28-1	1
NSCR Housing & Catalyst	**ZCS-30x31-12-XH2B1**	**1**
NSCR Housing	ZCS-30x31-12-HSG	1
Oxidation Catalyst	ZXS-RE-FULL354XH	2
Blind Catalyst	ZXS-RE-FULLBLIND	1
Nut, Bolt, and Gasket Set	NBG-ZXS3	1
Air/Fuel Ratio Controller	**MECL-22-FT-60**	**1**
Full Authority Control Valve	FT-60	2
Control Valve Cable	FT Cable-50	2
Flange Adapter	FLOTECH Flange Adaptor 2"	4
Engine Control Module	ECM-L	1
Terminal Connector Board	TCB	1
Enclosure	Enclosure-CSA	1
UEGO Sensor	UEGO Sensor	2
UEGO Cable	UEGO Cable-50	2
Magnetic Pick-Up	MAG PU	1
Magnetic Pick-Up Cable	MAG PU Cable-50	1
Manifold Absolute Pressure Sensor	MAP Sensor	1
Manifold Absolute Pressure Sensor Cable	MAP Cable-50	1
Manifold Air Temperature Sensor	MAT Sensor	1
Manifold Air Temperature Sensor Cable	MAT Cable-50	1
Oxygen Sensor Coupling	O2 NUT	2
Null Modem Cable	NM-10	1
Diagnostic Software and Manual CD	MECL-CD	1
Manual	MECL Manual	1

Customer Scope of Supply

Description
Support Structure
Attachment to Support Structure (Bolts, Nuts, Levels, etc.)
Expansion Joints
Exhaust Piping
Inlet Pipe Bolts, Nuts, & Gasket
Outlet Pipe Bolts, Nuts, & Gasket

Application Data

Project Information

Site Location:	New Mexico
Project Name:	Conoco Phillips
Application:	Gas Compression
Number of Engines:	1
Operating Hours per Year:	8760

Engine Specifications

Engine Manufacturer:	Waukesha
Model Number:	L 7042 GL
Operating Load for Engine Data Provided:	100%
Power Output:	1,478 bhp
Speed:	1,200 RPM
Type of Fuel:	Natural Gas
Sulfur Content:	0 ppmv or less
Fuel Consumption:	7,274 BTU/bhp-hr
Type of Lube Oil:	0.6 wt% sulfated ash or less
Lube Oil Consumption:	< 0.00027 gal/bhp-hr
Fuel Line Size:	2.0 in
Number of Carburetors:	2
Number of Exhaust Manifolds:	2
Exhaust Flow Rate:	207,712 scfh
Exhaust Temperature:	709°F

Raw Engine Emission Data

	g/bhp-hr	lb/MW-hr	ppmvd	ppmvd @ 15% O_2	lb/hr	g/kW-hr	tons/yr
NO_x	1.50	4.43	234	124	4.89	2.01	21.41
CO	2.65	7.83	678	361	8.63	3.55	37.82
NMNEHC	0.17	0.49	74	39	0.54	0.22	2.35
CH_2O	0.29	0.86	69	37	0.94	0.39	4.14

% O_2	9.8
H_2O Assumption	17.0

Post System Emission Data

	g/bhp-hr	lb/MW-hr	ppmvd	ppmvd @ 15% O_2	lb/hr	g/kW-hr	tons/yr
CO	0.27	0.78	68	36	0.86	0.36	3.78
CH_2O	0.03	0.09	7	4	0.09	0.04	0.41

Calculated Percent Reductions

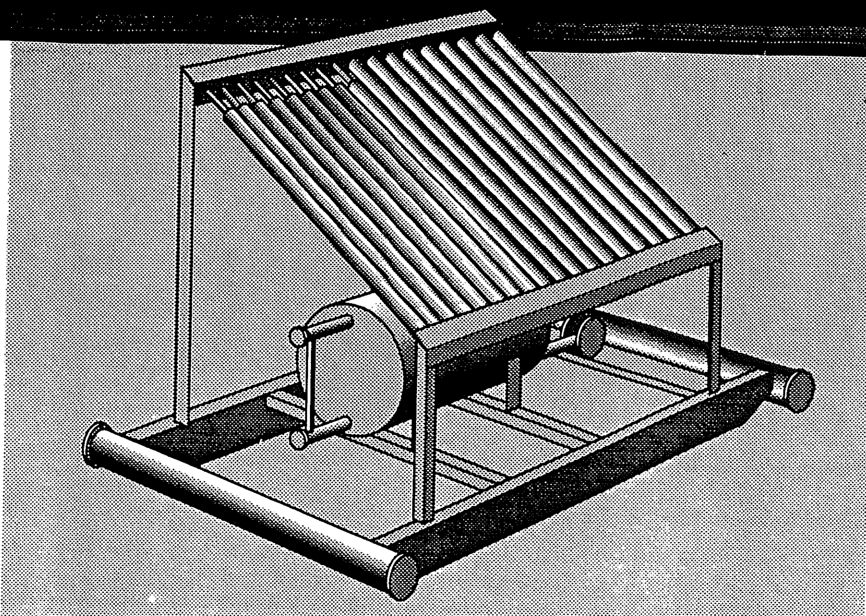
	% Reduction
CO	90.0
CH2O	90.0

NATCO

BTEX BUSTER™

Achieves 99.7%+ BTEX and VOC Removal Efficiency!

The Cost Effective Answer To Your Compliance Problems



Space saving skid mounted NATCO BTEX BUSTER is the cost effective answer to your compliance problems.

The NATCO BTEX BUSTER provides a removal efficiency greater than 99.7%, helps recover and collect saleable liquid hydrocarbons and prevents the loss of expensive fuel gas.

Field-proven, the NATCO BTEX BUSTER is now available through our 30 NATCO Sales and Service locations worldwide.

The unit was designed using the EPA approved GRI-GlyCalc™ computer simulation program with a flash-gas separator in the glycol regeneration process. Under common operating conditions, BTEX (Benzene, Toluene, Ethylbenzene and Xylene) as well as other volatile organic compounds (VOC's) are emitted to the atmosphere during the glycol regeneration process. The rates are usually proportional to the glycol circulation rate.

Meets Federal Regulation 40 CFR Part 63

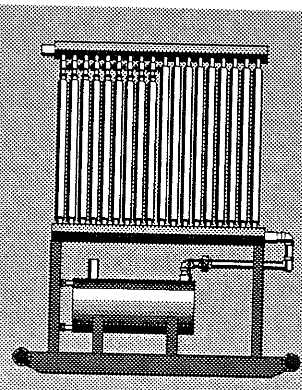
This cost efficient system is designed to assist operators in reducing BTEX and VOC emissions below the accepted levels and comply with Federal and State environmental regulations.

Economics of NATCO's BTEX BUSTER show that it can pay for itself by recovering saleable hydrocarbon liquids and fuel gas. By condensing troublesome glycol reconcentrator vapors and routing flash gas back to the reconcentrator fuel gas inlet for burning, the unit minimizes emissions during glycol plant dehydration processing.

The BTEX BUSTER incorporates field-proven NATCO burner accessories to help prevent sooting and back pressure on your regeneration system.

The BTEX BUSTER also features a design to eliminate potential freeze-up problems when operating in severe cold climates.

NATCO offers the BTEX BUSTER in standard sizes to accommodate most customer needs. Our units are backed by NATCO replacement parts, technical assistance and service available 24 hours a day.

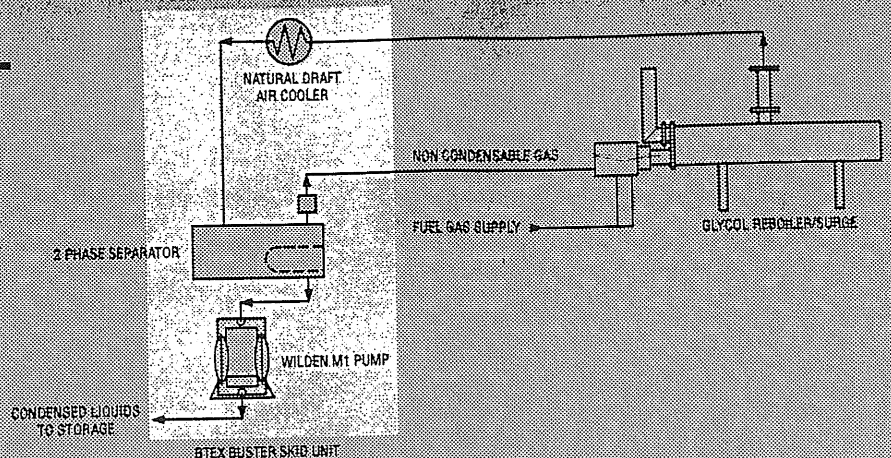


NATCO BTEX BUSTER units are designed and engineered for safe operation and meet today's environmental regulations

Features	Benefits
• Efficient	• Removal efficiency greater than 99.7%
• Environmentally Correct	• Meets Federal Regulation 40 CFR part 63 Meets or exceeds most stringent state regulations LAC:111.2116 and LAC 33:111, chapter 51
• Reduces Operating Costs	• Reduces fuel gas consumption Recovers saleable liquid hydrocarbons
• Safe	• In-line flash arrestor, high level switch, pressure safety valve, gas shutdown valves
• Designed For The Oilfield	• Includes NATCO field proven burner products Reduces freeze problems in most cold climates Pneumatic pump handles aromatic hydrocarbons
• NATCO Service	• Experienced staff, 30 locations, 24 hrs/day

NATCO

Flow Diagram – BTEX BUSTER Skid Package



Standard BTEX Size (1)	Reconcentrator Duty BTU/Hr	Glycol Pump Gallons/Hour	Maximum Capacity # Water/Day (2)	Non Condensable Vapor #/Day (3)	Cooler Duty BTU/Hr (4)
150	75,000	40	273	7	30,000
160	150,000	40	273	10	30,000
250	250,000	90	1216	27	51,000
375	375,000	210	1807	45	76,000
550	550,000	210	2650	60	112,000
750	750,000	450	3615	100	152,000

(1) Standard BTEX
Performance of unit is based on a non-condensable vapor HHV greater than 400 Btu/scf and less than 1800 Btu/scf and a glycol circulation rate of no more than 3 gallons per pound of water removed.

(2) Maximum Capacity # Water/Day
Represents the maximum capacity of water in pounds per day for each standard NATCO reboiler size based on a glycol circulation rate of 2 gallons of glycol per pound of water removed.

(3) Non-Condensable Vapor #/Day
Maximum non-condensable vapor rate was calculated with the GRI-GlyCalc computer simulation program with a flash gas separator used in the glycol regeneration process and a BTEX concentration in the inlet gas stream of no more than 700 ppm. Using adiabatic combustion calculations, a minimum of 99.7% of these non-condensable vapors are destroyed.

(4) Cooler Duty Btu/Hr
Cooler duty was calculated based on a prevailing windspeed of 3 mph and a maximum ambient temperature of 100°F.

Note: NATCO is not responsible for the disposal of any condensed liquids associated with its BTEX BUSTER units.

How It Works – The NATCO BTEX BUSTER is a relatively simple process that is designed to maintain greater than 99.7% removal of BTEX and VOC emissions.

The vapors emitted from the glycol still column are cooled in the natural draft air cooler to temperatures below 120°F (48.9°C).

The condensed liquids are collected in a small two-phase separator and pumped to customer storage. Non-condensable gases from the separator are piped through an in-line flash arrestor and then burned in the glycol reboiler firebox to achieve an overall minimum destruction efficiency of 99.7% plus.

Built-In Safety Features – NATCO BTEX BUSTER units are engineered with proper controls for safe operation and long in-service life. These include an in-line flash arrestor, separator high level switch, pressure safety valve and gas shut-down valves for high reboiler bath temperatures. It also incorporates field-proven NATCO burner accessories that help to prevent typical sooting and back pressures on your regeneration system.

NATCO – Your Single Source For:
- Design
- Engineering
- Procurement
- Fabrication
- Start-up
- Commissioning
- Operations Maintenance
- Education and Training
- Strategic Alliances

NATCO

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www.natco_us.com

Specification Sheet

COOLER SERVICE COMPANY

PROPOSAL NO.	BTX
DATE	2/12/99
PAGE	1 OF 1

CUSTOMER	NATCO
REF. NO.	750 Standard
MODEL	NC 36-6

PERFORMANCE OF ONE UNIT

1	SERVICE	Overhead Condenser
2	FLOW	5390 #/day
3	FLUID	Water vapor and HC vapor
4	TEMPERATURE IN, °F	220
5	TEMPERATURE OUT, °F	120
6	INLET PRESSURE, PSIA	14.9
7	PRESSURE DROP, PSI	0.2
8	DUTY, BTU/HOUR	152,000
9	CORRECTED MTD	58 wtd
10	BARE TUBE RATE	48.5 wtd
11	FOULING	.001
12	BARE TUBE SURFACE, SQ. FT.	54
13	TOTAL SURFACE, SQ. FT.	1170

CONSTRUCTION

14	NO SECTIONS	1
15	NO. TUBES/SECTION	36
16	LENGTH	6'
17	NO. ROWS	1
18	NO PASSES	1
19	COUNTERFLOW	
	TUBE O.D AND BWG	1" OD x 16 Bwg
	TUBE MATERIAL	SA214
22	DESIGN PRESSURE, PSI	15
23	DESIGN TEMPERATURE, °F	250
24	NOZZLES	2" NPT
25	HEADERS	CARBON STEEL BOX TYPE WITH REMOVABLE PLUGS
26	ASME CODE STAMP	
27		
28	GRVD TUBE SHEET	
29	CORROSION ALLOWANCE	
30	FINS	ALUMINUM, ANGLE BASE, MECHANICALLY BONDED
31	PLUGS, TYPE	
32	PLUGS, MATERIAL	
33	RETARDERS	
34	ACCELERATORS	

AIR DATA

35	INLET AIR, °F	100	ELEVATION, FT.	500
36	OUTLET AIR, °F		TOTAL SCFM	
37				

MECHANICAL EQUIPMENT

38	NO. FANS	HP/FAN	RPM	DIA.	NO. BLADES	MATERIAL	MAKE
39	DRIVE						
40							
41	DRAFT TYPE	OVERALL WIDTH		LENGTH		HEIGHT	
42	EST. SHIPPING WEIGHT						

	ACCESSORIES	Mounted at 45 degree angle
		Normal wind 5 mph
45		All welded construction
46		
47		
48		

Form A4, 9/84

APPENDIX E

GRI-GLYCalc Output Report

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: Ute CDP - 14.4 MMScf/Day Dehydration System
File Name: C:\Users\Sugar Magnolia\Desktop\Work\137 - ConocoPhillips_HH Applicability Determinations\Ute CDP\Dehydrator Emissions_Ute CDP_ Avg of 6,7,8_PTE for Title V_Controlled.ddf
Date: May 09, 2011

DESCRIPTION:

Description: Temperature/Pressure taken from the average values of gas analyses dated December 6, 7, and 8, 2010. Average gas dewpoint is 7.

Condenser outlet is conservatively assumed 75F.

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 83.13 deg. F
Pressure: 207.67 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	2.2871
Nitrogen	0.1644
Methane	85.2724
Ethane	7.3784
Propane	2.8767
Isobutane	0.5444
n-Butane	0.6294
Isopentane	0.2466
n-Pentane	0.1582
n-Hexane	0.0605
Cyclohexane	0.0340
Other Hexanes	0.1153
Heptanes	0.0801
Methylcyclohexane	0.0492
2,2,4-Trimethylpentane	0.0059
Benzene	0.0160
Toluene	0.0255
Ethylbenzene	0.0009
Xylenes	0.0094
C8+ Heavies	0.0454

DRY GAS:

Flow Rate: 14.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O

Recirculation Ratio: 3.0 gal/lb H2O

PUMP:

Glycol Pump Type: Electric/Pneumatic

FLASH TANK:

Flash Control: Recycle/recompression
Temperature: 90.0 deg. F
Pressure: 40.0 psig

REGENERATOR OVERHEADS CONTROL DEVICE:

Control Device: Condenser
Temperature: 75.0 deg. F
Pressure: 11.3 psia

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: Ute CDP - 14.4 MMScf/Day Dehydration System
File Name: C:\Users\Sugar Magnolia\Desktop\Work\137 - ConocoPhillips_HH Applicability Determinations\Ute CDP\Dehydrator Emissions_Ute CDP_ Avg of 6,7,8_PTE for Title V_Controlled.ddf
Date: May 09, 2011

DESCRIPTION:

Description: Temperature/Pressure taken from the average values of gas analyses dated December 6, 7, and 8, 2010. Average gas dewpoint is 7.

Condenser outlet is conservatively assumed 75F.

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

CONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2745	6.589	1.2025
Ethane	0.4245	10.187	1.8592
Propane	0.6206	14.893	2.7180
Isobutane	0.2179	5.229	0.9543
n-Butane	0.3039	7.293	1.3310
Isopentane	0.0846	2.030	0.3704
n-Pentane	0.0800	1.920	0.3503
n-Hexane	0.0249	0.599	0.1093
Cyclohexane	0.0430	1.031	0.1882
Other Hexanes	0.0489	1.173	0.2140
Heptanes	0.0305	0.731	0.1334
Methylcyclohexane	0.0455	1.092	0.1992
2,2,4-Trimethylpentane	0.0012	0.028	0.0051
Benzene	0.1299	3.118	0.5690
Toluene	0.1197	2.873	0.5244
Ethylbenzene	0.0022	0.052	0.0096
Xylenes	0.0254	0.610	0.1114
C8+ Heavies	0.0008	0.020	0.0036
Total Emissions	2.4778	59.468	10.8528
Total Hydrocarbon Emissions	2.4778	59.468	10.8528
Total VOC Emissions	1.7788	42.691	7.7912
Total HAP Emissions	0.3034	7.280	1.3287
Total BTEX Emissions	0.2772	6.654	1.2143

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.2773	6.656	1.2147
Ethane	0.4489	10.774	1.9663
Propane	0.8351	20.044	3.6579
Isobutane	0.3868	9.282	1.6940

n-Butane	0.6512	15.628	2.8521
Isopentane	0.3961	9.506	1.7348
n-Pentane	0.3385	8.125	1.4828
n-Hexane	0.3224	7.738	1.4122
Cyclohexane	0.7679	18.430	3.3635
Other Hexanes	0.4416	10.598	1.9341
Heptanes	1.1431	27.433	5.0066
Methylcyclohexane	1.7446	41.870	7.6413
2,2,4-Trimethylpentane	0.0430	1.032	0.1884
Benzene	2.9163	69.991	12.7733
Toluene	8.8451	212.282	38.7414
Ethylbenzene	0.5756	13.813	2.5209
Xylenes	7.8121	187.490	34.2169
C8+ Heavies	7.4422	178.613	32.5968
Total Emissions	35.3877	849.304	154.9979
Total Hydrocarbon Emissions	35.3877	849.304	154.9979
Total VOC Emissions	34.6614	831.874	151.8170
Total HAP Emissions	20.5144	492.346	89.8531
Total BTEX Emissions	20.1490	483.575	88.2525

FLASH GAS EMISSIONS

Note: Flash Gas Emissions are zero with the
Recycle/recompression control option.

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr
Methane	1.1798	28.314	5.1674
Ethane	0.4847	11.632	2.1229
Propane	0.3578	8.587	1.5671
Isobutane	0.1003	2.408	0.4394
n-Butane	0.1228	2.948	0.5380
Isopentane	0.0597	1.432	0.2614
n-Pentane	0.0401	0.963	0.1757
n-Hexane	0.0191	0.458	0.0835
Cyclohexane	0.0118	0.282	0.0516
Other Hexanes	0.0356	0.854	0.1559
Heptanes	0.0300	0.721	0.1316
Methylcyclohexane	0.0193	0.462	0.0844
2,2,4-Trimethylpentane	0.0023	0.056	0.0103
Benzene	0.0050	0.120	0.0219
Toluene	0.0088	0.212	0.0387
Ethylbenzene	0.0003	0.007	0.0013
Xylenes	0.0027	0.064	0.0117
C8+ Heavies	0.0204	0.489	0.0892
Total Emissions	2.5004	60.010	10.9519
Total Hydrocarbon Emissions	2.5004	60.010	10.9519
Total VOC Emissions	0.8360	20.063	3.6616
Total HAP Emissions	0.0382	0.917	0.1674
Total BTEX Emissions	0.0168	0.403	0.0736

EQUIPMENT REPORTS:

CONDENSER

Condenser Outlet Temperature:	75.00 deg. F
Condenser Pressure:	11.34 psia
Condenser Duty:	6.60e-002 MM BTU/hr
Hydrocarbon Recovery:	2.65 bbls/day
Produced Water:	4.97 bbls/day
VOC Control Efficiency:	94.87 %
HAP Control Efficiency:	98.52 %
BTEX Control Efficiency:	98.62 %
Dissolved Hydrocarbons in Water:	429.92 mg/L

Component	Emitted	Condensed
Water	0.09%	99.91%
Carbon Dioxide	95.31%	4.69%
Nitrogen	98.66%	1.34%
Methane	99.00%	1.00%
Ethane	94.55%	5.45%
Propane	74.30%	25.70%
Isobutane	56.34%	43.66%
n-Butane	46.67%	53.33%
Isopentane	21.35%	78.65%
n-Pentane	23.63%	76.37%
n-Hexane	7.74%	92.26%
Cyclohexane	5.59%	94.41%
Other Hexanes	11.06%	88.94%
Heptanes	2.66%	97.34%
Methylcyclohexane	2.61%	97.39%
2,2,4-Trimethylpentane	2.71%	97.29%
Benzene	4.45%	95.55%
Toluene	1.35%	98.65%
Ethylbenzene	0.38%	99.62%
Xylenes	0.33%	99.67%
C8+ Heavies	0.01%	99.99%

ABSORBER

Calculated Absorber Stages:	1.45
Specified Dry Gas Dew Point:	7.00 lbs. H2O/MMSCF
Temperature:	83.1 deg. F
Pressure:	207.7 psig
Dry Gas Flow Rate:	14.4000 MMSCF/day
Glycol Losses with Dry Gas:	0.0331 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	127.48 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	3.00 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.48%	94.52%
Carbon Dioxide	99.89%	0.11%
Nitrogen	99.99%	0.01%
Methane	99.99%	0.01%
Ethane	99.97%	0.03%

Propane	99.94%	0.06%
Isobutane	99.90%	0.10%
n-Butane	99.87%	0.13%
Isopentane	99.84%	0.16%
n-Pentane	99.79%	0.21%
n-Hexane	99.59%	0.41%
Cyclohexane	98.28%	1.72%
Other Hexanes	99.70%	0.30%
Heptanes	99.08%	0.92%
Methylcyclohexane	97.69%	2.31%
2,2,4-Trimethylpentane	99.57%	0.43%
Benzene	85.22%	14.78%
Toluene	76.18%	23.82%
Ethylbenzene	61.90%	38.10%
Xylenes	50.49%	49.51%
C8+ Heavies	93.90%	6.10%

FLASH TANK

Flash Control: Recycle/recompression
Flash Temperature: 90.0 deg. F
Flash Pressure: 40.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	100.00%	0.00%
Carbon Dioxide	78.67%	21.33%
Nitrogen	18.23%	81.77%
Methane	19.03%	80.97%
Ethane	48.08%	51.92%
Propane	70.01%	29.99%
Isobutane	79.40%	20.60%
n-Butane	84.13%	15.87%
Isopentane	86.97%	13.03%
n-Pentane	89.46%	10.54%
n-Hexane	94.44%	5.56%
Cyclohexane	98.54%	1.46%
Other Hexanes	92.62%	7.38%
Heptanes	97.45%	2.55%
Methylcyclohexane	98.95%	1.05%
2,2,4-Trimethylpentane	94.91%	5.09%
Benzene	99.84%	0.16%
Toluene	99.91%	0.09%
Ethylbenzene	99.95%	0.05%
Xylenes	99.97%	0.03%
C8+ Heavies	99.76%	0.24%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	29.59%	70.41%
Carbon Dioxide	0.00%	100.00%

Nitrogen	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
Isobutane	0.00%	100.00%
n-Butane	0.00%	100.00%
Isopentane	0.57%	99.43%
n-Pentane	0.56%	99.44%
n-Hexane	0.53%	99.47%
Cyclohexane	3.25%	96.75%
Other Hexanes	1.08%	98.92%
Heptanes	0.51%	99.49%
Methylcyclohexane	4.04%	95.96%
2,2,4-Trimethylpentane	1.58%	98.42%
Benzene	5.01%	94.99%
Toluene	7.91%	92.09%
Ethylbenzene	10.41%	89.59%
Xylenes	12.91%	87.09%
C8+ Heavies	12.04%	87.96%

STREAM REPORTS:

WET GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 6.02e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	2.69e-001	7.67e+001
Carbon Dioxide	2.28e+000	1.59e+003
Nitrogen	1.64e-001	7.28e+001
Methane	8.50e+001	2.16e+004
Ethane	7.36e+000	3.51e+003
Propane	2.87e+000	2.01e+003
Isobutane	5.43e-001	5.00e+002
n-Butane	6.28e-001	5.79e+002
Isopentane	2.46e-001	2.81e+002
n-Pentane	1.58e-001	1.81e+002
n-Hexane	6.03e-002	8.25e+001
Cyclohexane	3.39e-002	4.53e+001
Other Hexanes	1.15e-001	1.57e+002
Heptanes	7.99e-002	1.27e+002
Methylcyclohexane	4.91e-002	7.64e+001
2,2,4-Trimethylpentane	5.88e-003	1.07e+001
Benzene	1.60e-002	1.98e+001
Toluene	2.54e-002	3.72e+001
Ethylbenzene	8.98e-004	1.51e+000
Xylenes	9.37e-003	1.58e+001
C8+ Heavies	4.53e-002	1.22e+002
Total Components	100.00	3.11e+004

DRY GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 6.00e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.47e-002	4.20e+000
Carbon Dioxide	2.29e+000	1.59e+003
Nitrogen	1.64e-001	7.28e+001
Methane	8.53e+001	2.16e+004
Ethane	7.38e+000	3.51e+003
Propane	2.88e+000	2.01e+003
Isobutane	5.44e-001	5.00e+002
n-Butane	6.29e-001	5.78e+002
Isopentane	2.46e-001	2.81e+002
n-Pentane	1.58e-001	1.80e+002
n-Hexane	6.03e-002	8.21e+001
Cyclohexane	3.34e-002	4.45e+001
Other Hexanes	1.15e-001	1.57e+002
Heptanes	7.94e-002	1.26e+002
Methylcyclohexane	4.81e-002	7.47e+001
2,2,4-Trimethylpentane	5.88e-003	1.06e+001
Benzene	1.36e-002	1.68e+001
Toluene	1.94e-002	2.83e+001
Ethylbenzene	5.57e-004	9.36e-001
Xylenes	4.75e-003	7.97e+000
C8+ Heavies	4.26e-002	1.15e+002
Total Components	100.00	3.10e+004

LEAN GLYCOL STREAM

Temperature: 83.13 deg. F
Flow Rate: 3.61e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.83e+001	2.00e+003
Water	1.50e+000	3.05e+001
Carbon Dioxide	8.53e-012	1.73e-010
Nitrogen	2.40e-014	4.86e-013
Methane	2.41e-018	4.89e-017
Ethane	2.17e-008	4.41e-007
Propane	2.39e-009	4.85e-008
Isobutane	7.20e-010	1.46e-008
n-Butane	9.45e-010	1.92e-008
Isopentane	1.13e-004	2.29e-003
n-Pentane	9.37e-005	1.90e-003
n-Hexane	8.45e-005	1.72e-003
Cyclohexane	1.27e-003	2.58e-002
Other Hexanes	2.37e-004	4.82e-003
Heptanes	2.90e-004	5.89e-003
Methylcyclohexane	3.62e-003	7.35e-002
2,2,4-Trimethylpentane	3.40e-005	6.91e-004
Benzene	7.57e-003	1.54e-001
Toluene	3.74e-002	7.60e-001

Ethylbenzene	3.29e-003	6.69e-002
Xylenes	5.71e-002	1.16e+000
C8+ Heavies	5.02e-002	1.02e+000
Total Components	100.00	2.03e+003

RICH GLYCOL STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 3.84e+000 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.32e+001	1.99e+003
Water	4.81e+000	1.03e+002
Carbon Dioxide	8.09e-002	1.73e+000
Nitrogen	2.28e-004	4.89e-003
Methane	6.81e-002	1.46e+000
Ethane	4.36e-002	9.34e-001
Propane	5.57e-002	1.19e+000
Isobutane	2.28e-002	4.87e-001
n-Butane	3.62e-002	7.74e-001
Isopentane	2.14e-002	4.58e-001
n-Pentane	1.78e-002	3.81e-001
n-Hexane	1.60e-002	3.43e-001
Cyclohexane	3.76e-002	8.05e-001
Other Hexanes	2.25e-002	4.82e-001
Heptanes	5.51e-002	1.18e+000
Methylcyclohexane	8.58e-002	1.84e+000
2,2,4-Trimethylpentane	2.15e-003	4.61e-002
Benzene	1.44e-001	3.08e+000
Toluene	4.49e-001	9.61e+000
Ethylbenzene	3.00e-002	6.43e-001
Xylenes	4.19e-001	8.97e+000
C8+ Heavies	3.96e-001	8.48e+000
Total Components	100.00	2.14e+003

FLASH TANK OFF GAS STREAM

Temperature: 90.00 deg. F
Pressure: 54.70 psia
Flow Rate: 4.30e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.46e-001	2.97e-003
Carbon Dioxide	7.41e+000	3.70e-001
Nitrogen	1.26e-001	4.00e-003
Methane	6.49e+001	1.18e+000
Ethane	1.42e+001	4.85e-001
Propane	7.16e+000	3.58e-001
Isobutane	1.52e+000	1.00e-001
n-Butane	1.87e+000	1.23e-001
Isopentane	7.30e-001	5.97e-002
n-Pentane	4.91e-001	4.01e-002

n-Hexane	1.95e-001	1.91e-002
Cyclohexane	1.23e-001	1.18e-002
Other Hexanes	3.65e-001	3.56e-002
Heptanes	2.65e-001	3.00e-002
Methylcyclohexane	1.73e-001	1.93e-002
2,2,4-Trimethylpentane	1.81e-002	2.34e-003
Benzene	5.66e-002	5.01e-003
Toluene	8.46e-002	8.84e-003
Ethylbenzene	2.49e-003	2.99e-004
Xylenes	2.22e-002	2.67e-003
C8+ Heavies	1.05e-001	2.04e-002
Total Components	100.00	2.88e+000

FLASH TANK GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 3.83e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.33e+001	1.99e+003
Water	4.82e+000	1.03e+002
Carbon Dioxide	6.37e-002	1.36e+000
Nitrogen	4.17e-005	8.91e-004
Methane	1.30e-002	2.77e-001
Ethane	2.10e-002	4.49e-001
Propane	3.91e-002	8.35e-001
Isobutane	1.81e-002	3.87e-001
n-Butane	3.05e-002	6.51e-001
Isopentane	1.86e-002	3.98e-001
n-Pentane	1.59e-002	3.40e-001
n-Hexane	1.52e-002	3.24e-001
Cyclohexane	3.71e-002	7.94e-001
Other Hexanes	2.09e-002	4.46e-001
Heptanes	5.37e-002	1.15e+000
Methylcyclohexane	8.50e-002	1.82e+000
2,2,4-Trimethylpentane	2.04e-003	4.37e-002
Benzene	1.44e-001	3.07e+000
Toluene	4.49e-001	9.60e+000
Ethylbenzene	3.01e-002	6.42e-001
Xylenes	4.20e-001	8.97e+000
C8+ Heavies	3.96e-001	8.46e+000
Total Components	100.00	2.14e+003

FLASH GAS EMISSIONS

Control Method: Recycle/recompression
Control Efficiency: 100.00

Note: Flash Gas Emissions are zero with the Recycle/recompression control option.

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.68e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.07e+001	7.25e+001
Carbon Dioxide	6.97e-001	1.36e+000
Nitrogen	7.17e-004	8.91e-004
Methane	3.89e-001	2.77e-001
Ethane	3.36e-001	4.49e-001
Propane	4.27e-001	8.35e-001
Isobutane	1.50e-001	3.87e-001
n-Butane	2.52e-001	6.51e-001
Isopentane	1.24e-001	3.96e-001
n-Pentane	1.06e-001	3.39e-001
n-Hexane	8.43e-002	3.22e-001
Cyclohexane	2.05e-001	7.68e-001
Other Hexanes	1.15e-001	4.42e-001
Heptanes	2.57e-001	1.14e+000
Methylcyclohexane	4.00e-001	1.74e+000
2,2,4-Trimethylpentane	8.48e-003	4.30e-002
Benzene	8.41e-001	2.92e+000
Toluene	2.16e+000	8.85e+000
Ethylbenzene	1.22e-001	5.76e-001
Xylenes	1.66e+000	7.81e+000
C8+ Heavies	9.84e-001	7.44e+000
Total Components	100.00	1.09e+002

CONDENSER VENT GAS STREAM

Temperature: 75.00 deg. F
Pressure: 11.34 psia
Flow Rate: 3.61e+001 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	3.85e+000	6.60e-002
Carbon Dioxide	3.10e+001	1.30e+000
Nitrogen	3.30e-002	8.79e-004
Methane	1.80e+001	2.75e-001
Ethane	1.48e+001	4.24e-001
Propane	1.48e+001	6.21e-001
Isobutane	3.94e+000	2.18e-001
n-Butane	5.50e+000	3.04e-001
Isopentane	1.23e+000	8.46e-002
n-Pentane	1.17e+000	8.00e-002
n-Hexane	3.04e-001	2.49e-002
Cyclohexane	5.37e-001	4.30e-002
Other Hexanes	5.96e-001	4.89e-002
Heptanes	3.20e-001	3.05e-002
Methylcyclohexane	4.87e-001	4.55e-002
2,2,4-Trimethylpentane	1.07e-002	1.16e-003
Benzene	1.75e+000	1.30e-001
Toluene	1.37e+000	1.20e-001
Ethylbenzene	2.16e-002	2.18e-003
Xylenes	2.52e-001	2.54e-002

C8+ Heavies	5.05e-003	8.19e-004
Total Components	100.00	3.84e+000

CONDENSER PRODUCED WATER STREAM

Temperature: 75.00 deg. F
Flow Rate: 1.45e-001 gpm

Component	Conc. (wt%)	Loading (lb/hr)	(ppm)
Water	9.99e+001	7.24e+001	999203.
Carbon Dioxide	3.67e-002	2.66e-002	367.
Nitrogen	4.75e-007	3.44e-007	0.
Methane	3.19e-004	2.32e-004	3.
Ethane	6.57e-004	4.76e-004	7.
Propane	6.32e-004	4.58e-004	6.
Isobutane	1.28e-004	9.30e-005	1.
n-Butane	2.51e-004	1.82e-004	3.
Isopentane	5.29e-005	3.84e-005	1.
n-Pentane	5.57e-005	4.03e-005	1.
n-Hexane	1.59e-005	1.15e-005	0.
Cyclohexane	1.81e-004	1.31e-004	2.
Other Hexanes	2.41e-005	1.75e-005	0.
Heptanes	1.15e-005	8.34e-006	0.
Methylcyclohexane	9.58e-005	6.94e-005	1.
2,2,4-Trimethylpentane	2.83e-007	2.05e-007	0.
Benzene	1.98e-002	1.43e-002	198.
Toluene	1.64e-002	1.19e-002	164.
Ethylbenzene	2.44e-004	1.77e-004	2.
Xylenes	4.17e-003	3.02e-003	42.
C8+ Heavies	1.05e-007	7.64e-008	0.
Total Components	100.00	7.25e+001	1000000.

CONDENSER RECOVERED OIL STREAM

Temperature: 75.00 deg. F
Flow Rate: 7.74e-002 gpm

Component	Conc. (wt%)	Loading (lb/hr)
Water	2.99e-002	9.83e-003
Carbon Dioxide	1.13e-001	3.73e-002
Nitrogen	3.53e-005	1.16e-005
Methane	7.76e-003	2.55e-003
Ethane	7.28e-002	2.40e-002
Propane	6.50e-001	2.14e-001
Isobutane	5.13e-001	1.69e-001
n-Butane	1.05e+000	3.47e-001
Isopentane	9.46e-001	3.11e-001
n-Pentane	7.85e-001	2.59e-001
n-Hexane	9.03e-001	2.97e-001
Cyclohexane	2.20e+000	7.25e-001
Other Hexanes	1.19e+000	3.93e-001
Heptanes	3.38e+000	1.11e+000
Methylcyclohexane	5.16e+000	1.70e+000

2,2,4-Trimethylpentane	1.27e-001	4.19e-002
Benzene	8.42e+000	2.77e+000
Toluene	2.65e+001	8.71e+000
Ethylbenzene	1.74e+000	5.73e-001
Xylenes	2.36e+001	7.78e+000
C8+ Heavies	2.26e+001	7.44e+000
Total Components	100.00	3.29e+001

CONDENSER CONTROL CURVE DATA REPORT:

CONDENSER CONTROL EFFICIENCY CURVES

Note: Condenser curves computed for the range 40.0 F <= T <= 170.0 F. DO NOT EXTRAPOLATE BEYOND THIS RANGE!

Temp(F)	BTEX	Total HAP	VOC
40.0	99.61	99.58	97.06
45.0	99.53	99.49	96.81
50.0	99.43	99.39	96.54
55.0	99.32	99.27	96.26
60.0	99.19	99.12	95.95
65.0	99.03	98.96	95.62
70.0	98.85	98.76	95.27
75.0	98.63	98.53	94.88
80.0	98.37	98.25	94.45
85.0	98.07	97.94	93.99
90.0	97.72	97.56	93.48
95.0	97.30	97.12	92.91
100.0	96.81	96.60	92.28
105.0	96.22	95.99	91.56
110.0	95.52	95.26	90.75
115.0	94.68	94.38	89.82
120.0	93.67	93.33	88.74
125.0	92.43	92.05	87.48
130.0	90.91	90.48	86.00
135.0	89.02	88.55	84.22
140.0	86.66	86.13	82.07
145.0	83.41	82.83	79.23
150.0	79.39	78.76	75.85
155.0	74.11	73.44	71.57
160.0	67.11	66.43	66.11
165.0	57.89	57.23	59.15
170.0	46.32	45.75	50.58
Maximum temperature for 95% control (deg.F):	113.1	111.5	73.4

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: Ute CDP
File Name: C:\Users\etullos\Desktop\Work\137 - Conoco\HH Applicability Determinations\Ute CDP\Dehydrator Emissions_Ute CDP_ Avg of 6,7,8_PTE_5 YR Max of 14.4 MMscf.ddf
Date: February 16, 2011

DESCRIPTION:

Description: 14.4 MMScf/Day per 5 YR Subpart HH maximum; Temperature/Pressure taken from the average values of gas analyses dated December 6, 7, and 8, 2010; Gas dewpoint is 7; Saturated gas

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 83.13 deg. F
Pressure: 207.67 psig
Wet Gas Water Content: Saturated

Component	Conc. (vol %)
Carbon Dioxide	2.2871
Nitrogen	0.1644
Methane	85.2724
Ethane	7.3784
Propane	2.8767
Isobutane	0.5444
n-Butane	0.6294
Isopentane	0.2466
n-Pentane	0.1582
n-Hexane	0.0605
Cyclohexane	0.0340
Other Hexanes	0.1153
Heptanes	0.0801
Methylcyclohexane	0.0492
2,2,4-Trimethylpentane	0.0059
Benzene	0.0160
Toluene	0.0255
Ethylbenzene	0.0009
Xylenes	0.0094
C8+ Heavies	0.0454

DRY GAS:

Flow Rate: 14.4 MMSCF/day
Water Content: 7.0 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.5 wt% H2O
Recirculation Ratio: 3.0 gal/lb H2O

PUMP:

Glycol Pump Type: Gas Injection
Gas Injection Pump Volume Ratio: 0.120 acfm gas/gpm glycol

FLASH TANK:

Flash Control: Recycle/recompression
Temperature: 90.0 deg. F
Pressure: 40.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: Ute CDP
File Name: C:\Users\etullos\Desktop\Work\137 - Conoco\HH Applicability Determinations\Ute CDP\Dehydrator Emissions_Ute CDP_ Avg of 6,7,8_PTE_5 YR Max of 14.4 MMscf.ddf
Date: February 16, 2011

DESCRIPTION:

Description: 14.4 MMScf/Day per 5 YR Subpart HH maximum; Temperature/Pressure taken from the average values of gas analyses dated December 6, 7, and 8, 2010; Gas dewpoint is 7; Saturated gas

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.3379	8.111	1.4802
Ethane	0.2590	6.217	1.1346
Propane	0.4515	10.835	1.9774
Isobutane	0.2171	5.209	0.9507
n-Butane	0.3838	9.212	1.6812
Isopentane	0.2456	5.895	1.0759
n-Pentane	0.2197	5.272	0.9622
n-Hexane	0.2430	5.831	1.0641
Cyclohexane	0.6958	16.699	3.0475
Other Hexanes	0.3122	7.492	1.3673
Heptanes	0.9825	23.580	4.3034
Methylcyclohexane	1.6234	38.961	7.1105
2,2,4-Trimethylpentane	0.0331	0.795	0.1451
Benzene	2.8818	69.164	12.6224
Toluene	8.7856	210.854	38.4808
Ethylbenzene	0.5737	13.769	2.5128
Xylenes	7.7970	187.128	34.1509
C8+ Heavies	7.3312	175.950	32.1108
Total Emissions	33.3739	800.975	146.1778
Total Hydrocarbon Emissions	33.3739	800.975	146.1778
Total VOC Emissions	32.7770	786.647	143.5631
Total HAP Emissions	20.3142	487.541	88.9762
Total BTEX Emissions	20.0381	480.915	87.7669

FLASH GAS EMISSIONS

Note: Flash Gas Emissions are zero with the Recycle/recompression control option.

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr

Methane	15.3820	369.169	67.3734
Ethane	2.9882	71.716	13.0882
Propane	2.0644	49.545	9.0419
Isobutane	0.6000	14.399	2.6278
n-Butane	0.7716	18.519	3.3797
Isopentane	0.3957	9.496	1.7330
n-Pentane	0.2780	6.672	1.2177
n-Hexane	0.1529	3.670	0.6697
Cyclohexane	0.1137	2.730	0.4982
Other Hexanes	0.2686	6.447	1.1766
Heptanes	0.2743	6.583	1.2014
Methylcyclohexane	0.1908	4.580	0.8358
2,2,4-Trimethylpentane	0.0193	0.462	0.0843
Benzene	0.0525	1.259	0.2298
Toluene	0.0928	2.228	0.4066
Ethylbenzene	0.0032	0.076	0.0138
Xylenes	0.0281	0.675	0.1232
C8+ Heavies	0.2119	5.087	0.9283
Total Emissions	23.8880	573.312	104.6294
Total Hydrocarbon Emissions	23.8880	573.312	104.6294
Total VOC Emissions	5.5178	132.426	24.1678
Total HAP Emissions	0.3487	8.370	1.5275
Total BTEX Emissions	0.1766	4.238	0.7734

EQUIPMENT REPORTS:

ABSORBER

Calculated Absorber Stages:	1.45
Specified Dry Gas Dew Point:	7.00 lbs. H2O/MMSCF
Temperature:	83.1 deg. F
Pressure:	207.7 psig
Dry Gas Flow Rate:	14.4000 MMSCF/day
Glycol Losses with Dry Gas:	0.0331 lb/hr
Wet Gas Water Content:	Saturated
Calculated Wet Gas Water Content:	127.48 lbs. H2O/MMSCF
Specified Lean Glycol Recirc. Ratio:	3.00 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	5.48%	94.52%
Carbon Dioxide	99.89%	0.11%
Nitrogen	99.99%	0.01%
Methane	99.99%	0.01%
Ethane	99.97%	0.03%
Propane	99.94%	0.06%
Isobutane	99.90%	0.10%
n-Butane	99.87%	0.13%
Isopentane	99.84%	0.16%
n-Pentane	99.79%	0.21%
n-Hexane	99.59%	0.41%
Cyclohexane	98.28%	1.72%
Other Hexanes	99.70%	0.30%
Heptanes	99.08%	0.92%

Methylcyclohexane	97.69%	2.31%
2,2,4-Trimethylpentane	99.57%	0.43%
Benzene	85.22%	14.78%
Toluene	76.18%	23.82%
Ethylbenzene	61.90%	38.10%
Xylenes	50.49%	49.51%
C8+ Heavies	93.90%	6.10%

FLASH TANK

Flash Control: Recycle/recompression
Flash Temperature: 90.0 deg. F
Flash Pressure: 40.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.97%	0.03%
Carbon Dioxide	25.69%	74.31%
Nitrogen	2.04%	97.96%
Methane	2.15%	97.85%
Ethane	7.98%	92.02%
Propane	17.94%	82.06%
Isobutane	26.57%	73.43%
n-Butane	33.22%	66.78%
Isopentane	38.52%	61.48%
n-Pentane	44.35%	55.65%
n-Hexane	61.54%	38.46%
Cyclohexane	86.38%	13.62%
Other Hexanes	54.13%	45.87%
Heptanes	78.28%	21.72%
Methylcyclohexane	89.89%	10.11%
2,2,4-Trimethylpentane	63.72%	36.28%
Benzene	98.30%	1.70%
Toluene	99.04%	0.96%
Ethylbenzene	99.51%	0.49%
Xylenes	99.69%	0.31%
C8+ Heavies	97.52%	2.48%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	29.58%	70.42%
Carbon Dioxide	0.00%	100.00%
Nitrogen	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
Isobutane	0.00%	100.00%
n-Butane	0.00%	100.00%
Isopentane	0.92%	99.08%
n-Pentane	0.86%	99.14%

n-Hexane	0.70%	99.30%
Cyclohexane	3.57%	96.43%
Other Hexanes	1.52%	98.48%
Heptanes	0.60%	99.40%
Methylcyclohexane	4.33%	95.67%
2,2,4-Trimethylpentane	2.04%	97.96%
Benzene	5.06%	94.94%
Toluene	7.96%	92.04%
Ethylbenzene	10.44%	89.56%
Xylenes	12.93%	87.07%
C8+ Heavies	12.20%	87.80%

STREAM REPORTS:

WET GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 6.02e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	2.69e-001	7.67e+001
Carbon Dioxide	2.28e+000	1.59e+003
Nitrogen	1.64e-001	7.28e+001
Methane	8.50e+001	2.16e+004
Ethane	7.36e+000	3.51e+003
Propane	2.87e+000	2.01e+003
Isobutane	5.43e-001	5.00e+002
n-Butane	6.28e-001	5.79e+002
Isopentane	2.46e-001	2.81e+002
n-Pentane	1.58e-001	1.81e+002
n-Hexane	6.03e-002	8.25e+001
Cyclohexane	3.39e-002	4.53e+001
Other Hexanes	1.15e-001	1.57e+002
Heptanes	7.99e-002	1.27e+002
Methylcyclohexane	4.91e-002	7.64e+001
2,2,4-Trimethylpentane	5.88e-003	1.07e+001
Benzene	1.60e-002	1.98e+001
Toluene	2.54e-002	3.72e+001
Ethylbenzene	8.98e-004	1.51e+000
Xylenes	9.37e-003	1.58e+001
C8+ Heavies	4.53e-002	1.22e+002
Total Components	100.00	3.11e+004

DRY GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 6.00e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	1.47e-002	4.20e+000
Carbon Dioxide	2.29e+000	1.59e+003
Nitrogen	1.64e-001	7.28e+001
Methane	8.53e+001	2.16e+004
Ethane	7.38e+000	3.51e+003
Propane	2.88e+000	2.01e+003
Isobutane	5.44e-001	5.00e+002
n-Butane	6.29e-001	5.78e+002
Isopentane	2.46e-001	2.81e+002
n-Pentane	1.58e-001	1.80e+002
n-Hexane	6.03e-002	8.21e+001
Cyclohexane	3.34e-002	4.45e+001
Other Hexanes	1.15e-001	1.57e+002
Heptanes	7.94e-002	1.26e+002
Methylcyclohexane	4.81e-002	7.47e+001
2,2,4-Trimethylpentane	5.88e-003	1.06e+001
Benzene	1.36e-002	1.68e+001
Toluene	1.94e-002	2.83e+001
Ethylbenzene	5.57e-004	9.36e-001
Xylenes	4.75e-003	7.97e+000
C8+ Heavies	4.26e-002	1.15e+002
Total Components	100.00	3.10e+004

LEAN GLYCOL STREAM

Temperature: 83.13 deg. F
Flow Rate: 3.61e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.83e+001	2.00e+003
Water	1.50e+000	3.05e+001
Carbon Dioxide	8.53e-012	1.73e-010
Nitrogen	2.40e-014	4.86e-013
Methane	2.41e-018	4.89e-017
Ethane	2.17e-008	4.41e-007
Propane	2.39e-009	4.85e-008
Isobutane	7.20e-010	1.46e-008
n-Butane	9.45e-010	1.92e-008
Isopentane	1.13e-004	2.29e-003
n-Pentane	9.37e-005	1.90e-003
n-Hexane	8.45e-005	1.72e-003
Cyclohexane	1.27e-003	2.58e-002
Other Hexanes	2.37e-004	4.82e-003
Heptanes	2.90e-004	5.89e-003
Methylcyclohexane	3.62e-003	7.35e-002
2,2,4-Trimethylpentane	3.40e-005	6.91e-004
Benzene	7.57e-003	1.54e-001
Toluene	3.74e-002	7.60e-001
Ethylbenzene	3.29e-003	6.69e-002
Xylenes	5.71e-002	1.16e+000
C8+ Heavies	5.02e-002	1.02e+000
Total Components	100.00	2.03e+003

RICH GLYCOL AND PUMP GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 3.88e+000 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.23e+001	1.99e+003
Water	4.77e+000	1.03e+002
Carbon Dioxide	1.29e-001	2.78e+000
Nitrogen	2.45e-003	5.29e-002
Methane	7.27e-001	1.57e+001
Ethane	1.50e-001	3.25e+000
Propane	1.16e-001	2.52e+000
Isobutane	3.78e-002	8.17e-001
n-Butane	5.35e-002	1.16e+000
Isopentane	2.98e-002	6.44e-001
n-Pentane	2.31e-002	5.00e-001
n-Hexane	1.84e-002	3.98e-001
Cyclohexane	3.86e-002	8.35e-001
Other Hexanes	2.71e-002	5.86e-001
Heptanes	5.84e-002	1.26e+000
Methylcyclohexane	8.73e-002	1.89e+000
2,2,4-Trimethylpentane	2.46e-003	5.31e-002
Benzene	1.43e-001	3.09e+000
Toluene	4.46e-001	9.64e+000
Ethylbenzene	2.98e-002	6.44e-001
Xylenes	4.16e-001	8.98e+000
C8+ Heavies	3.96e-001	8.56e+000
Total Components	100.00	2.16e+003

FLASH TANK OFF GAS STREAM

Temperature: 90.00 deg. F
Pressure: 54.70 psia
Flow Rate: 4.56e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.46e-001	3.16e-002
Carbon Dioxide	3.90e+000	2.07e+000
Nitrogen	1.54e-001	5.18e-002
Methane	7.97e+001	1.54e+001
Ethane	8.26e+000	2.99e+000
Propane	3.89e+000	2.06e+000
Isobutane	8.58e-001	6.00e-001
n-Butane	1.10e+000	7.72e-001
Isopentane	4.56e-001	3.96e-001
n-Pentane	3.20e-001	2.78e-001
n-Hexane	1.47e-001	1.53e-001
Cyclohexane	1.12e-001	1.14e-001
Other Hexanes	2.59e-001	2.69e-001
Heptanes	2.28e-001	2.74e-001
Methylcyclohexane	1.62e-001	1.91e-001
2,2,4-Trimethylpentane	1.40e-002	1.93e-002
Benzene	5.58e-002	5.25e-002
Toluene	8.38e-002	9.28e-002

Ethylbenzene	2.47e-003	3.15e-003
Xylenes	2.20e-002	2.81e-002
C8+ Heavies	1.03e-001	2.12e-001
Total Components	100.00	2.60e+001

FLASH TANK GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 3.82e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.34e+001	1.99e+003
Water	4.82e+000	1.03e+002
Carbon Dioxide	3.35e-002	7.15e-001
Nitrogen	5.06e-005	1.08e-003
Methane	1.58e-002	3.38e-001
Ethane	1.21e-002	2.59e-001
Propane	2.11e-002	4.51e-001
Isobutane	1.02e-002	2.17e-001
n-Butane	1.80e-002	3.84e-001
Isopentane	1.16e-002	2.48e-001
n-Pentane	1.04e-002	2.22e-001
n-Hexane	1.15e-002	2.45e-001
Cyclohexane	3.38e-002	7.22e-001
Other Hexanes	1.48e-002	3.17e-001
Heptanes	4.63e-002	9.88e-001
Methylcyclohexane	7.95e-002	1.70e+000
2,2,4-Trimethylpentane	1.58e-003	3.38e-002
Benzene	1.42e-001	3.04e+000
Toluene	4.47e-001	9.55e+000
Ethylbenzene	3.00e-002	6.41e-001
Xylenes	4.19e-001	8.96e+000
C8+ Heavies	3.91e-001	8.35e+000
Total Components	100.00	2.14e+003

FLASH GAS EMISSIONS

Control Method: Recycle/recompression
Control Efficiency: 100.00

Note: Flash Gas Emissions are zero with the
Recycle/recompression control option.

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 1.67e+003 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	9.16e+001	7.25e+001
Carbon Dioxide	3.69e-001	7.15e-001
Nitrogen	8.77e-004	1.08e-003

Methane	4.79e-001	3.38e-001
Ethane	1.96e-001	2.59e-001
Propane	2.33e-001	4.51e-001
Isobutane	8.50e-002	2.17e-001
n-Butane	1.50e-001	3.84e-001
Isopentane	7.74e-002	2.46e-001
n-Pentane	6.93e-002	2.20e-001
n-Hexane	6.41e-002	2.43e-001
Cyclohexane	1.88e-001	6.96e-001
Other Hexanes	8.24e-002	3.12e-001
Heptanes	2.23e-001	9.83e-001
Methylcyclohexane	3.76e-001	1.62e+000
2,2,4-Trimethylpentane	6.60e-003	3.31e-002
Benzene	8.39e-001	2.88e+000
Toluene	2.17e+000	8.79e+000
Ethylbenzene	1.23e-001	5.74e-001
Xylenes	1.67e+000	7.80e+000
C8+ Heavies	9.79e-001	7.33e+000
Total Components	100.00	1.07e+002

APPENDIX F

GRI-HAPCalc Output Report

GRI-HAPCalc® 3.0
Fugitive Emissions Report

Facility ID:	**UTE CDP**	**Notes:**	**The number of components in light oil (condensate) service was estimated by assuming it is equivalent to 10% of the components in gas/vapor service.**
Operation Type:	**COMPRESSOR STATION**		
Facility Name:	**UTE CDP**		
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".

Fugitive Emissions

Calculation Method: EPA Average Factors

User Inputs

Component	Gas Service	Light Liquid Service	Heavy Liquid Service
Connections:	737	74	0
Flanges	120	12	0
Open-Ended Lines:	14	1	0
Pumps:	0	0	0
Valves:	257	26	0
Others:	30	3	0

Calculated Emissions (ton/yr)

Chemical Name	Emissions
HAPs	
Benzene	0.0039
Toluene	0.0070
Ethylbenzene	0.0005
Xylenes(m,p,o)	0.0020
Total	0.0134
Criteria Pollutants	
NMHC	1.6627
NMEHC	0.8516

GRI-HAPCalc® 3.0
Truck Loading Report

Facility ID:	**UTE CDP**	**Notes:**	**The number of components in light oil (condensate) service was estimated by assuming it is equivalent to 10% of the components in gas/vapor service.**
Operation Type:	**COMPRESSOR STATION**		
Facility Name:	**UTE CDP**		
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".

Truck Loading Unit

Unit Name: TL-1

Annual Throughput: 5,000.00 bbl/yr

Control Efficiency: 0.00 %

Ambient Temperature: 52.00 °F

Loading Factor: 0

Type of Loading: 0.6 - Submerged loading, dedicated service

Is Truck Required to Pass Annual Inspection?: NO

Are Vapors Routed to Control Device?: NO

User Concentration Inputs

Chemical Name	Feed Wt %
Ethane	3.7938
Propane	0.9954
Butane	1.2918
Pentane	1.8684
C6+	92.0500
n-Hexane	2.0685
Benzene	0.5996
Toluene	3.6329
Ethylbenzene	0.4925
Xylenes(m,p,o)	5.6530
2,2,4-Trimethylpentane	1.5090

Calculated Emissions (ton/yr)

	Chemical Name	Emissions
HAPs		
	Benzene	0.0007
	Toluene	0.0011
	Ethylbenzene	0.0000
	Xylenes(m,p,o)	0.0004
	2,2,4-Trimethylpentane	0.0009
	n-Hexane	0.0039
Total		0.0070

Criteria Pollutants

NMHC	2.4004
NMEHC	0.3363

Other Pollutants

Ethane	2.0641
Propane	0.1150
Butane	0.0351
Pentane	0.0130
C6+	0.1732

APPENDIX G

E&P Tank Output Reports

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File              : C:\Users\Sugar Magnolia\Desktop\Work\137 - Conoco\_Title V\Ute CDP\Ute CDP E&P Tank_
Flowsheet Selection       : Oil Tank with Separator
Calculation Method        : AP42
Control Efficiency        : 100.0%
Known Separator Stream    : Low Pressure Oil
Entering Air Composition  : No

Filed Name                : San Juan Basin
Well Name                 : Ute CDP
Well ID                   : Inlet Scrubber to Condensate Tanks
Date                      : 2011.04.11


******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure        : 49.02[psig]
Separator Temperature     : 52.67[F]
Ambient Pressure          : 11.20[psia]
Ambient Temperature       : 52.10[F]
C10+ SG                   : 0.7522
C10+ MW                   : 172.356

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component             mol %
   1      H2S                   0.0000
   2      O2                    0.0000
   3      CO2                   1.0532
   4      N2                    0.0323
   5      C1                   15.2754
   6      C2                    2.8457
   7      C3                    2.2485
   8      i-C4                  0.8541
   9      n-C4                  1.3596
   10     i-C5                  1.4608
   11     n-C5                  1.1185
   12     C6                    3.1739
   13     C7                   16.5335
   14     C8                   10.1878
   15     C9                    7.4041
   16     C10+                 22.2889
   17     Benzene               0.7645
   18     Toluene               3.9271
   19     E-Benzene             0.4620
   20     Xylenes               5.3035
   21     n-C6                  2.3908
   22     224Trimethylp         1.3158

-- Sales Oil -----------------------------------------------------------------------------
Production Rate           : 12.3[bbl/day]
Days of Annual Operation  : 365 [days/year]
API Gravity               : 58.0
Reid Vapor Pressure       : 3.90[psia]
Bulk Temperature          : 65.00[F]

-- Tank and Shell Data -------------------------------------------------------------------
Diameter                  : 12.00[ft]
Shell Height              : 15.00[ft]
Cone Roof Slope           : 0.06
Average Liquid Height     : 6.00[ft]
Vent Pressure Range       : 0.06[psi]
Solar Absorbance          : 0.68
```

-- Meteorological Data --

City	: Roswell, NM
Ambient Pressure	: 11.20[psia]
Ambient Temperature	: 52.10[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]
Total HAPs	0.950	0.217
Total HC	33.378	7.621
VOCs, C2+	18.338	4.187
VOCs, C3+	13.425	3.065

Uncontrolled Recovery Info.

Vapor	2.8900	[MSCFD]
HC Vapor	2.7600	[MSCFD]
GOR	234.96	[SCF/bbl]

-- Emission Composition --

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	2.761	0.630
4	N2	0.056	0.013
5	C1	15.039	3.434
6	C2	4.913	1.122
7	C3	4.574	1.044
8	i-C4	1.514	0.346
9	n-C4	1.924	0.439
10	i-C5	1.201	0.274
11	n-C5	0.692	0.158
12	C6	0.759	0.173
13	C7	1.430	0.326
14	C8	0.292	0.067
15	C9	0.074	0.017
16	C10+	0.012	0.003
17	Benzene	0.121	0.028
18	Toluene	0.190	0.043
19	E-Benzene	0.008	0.002
20	Xylenes	0.077	0.018
21	n-C6	0.450	0.103
22	224Trimethylp	0.106	0.024
	Total	36.193	8.263

-- 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	1.0532	0.0668	0.0036	4.5342	1.9089	4.5050
4	N2	28.01	0.0323	0.0002	0.0000	0.1457	0.0004	0.1440
5	C1	16.04	15.2754	0.3111	0.0000	68.0856	0.0003	67.3294
6	C2	30.07	2.8457	0.3489	0.0907	11.6571	18.6573	11.7348
7	C3	44.10	2.2485	0.8426	0.5918	7.2100	28.8111	7.4499
8	i-C4	58.12	0.8541	0.5892	0.5207	1.7891	9.1919	1.8713
9	n-C4	58.12	1.3596	1.1030	1.0170	2.2653	12.3603	2.3775
10	i-C5	72.15	1.4608	1.5541	1.5211	1.1315	6.8491	1.1950
11	n-C5	72.15	1.1185	1.2511	1.2363	0.6505	4.0699	0.6885

12	C6	86.16	3.1739	3.9004	3.9232	0.6101	4.1234	0.6491
13	C7	100.20	16.5335	20.9380	21.1801	0.9896	7.1975	1.0586
14	C8	114.23	10.1878	13.0248	13.2002	0.1757	1.3754	0.1891
15	C9	128.28	7.4041	9.4907	9.6238	0.0402	0.3371	0.0435
16	C10+	172.36	22.2889	28.6034	29.0122	0.0047	0.0474	0.0052
17	Benzene	78.11	0.7645	0.9514	0.9593	0.1048	0.7210	0.1117
18	Toluene	92.13	3.9271	5.0006	5.0639	0.1385	1.0330	0.1485
19	E-Benzene	106.17	0.4620	0.5915	0.5997	0.0049	0.0392	0.0053
20	Xylenes	106.17	5.3035	6.7926	6.8867	0.0482	0.3890	0.0520
21	n-C6	86.18	2.3908	2.9686	2.9916	0.3518	2.4328	0.3750
22	224Trimethylp	114.24	1.3158	1.6710	1.6912	0.0624	0.4548	0.0668
	MW		99.27	120.14	120.93	25.65	56.61	26.00
	Stream Mole Ratio		1.0000	0.7792	0.7767	0.2208	0.0025	0.2233
	Heating Value	[BTU/SCF]				1407.15	3112.73	1426.10
	Gas Gravity	[Gas/Air]				0.89	1.95	0.90
	Bubble Pt. @ 100F	[psia]	546.59	16.59	4.38			
	RVP @ 100F	[psia]	698.22	44.98	25.74			
	Spec. Gravity @ 100F		0.665	0.689	0.690			

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File              : C:\Users\Sugar Magnolia\Desktop\Work\137 - Conoco\_Title V\Ute CDP\Ute CDP E&P Tank
Flowsheet Selection       : Oil Tank with Separator
Calculation Method        : AP42
Control Efficiency        : 100.0%
Known Separator Stream    : Low Pressure Oil
Entering Air Composition  : No

Filed Name                : San Juan Basin
Well Name                 : Ute CDP
Well ID                   : Discharge Scrubber to Condensate Tanks
Date                      : 2011.04.11


******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure        : 188.00[psig]
Separator Temperature     : 70.10[F]
Ambient Pressure          : 11.20[psia]
Ambient Temperature       : 52.10[F]
C10+ SG                   : 0.7522
C10+ MW                   : 172.356

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component            mol %
   1      H2S                   0.0000
   2      O2                    0.0000
   3      CO2                   1.0532
   4      N2                    0.0323
   5      C1                   15.2754
   6      C2                    2.8457
   7      C3                    2.2485
   8      i-C4                  0.8541
   9      n-C4                  1.3596
   10     i-C5                  1.4608
   11     n-C5                  1.1185
   12     C6                    3.1739
   13     C7                   16.5335
   14     C8                   10.1878
   15     C9                    7.4041
   16     C10+                 22.2889
   17     Benzene               0.7645
   18     Toluene               3.9271
   19     E-Benzene             0.4620
   20     Xylenes               5.3035
   21     n-C6                  2.3908
   22     224Trimethylp         1.3158

-- Sales Oil -----------------------------------------------------------------------------
Production Rate           : 1.4[bbl/day]
Days of Annual Operation  : 365 [days/year]
API Gravity               : 58.0
Reid Vapor Pressure       : 3.90[psia]
Bulk Temperature          : 65.00[F]

-- Tank and Shell Data -------------------------------------------------------------------
Diameter                  : 12.00[ft]
Shell Height              : 15.00[ft]
Cone Roof Slope           : 0.06
Average Liquid Height     : 6.00[ft]
Vent Pressure Range       : 0.06[psi]
Solar Absorbance          : 0.68
```

-- Meteorological Data --

City	: Roswell, NM
Ambient Pressure	: 11.20[psia]
Ambient Temperature	: 52.10[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]
Total HAPs	0.140	0.032
Total HC	3.890	0.888
VOCs, C2+	2.204	0.503
VOCs, C3+	1.665	0.380

Uncontrolled Recovery Info.

Vapor	326.4400 x1E-3	[MSCFD]
HC Vapor	311.4700 x1E-3	[MSCFD]
GOR	233.17	[SCF/bbl]

-- Emission Composition ---

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.308	0.070
4	N2	0.006	0.001
5	C1	1.686	0.385
6	C2	0.539	0.123
7	C3	0.483	0.110
8	i-C4	0.168	0.038
9	n-C4	0.224	0.051
10	i-C5	0.159	0.036
11	n-C5	0.095	0.022
12	C6	0.112	0.026
13	C7	0.219	0.050
14	C8	0.046	0.011
15	C9	0.012	0.003
16	C10+	0.002	0.000
17	Benzene	0.018	0.004
18	Toluene	0.029	0.007
19	E-Benzene	0.001	0.000
20	Xylenes	0.012	0.003
21	n-C6	0.067	0.015
22	224Trimethylp	0.016	0.004
	Total	4.202	0.959

-- 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	1.0532	0.0697	0.0000	4.5639	0.0001	4.4450
4	N2	28.01	0.0323	0.0002	0.0000	0.1469	0.0001	0.1431
5	C1	16.04	15.2754	0.3192	0.0000	68.6620	0.0001	66.8736
6	C2	30.07	2.8457	0.3647	0.0000	11.7019	0.0001	11.3971
7	C3	44.10	2.2485	0.8816	0.0104	7.1276	1.1898	6.9729
8	i-C4	58.12	0.8541	0.6094	0.1285	1.7275	6.1653	1.8431
9	n-C4	58.12	1.3596	1.1343	0.3915	2.1637	13.3118	2.4541
10	i-C5	72.15	1.4608	1.5751	1.1080	1.0529	14.5321	1.4039
11	n-C5	72.15	1.1185	1.2638	0.9991	0.6000	9.6433	0.8355

12	C6	86.16	3.1739	3.9088	3.8510	0.5508	11.9552	0.8479
13	C7	100.20	16.5335	20.9195	22.1218	0.8775	22.2740	1.4348
14	C8	114.23	10.1878	12.9990	14.0738	0.1532	4.3465	0.2625
15	C9	128.28	7.4041	9.4687	10.3229	0.0345	1.0714	0.0615
16	C10+	172.36	22.2889	28.5320	31.2102	0.0039	0.1487	0.0076
17	Benzene	78.11	0.7645	0.9523	0.9666	0.0942	2.1466	0.1477
18	Toluene	92.13	3.9271	4.9930	5.3523	0.1222	3.2321	0.2032
19	E-Benzene	106.17	0.4620	0.5902	0.6415	0.0043	0.1240	0.0074
20	Xylenes	106.17	5.3035	6.7776	7.3732	0.0418	1.2324	0.0728
21	n-C6	86.18	2.3908	2.9721	2.9981	0.3159	7.2095	0.4955
22	224Trimethylp	114.24	1.3158	1.6689	1.7774	0.0553	1.4168	0.0908
	MW		99.27	120.00	122.93	25.28	81.26	26.74
	Stream Mole Ratio		1.0000	0.7812	0.7753	0.2188	0.0059	0.2247
	Heating Value	[BTU/SCF]				1387.13	4426.26	1466.29
	Gas Gravity	[Gas/Air]				0.87	2.80	0.92
	Bubble Pt. @ 100F	[psia]	546.59	17.08	1.89			
	RVP @ 100F	[psia]	698.22	46.31	12.69			
	Spec. Gravity @ 100F		0.665	0.689	0.692			

APPENDIX H

EPA Tanks 4.09d Output Report

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	BGT-1
City:	
State:	Colorado
Company:	ConocoPhillips
Type of Tank:	Vertical Fixed Roof Tank
Description:	Pit sump liquids storage tank

Tank Dimensions

Shell Height (ft):	5.00
Diameter (ft):	13.00
Liquid Height (ft) :	5.00
Avg. Liquid Height (ft):	1.00
Volume (gallons):	5,040.00
Turnovers:	4.00
Net Throughput(gal/yr):	20,140.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Red/Primer
Shell Condition	Poor
Roof Color/Shade:	Red/Primer
Roof Condition:	Poor

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

BGT-1 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Distillate fuel oil no. 2	All	55.56	38.56	72.56	45.54	0.0056	0.0031	0.0098	130.0000			188.00	Option 1: VP50 = .0045 VP60 = .0065

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

BGT-1 - Vertical Fixed Roof Tank

Annual Emission Calcaulations

Standing Losses (lb):	3.3590
Vapor Space Volume (cu ft):	548.9033
Vapor Density (lb/cu ft):	0.0001
Vapor Space Expansion Factor:	0.1272
Vented Vapor Saturation Factor:	0.9988
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	548.9033
Tank Diameter (ft):	13.0000
Vapor Space Outage (ft):	4.1354
Tank Shell Height (ft):	5.0000
Average Liquid Height (ft):	1.0000
Roof Outage (ft):	0.1354
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.1354
Roof Height (ft):	0.0000
Roof Slope (ft/ft):	0.0625
Shell Radius (ft):	6.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0001
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0056
Daily Avg. Liquid Surface Temp. (deg. R):	515.2302
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	505.2050
Tank Paint Solar Absorptance (Shell):	0.9100
Tank Paint Solar Absorptance (Roof):	0.9100
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1272
Daily Vapor Temperature Range (deg. R):	67.9997
Daily Vapor Pressure Range (psia):	0.0067
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0056
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0031
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0098
Daily Avg. Liquid Surface Temp. (deg R):	515.2302
Daily Min. Liquid Surface Temp. (deg R):	498.2303
Daily Max. Liquid Surface Temp. (deg R):	532.2301
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9988
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0056
Vapor Space Outage (ft):	4.1354

Working Losses (lb):	0.3498
Vapor Molecular Weight (lb/lb-mole):	130.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0056
Annual Net Throughput (gal/yr.):	20,140.0000
Annual Turnovers:	4.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	5,040.0000
Maximum Liquid Height (ft):	5.0000
Tank Diameter (ft):	13.0000
Working Loss Product Factor:	1.0000
Total Losses (lb):	3.7088

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

BGT-1 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Distillate fuel oil no. 2	0.35	3.36	3.71

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	BGT-2
City:	
State:	Colorado
Company:	ConocoPhillips
Type of Tank:	Vertical Fixed Roof Tank
Description:	Drain tank for Condenser Liquids - Data from the inlet scrubber and sales liquids were used to create the chemical profile
Tank Dimensions	
Shell Height (ft):	5.00
Diameter (ft):	13.00
Liquid Height (ft) :	5.00
Avg. Liquid Height (ft):	1.00
Volume (gallons):	5,040.00
Turnovers:	4.00
Net Throughput(gal/yr):	20,140.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good
Roof Characteristics	
Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.06
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

BGT-2 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Ute Condenser Drip	All	49.44	36.76	62.12	43.32	1.6360	1.2349	2.1380	172.3600			99.61	Option 4: RVP=3.9

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

BGT-2 - Vertical Fixed Roof Tank

Annual Emission Calcaulations	
Standing Losses (lb):	1,429.7591
Vapor Space Volume (cu ft):	548.9033
Vapor Density (lb/cu ft):	0.0516
Vapor Space Expansion Factor:	0.1878
Vented Vapor Saturation Factor:	0.7361
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	548.9033
Tank Diameter (ft):	13.0000
Vapor Space Outage (ft):	4.1354
Tank Shell Height (ft):	5.0000
Average Liquid Height (ft):	1.0000
Roof Outage (ft):	0.1354
Roof Outage (Cone Roof)	
Roof Outage (ft):	0.1354
Roof Height (ft):	0.0000
Roof Slope (ft/ft):	0.0625
Shell Radius (ft):	6.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0516
Vapor Molecular Weight (lb/lb-mole):	172.3600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.6360
Daily Avg. Liquid Surface Temp. (deg. R):	509.1129
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	502.9850
Tank Paint Solar Absorptance (Shell):	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1878
Daily Vapor Temperature Range (deg. R):	50.7245
Daily Vapor Pressure Range (psia):	0.9031
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.6360
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.2349
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	2.1380
Daily Avg. Liquid Surface Temp. (deg R):	509.1129
Daily Min. Liquid Surface Temp. (deg R):	496.4318
Daily Max. Liquid Surface Temp. (deg R):	521.7940
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.7361
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	1.6360
Vapor Space Outage (ft):	4.1354

Working Losses (lb):	101.4121
Vapor Molecular Weight (lb/lb-mole):	172.3600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.6360
Annual Net Throughput (gal/yr.):	20,140.0000
Annual Turnovers:	4.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	5,040.0000
Maximum Liquid Height (ft):	5.0000
Tank Diameter (ft):	13.0000
Working Loss Product Factor:	0.7500
Total Losses (lb):	1,531.1712

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

BGT-2 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Ute Condenser Drip	101.41	1,429.76	1,531.17

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	CT-1
City:	
State:	Colorado
Company:	ConocoPhillips
Type of Tank:	Vertical Fixed Roof Tank
Description:	Coolant storage tank (50% water)
Tank Dimensions	
Shell Height (ft):	12.00
Diameter (ft):	7.00
Liquid Height (ft) :	12.00
Avg. Liquid Height (ft):	6.00
Volume (gallons):	3,454.00
Turnovers:	10.00
Net Throughput(gal/yr):	34,540.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.25
Radius (ft) (Dome Roof)	7.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

CT-1 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Ethylene glycol	All	51.76	37.44	66.07	44.16	0.0007	0.0003	0.0015	200.0000			62.07	Option 2: A=8.7945, B=2615.4, C=244.91

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

CT-1 - Vertical Fixed Roof Tank

Annual Emission Calcaulations	
Standing Losses (lb):	0.2423
Vapor Space Volume (cu ft):	235.7258
Vapor Density (lb/cu ft):	0.0000
Vapor Space Expansion Factor:	0.1067
Vented Vapor Saturation Factor:	0.9998
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	235.7258
Tank Diameter (ft):	7.0000
Vapor Space Outage (ft):	6.1252
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.1252
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.1252
Dome Radius (ft):	7.0000
Shell Radius (ft):	3.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0000
Vapor Molecular Weight (lb/lb-mole):	200.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0007
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1067
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	0.0011
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0007
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0003
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0015
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9998
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0007
Vapor Space Outage (ft):	6.1252
Working Losses (lb):	0.1191

Vapor Molecular Weight (lb/lb-mole):	200.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0007
Annual Net Throughput (gal/yr.):	34,540.0000
Annual Turnovers:	10.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	3,454.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	7.0000
Working Loss Product Factor:	1.0000

Total Losses (lb):	0.3614

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

CT-1 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Ethylene glycol	0.12	0.24	0.36

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	GT-1
City:	
State:	Colorado
Company:	ConocoPhillips
Type of Tank:	Vertical Fixed Roof Tank
Description:	Glycol storage tank

Tank Dimensions

Shell Height (ft):		12.00
Diameter (ft):		4.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		1,130.00
Turnovers:		10.00
Net Throughput(gal/yr):		11,300.00
Is Tank Heated (y/n):	N	

Paint Characteristics

Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good

Roof Characteristics

Type:	Dome	
Height (ft)		0.25
Radius (ft) (Dome Roof)		4.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

GT-1 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Ethylene glycol	All	51.76	37.44	66.07	44.16	0.0007	0.0003	0.0015	200.0000			62.07	Option 2: A=8.7945, B=2615.4, C=244.91

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

GT-1 - Vertical Fixed Roof Tank

Annual Emission Calcaulations	
Standing Losses (lb):	0.0791
Vapor Space Volume (cu ft):	76.9772
Vapor Density (lb/cu ft):	0.0000
Vapor Space Expansion Factor:	0.1067
Vented Vapor Saturation Factor:	0.9998
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	76.9772
Tank Diameter (ft):	4.0000
Vapor Space Outage (ft):	6.1257
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.1257
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.1257
Dome Radius (ft):	4.0000
Shell Radius (ft):	2.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0000
Vapor Molecular Weight (lb/lb-mole):	200.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0007
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.1067
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	0.0011
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0007
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.0003
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	0.0015
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.9998
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	0.0007
Vapor Space Outage (ft):	6.1257
Working Losses (lb):	0.0390

Vapor Molecular Weight (lb/lb-mole):	200.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	0.0007
Annual Net Throughput (gal/yr.):	11,300.0000
Annual Turnovers:	10.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	1,130.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	4.0000
Working Loss Product Factor:	1.0000

Total Losses (lb):	0.1181

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

GT-1 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Ethylene glycol	0.04	0.08	0.12

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	MT-1
City:	
State:	Colorado
Company:	ConocoPhillips
Type of Tank:	Vertical Fixed Roof Tank
Description:	Methanol storage tank
Tank Dimensions	
Shell Height (ft):	12.00
Diameter (ft):	7.00
Liquid Height (ft) :	12.00
Avg. Liquid Height (ft):	6.00
Volume (gallons):	3,454.00
Turnovers:	10.00
Net Throughput(gal/yr):	34,540.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.25
Radius (ft) (Dome Roof)	7.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

MT-1 - Vertical Fixed Roof Tank

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	All	51.76	37.44	66.07	44.16	1.1069	0.6820	1.7416	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

MT-1 - Vertical Fixed Roof Tank

Annual Emission Calcaulations	
Standing Losses (lb):	86.3260
Vapor Space Volume (cu ft):	235.7258
Vapor Density (lb/cu ft):	0.0065
Vapor Space Expansion Factor:	0.2111
Vented Vapor Saturation Factor:	0.7357
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	235.7258
Tank Diameter (ft):	7.0000
Vapor Space Outage (ft):	6.1252
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.1252
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.1252
Dome Radius (ft):	7.0000
Shell Radius (ft):	3.5000
Vapor Density	
Vapor Density (lb/cu ft):	0.0065
Vapor Molecular Weight (lb/lb-mole):	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.1069
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2111
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.0595
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.1069
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	0.6820
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	1.7416
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.7357
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	1.1069
Vapor Space Outage (ft):	6.1252
Working Losses (lb):	29.1658

Vapor Molecular Weight (lb/lb-mole):	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.1069
Annual Net Throughput (gal/yr.):	34,540.0000
Annual Turnovers:	10.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	3,454.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	7.0000
Working Loss Product Factor:	1.0000

Total Losses (lb):	115.4918

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

MT-1 - Vertical Fixed Roof Tank

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	29.17	86.33	115.49

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification		
User Identification:	OT-1	
City:		
State:	Colorado	
Company:	ConocoPhillips	
Type of Tank:	Vertical Fixed Roof Tank	
Description:	Oil storage tank (for compressors)	
Tank Dimensions		
Shell Height (ft):		12.00
Diameter (ft):		8.00
Liquid Height (ft) :		12.00
Avg. Liquid Height (ft):		6.00
Volume (gallons):		4,512.00
Turnovers:		10.00
Net Throughput(gal/yr):		45,120.00
Is Tank Heated (y/n):	N	
Paint Characteristics		
Shell Color/Shade:	Gray/Medium	
Shell Condition	Good	
Roof Color/Shade:	Gray/Medium	
Roof Condition:	Good	
Roof Characteristics		
Type:	Dome	
Height (ft)		0.50
Radius (ft) (Dome Roof)		8.00
Breather Vent Settings		
Vacuum Settings (psig):		-0.03
Pressure Settings (psig)		0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

OT-1 - Vertical Fixed Roof Tank
, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	51.76	37.44	66.07	44.16	2.4413	1.8110	3.2379	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

OT-1 - Vertical Fixed Roof Tank
, Colorado

Annual Emission Calcaulations

Standing Losses (lb):	378.1278
Vapor Space Volume (cu ft):	314.2247
Vapor Density (lb/cu ft):	0.0222
Vapor Space Expansion Factor:	0.2681
Vented Vapor Saturation Factor:	0.5528
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	314.2247
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	6.2513
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.2513
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2513
Dome Radius (ft):	8.0000
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0222
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2681
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.4269
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.8110
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	3.2379
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.5528
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.4413
Vapor Space Outage (ft):	6.2513

Working Losses (lb):	98.3496
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Annual Net Throughput (gal/yr.):	45,120.0000
Annual Turnovers:	10.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,512.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	0.7500
Total Losses (lb):	476.4774

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

OT-1 - Vertical Fixed Roof Tank
, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	98.35	378.13	476.48

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	UOT-1
City:	
State:	Colorado
Company:	ConocoPhillips
Type of Tank:	Vertical Fixed Roof Tank
Description:	Used oil storage tank
Tank Dimensions	
Shell Height (ft):	12.00
Diameter (ft):	8.00
Liquid Height (ft) :	12.00
Avg. Liquid Height (ft):	6.00
Volume (gallons):	4,512.00
Turnovers:	10.00
Net Throughput(gal/yr):	45,120.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Medium
Shell Condition	Good
Roof Color/Shade:	Gray/Medium
Roof Condition:	Good
Roof Characteristics	
Type:	Dome
Height (ft)	0.50
Radius (ft) (Dome Roof)	8.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Alamosa, Colorado (Avg Atmospheric Pressure = 11.19 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

UOT-1 - Vertical Fixed Roof Tank
, Colorado

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Crude oil (RVP 5)	All	51.76	37.44	66.07	44.16	2.4413	1.8110	3.2379	50.0000			207.00	Option 4: RVP=5

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

UOT-1 - Vertical Fixed Roof Tank
, Colorado

Annual Emission Calcaulations

Standing Losses (lb):	378.1278
Vapor Space Volume (cu ft):	314.2247
Vapor Density (lb/cu ft):	0.0222
Vapor Space Expansion Factor:	0.2681
Vented Vapor Saturation Factor:	0.5528
Tank Vapor Space Volume:	
Vapor Space Volume (cu ft):	314.2247
Tank Diameter (ft):	8.0000
Vapor Space Outage (ft):	6.2513
Tank Shell Height (ft):	12.0000
Average Liquid Height (ft):	6.0000
Roof Outage (ft):	0.2513
Roof Outage (Dome Roof)	
Roof Outage (ft):	0.2513
Dome Radius (ft):	8.0000
Shell Radius (ft):	4.0000
Vapor Density	
Vapor Density (lb/cu ft):	0.0222
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Daily Avg. Liquid Surface Temp. (deg. R):	511.4276
Daily Average Ambient Temp. (deg. F):	41.0750
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731
Liquid Bulk Temperature (deg. R):	503.8250
Tank Paint Solar Absorptance (Shell):	0.6800
Tank Paint Solar Absorptance (Roof):	0.6800
Daily Total Solar Insulation Factor (Btu/sqft day):	1,667.4918
Vapor Space Expansion Factor	
Vapor Space Expansion Factor:	0.2681
Daily Vapor Temperature Range (deg. R):	57.2610
Daily Vapor Pressure Range (psia):	1.4269
Breather Vent Press. Setting Range(psia):	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.8110
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	3.2379
Daily Avg. Liquid Surface Temp. (deg R):	511.4276
Daily Min. Liquid Surface Temp. (deg R):	497.1123
Daily Max. Liquid Surface Temp. (deg R):	525.7428
Daily Ambient Temp. Range (deg. R):	35.4333
Vented Vapor Saturation Factor	
Vented Vapor Saturation Factor:	0.5528
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.4413
Vapor Space Outage (ft):	6.2513

Working Losses (lb):	98.3496
Vapor Molecular Weight (lb/lb-mole):	50.0000
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.4413
Annual Net Throughput (gal/yr.):	45,120.0000
Annual Turnovers:	10.0000
Turnover Factor:	1.0000
Maximum Liquid Volume (gal):	4,512.0000
Maximum Liquid Height (ft):	12.0000
Tank Diameter (ft):	8.0000
Working Loss Product Factor:	0.7500
Total Losses (lb):	476.4774

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: Annual

UOT-1 - Vertical Fixed Roof Tank
, Colorado

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Crude oil (RVP 5)	98.35	378.13	476.48

TANKS 4.0.9d
Emissions Report - Detail Format
Total Emissions Summaries - All Tanks in Report

Emissions Report for: Annual

Tank Identification				Losses (lbs)
BGT-1	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	3.71
BGT-2	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	1,531.17
CT-1	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	0.36
GT-1	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	0.12
MT-1	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	115.49
OT-1	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	476.48
UOT-1	ConocoPhillips	Vertical Fixed Roof Tank	, Colorado	476.48
Total Emissions for all Tanks:				2,603.81

APPENDIX I

Gas and Liquid Analyses

Input for GRI-GLYCalc

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A		Description:	Ute CDP Inlet to Dehy
Analysis Date/Time:	12/7/2010	5:06 PM	Field:	Farmington, NM
Analyst Initials:	AST		ML#:	ConocoPhillips
Instrument ID:	Instrument 1		GC Method:	Quesbtex
Data File:	QPC24.D			
Date Sampled:	12/6/2010			

Component	Mol%	Wt%	LV%
Methane	85.3946	70.0552	79.0010
Ethane	7.3491	11.3004	10.7563
Propane	2.8593	6.4476	4.3028
Isobutane	0.5306	1.5771	0.9480
n-Butane	0.6218	1.8480	1.0706
Neopentane	0.0054	0.0200	0.0113
Isopentane	0.2346	0.8656	0.4690
n-Pentane	0.1546	0.5702	0.3057
2,2-Dimethylbutane	0.0069	0.0305	0.0158
2,3-Dimethylbutane	0.0193	0.0849	0.0431
2-Methylpentane	0.0539	0.2376	0.1222
3-Methylpentane	0.0308	0.1359	0.0687
n-Hexane	0.0585	0.2577	0.1313
Heptanes	0.1973	0.9322	0.4105
Octanes	0.0300	0.1756	0.0820
Nonanes	0.0155	0.0916	0.0392
Decanes plus	0.0021	0.0152	0.0070
Nitrogen	0.1550	0.2221	0.0928
Carbon Dioxide	2.2807	5.1326	2.1227
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1144.6	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1125.8	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6768	air=1
Avg Molecular Weight	19.556	gm/mole
Propane GPM	0.783627	gal/MCF
Butane GPM	0.368718	gal/MCF
Gasoline GPM	0.290145	gal/MCF
26# Gasoline GPM	0.487829	gal/MCF
Total GPM	1.444646	gal/MCF
Base Mol%	99.904	%v/v
Sample Temperature:	85	°F
Sample Pressure:	198	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0151	0.0603	0.0231
Toluene	0.0238	0.1122	0.0435
Ethylbenzene	0.0008	0.0043	0.0017
M&P Xylene	0.0069	0.0374	0.0146
O-Xylene	0.0010	0.0055	0.0021
2,2,4-Trimethylpentane	0.0057	0.0334	0.0157
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0332	0.1428	0.0617
Methylcyclohexane	0.0473	0.2373	0.1037
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.2807	5.1326	2.1227
Hydrogen Sulfide	0.0000	0.0000	0.0000
Nitrogen	0.1550	0.2221	0.0928
Methane	85.3946	70.0552	79.0010
Ethane	7.3491	11.3004	10.7563
Propane	2.8593	6.4476	4.3028
Isobutane	0.5306	1.5771	0.9480
n-Butane	0.6218	1.8480	1.0706
Isopentane	0.2400	0.8856	0.4803
n-Pentane	0.1546	0.5702	0.3057
Cyclopentane	0.0000	0.0000	0.0000
n-Hexane	0.0585	0.2577	0.1313
Cyclohexane	0.0332	0.1428	0.0617
Other Hexanes	0.1109	0.4889	0.2498
Heptanes	0.0722	0.3462	0.1628
Methylcyclohexane	0.0473	0.2373	0.1037
2,2,4 Trimethylpentane	0.0057	0.0334	0.0157
Benzene	0.0151	0.0603	0.0231
Toluene	0.0238	0.1122	0.0435
Ethylbenzene	0.0008	0.0043	0.0017
Xylenes	0.0079	0.0429	0.0167
C8+ Heavies	0.0389	0.2352	0.1098
Subtotal	100.0000	100.0000	100.0000
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

QUESTAR APPLIED TECHNOLOGY

Input for GRI-GLYCalc

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A		Description:	Ute CDP Inlet to Dehy
Analysis Date/Time:	12/9/2010	12:05 PM	Field:	Farmington, NM
Analyst Initials:	AST		ML#:	ConocoPhillips
Instrument ID:	Instrument 1		GC Method:	Quesbtex
Data File:	QPC41.D			
Date Sampled:	12/7/2010			

Component	Mol%	Wt%	LV%
Methane	85.4429	69.9588	79.0389
Ethane	7.2336	11.1012	10.5864
Propane	2.8160	6.3375	4.2373
Isobutane	0.5418	1.6071	0.9678
n-Butane	0.6161	1.8277	1.0608
Neopentane	0.0055	0.0204	0.0116
Isopentane	0.2399	0.8834	0.4795
n-Pentane	0.1566	0.5766	0.3097
2,2-Dimethylbutane	0.0072	0.0318	0.0165
2,3-Dimethylbutane	0.0201	0.0883	0.0449
2-Methylpentane	0.0569	0.2501	0.1289
3-Methylpentane	0.0326	0.1432	0.0726
n-Hexane	0.0615	0.2706	0.1381
Heptanes	0.2172	1.0275	0.4530
Octanes	0.0386	0.2237	0.1049
Nonanes	0.0291	0.1738	0.0753
Decanes plus	0.0079	0.0572	0.0264
Nitrogen	0.1733	0.2478	0.1038
Carbon Dioxide	2.3032	5.1733	2.1436
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1146.1	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1126.9	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6780	air=1
Avg Molecular Weight	19.594	gm/mole
Propane GPM	0.771761	gal/MCF
Butane GPM	0.370581	gal/MCF
Gasoline GPM	0.306042	gal/MCF
26# Gasoline GPM	0.504322	gal/MCF
Total GPM	1.452927	gal/MCF
Base Mol%	100.118	%v/v
Sample Temperature:	85	°F
Sample Pressure:	230	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0167	0.0667	0.0256
Toluene	0.0282	0.1326	0.0516
Ethylbenzene	0.0013	0.0069	0.0027
M&P Xylene	0.0115	0.0623	0.0243
O-Xylene	0.0018	0.0099	0.0038
2,2,4-Trimethylpentane	0.0062	0.0361	0.0170
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0350	0.1505	0.0651
Methylcyclohexane	0.0529	0.2650	0.1160
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.3032	5.1733	2.1436
Hydrogen Sulfide	0.0000	0.0000	0.0000
Nitrogen	0.1733	0.2478	0.1038
Methane	85.4429	69.9588	79.0389
Ethane	7.2336	11.1012	10.5864
Propane	2.8160	6.3375	4.2373
Isobutane	0.5418	1.6071	0.9678
n-Butane	0.6161	1.8277	1.0608
Isopentane	0.2454	0.9038	0.4911
n-Pentane	0.1566	0.5766	0.3097
Cyclopentane	0.0000	0.0000	0.0000
n-Hexane	0.0615	0.2706	0.1381
Cyclohexane	0.0350	0.1505	0.0651
Other Hexanes	0.1168	0.5134	0.2629
Heptanes	0.0782	0.3766	0.1777
Methylcyclohexane	0.0529	0.2650	0.1160
2,2,4 Trimethylpentane	0.0062	0.0361	0.0170
Benzene	0.0167	0.0667	0.0256
Toluene	0.0282	0.1326	0.0516
Ethylbenzene	0.0013	0.0069	0.0027
Xylenes	0.0133	0.0722	0.0281
C8+ Heavies	0.0610	0.3756	0.1758
Subtotal	100.0000	100.0000	100.0000
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

Input for GRI-GLYCalc

LIMS ID:	N/A	Description:	Ute CDP Inlet to Dehy
Analysis Date/Time:	12/14/2010 8:59 AM	Field:	Farmington, NM
Analyst Initials:	AST	ML#:	ConocoPhillips
Instrument ID:	Instrument 1	GC Method:	Quesbtex
Data File:	QPC73.D		
Date Sampled:	12/8/2010		

Component	Mol%	Wt%	LV%
Methane	84.9797	69.3126	78.4038
Ethane	7.5525	11.5461	11.0241
Propane	2.9548	6.6243	4.4344
Isobutane	0.5609	1.6575	0.9993
n-Butane	0.6503	1.9216	1.1166
Neopentane	0.0058	0.0213	0.0121
Isopentane	0.2487	0.9125	0.4959
n-Pentane	0.1633	0.5989	0.3221
2,2-Dimethylbutane	0.0073	0.0319	0.0165
2,3-Dimethylbutane	0.0205	0.0897	0.0457
2-Methylpentane	0.0576	0.2525	0.1302
3-Methylpentane	0.0329	0.1440	0.0731
n-Hexane	0.0615	0.2693	0.1376
Heptanes	0.2176	1.0275	0.4580
Octanes	0.0282	0.1634	0.0764
Nonanes	0.0146	0.0868	0.0375
Decanes plus	0.0013	0.0091	0.0042
Nitrogen	0.1650	0.2350	0.0985
Carbon Dioxide	2.2775	5.0960	2.1140
Oxygen	0.0000	0.0000	0.0000
Hydrogen Sulfide	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Global Properties		Units
Gross BTU/Real CF	1150.6	BTU/SCF at 60°F and14.73 psia
Sat.Gross BTU/Real CF	1131.8	BTU/SCF at 60°F and14.73 psia
Gas Compressibility (Z)	0.9970	
Specific Gravity	0.6808	air=1
Avg Molecular Weight	19.669	gm/mole
Propane GPM	0.809800	gal/MCF
Butane GPM	0.387570	gal/MCF
Gasoline GPM	0.311189	gal/MCF
26# Gasoline GPM	0.516731	gal/MCF
Total GPM	1.509610	gal/MCF
Base Mol%	99.898	%v/v
Sample Temperature:	79.4	°F
Sample Pressure:	195	psig
H2SLength of Stain Tube	N/A	ppm

Component	Mol%	Wt%	LV%
Benzene	0.0162	0.0644	0.0247
Toluene	0.0246	0.1153	0.0449
Ethylbenzene	0.0007	0.0038	0.0015
M&P Xylene	0.0062	0.0334	0.0131
O-Xylene	0.0008	0.0043	0.0016
2,2,4-Trimethylpentane	0.0058	0.0334	0.0158
Cyclopentane	0.0000	0.0000	0.0000
Cyclohexane	0.0338	0.1447	0.0627
Methylcyclohexane	0.0474	0.2368	0.1038
Description:	Ute CDP Inlet to Dehy		

GRI GlyCalc Information

Component	Mol%	Wt%	LV%
Carbon Dioxide	2.2775	5.0960	2.1140
Hydrogen Sulfide	0.0000	0.0000	0.0000
Nitrogen	0.1650	0.2350	0.0985
Methane	84.9797	69.3126	78.4038
Ethane	7.5525	11.5461	11.0241
Propane	2.9548	6.6243	4.4344
Isobutane	0.5609	1.6575	0.9993
n-Butane	0.6503	1.9216	1.1166
Isopentane	0.2545	0.9338	0.5080
n-Pentane	0.1633	0.5989	0.3221
Cyclopentane	0.0000	0.0000	0.0000
n-Hexane	0.0615	0.2693	0.1376
Cyclohexane	0.0338	0.1447	0.0627
Other Hexanes	0.1183	0.5181	0.2655
Heptanes	0.0898	0.4329	0.2061
Methylcyclohexane	0.0474	0.2368	0.1038
2,2,4 Trimethylpentane	0.0058	0.0334	0.0158
Benzene	0.0162	0.0644	0.0247
Toluene	0.0246	0.1153	0.0449
Ethylbenzene	0.0007	0.0038	0.0015
Xylenes	0.0070	0.0377	0.0147
C8+ Heavies	0.0364	0.2178	0.1019
Subtotal	100.0000	100.0000	100.0000
Oxygen	0.0000	0.0000	0.0000
Total	100.0000	100.0000	100.0000

Average of Samples Collected December 6, 7, and 8, 2010

ConocoPhillips - Ute CDP

Compound	Average Mol%
Carbon Dioxide	2.2871
Hydrogen Sulfide	0.0000
Nitrogen	0.1644
Methane	85.2724
Ethane	7.3784
Propane	2.8767
Isobutane	0.5444
n-Butane	0.6294
Isopentane	0.2466
n-Pentane	0.1582
Cyclopentane	0.0000
n-Hexane	0.0605
Cyclohexane	0.0340
Other Hexanes	0.1153
Heptanes	0.0801
Methylcyclohexane	0.0492
2,2,4 Trimethylpentane	0.0059
Benzene	0.0160
Toluene	0.0255
Ethylbenzene	0.0009
Xylenes	0.0094
C8+ Heavies	0.0454

Temp	Press	Specific Gravity
83.13	207.67	0.679

1210 D Street
Rock Springs, Wy. 82901
Ph: 307-352-7292
Fax: 307-352-7326

Questar Energy Services
Applied Technology Services

API Gravity
Reid Vapor Pressure

Producer:	**Conoco Phillips**
Well Name:	**Ute CDP**
Field:	**Farmington**
County and State:	**New Mexico**
Corrected API Gravity:	**58.0@60*f**
RVP:	**3.9#**
Date Sampled:	**4/14/11**
Date Analyzed:	**4/21/11**
Sampled By:	**Salyzar**
Analyzed By:	**Putnam**

*** This is a sample of the sales oil.**

Inlet liquids sample
for E&P Tank

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

LIMS ID:	N/A		Description:	Ute CDP Coalescing Scrubber
Analysis Date/Time:	4/20/2011	10:39 AM	Field:	Farmington, NM
Analyst Initials:	AST		ML#:	Conoco Phillips
Sample Temperature:	70.1 F		GC Method:	Quesliq1.M
Sample Pressure:	188		Data File:	QPC40.D
Date Sampled:	4/14/2011		Instrument ID:	1

Component	Mol%	Wt%	LV%
Methane	15.2754	2.4603	5.7886
Ethane	2.8457	0.8591	1.7019
Propane	2.2485	0.9954	1.3853
Isobutane	0.8541	0.4984	0.6250
n-Butane	1.3596	0.7934	0.9586
Neopentane	0.0015	0.0011	0.0013
Isopentane	1.4593	1.0571	1.1935
n-Pentane	1.1185	0.8102	0.9067
2,2-Dimethylbutane	0.1311	0.1134	0.1224
2,3-Dimethylbutane	0.5821	0.5036	0.5335
2-Methylpentane	1.5211	1.3161	1.4120
3-Methylpentane	0.9396	0.8129	0.8575
n-Hexane	2.3908	2.0685	2.1987
Heptanes	17.2980	16.5910	15.9630
Octanes	15.4307	16.8176	15.8602
Nonanes	13.1696	15.6794	14.3081
Decanes plus	22.2889	38.1475	35.7760
Nitrogen	0.0323	0.0091	0.0079
Carbon Dioxide	1.0532	0.4653	0.4019
Total	100.0000	100.0000	100.0000

Global Properties		**Units**
Avg Molecular Weight	99.6064	gm/mole
Pseudocritical Pressure	460.85	psia
Pseudocritical Temperatu	452.60	degF
Specific Gravity	0.70588	gm/ml
Liquid Density	5.8848	lb/gal
Liquid Density	247.16	lb/bbl
Specific Gravity	2.5602	air=1
SCF/bbl	944.95	SCF/bbl
SCF/gal	22.4989	SCF/gal
MCF/gal	0.0225	MCF/gal
gal/MCF	44.461	gal/MCF
Net Heating Value	4965.9	BTU/SCF at 60°F
Net Heating Value	18302.0	BTU/lb at 60°F
Gross Heating Value	5086.9	BTU/SCF at 60°F
Gross Heating Value	19671.5	BTU/lb at 60°F
Gross Heating Value	120893.1	BTU/gal at 60°F
API Gravity	68.95900153	
MON	53.7	
RON	55.2	
RVP	808.062	psia

QUESTAR APPLIED TECHNOLOGY

1210 D. Street, Rock Springs, Wyoming 82901

(307) 352-7292

Component	Mol%	Wt%	LV%
Benzene	0.7645	0.5996	0.4784
Toluene	3.9271	3.6329	2.9409
Ethylbenzene	0.4620	0.4925	0.3987
M&P Xylene	4.4878	4.7836	3.8863
O-Xylene	0.8157	0.8694	0.6937
2,2,4-Trimethylpentane	1.3158	1.5090	1.4789

Data File: Ute CDP Coalescing Scrubber Page #2

GRI E&P TANK INFORMATION

Component	Mol%	Wt%	LV%
H2S			
O2			
CO2	1.0532	0.4653	0.4019
N2	0.0323	0.0091	0.0079
C1	15.2754	2.4603	5.7886
C2	2.8457	0.8591	1.7019
C3	2.2485	0.9954	1.3853
IC4	0.8541	0.4984	0.6250
NC4	1.3596	0.7934	0.9586
IC5	1.4608	1.0582	1.1948
NC5	1.1185	0.8102	0.9067
Hexanes	3.1739	2.7460	2.9254
Heptanes	16.5335	15.9914	15.4846
Octanes	10.1878	11.6757	11.4404
Nonanes	7.4041	9.5339	9.3294
Benzene	0.7645	0.5996	0.4784
Toluene	3.9271	3.6329	2.9409
E-Benzene	0.4620	0.4925	0.3987
Xylene	5.3035	5.6530	4.5800
n-C6	2.3908	2.0685	2.1987
2,2,4-Trimethylpentane	1.3158	1.5090	1.4789
C10 Plus			
C10 Mole %	22.2889	38.1475	35.7760
Molecular Wt.	172.3562		
Specific Gravity	0.7522		
Total	100.00	100.00	100.00

Ethane (includes CO2, N2, and C1)	19.2066	3.7938
C6+	73.75190	92.05000

APPENDIX J

Permit Fee Forms and Basis Calculations

ConocoPhillips

San Juan Business Unit
P.O. Box 4289
Farmington, NM 87499-4289
(505) 326-9700

<u>SENT VIA UPS</u>

May 11, 2011

Attention: Ms. Natalie Pearson
U.S. Bank
Government Lockbox 979078
U.S. EPA FOIA & Miscellaneous Payments
1005 Convention Plaza
Mail Station SL-MO-C2-GL
St. Louis, MO 63101

RE: 2010 Emission Fees
Ute CDP
Part 71 Permit
Check Number 00987838

Dear Ms. Pearson:

Enclosed are the form FF and a check in the amount of $5,704.00 for initial Title V fees pertaining to the Ute CDP for the calendar year 2010. A Title V permit has not yet been issued but payment of emission fees for the previous calendar year is due upon submitting the initial application.

If you have any questions concerning this submittal, please call me at 505-326-9811.

Sincerely,

Randy Poteet

Randy Poteet
Principal Environmental Consultant

Enclosures

cc: Eric Wortman, EPA Region 8 (also with form FEE)
Brenda Jarrell, Southern Ute Indian Tribe (also with form FEE)

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

FEE FILING FORM (FF)

Complete this form each time you prepare form **FEE** and send this form to the appropriate lockbox bank address, along with full payment. This form required at time of initial fee payment, and thereafter, when paying annual fees.

Source or Facility Name Ute CDP

Mailing Address:

Street/P.O. Box P.O. Box 4289 City Farmington

State NM ZIP 87499-4289

Contact Person: Randy Poteet Title Principal Environmental Consultant

Telephone (505) 326 - 9811 Ext. ________

Total Fee Payment Remitted: $ 5704

This check was issued by ConocoPhillips Company

DATE	INVOICE(DESCRIPT)	CO	DOCUMENT NO.		GROSS	DISCOUNT	NET
05/06/11	USENVPA03	NANN	1200062655	USD	5,704.00	0.00	5,704.00

PAYEE NUMBER	CHECK DATE	CHECK NO	CHECK AMOUNT
96069	05/10/2011	00987838	5704.00

If you have questions about this check, call (918)661-5746
or logon to https://vis.conocophillips.com.

ConocoPhillips is currently adopting direct deposit (ACH) as our primary tool for payment in place of checks. Please access the following website http://vendors.conocophillips.com/EN/payment/Pages/index.aspx for application instructions. Your prompt response is greatly appreciated

17-15750 N, 04-09

THIS IS WATERMARKED PAPER - DO NOT ACCEPT WITHOUT NOTING WATERMARK - HOLD TO LIGHT TO VERIFY WATERMARK

Deutsche Bank Trust
Company Delaware

ConocoPhillips Company
Houston, TX

62-38/311
Check No: **00987838**

96069 05/10/2011 00987838 $5,704.00*

PAY TO THE ORDER OF EXACTLY ****5704 US Dollars and 00 Cents****

U S ENVIRONMENTAL PROTECTION AGENCY
C/O US BANK GOVT LOCK BOX 979078
US EPA FOIA & MISC PAYMENTS
MAIL STATION SL MO C2GL
1005 CONVENTION PLAZA
SAINT LOUIS, MO 63101-1200

Frances M Vallejo
Treasurer

⑈00987838⑈ ⑆031100380⑆ 00538062⑈

United States Environmental Protection Agency

OMB No. 2060-0336, Approval Expires 04/30/2012

Federal Operating Permit Program (40 CFR Part 71)

FEE CALCULATION WORKSHEET (FEE)

Use this form initially, or thereafter on an annual basis, to calculate part 71 fees.

A. General Information

Type of fee (Check one): _X_ Initial ___Annual

Deadline for submitting fee calculation worksheet ____/____/_______

For initial fees, emissions are based on (Check one):

X__ Actual emissions for the preceding calendar year. (Required in most circumstances.)

___ Estimates of actual emissions for the current calendar year. (Required when operations commenced during the preceding calendar year.)

Date commenced operations ____/____/______

___ Estimates of actual emissions for the preceding calendar year. (Optional after a part 71 permit was issued to replace a part 70 permit, but only if initial fee payment is due between January 1 and March 31; otherwise use actual emissions for the preceding calendar year.)

For annual fee payment, you are required to use actual emissions for the preceding calendar year.

B. Source Information: Complete this section only if you are paying fees but not applying for a permit.

Source or facility name

Mailing address: Street or P.O. Box

City _______________ State ______________ ZIP

Contact person: _______________ Title

Telephone (_) ___- ____ Ext________ Part 71 permit no. _____________________

C. Certification of Truth, Accuracy and Completeness: Only needed if not submitting a separate form CTAC.

D. Annual Emissions Report for Fee Calculation Purposes -- Non-HAP

You may use this to report actual emissions (tons per year) of regulated pollutants (for fee calculation) on a calendar-year basis for both initial and annual fee calculation purposes. Section E is designed to report HAP emissions. Quantify all actual emissions, including fugitives, but do not include insignificant emissions and certain regulated air pollutants that are not counted for fee purposes, such as CO (see instructions). You may round to the nearest tenth of a ton on this form. Sum the emissions in each column and enter a subtotal at the bottom of the page. If any subtotal exceeds 4,000 tons, enter 4,000 for that column.

This data is for 2010 (year)

Emission Unit ID	NOx	VOC	SO2	PM10	Lead	Other
E-1 (5108GL) – Did not operate	0	0	0	0	-	-
E-2 (5108GL)	13.3	8.9	0.5	0.4	-	-
E-3 (5108GL)	11.8	7.9	0.5	0.3	-	-
DEHY-1	0.1	68.2	0.0	0.0	-	-
TK-1 and TK-2	-	5.9	-	-	-	-
Fugitive Emissions	-	0.9	-	-	-	-
	25.2	91.8	1.0	0.7	-	

SUBTOTALS

E. Annual Emissions Report for Fee Calculation Purposes -- HAP

HAP Identification. Identify individual HAP emitted at the facility, identify the CAS number, and assign a unique identifier for use in the second table in this section. Whenever assigning identifier codes, use "HAP1" for the first, "HAP2" for the second, and so on.

Name of HAP	CAS No	Identifier
Formaldehyde	50-00-0	1
Acetaldehyde	75-07-0	2
Acrolein	107-02-8	3
Benzene	71-43-2	4
Toluene	108-88-3	5
Ethylbenzene	100-41-4	6
Xylene	1330-20-7	7
n-Hexane	110-54-3	8

HAP Emissions. Report the actual emissions of individual HAP identified above. Use the identifiers assigned in the table above. Include all emissions, including fugitives, and do not include insignificant emissions. You may round to the nearest tenth of a ton. Sum the emissions in each column and enter a subtotal at the bottom of the page. If any subtotal exceeds 4,000 tons, enter 4,000.

This data is for 2010 (year)

Emissions Unit ID	Actual Emissions (Tons/Year)							
	HAP 1	HAP 2	HAP 3	HAP 4	HAP 5	HAP 6	HAP 7	HAP 8
E-1	0	0	0	0	-	-	-	-
E-2	2.6	0.3	0.2	0	-	-	-	-
E-3	2.3	0.3	0.2	0	-	-	-	-
DEHY-1	-	-	-	5.6	18.0	1.3	18.8	0.5
TK-1 and TK-2	-	-	-	0.1	0.1	0.0	0.0	0.2
SUBTOTALS	4.9	0.5	0.3	5.7	18.1	1.3	18.8	0.7

F. Fee Calculation Worksheet

This section is used to calculate the total fee owed for both initial and annual fee payment purposes. Reconciliation is only for cases where you are paying the annual fee and you used any type of estimate of actual emissions when you calculated the initial fee. If you do not need to reconcile fees, only complete line 1-5 and then skip down to lines 21 – 26. See instructions for more detailed explanation.

1. Sum the emissions from section D of this form (non-HAP) and enter the total (tons).	118.7
2. Sum the emissions from section E of this form (HAP) and enter the total (tons).	50.3
3. Sum lines 1 and 2.	169
4. Enter the emissions that were counted twice. If none, enter "0." (HAP 2 to 8)	45.4
5. Subtract line 4 from line 3, round to the nearest ton, and enter the result here.	124

RECONCILIATION
(WHEN INITIAL FEES WERE BASED ON ESTIMATES
FOR THE "CURRENT" CALENDAR YEAR)

Only complete lines 6-10 if you are paying the first annual fee and initial fees were based on estimated actual emissions for the calendar year in which you paid initial fees; otherwise skip to line 11 or to line 21.

6. Enter the total estimated actual emissions for the year the initial fee was paid (previously reported on line 5 of the initial fee form).	
7. If line 5 is greater than line 6, subtract line 6 from line 5, and enter the result. Otherwise enter "0."	
8. If line 6 is greater than line 5, subtract line 5 from line 6, and enter the result. Otherwise enter "0."	
9. If line 7 is greater than 0, multiply line 7 by last year's fee rate ($/ton) and enter the result here. This is the underpayment. Go to line 21.	
10. If line 8 is greater than 0, multiply line 8 by last year's fee rate ($/ton) and enter the result here. This is the overpayment. Go to line 21.	

RECONCILIATION
(WHEN INITIAL FEES WERE BASED ON ESTIMATES
FOR THE "PRECEDING" CALENDAR YEAR)

Only complete lines 11-20 if you are paying the first annual fee and initial fees were based on estimated actual emissions for the calendar year preceding initial fee payment; otherwise skip to line 21. If completing this section, you will also need to complete sections D and E to report actual emissions for the calendar year preceding initial fee payment.

11. Sum the actual emissions from section D (non-HAP) for the calendar year preceding initial fee payment and enter the result here.	
12. Sum the actual emissions from section E (HAP) for the calendar year preceding initial fee payment and enter the result here.	
13. Add lines 11 and 12 and enter the total here. These are total actual emissions for the calendar year preceding initial fee payment.	
14. Enter double counted emission from line 13 here. If none, enter "0."	
15. Subtract line 14 from line 13, round to the nearest ton, and enter the result here.	

16. Enter the total estimated actual emissions previously reported on line 5 of the initial fee form. These are estimated actual emissions for the calendar year preceding initial fee payment.	
17. If line 15 is greater than line 16, subtract line 16 from line 15, and enter the result here. Otherwise enter "0."	
18. If line 16 is greater than line 15, subtract line 15 from line 16, and enter the result here. Otherwise enter "0."	
19. If line 17 is greater than 0, multiply line 17 by last year's fee rate ($/ton) and enter the result here. This is the underpayment.	
20. If line 18 is greater than 0, multiply line 18 by last year's fee rate ($/ton) and enter the result on this line. This is the overpayment.	
FEE CALCULATION	
21. Multiply line 5 (tons) by the current fee rate ($46/ton) and enter the result here.	$5704
22. Enter any underpayment from line 9 or 19 here. Otherwise enter "0."	$0
23. Enter any overpayment from line 10 or 20 here. Otherwise enter "0."	$0
24. If line 22 is greater than "0," add it to line 21 and enter the result here. If line 23 is greater than "0," subtract this from line 21 and enter the result here. Otherwise enter the amount on line 21 here. This is the fee adjusted for reconciliation.	$5704
25. If your account was credited for fee assessment error since the last time you paid fees, enter the amount of the credit here. Otherwise enter "0."	$0
26. Subtract line 25 from line 24 and enter the result here. Stop here. This is the total fee amount that you must remit to EPA.	$5704

ConocoPhillips Company - San Juan Basin

Ute CDP

2010 Actual Facility Emissions

Unit ID	**E-1**	**E-2**	**E-3**	**DEHY-1**	**TK-1 and TK-2**	**Total by Pollutant**
Description	L5108GL	L5108GL	L5108GL	Dehydrator[1]	Condensate Tanks[2]	
Rated Capacity (horsepower)	1,072	1,072	1,072	-	-	
Rated Capacity (MMBtu/hr)	-	-	-	0.125	-	
Hourly Emission Rate						
NO_x	0.00	3.30	3.30	0.01	-	**6.61**
CO	0.00	5.82	5.82	0.01	-	**11.66**
VOC	0.00	2.20	2.20	15.57	1.34	**21.30**
SO_2	0.00	0.13	0.13	0.002	-	**0.27**
PM/PM_{10}	0.00	0.09	0.09	0.001	-	**0.18**
Formaldehyde	0.00	0.64	0.64	-	-	**1.27**
Acetaldehyde	0.00	0.08	0.08	-	-	**0.15**
Acrolein	0.00	0.05	0.05	-	-	**0.09**
Hexane	-	-	-	0.11	0.05	**0.15**
Benzene	0.00	0.004	0.004	1.27	0.01	**1.29**
Toluene	-	-	-	4.10	0.02	**4.12**
Ethylbenzene	-	-	-	0.29	0.001	**0.30**
Xylene	-	-	-	4.29	0.01	**4.30**
Annual PTE						
NO_x	0.00	13.34	11.82	0.06	-	**25.21**
CO	0.00	23.56	20.88	0.05	-	**44.49**
VOC	0.00	8.89	7.88	68.19	5.85	**90.81**
SO_2	0.00	0.54	0.48	0.008	-	**1.02**
PM/PM_{10}	0.00	0.35	0.31	0.004	-	**0.67**
Formaldehyde	0.00	2.58	2.28	-	-	**4.86**
Acetaldehyde	0.00	0.31	0.27	-	-	**0.58**
Acrolein	0.00	0.18	0.16	-	-	**0.35**
Hexane	-	-	-	0.46	0.22	**0.68**
Benzene	0.00	0.02	0.01	5.57	0.06	**5.66**
Toluene	-	-	-	17.97	0.10	**18.07**
Ethylbenzene	-	-	-	1.29	0.004	**1.29**
Xylene	-	-	-	18.78	0.04	**18.82**

Notes:

[1] The dehydrator includes VOC/HAP emissions from the still vent. Reboiler criteria pollutant emissions are based on AP-42, Chapter 1.4, Natural Gas Combustion. SO2 emissions are based on a sulfur content of 50 grams/Mscf.

[2] Emissions from condensate tanks were estimated using E&P Tank and an annual throughput of 1,811 barrels (1,630 inlet/181 discharge). Total emissions were combined for the 2 tanks and include working, breathing, and flashing losses.

[3] Emissions from insignificant activities are not included in the 2010 emissions inventory per the instructions. This includes the heaters, microturbines, oil/coolant storage tanks, and truck loading.

ConocoPhillips Company - San Juan Basin

Ute CDP

2010 Actual Waukesha L5108GL Emissions

Emission Unit Designation	E-1	
Source Description	Waukesha 5108GL (Serial # 399990)	
Type	Turbocharged 4SLB engine	
Rated Output	1,072	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	997	hp
Fuel Use Rate	8850	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.82	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	9.29	Mscf/hr, site derated
Annual Fuel Consumption	0.0	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	0	hrs/year

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	^{o}F, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency	Emission Rate				Notes
					Uncontrolled		Controlled		
				(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
Criteria Pollutants	NO_x	1.50	g/hp-hr		0.00	0.00			1
	CO	2.65	g/hp-hr		0.00	0.00			1
	VOC	1.00	g/hp-hr		0.00	0.00			1
	SO_2	14.29	lb/MMscf		0.00	0.00			2
	PM_{10}	9.91E-03	lb/MMBtu		0.00	0.00			3
HAP	Formaldehyde	0.29	g/hp-hr		0.00	0.00			1
	Acetaldehyde	8.60E-03	lb/MMBtu		0.00	0.00			3
	Acrolein	5.14E-03	lb/MMBtu		0.00	0.00			3
	Benzene	4.40E-04	lb/MMBtu		0.000	0.00			3

[1] Manufacturer engine specification

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

2010 Actual Waukesha L5108GL Emissions

Emission Unit Designation	E-2	
Source Description	Waukesha 5108GL (Serial # 240747)	
Type	Turbocharged 4SLB engine	
Rated Output	1,072	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	997	hp
Fuel Use Rate	8850	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.82	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	9.29	Mscf/hr, site derated
Annual Fuel Consumption	75.1	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	8090.5	hrs/year

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	^oF, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

Pollutant		Emission Factor		Control Efficiency	Emission Rate				Notes
					Uncontrolled		Controlled		
				(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
Criteria Pollutants	NO_x	1.50	g/hp-hr		3.30	13.34			1
	CO	2.65	g/hp-hr		5.82	23.56			1
	VOC	1.00	g/hp-hr		2.20	8.89			1
	SO_2	14.29	lb/MMscf		0.13	0.54			2
	PM_{10}	9.91E-03	lb/MMBtu		0.09	0.35			3
HAP	Formaldehyde	0.29	g/hp-hr		0.64	2.58			1
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.31			3
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.18			3
	Benzene	4.40E-04	lb/MMBtu		0.004	0.02			3

[1] Manufacturer engine specification

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

2010 Actual Waukesha L5108GL Emissions

Emission Unit Designation	E-3	
Source Description	Waukesha 5108GL (Serial # 399989)	
Type	Turbocharged 4SLB engine	
Rated Output	1,072	hp, per manufacturer
Site Elevation, ft	6,333	ft, per topographic map
Altitude Deration Factor	0.93	3% per 1000' over 4000' for turbocharged engines
Altitude Derated Output	997	hp
Fuel Use Rate	8850	Btu/hp-hr, per manufacturer
Maximum Design Heat Input	8.82	MMBtu/hr, site derated
Fuel Gas Heating Value	950	Btu/scf, estimated
Hourly Fuel Consumption	9.29	Mscf/hr, site derated
Annual Fuel Consumption	66.6	MMscf/yr, site derated
Fuel Sulfur Content	50	gr/Mscf, pipeline specifications
Operating Time	7168	hrs/year

Stack Height	TBD	ft
Exhaust Gas Velocity	Unknown	ft/sec
Exhaust Temp	900	^oF, estimated
Stack Inside Diameter	TBD	ft
Exhaust Gas Flow	Unknown	cfm

	Pollutant	Emission Factor		Control Efficiency	Emission Rate				Notes
					Uncontrolled		Controlled		
				(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
Criteria Pollutants	NO_x	1.50	g/hp-hr		3.30	11.82			1
	CO	2.65	g/hp-hr		5.82	20.88			1
	VOC	1.00	g/hp-hr		2.20	7.88			1
	SO_2	14.29	lb/MMscf		0.13	0.48			2
	PM_{10}	9.91E-03	lb/MMBtu		0.09	0.31			3
HAP	Formaldehyde	0.29	g/hp-hr		0.64	2.28			1
	Acetaldehyde	8.60E-03	lb/MMBtu		0.08	0.27			3
	Acrolein	5.14E-03	lb/MMBtu		0.05	0.16			3
	Benzene	4.40E-04	lb/MMBtu		0.004	0.01			3

[1] Manufacturer engine specification

[2] Fuel Sulfur Content (gr/Mscf) / 7000 (gr/lb) x 1000 (Mscf/MMscf) * 64 lb/lb-mol SO_2/32 lb/lb-mol S

[3] USEPA AP-42 Ch. 3.2 Natural Gas-fired Reciprocating Engines

ConocoPhillips Company - San Juan Basin

Ute CDP

2010 Actual TEG Dehydrator Still Vent Emissions

Emission Unit	DEHY-1
Source Description	Triethylene Glycol Dehydrator Still Vent
Manufacturer	Pesco
Glycol Pump	Pnuematic
2010 Flowrate	10.158 MMscfd
Contract Gas Dewpoint	3.73 lb H20/MMscf
Glycol Recirculation Rate	1.5 gpm

Stack Height	22	ft, per site inspection
Exhaust Gas Velocity	5	ft/sec, estimated
Exhaust Gas Flow	14.7	cfm, estimated
Exhaust Temperature	100	^{o}F, estimated
Stack Inside Diameter	0.25	ft, per site inspection
Rated Input Capacity	0.125	MMBtu/hr, per manufacturer
Fuel Gas Heating Value	950	Btu/scf, estimated
Fuel Use Rate	131.58	scfh @ 950 Btu/scf
Fuel Use Rate	1.15	MMscf/yr @ 950 Btu/scf
Fuel Sulfur Content	50	(gr/Mscf)
Operating Time	8760	(hrs/year)

Source Description	Glycol Regenerator
Control Device	None

Pollutant		Control Efficiency	Emission Rate				Notes
			Uncontrolled		Controlled		
		(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)	
VOC			15.57	68.19			1
HAP	n-Hexane		0.11	0.46			1
	Benzene		1.27	5.57			1
	Toluene		4.10	17.97			1
	Ethylbenze		0.29	1.29			1
	Xylenes		4.29	18.78			1

Notes:

[1] GRI GlyCalc v4.0 Calculations based on extended gas analysis

ConocoPhillips Company - San Juan Basin

Ute CDP

2010 Actual Heater Emissions

Unit ID	DEHY-1	Units, Data Source
Description	Reboiler	
Fuel Type	NG	manufacturer
Operating hr/yr	8,760	Maximum actual hours
Stack Information		
Stack Height	22	ft
Exhaust Gas Velocity	5	ft/sec, estimated
Exhaust Temp	100	^{o}F, estimated
Stack Inside Diameter	0.67	ft, site inspection
Exhaust Gas Flow	104.7	cfm
Emission Factor (EF)[1]		
NO_x	100	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
CO	84	lb/MMscf, AP-42 Tbl 1.4-1 (07/98)
VOC	5.5	lb/MMscf, AP-42 Tbl 1.4-2 (07/98)
SO_2[2]	14.3	lb/MMscf (50 grains S/Mscf assumed), AP-42 Tbl 1.4-2 (07/98)
PM/PM_{10}	7.6	lb/MMscf [total assumed], AP-42 Tbl 1.4-2 (07/98)
Formaldehyde	0.08	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hexane	1.8	lb/MMscf, AP-42 Tbl 1.4-3 (07/98).
Hourly Emission Rate in pounds per hour		
NO_x	0.01	lb/hr, calc'd from EF data
CO	0.01	lb/hr, calc'd from EF data
VOC	0.001	lb/hr, calc'd from EF data
SO_2	0.002	lb/hr, calc'd from EF data
PM/PM_{10}	0.001	lb/hr, calc'd from EF data
Formaldehyde	0.000	lb/hr, calc'd from EF data
Hexane	0.000	lb/hr, calc'd from EF data
Annual Potential To Emit (PTE) in tons per year		
NO_x	0.06	tpy, calc'd from lb/hr data
CO	0.05	tpy, calc'd from lb/hr data
VOC	0.003	tpy, calc'd from lb/hr data
SO_2	0.008	tpy, calc'd from lb/hr data
PM/PM_{10}	0.004	tpy, calc'd from lb/hr data
Formaldehyde	0.000	tpy, calc'd from lb/hr data
Hexane	0.001	tpy, calc'd from lb/hr data
Fuel Flowrates		
Rated Input Capacity	0.125	MMBtu/hr, per manufacturer
Fuel LHV	950	Btu/scf, estimated
Fuel Use Rate	131.6	scfh @ 950 Btu/scf (LHV)
Fuel Use Rate	1.2	MMscf/yr @ 950 Btu/scf (LHV)

Notes:

[1] USEPA AP-42 Ch. 1.4 Natural Gas Combustion

[2] Fuel Sulfur Content (gr/Mscf) * (lb/7000 gr) * (1000 Mscf/MMscf) * (64 lb/lb-mol SO_2/32 lb/lb-mol S)

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File              : C:\Users\Sugar Magnolia\Desktop\Work\137 - ConocoPhillips\_Title V\Ute CDP\Ute CDP E
Flowsheet Selection       : Oil Tank with Separator
Calculation Method        : AP42
Control Efficiency        : 100.0%
Known Separator Stream    : Low Pressure Oil
Entering Air Composition  : No

Filed Name                : San Juan Basin
Well Name                 : Ute CDP
Well ID                   : Inlet Scrubber to Condensate Tanks
Date                      : 2011.04.11


******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure        : 49.02[psig]
Separator Temperature     : 52.67[F]
Ambient Pressure          : 11.20[psia]
Ambient Temperature       : 52.10[F]
C10+ SG                   : 0.7522
C10+ MW                   : 172.356

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component             mol %
   1      H2S                   0.0000
   2      O2                    0.0000
   3      CO2                   1.0532
   4      N2                    0.0323
   5      C1                   15.2754
   6      C2                    2.8457
   7      C3                    2.2485
   8      i-C4                  0.8541
   9      n-C4                  1.3596
   10     i-C5                  1.4608
   11     n-C5                  1.1185
   12     C6                    3.1739
   13     C7                   16.5335
   14     C8                   10.1878
   15     C9                    7.4041
   16     C10+                 22.2889
   17     Benzene               0.7645
   18     Toluene               3.9271
   19     E-Benzene             0.4620
   20     Xylenes               5.3035
   21     n-C6                  2.3908
   22     224Trimethylp         1.3158

-- Sales Oil -----------------------------------------------------------------------------
Production Rate           : 4.5[bbl/day]
Days of Annual Operation  : 365 [days/year]
API Gravity               : 58.0
Reid Vapor Pressure       : 3.90[psia]
Bulk Temperature          : 65.00[F]

-- Tank and Shell Data -------------------------------------------------------------------
Diameter                  : 12.00[ft]
Shell Height              : 15.00[ft]
Cone Roof Slope           : 0.06
Average Liquid Height     : 6.00[ft]
Vent Pressure Range       : 0.06[psi]
Solar Absorbance          : 0.68
```

-- Meteorological Data ---

City	: Roswell, NM
Ambient Pressure	: 11.20[psia]
Ambient Temperature	: 52.10[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]
Total HAPs	0.380	0.087
Total HC	12.395	2.830
VOCs, C2+	6.917	1.579
VOCs, C3+	5.157	1.177

Uncontrolled Recovery Info.

Vapor	1.0600	[MSCFD]
HC Vapor	1.0100	[MSCFD]
GOR	235.56	[SCF/bbl]

-- Emission Composition ---

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	1.001	0.229
4	N2	0.020	0.005
5	C1	5.478	1.251
6	C2	1.760	0.402
7	C3	1.671	0.382
8	i-C4	0.576	0.132
9	n-C4	0.741	0.169
10	i-C5	0.473	0.108
11	n-C5	0.274	0.063
12	C6	0.305	0.070
13	C7	0.578	0.132
14	C8	0.119	0.027
15	C9	0.031	0.007
16	C10+	0.005	0.001
17	Benzene	0.049	0.011
18	Toluene	0.077	0.018
19	E-Benzene	0.003	0.001
20	Xylenes	0.031	0.007
21	n-C6	0.181	0.041
22	224Trimethylp	0.043	0.010
	Total	13.416	3.063

-- 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	1.0532	0.0668	0.0000	4.5342	0.0002	4.4625
4	N2	28.01	0.0323	0.0002	0.0000	0.1457	0.0002	0.1434
5	C1	16.04	15.2754	0.3111	0.0000	68.0856	0.0002	67.0092
6	C2	30.07	2.8457	0.3489	0.0026	11.6571	0.8556	11.4863
7	C3	44.10	2.2485	0.8426	0.2628	7.2100	21.4895	7.4357
8	i-C4	58.12	0.8541	0.5892	0.3870	1.7891	11.6057	1.9443
9	n-C4	58.12	1.3596	1.1030	0.8320	2.2653	17.2127	2.5016
10	i-C5	72.15	1.4608	1.5541	1.4270	1.1315	10.9627	1.2870
11	n-C5	72.15	1.1185	1.2511	1.1856	0.6505	6.6618	0.7456

12	C6	86.16	3.1739	3.9004	3.9203	0.6101	7.0265	0.7115
13	C7	100.20	16.5335	20.9380	21.4435	0.9896	12.4233	1.1704
14	C8	114.23	10.1878	13.0248	13.4226	0.1757	2.3831	0.2106
15	C9	128.28	7.4041	9.4907	9.7985	0.0402	0.5846	0.0488
16	C10+	172.36	22.2889	28.6034	29.5571	0.0047	0.0818	0.0059
17	Benzene	78.11	0.7645	0.9514	0.9639	0.1048	1.2348	0.1227
18	Toluene	92.13	3.9271	5.0006	5.1398	0.1385	1.7860	0.1646
19	E-Benzene	106.17	0.4620	0.5915	0.6102	0.0049	0.0678	0.0059
20	Xylenes	106.17	5.3035	6.7926	7.0090	0.0482	0.6739	0.0581
21	n-C6	86.18	2.3908	2.9686	3.0025	0.3518	4.1637	0.4121
22	224Trimethylp	114.24	1.3158	1.6710	1.7145	0.0624	0.7860	0.0739
	MW		99.27	120.14	121.65	25.65	68.54	26.33
	Stream Mole Ratio		1.0000	0.7792	0.7757	0.2208	0.0035	0.2243
	Heating Value	[BTU/SCF]				1407.15	3778.60	1444.65
	Gas Gravity	[Gas/Air]				0.89	2.37	0.91
	Bubble Pt. @ 100F	[psia]	546.59	16.59	2.95			
	RVP @ 100F	[psia]	698.22	44.98	18.85			
	Spec. Gravity @ 100F		0.665	0.689	0.691			

```
******************************************************************************************
*     Project Setup Information                                                          *
******************************************************************************************
Project File             : C:\Users\Sugar Magnolia\Desktop\Work\137 - ConocoPhillips\_Title V\Ute CDP\Ute CDP E
Flowsheet Selection      : Oil Tank with Separator
Calculation Method       : AP42
Control Efficiency       : 100.0%
Known Separator Stream   : Low Pressure Oil
Entering Air Composition : No

Filed Name               : San Juan Basin
Well Name                : Ute CDP
Well ID                  : Discharge Scrubber to Condensate Tanks
Date                     : 2011.04.11


******************************************************************************************
*     Data Input                                                                         *
******************************************************************************************

Separator Pressure       : 188.00[psig]
Separator Temperature    : 70.10[F]
Ambient Pressure         : 11.20[psia]
Ambient Temperature      : 52.10[F]
C10+ SG                  : 0.7522
C10+ MW                  : 172.356

-- Low Pressure Oil ----------------------------------------------------------------------
   No.    Component           mol %
   1      H2S                 0.0000
   2      O2                  0.0000
   3      CO2                 1.0532
   4      N2                  0.0323
   5      C1                 15.2754
   6      C2                  2.8457
   7      C3                  2.2485
   8      i-C4                0.8541
   9      n-C4                1.3596
   10     i-C5                1.4608
   11     n-C5                1.1185
   12     C6                  3.1739
   13     C7                 16.5335
   14     C8                 10.1878
   15     C9                  7.4041
   16     C10+               22.2889
   17     Benzene             0.7645
   18     Toluene             3.9271
   19     E-Benzene           0.4620
   20     Xylenes             5.3035
   21     n-C6                2.3908
   22     224Trimethylp       1.3158

-- Sales Oil -----------------------------------------------------------------------------
Production Rate          : 0.5[bbl/day]
Days of Annual Operation : 365 [days/year]
API Gravity              : 58.0
Reid Vapor Pressure      : 3.90[psia]
Bulk Temperature         : 65.00[F]

-- Tank and Shell Data -------------------------------------------------------------------
Diameter                 : 12.00[ft]
Shell Height             : 15.00[ft]
Cone Roof Slope          : 0.06
Average Liquid Height    : 6.00[ft]
Vent Pressure Range      : 0.06[psi]
Solar Absorbance         : 0.68
```

-- Meteorological Data --

City	: Roswell, NM
Ambient Pressure	: 11.20[psia]
Ambient Temperature	: 52.10[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]
Total HAPs	0.080	0.018
Total HC	1.483	0.339
VOCs, C2+	0.886	0.202
VOCs, C3+	0.696	0.159

Uncontrolled Recovery Info.

Vapor	117.6500 x1E-3	[MSCFD]
HC Vapor	112.3500 x1E-3	[MSCFD]
GOR	235.30	[SCF/bbl]

-- Emission Composition ---

No	Component	Uncontrolled [ton/yr]	Uncontrolled [lb/hr]
1	H2S	0.000	0.000
2	O2	0.000	0.000
3	CO2	0.109	0.025
4	N2	0.002	0.000
5	C1	0.597	0.136
6	C2	0.191	0.044
7	C3	0.170	0.039
8	i-C4	0.055	0.013
9	n-C4	0.071	0.016
10	i-C5	0.058	0.013
11	n-C5	0.037	0.008
12	C6	0.057	0.013
13	C7	0.128	0.029
14	C8	0.029	0.007
15	C9	0.008	0.002
16	C10+	0.001	0.000
17	Benzene	0.010	0.002
18	Toluene	0.018	0.004
19	E-Benzene	0.001	0.000
20	Xylenes	0.008	0.002
21	n-C6	0.036	0.008
22	224Trimethylp	0.010	0.002
	Total	1.596	0.364

-- 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	1.0532	0.0697	0.0000	4.5639	0.0000	4.3634
4	N2	28.01	0.0323	0.0002	0.0000	0.1469	0.0000	0.1405
5	C1	16.04	15.2754	0.3192	0.0000	68.6620	0.0000	65.6462
6	C2	30.07	2.8457	0.3647	0.0000	11.7019	0.0000	11.1879
7	C3	44.10	2.2485	0.8816	0.0000	7.1276	0.0000	6.8145
8	i-C4	58.12	0.8541	0.6094	0.0087	1.7275	0.3936	1.6689
9	n-C4	58.12	1.3596	1.1343	0.0608	2.1637	2.1805	2.1644
10	i-C5	72.15	1.4608	1.5751	0.5451	1.0529	9.1148	1.4070
11	n-C5	72.15	1.1185	1.2638	0.6033	0.6000	7.6941	0.9116

12	C6	86.16	3.1739	3.9088	3.5264	0.5508	15.4165	1.2038
13	C7	100.20	16.5335	20.9195	23.3660	0.8775	33.9153	2.3286
14	C8	114.23	10.1878	12.9990	15.6095	0.1532	7.0040	0.4541
15	C9	128.28	7.4041	9.4687	11.6163	0.0345	1.7555	0.1101
16	C10+	172.36	22.2889	28.5320	35.3684	0.0039	0.2435	0.0144
17	Benzene	78.11	0.7645	0.9523	0.9393	0.0942	2.9682	0.2205
18	Toluene	92.13	3.9271	4.9930	5.8145	0.1222	5.0877	0.3403
19	E-Benzene	106.17	0.4620	0.5902	0.7174	0.0043	0.2018	0.0129
20	Xylenes	106.17	5.3035	6.7776	8.2599	0.0418	2.0103	0.1282
21	n-C6	86.18	2.3908	2.9721	2.8775	0.3159	9.8203	0.7334
22	224Trimethylp	114.24	1.3158	1.6689	1.9050	0.0553	2.1938	0.1492
	MW		99.27	120.00	124.77	25.28	90.15	28.13
	Stream Mole Ratio		1.0000	0.7812	0.7711	0.2188	0.0101	0.2289
	Heating Value	[BTU/SCF]				1387.13	4870.98	1540.15
	Gas Gravity	[Gas/Air]				0.87	3.11	0.97
	Bubble Pt. @ 100F	[psia]	546.59	17.08	1.34			
	RVP @ 100F	[psia]	698.22	46.31	9.17			
	Spec. Gravity @ 100F		0.665	0.689	0.693			

GRI-GLYCalc VERSION 4.0 - SUMMARY OF INPUT VALUES

Case Name: Ute CDP
File Name: C:\Users\etullos\Desktop\Work\137 - Conoco\HH Applicability Determinations\Ute CDP\Dehydrator Emissions_Ute CDP_Avg of 6,7,8_Past Actuals.ddf
Date: February 22, 2011

DESCRIPTION:

Description: 10.158 MMScf/Day Dehydration System Temperature/Pressure taken from the average values of gas analyses dated December 6, 7, and 8, 2010. Average gas dewpoint is 3.73.

Annual Hours of Operation: 8760.0 hours/yr

WET GAS:

Temperature: 83.13 deg. F
Pressure: 207.67 psig
Wet Gas Water Content: Subsaturated
Specified Wet Gas Water Content: 60.00 lbs. H2O/MMSCF

Component	Conc. (vol %)
Carbon Dioxide	2.2871
Nitrogen	0.1644
Methane	85.2724
Ethane	7.3784
Propane	2.8767
Isobutane	0.5444
n-Butane	0.6294
Isopentane	0.2466
n-Pentane	0.1582
n-Hexane	0.0605
Cyclohexane	0.0340
Other Hexanes	0.1153
Heptanes	0.0801
Methylcyclohexane	0.0492
2,2,4-Trimethylpentane	0.0059
Benzene	0.0160
Toluene	0.0255
Ethylbenzene	0.0009
Xylenes	0.0094
C8+ Heavies	0.0454

DRY GAS:

Flow Rate: 10.2 MMSCF/day
Water Content: 3.7 lbs. H2O/MMSCF

LEAN GLYCOL:

Glycol Type: TEG
Water Content: 1.1 wt% H2O
Flow Rate: 1.5 gpm

PUMP:

Glycol Pump Type: Gas Injection
Gas Injection Pump Volume Ratio: 0.120 acfm gas/gpm glycol

FLASH TANK:

Flash Control: Recycle/recompression
Temperature: 90.0 deg. F
Pressure: 40.0 psig

GRI-GLYCalc VERSION 4.0 - AGGREGATE CALCULATIONS REPORT

Case Name: Ute CDP
File Name: C:\Users\etullos\Desktop\Work\137 - Conoco\HH Applicability Determinations\Ute CDP\Dehydrator Emissions_Ute CDP_Avg of 6,7,8_Past Actuals.ddf
Date: February 22, 2011

DESCRIPTION:

Description: 10.158 MMScf/Day Dehydration System Temperature/Pressure taken from the average values of gas analyses dated December 6, 7, and 8, 2010. Average gas dewpoint is 3.73.

Annual Hours of Operation: 8760.0 hours/yr

EMISSIONS REPORTS:

UNCONTROLLED REGENERATOR EMISSIONS

Component	lbs/hr	lbs/day	tons/yr
Methane	0.1423	3.414	0.6231
Ethane	0.1128	2.707	0.4940
Propane	0.1894	4.546	0.8297
Isobutane	0.0920	2.207	0.4028
n-Butane	0.1626	3.902	0.7121
Isopentane	0.1051	2.523	0.4605
n-Pentane	0.0937	2.249	0.4104
n-Hexane	0.1044	2.506	0.4574
Cyclohexane	0.3044	7.305	1.3331
Other Hexanes	0.1346	3.230	0.5894
Heptanes	0.4251	10.202	1.8619
Methylcyclohexane	0.7097	17.032	3.1083
2,2,4-Trimethylpentane	0.0145	0.348	0.0635
Benzene	1.2713	30.511	5.5683
Toluene	4.1032	98.477	17.9720
Ethylbenzene	0.2945	7.068	1.2899
Xylenes	4.2887	102.930	18.7847
C8+ Heavies	3.2764	78.633	14.3506
Total Emissions	15.8246	379.791	69.3118
Total Hydrocarbon Emissions	15.8246	379.791	69.3118
Total VOC Emissions	15.5696	373.670	68.1948
Total HAP Emissions	10.0767	241.840	44.1358
Total BTEX Emissions	9.9577	238.986	43.6149

FLASH GAS EMISSIONS

Note: Flash Gas Emissions are zero with the Recycle/recompression control option.

FLASH TANK OFF GAS

Component	lbs/hr	lbs/day	tons/yr

Methane	6.2578	150.187	27.4092
Ethane	1.2236	29.367	5.3595
Propane	0.8427	20.225	3.6911
Isobutane	0.2453	5.887	1.0743
n-Butane	0.3153	7.568	1.3812
Isopentane	0.1617	3.880	0.7081
n-Pentane	0.1135	2.724	0.4972
n-Hexane	0.0622	1.492	0.2722
Cyclohexane	0.0456	1.096	0.1999
Other Hexanes	0.1094	2.627	0.4793
Heptanes	0.1107	2.656	0.4847
Methylcyclohexane	0.0765	1.835	0.3349
2,2,4-Trimethylpentane	0.0078	0.187	0.0342
Benzene	0.0223	0.535	0.0977
Toluene	0.0413	0.990	0.1808
Ethylbenzene	0.0015	0.037	0.0067
Xylenes	0.0148	0.354	0.0646
C8+ Heavies	0.0844	2.025	0.3695
Total Emissions	9.7364	233.672	42.6452
Total Hydrocarbon Emissions	9.7364	233.672	42.6452
Total VOC Emissions	2.2549	54.118	9.8765
Total HAP Emissions	0.1498	3.596	0.6562
Total BTEX Emissions	0.0799	1.917	0.3498

EQUIPMENT REPORTS:

ABSORBER

Calculated Absorber Stages:	2.09
Specified Dry Gas Dew Point:	3.73 lbs. H2O/MMSCF
Temperature:	83.1 deg. F
Pressure:	207.7 psig
Dry Gas Flow Rate:	10.1580 MMSCF/day
Glycol Losses with Dry Gas:	0.0242 lb/hr
Wet Gas Water Content:	Subsaturated
Specified Wet Gas Water Content:	60.00 lbs. H2O/MMSCF
Calculated Lean Glycol Recirc. Ratio:	3.69 gal/lb H2O

Component	Remaining in Dry Gas	Absorbed in Glycol
Water	6.21%	93.79%
Carbon Dioxide	99.94%	0.06%
Nitrogen	100.00%	0.00%
Methane	100.00%	0.00%
Ethane	99.98%	0.02%
Propane	99.96%	0.04%
Isobutane	99.94%	0.06%
n-Butane	99.92%	0.08%
Isopentane	99.90%	0.10%
n-Pentane	99.88%	0.12%
n-Hexane	99.75%	0.25%
Cyclohexane	98.94%	1.06%
Other Hexanes	99.82%	0.18%
Heptanes	99.44%	0.56%

Methylcyclohexane	98.58%	1.42%
2,2,4-Trimethylpentane	99.74%	0.26%
Benzene	90.76%	9.24%
Toluene	84.23%	15.77%
Ethylbenzene	72.27%	27.73%
Xylenes	61.39%	38.61%
C8+ Heavies	96.14%	3.86%

FLASH TANK

Flash Control: Recycle/recompression
Flash Temperature: 90.0 deg. F
Flash Pressure: 40.0 psig

Component	Left in Glycol	Removed in Flash Gas
Water	99.97%	0.03%
Carbon Dioxide	26.10%	73.90%
Nitrogen	2.15%	97.85%
Methane	2.22%	97.78%
Ethane	8.44%	91.56%
Propane	18.35%	81.65%
Isobutane	27.27%	72.73%
n-Butane	34.02%	65.98%
Isopentane	39.62%	60.38%
n-Pentane	45.43%	54.57%
n-Hexane	62.85%	37.15%
Cyclohexane	87.36%	12.64%
Other Hexanes	55.52%	44.48%
Heptanes	79.44%	20.56%
Methylcyclohexane	90.65%	9.35%
2,2,4-Trimethylpentane	65.45%	34.55%
Benzene	98.36%	1.64%
Toluene	99.08%	0.92%
Ethylbenzene	99.54%	0.46%
Xylenes	99.70%	0.30%
C8+ Heavies	97.79%	2.21%

REGENERATOR

No Stripping Gas used in regenerator.

Component	Remaining in Glycol	Distilled Overhead
Water	27.58%	72.42%
Carbon Dioxide	0.00%	100.00%
Nitrogen	0.00%	100.00%
Methane	0.00%	100.00%
Ethane	0.00%	100.00%
Propane	0.00%	100.00%
Isobutane	0.00%	100.00%
n-Butane	0.00%	100.00%
Isopentane	0.91%	99.09%
n-Pentane	0.85%	99.15%

n-Hexane	0.69%	99.31%
Cyclohexane	3.54%	96.46%
Other Hexanes	1.49%	98.51%
Heptanes	0.59%	99.41%
Methylcyclohexane	4.30%	95.70%
2,2,4-Trimethylpentane	2.00%	98.00%
Benzene	5.06%	94.94%
Toluene	7.96%	92.04%
Ethylbenzene	10.43%	89.57%
Xylenes	12.92%	87.08%
C8+ Heavies	12.17%	87.83%

STREAM REPORTS:

WET GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 4.24e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.26e-001	2.54e+001
Carbon Dioxide	2.28e+000	1.12e+003
Nitrogen	1.64e-001	5.14e+001
Methane	8.52e+001	1.53e+004
Ethane	7.37e+000	2.48e+003
Propane	2.87e+000	1.42e+003
Isobutane	5.44e-001	3.53e+002
n-Butane	6.29e-001	4.08e+002
Isopentane	2.46e-001	1.99e+002
n-Pentane	1.58e-001	1.27e+002
n-Hexane	6.04e-002	5.82e+001
Cyclohexane	3.40e-002	3.19e+001
Other Hexanes	1.15e-001	1.11e+002
Heptanes	8.00e-002	8.96e+001
Methylcyclohexane	4.91e-002	5.39e+001
2,2,4-Trimethylpentane	5.89e-003	7.52e+000
Benzene	1.60e-002	1.39e+001
Toluene	2.55e-002	2.62e+001
Ethylbenzene	8.99e-004	1.07e+000
Xylenes	9.39e-003	1.11e+001
C8+ Heavies	4.53e-002	8.63e+001
Total Components	100.00	2.19e+004

DRY GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 4.23e+005 scfh

Component	Conc. (vol%)	Loading (lb/hr)

Water	7.86e-003	1.58e+000
Carbon Dioxide	2.29e+000	1.12e+003
Nitrogen	1.64e-001	5.14e+001
Methane	8.53e+001	1.53e+004
Ethane	7.38e+000	2.47e+003
Propane	2.88e+000	1.41e+003
Isobutane	5.44e-001	3.53e+002
n-Butane	6.29e-001	4.08e+002
Isopentane	2.46e-001	1.98e+002
n-Pentane	1.58e-001	1.27e+002
n-Hexane	6.04e-002	5.80e+001
Cyclohexane	3.36e-002	3.16e+001
Other Hexanes	1.15e-001	1.11e+002
Heptanes	7.97e-002	8.91e+001
Methylcyclohexane	4.85e-002	5.31e+001
2,2,4-Trimethylpentane	5.89e-003	7.50e+000
Benzene	1.45e-002	1.27e+001
Toluene	2.15e-002	2.21e+001
Ethylbenzene	6.51e-004	7.70e-001
Xylenes	5.77e-003	6.84e+000
C8+ Heavies	4.37e-002	8.30e+001
Total Components	100.00	2.19e+004

LEAN GLYCOL STREAM

Temperature: 83.13 deg. F
Flow Rate: 1.47e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.87e+001	8.15e+002
Water	1.10e+000	9.09e+000
Carbon Dioxide	8.69e-012	7.17e-011
Nitrogen	2.53e-014	2.09e-013
Methane	2.50e-018	2.06e-017
Ethane	2.28e-008	1.88e-007
Propane	2.44e-009	2.02e-008
Isobutane	7.39e-010	6.10e-009
n-Butane	9.71e-010	8.02e-009
Isopentane	1.17e-004	9.63e-004
n-Pentane	9.67e-005	7.99e-004
n-Hexane	8.80e-005	7.26e-004
Cyclohexane	1.35e-003	1.12e-002
Other Hexanes	2.47e-004	2.04e-003
Heptanes	3.05e-004	2.52e-003
Methylcyclohexane	3.86e-003	3.19e-002
2,2,4-Trimethylpentane	3.59e-005	2.96e-004
Benzene	8.21e-003	6.78e-002
Toluene	4.30e-002	3.55e-001
Ethylbenzene	4.16e-003	3.43e-002
Xylenes	7.71e-002	6.37e-001
C8+ Heavies	5.50e-002	4.54e-001
Total Components	100.00	8.25e+002

RICH GLYCOL AND PUMP GAS STREAM

Temperature: 83.13 deg. F
Pressure: 222.37 psia
Flow Rate: 1.57e+000 gpm
NOTE: Stream has more than one phase.

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.30e+001	8.15e+002
Water	3.76e+000	3.29e+001
Carbon Dioxide	1.30e-001	1.14e+000
Nitrogen	2.46e-003	2.16e-002
Methane	7.31e-001	6.40e+000
Ethane	1.53e-001	1.34e+000
Propane	1.18e-001	1.03e+000
Isobutane	3.85e-002	3.37e-001
n-Butane	5.46e-002	4.78e-001
Isopentane	3.06e-002	2.68e-001
n-Pentane	2.37e-002	2.08e-001
n-Hexane	1.91e-002	1.67e-001
Cyclohexane	4.12e-002	3.61e-001
Other Hexanes	2.81e-002	2.46e-001
Heptanes	6.15e-002	5.38e-001
Methylcyclohexane	9.34e-002	8.18e-001
2,2,4-Trimethylpentane	2.58e-003	2.26e-002
Benzene	1.55e-001	1.36e+000
Toluene	5.14e-001	4.50e+000
Ethylbenzene	3.77e-002	3.30e-001
Xylenes	5.64e-001	4.94e+000
C8+ Heavies	4.36e-001	3.81e+000
Total Components	100.00	8.76e+002

FLASH TANK OFF GAS STREAM

Temperature: 90.00 deg. F
Pressure: 54.70 psia
Flow Rate: 1.86e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	1.14e-001	1.00e-002
Carbon Dioxide	3.92e+000	8.44e-001
Nitrogen	1.54e-001	2.11e-002
Methane	7.97e+001	6.26e+000
Ethane	8.31e+000	1.22e+000
Propane	3.90e+000	8.43e-001
Isobutane	8.62e-001	2.45e-001
n-Butane	1.11e+000	3.15e-001
Isopentane	4.58e-001	1.62e-001
n-Pentane	3.21e-001	1.14e-001
n-Hexane	1.47e-001	6.22e-002
Cyclohexane	1.11e-001	4.56e-002
Other Hexanes	2.59e-001	1.09e-001
Heptanes	2.25e-001	1.11e-001
Methylcyclohexane	1.59e-001	7.65e-002
2,2,4-Trimethylpentane	1.40e-002	7.81e-003
Benzene	5.83e-002	2.23e-002
Toluene	9.15e-002	4.13e-002

Ethylbenzene	2.93e-003	1.53e-003
Xylenes	2.84e-002	1.48e-002
C8+ Heavies	1.01e-001	8.44e-002
Total Components	100.00	1.06e+001

FLASH TANK GLYCOL STREAM

Temperature: 90.00 deg. F
Flow Rate: 1.55e+000 gpm

Component	Conc. (wt%)	Loading (lb/hr)
TEG	9.41e+001	8.15e+002
Water	3.81e+000	3.29e+001
Carbon Dioxide	3.45e-002	2.98e-001
Nitrogen	5.35e-005	4.63e-004
Methane	1.64e-002	1.42e-001
Ethane	1.30e-002	1.13e-001
Propane	2.19e-002	1.89e-001
Isobutane	1.06e-002	9.20e-002
n-Butane	1.88e-002	1.63e-001
Isopentane	1.23e-002	1.06e-001
n-Pentane	1.09e-002	9.45e-002
n-Hexane	1.22e-002	1.05e-001
Cyclohexane	3.65e-002	3.16e-001
Other Hexanes	1.58e-002	1.37e-001
Heptanes	4.94e-002	4.28e-001
Methylcyclohexane	8.57e-002	7.42e-001
2,2,4-Trimethylpentane	1.71e-003	1.48e-002
Benzene	1.55e-001	1.34e+000
Toluene	5.15e-001	4.46e+000
Ethylbenzene	3.80e-002	3.29e-001
Xylenes	5.69e-001	4.93e+000
C8+ Heavies	4.31e-001	3.73e+000
Total Components	100.00	8.65e+002

FLASH GAS EMISSIONS

Control Method: Recycle/recompression
Control Efficiency: 100.00

Note: Flash Gas Emissions are zero with the
Recycle/recompression control option.

REGENERATOR OVERHEADS STREAM

Temperature: 212.00 deg. F
Pressure: 14.70 psia
Flow Rate: 5.68e+002 scfh

Component	Conc. (vol%)	Loading (lb/hr)
Water	8.85e+001	2.39e+001
Carbon Dioxide	4.53e-001	2.98e-001
Nitrogen	1.10e-003	4.63e-004

Methane	5.93e-001	1.42e-001
Ethane	2.51e-001	1.13e-001
Propane	2.87e-001	1.89e-001
Isobutane	1.06e-001	9.20e-002
n-Butane	1.87e-001	1.63e-001
Isopentane	9.74e-002	1.05e-001
n-Pentane	8.68e-002	9.37e-002
n-Hexane	8.10e-002	1.04e-001
Cyclohexane	2.42e-001	3.04e-001
Other Hexanes	1.04e-001	1.35e-001
Heptanes	2.83e-001	4.25e-001
Methylcyclohexane	4.83e-001	7.10e-001
2,2,4-Trimethylpentane	8.48e-003	1.45e-002
Benzene	1.09e+000	1.27e+000
Toluene	2.98e+000	4.10e+000
Ethylbenzene	1.85e-001	2.95e-001
Xylenes	2.70e+000	4.29e+000
C8+ Heavies	1.29e+000	3.28e+000
Total Components	100.00	4.00e+001

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 WYNKOOP STREET
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

2011 SEP 30 AM 10: 10
FILED
EPA REGION VIII
HEARING CLERK

DOCKET NO.: CAA-08-2011-0032

IN THE MATTER OF:	)	
CONOCO PHILLIPS COMPANY,	)	**FINAL ORDER**
Respondent	)	

Pursuant to 40 C.F.R. § 22.13(b) and 22.18, of EPA's Consolidated Rules of Practice, the Consent Agreement resolving this matter is hereby approved and incorporated by reference into this Final Order. The Respondent is hereby **ORDERED** to comply with all of the terms of the Consent Agreement, effective immediately upon receipt by Respondent of this Consent Agreement and Final Order.

The Parties are hereby **ORDERED** to comply with all of the terms of this Final Order.

SO ORDERED THIS 30th **Day of** September **, 2011**

Elyana R. Sutin
Regional Judicial Officer

UNITED STATES
ENVIRONMENTAL PROTECTION AGENCY
REGION 8

2011 SEP 30 AM 10: 10

FILED
EPA REGION VIII
HEARING CLERK

Docket No.: CAA-08-2011-0032

IN THE MATTER OF	)	
	)	**COMPLAINT AND**
ConocoPhillips Company,	)	**SETTLEMENT AGREEMENT**
	)	
Respondent.	)	

Complainant, United States Environmental Protection Agency, Region 8 (EPA or Complainant), and Respondent, ConocoPhillips Company (Respondent) (collectively hereafter the Parties), by their undersigned representatives, hereby consent and agree as follows:

A. PRELIMINARY MATTERS

1. This Complaint and Settlement Agreement (Agreement) is entered into by Respondent and EPA to settle alleged violations of the Clean Air Act (CAA), specifically of 40 C.F.R. Parts 63 and 71, at the Ute Compressor Station Facility owned and/or operated by Respondent.

2. This proceeding is governed by the Consolidated Rules of Practice Governing the Administrative Assessment of Civil Penalties, and the Revocation, Termination or Suspension of Permits (Consolidated Rules) set forth at 40 C.F.R. Part 22. The U.S. Department of Justice has concurred with EPA Region 8's request for authorization to commence an administrative enforcement action in this matter.

3. This Agreement is entered into by the Parties for the purpose of simultaneously commencing and concluding this matter, as authorized by 40 C.F.R. Part 22 §13(b), and executed pursuant to 40 C.F.R. Part 22 §18(b)(2) and (3) of the Consolidated Rules.

4. EPA has jurisdiction over this matter pursuant to §113(d)(1)(B) of the CAA, 42 U.S.C. §7413(d)(1)(B), as amended on November 15, 1990.

5. Respondent admits the jurisdictional allegations in this Agreement, but does not admit the specific factual allegations or legal conclusions made by the Complainant herein.

6. Respondent waives its rights to a hearing before any tribunal and to contest any issue of law or fact set forth in this Agreement.

7. Complainant asserts that settlement of this matter is in the public interest, and Complainant and Respondent agree that entry of this Agreement and Final Order without further litigation and without adjudication of any issue of fact or law is the most appropriate means of resolving this matter.

8. This Agreement, upon incorporation into a Final Order, applies to and is binding upon EPA and upon Respondent, and Respondent's officers, directors, employees, agents, successors and assigns. Any change in ownership or corporate status of Respondent including, but not limited to, any transfer of assets or real or personal property shall not alter Respondent's responsibilities under this agreement.

9. This Agreement contains all terms of the settlement agreed to by the Parties.

10. The Facility to which this Agreement relates is on "Indian country" land as defined at 18 U.S.C. § 1151:

Township 32N, Range 11W, Sections 14-15 at latitude 37.01726666 longitude -108.0200833,within the exterior boundaries of the Southern Ute Indian Reservation in La Plata County, Colorado.

11. Respondent submitted a self-disclosure of certain violations of 40 C.F.R. Part 63 §760-778 (Subpart HH, National Emissions Standard for Hazardous Air Pollutants from Oil and

Natural Gas Production Facilities) and 40 C.F.R. Part 71 §1-13 (Subpart A, Federal Operating Permit Programs) to EPA on February 24, 2011. That disclosure meets the criteria in the EPA policy titled "Incentives for Self-Policing: Discovery, Disclosure, Correction and Prevention of Violations," issued April 11, 2000.

B. ALLEGED VIOLATIONS

1. Respondent is a Delaware corporation and therefore a "person" as defined in section 7602(e) of the CAA, 42 U.S.C. §7602. Respondent became the owner of the Ute Compressor Station Facility in 2006.
2. Respondent owns and/or operates the Facility described in paragraph A.10, above.
3. Complainant alleges that Respondent violated the CAA by violating 40 C.F.R. Part 71 (Federal Operating Permit Programs) by failing to obtain a Title V permit and is violating 40 C.F.R. Part 63 by failing to control emissions from its glycol dehydration unit.

COUNT #1: The Facility was and is operating as a major source (as defined by 40 C.F.R. Part 63) of hazardous air pollutants. As such, the Respondent was required to obtain a Part 71 operating permit. It has not yet obtained that permit.

COUNT #2: 40 C.F.R. Part 63 §760-778, requires that total hazardous air pollutants from the glycol dehydration unit process vent at a major source in the oil and natural gas production sector be reduced by 95%. Respondent has not met that requirement.

C. REQUIREMENTS UNDER THIS AGREEMENT

C.1. Compressor Engines

(1) The Waukesha L7042 GL reciprocating internal combustion engine (RICE) at the Ute Compressor Station shall be equipped with oxidation catalyst control system capable of reducing uncontrolled emissions of carbon monoxide (CO) by at least 75% and formaldehyde emissions by at least 75% at maximum operating rate (90% to

110% of engine capacity at site elevation).[1] Any replacement engine shall also be equipped with an oxidation catalyst control system capable of meeting the same requirements of Section C.1 herein.

(2) The Respondent shall follow, for the RICE in C.1(1) and its respective catalyst, the manufacturer's recommended maintenance schedule and procedures to ensure optimum performance of each engine and catalyst.

(3) By no later than six months after the date of the final order, the Respondent shall install oxidation catalysts as specified in paragraph C.1.(1) and begin complying with requirements specified in paragraph C.1.(2)

C.2. Control of Glycol Dehydrator Emissions

(1) Respondent has installed the emission control system for hazardous air pollutants from the glycol dehydrator. The glycol dehydrator emission control system shall meet all the applicable requirements in 40 C.F.R. Part 63 §760-778 including but not limited to design and control requirements. The Respondent shall also meet the all other applicable requirements in 40 C.F.R. Part 63 §760-778 with respect to the glycol dehydrator including but not limited to monitoring, testing, record keeping, notification and reporting requirements.

C.3. Pneumatic Controllers

(1) Retrofit or Replacement. By no later than six months after the date of the Final Order, Respondent shall retrofit or replace all existing "high-bleed" pneumatic controllers with "low-bleed" or "no bleed" controllers at the Ute Compressor Station and at existing wells feeding into this Facility which are owned by Respondent. The relevant

1 This requirement is not a numerical emission limitation. Rather, this is a requirement that the oxidation catalyst system to be installed is designed to meet these specifications at a minimum for the make and model of engine at each facility. The emission limits that the engine is subject to will be listed in the respective title V permit.

"high-bleed" pneumatic controllers and their well site or compressor station description are listed in Appendix "A". For purposes of this Agreement, a "high-bleed" pneumatic controller is any pneumatic control device that has the capacity to bleed in excess of 6 standard cubic feet (scf) of natural gas per hour (i.e., 50,000 scf/year) in normal operation, and a "low-bleed controller" is a pneumatic control device that bleeds natural gas at a lesser rate than a "high-bleed" pneumatic controller. During the performance of the retrofit/replacement project, Respondent shall, to the extent practicable, repair or replace leaking gaskets, tubing fittings, and seals, and all work will be completed so as to minimize potential emissions associated with the retrofit/replacement project.

(2) Within 60 calendar days after the retrofit/replacement project is completed, Respondent shall provide a report to EPA that certifies completion of the retrofit/replacement project at the Ute Compressor Station and at existing wells for the facilities owned and/or operated by Respondent listed in Appendix "A". It shall identify each unit retrofitted or replaced, its site location, its service, the date the retrofit or replacement was completed, the estimated bleed rate reductions and corresponding estimates of both annual VOC reductions and amount of natural gas conserved, and the approximate cost of each retrofit or replacement.

C.4. Leak Detection Program

(1) Respondent shall implement a directed inspection and maintenance program to detect and repair leaking equipment components at its Ute Compressor Station (the Program). At a minimum, the Program shall address detecting and repairing leaks at each pump, thief hatch, pressure release device, open-ended valve or line, flange, and

compressor. The program shall use a thermal infrared camera capable of detecting emissions of volatile organic compounds.

(2) By no later than three months after the date of the Final Order, Respondent shall submit a protocol outlining the specifics for the Program, including the technical procedures for monitoring with the infrared camera, a schedule for monitoring, defining when a "leak" is detected, repair schedule for leaking equipment (including delay of repair), and recordkeeping format.

(3) Respondent will begin implementing the Program upon approval of the protocol by EPA, with a start date specified in the approved schedule for conducting monitoring.

(4) By no later than thirty calendar days subsequent to any required monitoring, Respondent will submit reports of the monitoring results, repairs made, repairs delayed and the reason for the repair delay. At a minimum, the reports shall include the information specified in the approved protocol for the Program.

(5) The approved protocol for the Program can be modified at any time as deemed necessary by EPA. Respondent can also submit a modified protocol for approval to EPA at any time. The existing approved protocol shall remain effective until such time a modified protocol is approved by EPA.

C.5. Permitting Requirements

Respondent submitted an application for a Title V Permit for Ute Compressor Station to EPA in May 2011. The permit will incorporate all installation, operation, testing, monitoring, recordkeeping, and reporting requirements set forth in Sections C.1, C.2 and

C.4 of this Agreement. These conditions shall remain in the Title V permit as "applicable requirements" (as defined in part 70 and part 71) under this Agreement, until such time they are incorporated into a federally enforceable non-Title V permit, where they shall then become "applicable requirements" under the non-Title V permit.

C.6. Submission Address

Unless otherwise specified herein, all reports, submissions or other notifications required by this agreement to be sent to EPA shall be addressed to:

Air & Toxics Technical Enforcement Program Director
U.S. EPA Region 8 (Mail Code 8ENF-AT)
1595 Wynkoop St.
Denver, CO 80202-1129

D. CIVIL PENALTY

1. Pursuant to an analysis of the facts and circumstances of this case with the statutory factors described in section 113(d)(1)(B) of the CAA, 42 U.S.C. §7413(d)(1)(B), EPA has determined that an appropriate civil penalty to settle this action is the amount of one-hundred and nine-eight thousand dollars ($198,000).

2. Respondent consents to the issuance of a Final Order and consents for the purposes of settlement to the payment of the civil penalty in the amount of one-hundred and ninety-eight thousand dollars ($198,000) in the manner described below in this paragraph:

   a. **Payment is due within 30 calendar days from the date written on the Final Order, to be** issued by the Regional Judicial Officer, that adopts this Complaint and Settlement Agreement. If the due date falls on a weekend or legal federal holiday, then the due date becomes the next business day. The date the payment is made is considered to be the date processed by the Bank described below.

Payments received by 11:00 AM EST are processed on the same day, those received after 11:00 AM are processed on the next business day.

b. The payment shall be made by remitting a cashier's or certified check, including the name and docket number of this case, for the amount, **payable to "Treasurer, United States of America," to:**

CHECK PAYMENT:

US Environmental Protection Agency
Fines and Penalties
Cincinnati Finance Center
PO Box 979077
St. Louis, MO 63197-9000

OVERNIGHT MAIL:

U.S. Bank
1005 Convention Plaza
Mail Station SL-MO-C2GL
St. Louis, MO 63101

Contact: Natalie Pearson
314-418-4087

WIRE TRANSFER:

Wire transfers should be directed to the Federal Reserve Bank of New York

Federal Reserve Bank of New York
ABA = 021030004
Account = 68010727
SWIFT address = FRNYUS33
33 Liberty Street
New York, NY 10045
Field Tag 4200 of the Fedwire message should read AD 68010727 Environmental Protection Agency"

ACH (also known as REX or remittance express)

Automated Clearinghouse (ACH) for receiving US currency
PNC Bank
808 17th Street, NW
Washington, DC 20074
Contact B Jesse White 301-887-6548
ABA = 051036706
Transaction Code 22 – checking
Environmental Protection Agency
Account 310006
CTX Format

ON LINE PAYMENT:

There is now an On Line Payment Option, available through the Dept. of Treasury. This payment option can be accessed from the information below:

WWW.PAY.GOV
Enter sfo 1.1 in the search field. Open form and complete required fields.

A copy of the check, or wire transfer, shall be sent simultaneously to:

Alejandro Siemel (8ENF-AT) U.S. EPA Region 8 Technical Enforcement Program 1595 Wynkoop St. Denver, CO 80202-1129	and	Tina Artemis Regional Hearing Clerk (8RC) U.S. EPA Region 8 1595 Wynkoop St. Denver, CO 80202-1129

c. Payment of the penalty in this manner does not relieve Respondent of its obligations to comply with the requirements of the CAA statute and regulations.

E. TERMS AND CONDITIONS

1. Failure by Respondent to comply with any of the terms of this Agreement shall constitute

a

breach of the Agreement and may result in referral of the matter to the Department of Justice for enforcement of this Agreement and for such other relief as may be appropriate.

2. Nothing in this Agreement shall be construed as a waiver by the EPA or any other federal entity of its authority to seek costs or any appropriate penalty associated with any collection action instituted as a result of Respondent's failure to perform pursuant to the terms of this Agreement.

3. Each undersigned representative of the Parties to this Agreement certifies that he or she is fully authorized by the party represented to bind the party to the terms and conditions of this Agreement and to execute and legally bind that party to this Agreement.

4. The Parties agree to submit this Agreement to the Regional Judicial Officer, with a request

that it be incorporated into a Final Order.

5. This Agreement, upon incorporation into a Final Order by the Regional Judicial Officer and

full satisfaction by the Parties, shall be a complete, full and final settlement of the violations alleged in this Agreement.

6. The terms, conditions, and compliance requirements of this Agreement may not be modified

or amended except upon the written agreement of the Parties, and approval of a Regional Judicial Officer.

7. Each party shall bear its own costs and attorneys fees in connection with all issues associated with this Agreement.

Signature Page
COMPLAINT AND SETTLEMENT AGREEMENT

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY REGION 8, Complainant.

Date: September 30, 2011

By: ______________________
Andrew M. Gaydosh
Assistant Regional Administrator
Office of Enforcement, Compliance and Environmental Justice

Date: September 26, 2011

By: David Rochlin
David Rochlin
Senior Enforcement Attorney
U.S. EPA, Region 8

CONOCOPHILLIPS COMPANY, Respondent.

Date: September 19, 2011

By: ______________________
Roy Lyons, General Manager
San Juan Business Unit

CERTIFICATE OF SERVICE

The undersigned certifies that the original of the attached **COMPLAINT, SETTLEMENT AGREEMENT AND FINAL ORDER** in the matter of **CONOCO PHILLIPS COMPANY; DOCKET NO.: CAA-08-2011-0032,** was filed with the Regional Hearing Clerk on September 30, 2011.

Further, the undersigned certifies that a true and correct copy of the document was delivered to David Rochlin, Senior Enforcement Attorney, U. S. EPA – Region 8, 1595 Wynkoop Street, Denver, CO 80202-1129. True and correct copies of the aforementioned documents were placed in the United States mail on September 30, 2011, to:

Roy Lyons, General Manager
SanJuan Business Unit
Conoco Phillips Co.
P. O. Box 4289
Farmington, NM

Steve Ellison, Senior Counsel
Conoco Phillips Company
2084 McLean/P. O. Box 4783
Houston, TX 77210-4783

And emailed to:

Elizabeth Whitsel
U. S. Environmental Protection Agency
Cincinnati Finance Center
26 W. Martin Luther King Drive (MS-0002)
Cincinnati, Ohio 45268

September 30, 2011

Tina Artemis
Tina Artemis
Paralegal/Regional Hearing Clerk

Appendix A
ConocoPhillips Ute Compressor Stations Well Pneumatic Device Retrofit/Replacements Inventory

Schedule:
NOTE: **All pnuematics in the Ute Compressor Station run off compressed air.**
By no later than 6 months after the effective date of the Final Order, replace "high-bleed" pneumatic controllers with "low-bleed" or "no bleed" pneumatic or electric-pneumatic controllers at the well sites.
Within 60 days of project completion Submit report to EPA certifying project completion within 60 days of project completion - use format below

PNEUMATIC DEVICE RETROFITS/REPLACEMENTS - UTE WELLS

		Location			Bleed Rate			Low/No-Bleed Retrofit or Replace Device			Bleed Rate (cfh)		Bleed Rate Reduction (Mcf/yr)
Make/Model	Type	Lease/Well Name	Equipment Piece	Number of Devices	Volume per Device (cfh)	Total Device Volume (cfh)	Intermittent (I) or Continuous (C)	Install Date	Make/Model	Approximate cost ($)	Volume per Device (cfh)	Total Device Volume (cfh)	
		Ute CS Wells								**Ute CS Wells**			
		FARMER 1											
		FARMER 80 1											
		GODBEY 232											
		IVIE 1											
		IVIE 2											
		UTE 1											
		UTE 10A											
		UTE 11											
		UTE 13											
		UTE 14											
		UTE 15											
		UTE 16											
		UTE 1AR											
		UTE 1B											
		UTE 1C											
		UTE 2											
		UTE 20											
		UTE 21											
		UTE 23											
		UTE 2-34											
		UTE 24											
		UTE 25											
		UTE 26											
		UTE 27											
		UTE 2A											
		UTE 2B											
		UTE 2C											
		UTE 3											
		UTE 30											
		UTE 32-11 202											
		UTE 33											
		UTE 34											
		UTE 35											
		UTE 39											
		UTE 3A											
		UTE 4											
		UTE 41											
		UTE 44											
		UTE 4A											
		UTE 4B											
		UTE 5											
		UTE 55											
		UTE 5A											
		UTE 5B											
		UTE 6											
		UTE 60											
		UTE 6A											
		UTE 7											

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		GODBEY 232											
		IVIE 1											
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		UTE 10A											
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		UTE 16											
		UTE 1AR											
		UTE 1B											
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		UTE 26											
		UTE 27											
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		UTE 2B											
		UTE 2C											
		UTE 3											
		UTE 30											
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		UTE 33											
		UTE 34											
		UTE 35											
		UTE 39											
		UTE 3A											
		UTE 4											
		UTE 41											
		UTE 44											
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			Ute CS Wells							**Ute CS Wells**			
		UTE 7A											
		UTE 7B											
		UTE 80 1											
		UTE 80 11											
		UTE 80 13											
		UTE 80 14											
		UTE 80 15											
		UTE 80 16											
		UTE 80 1AR											
		UTE 80 2											
		UTE 80 23											
		UTE 80 2A											
		UTE 80 2B											
		UTE 80 3											
		UTE 80 30											
		UTE 80 35											
		UTE 80 4A											
		UTE 80 4B											
		UTE 80 7A											
		UTE 8A											
		UTE B 2											
		VIRBETH 1A											
		VIRBETH 1R											
		VIRBETH 2											
		VIRBETH 80 1A											
		VIRBETH 80 1R											
			Totals:	**TBD**		**TBD**				**TBD**		**TBD**	

TOTAL GAS CONSERVED (Mcf/yr)	TBD
VOC Emissions Reduced (lb/yr)	TBD