Montana Department of
ENVIRONMENTAL QUALITY

Brian Schweitzer, Governor

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July 16, 2012

Mr. Geoffrey Sands
ONEOK Rockies Midstream, LLC
Baker Gas Plant
P.O. Box 871
Tulsa, OK 74102-0871

Dear Mr. Sands:

Montana Air Quality Permit #2736-10 is deemed final as of July 14, 2012, by the Department of Environmental Quality (Department). This permit is for a natural gas processing plant. All conditions of the Department's Decision remain the same. Enclosed is a copy of your permit with the final date indicated.

For the Department,

Charles Homer
Manager, Air Permitting, Compliance and Registration
Air Resources Management Bureau
(406) 444-5279

Craig Henrikson, PE
Environmental Engineer
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CH:CPH
Enclosure

Montana Department of Environmental Quality
Permitting and Compliance Division

Montana Air Quality Permit #2736-10

ONEOK Rockies Midstream, LLC
Baker Gas Plant
P.O. Box 871
Tulsa, OK 74102-0871

July 14, 2012

MONTANA AIR QUALITY PERMIT

Issued To: ONEOK Rockies Midstream, LLC Baker Gas Plant P.O. Box 871 Tulsa, OK 74102-0871	Montana Air Quality Permit #2736-10 Administrative Amendment (AA) Request Received: 06/18/12 Department Decision on AA: 06/28/12 Permit Final: 07/14/12 AFS #025-0001

A Montana Air Quality Permit (MAQP), with conditions, is hereby granted to ONEOK Rockies Midstream, LLC (ORM) pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA) and the Administrative Rules of Montana (ARM) 17.8.740 *et seq*., as amended, for the following:

Section I: Permitted Facilities

A. Location

ORM operates a natural gas processing plant and associated equipment located in the SW¼ of the SW¼ of Section 6, Township 7 North, Range 60 East, in Fallon County, Montana. This facility is known as the Baker Gas Plant. A complete list of the facility's permitted equipment can be found in Section I.A. of the Permit Analysis.

B. Current Permit Action

The Department of Environmental Quality (Department) received notification on June 18, 2012, from Bear Paw Energy, LLC requesting an amendment to MAQP #2736-09 to change their name to ONEOK Rockies Midstream, LLC. All permit references to the facility's name with the exception of the permit history have been changed throughout this document.

Section II: Conditions and Limitations

A. Emission Limitations:

1. ORM is permitted to operate a 1250-brake-horsepower (bhp) engine or a series of engines with a cumulative rated capacity equal to or less than 1250 bhp (excluding the engines identified in Sections II.A.3. and II.A.4). Each engine shall be controlled by a catalytic converter (ARM 17.8.749 and ARM 17.8.752).

2. The combined emissions from all engine(s) comprising the 1250 bhp shall not exceed the following limits (ARM 17.8.752):

Oxides of Nitrogen (NO_X)[1]	5.51 lb/hr
Carbon Monoxide (CO)	5.51 lb/hr
Volatile Organic Compounds (VOC)	2.76 lb/hr

3. The 448-bhp Waukesha compressor engine shall be operated with an air-to-fuel ratio (AFR) controller and a non-selective catalytic reduction (NSCR) unit. Emissions from the 448-bhp Waukesha compressor engine shall not exceed the following limits (ARM 17.8.752):

[1] NO_X reported as NO_2.

NO_X[1]	1.98 lb/hr
CO	2.96 lb/hr
VOC	1.00 lb/hr

4. The 800-bhp White Superior compressor engine shall be operated with an AFR controller and an NSCR unit. Emissions from the 800-bhp White Superior compressor engine shall not exceed the following limits (ARM 17.8.752):

NO_X[1]	3.53 lb/hr
CO	5.29 lb/hr
VOC	1.76 lb/hr

5. ORM shall route the dehydrator regenerator off gases to the Anderson Hot Oil heater for thermal destruction at all times, except when the heater is not operating. The flash separator off gases shall be routed to the inlet condensate knockout drum (ARM 17.8.752).

6. The condensate/natural gasoline product loading and receiving at the Baker Gas Plant shall be operated under a vapor balance system. All condensate/natural gasoline product loading to tank trucks shall be conducted using bottom loading. Vapor displacement resulting from loadout operations shall be returned to the associated storage vessel to maintain vapor balanced emissions control. The propane, butane, and Y-grade products are stored in pressurized storage tanks. All propane, butane, and Y-grade loading lines shall have a valve at their ends; therefore, any vapors associated with product loading are contained within a closed system (ARM 17.8.752 and ARM 17.8.324).

7. ORM shall use fixed roof tanks for storage of condensate and natural gasoline and pressurized tanks for storage of Y-grade, propane, and butane. The fixed roof tanks shall be vapor balanced, submerge filled and equipped with a pressure/vacuum vent. The pressurized tanks shall be submerge-filled and equipped with a pressure relief valve (ARM 17.8.752 and ARM 17.8.324).

8. ORM shall not cause or authorize to be discharged into the atmosphere from either flare:

   a. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.316); and

   b. Any particulate emissions in excess of 0.10 grains per dry standard cubic feet (gr/dscf) corrected to 12% carbon dioxide (CO_2) (ARM 17.8.316).

9. ORM shall be limited to a maximum production rate of 3,102.5 million standard cubic feet (MMScf) during any rolling 12-month period (ARM 17.8.749 and 17.8.752).

10. ORM shall route all stack emissions from the amine regenerator to the Acid Gas Flare (ARM 17.8.752).

11. ORM shall add natural gas to the acid gas stream prior to flaring. Natural gas shall be added to achieve 20% natural gas in the total gas stream flared (ARM 17.8.749).

12. ORM shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

13. ORM shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308).

14. ORM shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.13 (ARM 17.8.749).

15. ORM shall install and continuously operate a thermocouple and an associated recorder or any equivalent device to detect the presence of a flame (ARM 17.8.752, 40 CFR 60, Subpart KKK and 40 CFR 60, Subpart LLL, as applicable).

16. ORM's Guyed Utility Flare is limited to 300 hours of total plant equipment downtime during planned maintenance activities during any rolling 12-month period.

B. Testing Requirements:

1. ORM shall test the 1250-bhp compressor engine (or combined engines up to 1250-bhp) for NO_X and CO, concurrently, and demonstrate compliance with the NO_X and CO emission limits contained in Section II.A.2. Testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

2. ORM shall test the 448-bhp Waukesha compressor engine for NO_X and CO, concurrently, and demonstrate compliance with the emission limits contained in Section II.A.3. Testing shall continue on an every 4-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

3. ORM shall test the 800-bhp White Superior compressor engine for NO_X and CO, concurrently, and demonstrate compliance with the NO_X and CO emission limits contained in Section II.A.4. Testing shall continue on an every 4-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

4. During each test, ORM shall monitor and record the following: intake manifold temperature and pressure, exhaust manifold temperature and pressure, engine rpm, and all parameters necessary to calculate horsepower. This information shall be submitted to the Department along with the Source Test Report (ARM 17.8.105).

5. An Environmental Protection Agency (EPA) Method 9 opacity test and/or other methods and procedures as specified in 40 CFR Part 60, Subpart KKK must be performed on the flares at the facility on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the emission limitations contained in Section II.A.8. (ARM 17.8.105, ARM 17.8.749, and 40 CFR 60, Subpart KKK).

6. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

7. The Department may require further testing (ARM 17.8.105).

C. Inspection, Repair, and Recordkeeping Requirements:

1. Each calendar month, all fugitive piping components (valves, flanges, pump seals, and open-ended lines, etc.) shall be inspected for leaks. For purposes of this requirement, detection methods incorporating sight, sound, or smell are acceptable (ARM 17.8.105 and ARM 17.8.752).

2. ORM shall (ARM 17.8.105 and ARM 17.8.752):

   a. Make a first attempt at repair for any leak not later than 5 calendar days after the leak is detected; and

   b. Repair any leak as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in Section II.C.3.

3. Delay of repair of equipment for which a leak has been detected will be allowed if repair is technically infeasible without a source shutdown. Such equipment shall be repaired before the end of the first source shutdown after detection of the leak (ARM 17.8.752).

4. A record of each monthly leak inspection, required under Section II.C.1, shall be kept on file at the facility. Inspection records shall include, at a minimum, the following information (ARM 17.8.105):

   a. Date of inspection;

   b. Findings (may indicate no leaks discovered or the location, nature, and severity of each leak);

   c. Leak determination method;

   d. Corrective action (date each leak repaired and reasons for any repair interval in excess of 15 calendar days); and

   e. Inspector name and signature.

D. Operational Reporting Requirements:

1. ORM shall supply the Department with annual production information for all emission points, as required by the Department in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis.

   Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in the units required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. ORM shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include ***the addition of a new emissions unit***, change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. ORM shall document, by month, the facility throughput in MMScf. By the 25th day of each month, ORM shall total the amount of throughput for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.A.9. A written report of the compliance verification shall be submitted along with annual emission inventory (ARM 17.8.749).

4. ORM shall document the amount of acid gas sent to the flare and the amount of natural gas added to the acid gas stream prior to flaring to verify compliance with the limitation in Section II.A.11. A written report of the compliance verification shall be submitted to the Department by the date required in the emission inventory request and may be submitted along with the annual emission inventory (ARM 17.8.749).

5. All records compiled in accordance with this permit must be maintained by ORM as a permanent business record for at least 5 years following the date of the measurement, must be available at the plant site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

Section III: General Conditions

A. Inspection – ORM shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (e.g., Continuous Emission Monitoring System (CEMS), Compliance Emission Rate Monitoring System (CERMS)) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if ORM fails to appeal as indicated below.

C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving ORM of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*. (ARM 17.8.756).

D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of

Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.

G. Permit Fee – Pursuant to Section 75-2-220, MCA, failure to pay the annual operation fee by ORM may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Duration of Permit – Construction or installation must begin or contractual obligations entered into that would constitute substantial loss within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall expire (ARM 17.8.762).

MONTANA AIR QUALITY PERMIT (MAQP) ANALYSIS
ONEOK Rockies Midstream, LLC
MAQP #2736-10

I. Introduction/Process Description

A. Permitted Equipment

The ONEOK Rockies Midstream, LLC (ORM) Baker Gas Plant is a natural gas processing plant located in the SW¼ of the SW¼ of Section 6, Township 7 North, Range 60 East, in Fallon County, Montana. The facility includes, but is not limited to, the following:

- 1981 Waukesha 448 brake-horsepower (bhp) F-3521 G compressor engine
- 1981 White Superior 800-bhp 8G-825 compressor engine
- Waukesha L-7042 GSI 1250-bhp compressor engine (or combined engines up to 1250-bhp)
- Storage Tanks - Pressurized, submerge filled, equipped with pressure relief valve - two (2) Y-grade tanks, three (3) propane tanks, two (2) butane tanks
- Four (4) 400 barrel (bbl) Condensate/Natural Gasoline storage tanks - fixed roof, vapor balanced, submerge filled, equipped with a pressure/vacuum vent
- Product Loading for Y-grade, propane, and butane – closed systems
- Product Loading for Natural Gasoline – bottom loading, vapor balanced
- 8.5 million standard cubic feet/day (MMScfd) ethylene glycol (EG) dehydration unit, vent and flash tank
- 1981 6.5 million British thermal units per hour (MMBtu/hr) Anderson Baird Hot Oil Heater
- 1997 2.0 MMBtu/hr amine reboiler
- 0.5 MMBtu/hr glycol line heater
- 6.5 MMScfd amine regenerator
- 1997 80-ft Flare Industries Guyed DU-6 utility flare
- Acid Gas Flare
- Fugitive volatile organic compounds (VOC) (components in VOC service)

One depropanizer unit, two heat exchangers, 60,000 gallons of propane storage, and associated valves, flanges, pumps, connectors, etc.

B. Source Description

Natural gas processing plants remove certain compounds from natural gas that are of considerable value by themselves and other contaminants that render the gas unsuitable for sale. The predominant constituent of natural gas is methane and ethane, with smaller amounts of other hydrocarbons.

The Baker Gas Plant receives natural gas from surrounding fields. Inlet gas flows through a separator that separates water and condensate from the gas. The water and condensate are stored in the condensate tank(s). Compressor engines accomplish initial compression of the gas. The compressed natural gas is then routed to an amine-sweetening unit, which removes any acid gases (hydrogen sulfide (H_2S) and carbon dioxide (CO_2)) present in the incoming gas stream. From the amine contactor, the rich amine flows through a pre-heater (heat exchanger) before going to the amine regenerator.

The amine regenerator uses a heater to elevate the temperature of the rich amine, driving off the acid gases. The acid gases leaving the regenerator are routed to the Acid Gas Flare for combustion/oxidation. These gases were previously sent to the Challenger Flare, which is now out of service. The facility utilizes another flare, the Guyed Utility Flare, for the combustion of vent gases during emergency upset conditions or process venting. Both flares are continuously piloted with pipeline quality natural gas and are equipped with an auto-igniter. They are also equipped with a thermocouple and associated recorder.

Lean amine, now stripped of acid gas, flows back through the pre-heater to preheat the rich amine going to the regenerator. The compressed natural gas is then dehydrated through an EG dehydration unit. In addition to water, some benzene, toluene, ethyl benzene, xylene (BTEX), and VOCs are absorbed by the glycol and removed from the natural gas. The VOCs and BTEX are then separated from the glycol in the glycol regenerator and flash tank. Off-gases from the regenerator still column are routed to the Anderson heater for thermal destruction. The still vent has a pressure control valve that can be opened to atmosphere when the Anderson heater is down. Off-gases from the flash tank are hard-piped to the inlet condensate separator.

The plant also serves as a fractionation plant. After being dehydrated and de-sulfurized, natural gas liquids (NGLs) are separated from the natural gas. The NGL is referred to as Y-grade and the remaining natural gas is referred to as residue gas. The Y-grade can then be stored for sale or fractionation into its components of propane, butane, and natural gasoline. With the exception of residue gas, these components, along with the condensate initially separated from the inlet gas, are stored in tanks prior to removal from their tanks by tank trucks. Butane, propane, and Y-grade are stored in pressurized storage tanks whereas the condensate and natural gasoline are stored in atmospheric tanks. The pressurized tanks' loading lines have valves at the ends so any vapors are contained within a closed system. The four atmospheric condensate/natural gasoline storage tanks are all piped together for vapor balance and equipped with VOC vapor return lines. Vapor displacement resulting from loadout operations is located at the end of each transfer line, creating a closed system. Therefore, no vapors are allowed to escape during product storage or product transfers.

C. Permit History

In May 1992, Western Gas Resources (WGR) applied for a permit to operate their existing natural gas processing plant and associated equipment and to construct a Challenger Flare that was used for emergency situations to increase safety.

On June 28, 1993, WGR's **MAQP #2736-00** was final. The flare was constructed and placed in operation in October 1993. Also, as a requirement of the MAQP, WGR was required to install Non-Selective Catalytic Reduction (NSCR) units on the two compressor engines for control of nitrogen oxides (NO_X), carbon monoxide (CO), and VOC emissions. The 800-bhp White Superior compressor engine was permitted, as it existed at the time, with two exhaust stacks. In October 1993, the White Superior compressor engine exhaust stacks were retrofitted into one stack; therefore, only one NSCR unit was required for that source. The NSCR units were then installed in November 1993, and the engines were tested in January 1994.

On February 8, 1995, MAQP #2736-01 became final. The permitting action reflected a modification to remove all references to the second stack on the 800-bhp White Superior compressor engine, change the emission limits to reflect mass emission limits in pounds per hour (lb/hr) rather than grams per bhp-hour (g/bhp-hr), and change the de-rated horsepower to the rated horsepower. WGR also requested the permit testing language be changed to reflect the updated Montana Source Test Protocol and Procedures Manual. **MAQP #2736-01** replaced MAQP #2736-00.

On December 10, 1993, a lottery was held and WGR's Baker Gas Plant (MAQP #2736-01) was selected to submit their Title V operating permit application in the first year. WGR requested that the facility be removed from the Title V permit list since MAQP #2736-01 indicated the total criteria pollutants were less than 100 tons per year (tpy).

On August 25, 1996, MAQP #2736-02 became final. Before the Department of Environmental Quality (Department) made a final determination on whether a Title V permit was necessary for this facility, a complete emission inventory of hazardous air pollutants (HAPs) emitted was developed and submitted to the Department for review. A complete emission inventory of fugitive VOC was also required since a number of fugitive VOC sources were not identified during the initial permitting action. WGR submitted a permit alteration for all sources of VOC and HAPs not previously identified in MAQP #2736-01. This permit alteration was for the following VOC emission units:

- Fugitive VOC leaks from components in VOC service;
- 4.0 MMscfd EG dehydration unit;
- Bottom loading, vapor balance, product loading facility; and
- 3 fixed-roof condensate storage tanks.

MAQP #2736-02 replaced MAQP #2736-01.

On June 27, 1997, MAQP #2736-03 became final. The permitting action included: a change of ownership from WGR to BPE; a proposed increase in production from 1.4 MMScfd to 4.2 MMScfd; and a proposal to add an amine sweetening unit and a new Guyed flare to control emissions from the proposed production increase. The proposed amine unit supplemented the previously permitted iron sponge. The alteration also increased sulfur dioxide (SO_2) by 116 tpy, which resulted from the production increase at the facility. Emissions were controlled by an amine sweetening unit and a new flare. The increase in emissions was below New Source Review (NSR) threshold levels and did not trigger Prevention of Significant Deterioration (PSD). However, the BPE facility became a Title V source because of the increase in emissions. **MAQP #2736-03** replaced MAQP #2736-02.

The Department received a request from BPE on September 22, 1997, to modify MAQP #2736-03. BPE was previously required to route the pressurized tanks to a flare. During the 1997 inspection conducted by the Department, it was discovered that the pressurized tanks were not routed to the flare as required by MAQP #2736-03. However, upon further investigation, the Department determined that it does not make sense to have these pressurized tanks routed to the flare because they only vent in emergency situations. Furthermore, the routing could cause venting, that means a direct product loss to the company. Removing the routing language modified MAQP #2736-03. There was no change in the potential emissions because the emissions inventory did not calculate the tank emissions as being controlled by the flare. On November 21, 1997, **MAQP #2736-04** became final and replaced MAQP #2736-03.

On September 23, 1998, the Department received a complete application requesting an alteration to MAQP #2736-04. Bear Paw requested to add a single 1250-bhp Waukesha compressor engine or a series of Waukesha compressor engines equivalent to 1250 bhp.

Because the emissions would be the same if there were one engine or a series of engines, the Department approved this alteration to allow BPE operational flexibility. On November 8, 1998, **MAQP #2736-05** became final and replaced MAQP #2736-04.

On September 4, 2001, the Department received a permit application from Compliance Partners, Inc., on behalf of BPE, requesting an alteration to MAQP #2736-05. The application requested to increase the facility's throughput from 4.2 MMScfd to 8.5 MMScfd. The application was deemed complete upon submittal of additional information on October 12, 2001. The alteration increased SO_2 emissions from 117.1 tpy to 235.3 tpy. The proposed 118.2 tpy emission increase was below NSR threshold levels and did not trigger PSD. The alteration increased the facility's throughput from 4.2 MMScfd to 8.5 MMScfd. In addition, the permit format and permit language were updated. On December 13, 2001, **MAQP #2736-06** became final and replaced MAQP #2736-05.

On May 21, 2002, the Department received a letter from BPE notifying the Department of a de minimis change at the BPE facility. The de minimis change consisted of switching the responsibilities of the two flares at the facility. The Department requested that BPE submit a gas analysis for the facility because the calculations submitted for Department review used an H_2S concentration lower than the concentration in the emission inventory of MAQP #2736-06. On July 14, 2002, BPE submitted a gas analysis for the facility demonstrating that the concentration of H_2S in the gas stream was 600 parts per million (ppm). The permit action did not increase emissions from the facility. In fact, the gas analysis submitted to the Department demonstrated that SO_2 emissions from the facility would decrease.

In addition, BPE requested a condition be added to the permit regulating the amount of natural gas (supplemental fuel) added to the acid gas stream prior to flaring (950 cubic feet per hour (cf/hr) at maximum capacity). The condition would ensure that the impacts from the emissions from the shorter challenger flare would not violate either the National Ambient Air Quality Standards (NAAQS) or the Montana Ambient Air Quality Standards (MAAQS).

The permit action switched the responsibilities of the two flares according to the provisions of Administrative Rules of Montana (ARM) 17.8.705(1)(r). The Guyed utility acid gas flare would now be used to destroy the gas stream created from process upsets (including emergency relief valves) and the challenger flare would now be used to destroy the acid gas stream from the amine regenerator. In addition, the permit action modified the permit according to the provisions of ARM 17.8.705(2) to add a condition requiring 20% of the total gas routed to the flare was natural gas. **MAQP #2736-07** replaced MAQP #2736-06.

On December 8, 2004, the Department received a letter from BPE notifying the Department of a de minimis change at the BPE facility. The de minimis change consisted of adding one depropanizer, two heat exchangers, 60,000 gallons of propane storage, and associated valves, flanges, pumps, etc. The permit action increased emissions from the facility by approximately 5.73 tpy.

The permit changes did not increase natural gas throughput of the facility; however, more gas liquids will be captured in the depropanizer unit requiring the additional propane storage capacity and associated equipment.

The permit changes also triggered New Source Performance Standards (NSPS) 40 Code of Federal Regulations (CFR) 60, Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. Under the provisions of ARM 17.8.745, the permit action added one depropanizer, two heat exchangers, 60,000 gallons of propane storage, and associated valves, flanges, pumps, etc. The permit action also updated the permit to reflect current permit language and rule references used by the Department. **MAQP #2736-08** replaced MAQP #2736-07.

On January 19, 2010, the Department received an administrative amendment request from BPE for MAQP #2736-08. BPE requested the Department to administratively change MAQP #2736-08 to be consistent with BPE's Operating Permit #OP2736-07 renewal application. This permit action updated the permit to reflect administrative changes, current permit language, PTE, and rule references used by the Department. Details for the administrative actions were provided in the permit analysis:

- Removed limitations on revolutions per minute (rpm) for the 448 bhp Waukesha compressor engine and the 800 bhp White Superior compressor engine;
- Updated language under II.A.6 and II.A.7 for product loading, receiving, and storage tanks at the Baker Gas Plant;
- Updated language under II.A.10 for routing stack emissions from the amine regenerator to the Acid Gas Flare;
- Updated emission limitations for the Guyed Utility Flare to account for emissions during planned maintenance shutdowns (300 hours of total plant equipment downtime during planned maintenance activities);
- Removed the Challenger flare from the equipment list. The Challenger flare was out-of-service/abandoned;
- Removed methanol storage tank from the equipment list. This tank had been permanently removed from the facility;
- Added one 0.5 MMBtu/hr glycol line heater to equipment list. The heater was inadvertently left off the previous equipment list;
- Updated process description; and
- Updated site-wide potential to emit (PTE) calculations for the facility;

The permit action also updated the permit to reflect current permit language and rule references used by the Department. **MAQP #2736-09** replaced MAQP #2736-08.

D. Current Permit Action

The Department received notification on June 18, 2012, from Bear Paw Energy, LLC requesting an amendment to MAQP #2736-09 to change their name to ONEOK Rockies Midstream, LLC. All permit references to the facility name with the exception of the permit history have been changed throughout this document. The permit action also updated the permit to reflect current permit language and rule references used by the Department. **MAQP #2736-10** replaces MAQP #2736-09.

E. Additional Information

Additional information, such as applicable rules and regulations, Best Available Control Technology (BACT)/Reasonably Available Control Technology (RACT) determinations, air quality impacts, and environmental assessments, is included in the analysis associated with each change to the permit.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available upon request from the Department. Upon request, the Department will provide references for the location of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1 - General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule includes a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment (including instruments and sensing devices) and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department.

3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq*., Montana Code Annotated (MCA).

   ORM shall comply with the requirements contained in the Montana Source Test Protocol and Procedures Manual, including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation or to continue for a period greater than 4 hours.

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

B. ARM 17.8, Subchapter 2 - Ambient Air Quality, including, but not limited to the following:

1. ARM 17.8.204 Ambient Air Monitoring
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone
6. ARM 17.8.214 Ambient Air Quality Standard for Hydrogen Sulfide
7. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter

8. ARM 17.8.221 Ambient Air Quality Standard for Visibility
9. ARM 17.8.222 Ambient Air Quality Standard for Lead
10. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}
11. ARM 17.8.230 Fluoride in Forage

ORM must comply with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3 - Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes.

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of less than 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, ORM shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.

3. ARM 17.8.309 Particulate Matter, Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this rule.

4. ARM 17.8.310 Particulate Matter, Industrial Process. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this rule.

5. ARM 17.8.316 Incinerators. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any incinerator, particulate matter in excess of 0.10 grains per standard cubic feet of dry flue gas, adjusted to 12% carbon dioxide and calculated as if no auxiliary fuel had been used. Further, no person shall cause or authorize to be discharged into the outdoor atmosphere, from any incinerator, emissions that exhibit an opacity of 10% or greater averaged over 6 consecutive minutes.

6. ARM 17.8.322 Sulfur Oxide Emissions - Sulfur in Fuel. (4) Commencing July 1, 1972, no person shall burn liquid or solid fuels containing sulfur in excess of 1 pound of sulfur per million British thermal unit (Btu) fired. (5) Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions. ORM will consume pipeline quality natural gas in their fuel burning equipment, which will meet this limitation.

7. ARM 17.8.324 Hydrocarbon Emissions - Petroleum Products. (3) No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule.

8. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR 60, Standards of Performance for New Stationary Sources (NSPS). ORM is considered an NSPS affected facility under 40 CFR Part 60 and is subject to the requirements of the following subparts:

   a. 40 CFR 60, Subpart A - General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below:

   b. 40 CFR 60, Subpart XX - Standards of Performance for Bulk Gasoline Terminals. Owners and operators are subject to 40 CFR 60, Subpart XX if the bulk gasoline terminal has loading racks that deliver liquid product into gasoline tank trucks. Under 40 CFR 60, Subpart XX, gasoline is defined as any petroleum distillate or petroleum distillate/alcohol blend having a Reid vapor pressure of 27.6 kilopascals or greater that is used as a fuel for internal combustion engines. The product loaded at the facility is Y-grade fractionated natural gas liquids and does not fit the definition of gasoline; therefore 40 CFR 60, Subpart XX is not applicable to the Baker Gas Plant.

   c. 40 CFR 60, Subpart KKK - Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants. ORM is an NSPS affected source because it meets the definition of a natural gas processing plant as defined in 40 CFR 60, Subpart KKK.

   d. 40 CFR 60, Subpart LLL, Standards of Performance for Onshore Natural Gas Processing: SO_2 Emissions. 40 CFR 60, Subpart LLL is applicable to the Baker Gas Plant amine unit. However, because ORM has demonstrated that the design capacity of the facility is less than 2 long tons/day of hydrogen sulfide in the acid gas (expressed as sulfur), only 40 CFR 60.647(c) is applicable to the facility.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR Part 63, shall comply with the requirements of 40 CFR Part 63, as listed below:

   a. 40 CFR 63, Subpart A - General Provisions apply to all equipment or facilities subject to a NESHAP Subpart as listed below.

   b. 40 CFR 63, Subpart HH National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities. Owners or operators of oil and natural gas production facilities, as defined and applied in 40 CFR Part 63, shall comply with the applicable provisions of 40 CFR 63, Subpart HH. In order for a natural gas production facility to be subject to 40 CFR 63, Subpart HH requirements, certain criteria must be met. First, the facility must be a major or area source of HAPs as determined according to paragraphs (a)(1)(i) through (a)(1)(iii) of 40 CFR 63, Subpart HH. Second, a facility that is determined to be either a major or area source for HAPs must also either process, upgrade, or store hydrocarbon liquids prior to the point of custody transfer, or process, upgrade, or store natural gas prior to the point at which natural gas enters the natural gas transmission and storage source category or is delivered to a final end user. Third, the facility must also contain an affected source as specified in paragraphs (b)(1) through (b)(4) of 40 CFR 63, Subpart HH. Finally, if the first three criteria are met, and the exemptions contained in paragraphs (e)(1) and (e)(2) of 40 CFR 63, Subpart HH do not apply, the facility is subject to the applicable provisions of 40 CFR 63, Subpart HH. Based on information submitted by ORM, the Baker Gas Plant is not a major source of HAPs. For area sources under 40 CFR 63, Subpart HH, the affected sources include each TEG glycol dehydration unit. The Baker Gas Plant operates dehydration units; however, they are EG dehydration units not TEG units. Therefore, ORM does not operate an affected source under the area source provisions of Subpart HH.

c. 40 CFR 63, Subpart HHH National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities. Owners or operators of natural gas transmission or storage facilities, as defined and applied in 40 CFR Part 63, shall comply with the standards and provisions of 40 CFR Part 63, Subpart HHH. In order for a natural gas transmission and storage facility to be subject to 40 CFR 63, Subpart HHH requirements, certain criteria must be met. First the facility must transport or store natural gas prior to the gas entering the pipeline to a local distribution company or to a final end user if there is no local distribution company. In addition, the facility must be a major source of HAPs as determined using the maximum natural gas throughput as calculated in either paragraphs (a)(1) and (a)(2) or paragraphs (a)(2) and (a)(3) of 40 CFR 63, Subpart HHH. Second, a facility must contain an affected source (glycol dehydration unit) as defined in paragraph (b) of 40 CFR 63, Subpart HHH. Finally, if the first two criteria are met, and the exemptions contained in paragraph (f) of 40 CFR 63, Subpart HHH, do not apply, the facility is subject to the applicable provisions of 40 CFR 63, Subpart HHH. Based on the information submitted by ORM, the Baker Gas Plant is not subject to the provisions of 40 CFR 63, Subpart HHH because the facility is not a major source of HAPs.

d. 40 CFR 63, Subpart ZZZZ National Emission Standards for Hazardous Air Pollutants for Reciprocating Internal Combustion Engines (RICE). Pursuant to 40 CFR 63.6590(a), an affected source is any existing, new, or reconstructed stationary RICE located at a major or area source of HAP emissions, excluding stationary RICE being tested at a stationary RICE test cell/stand. Pursuant to 40 CFR 63.6590(a)(2)(iii), a stationary RICE located at an area source of HAP emissions is new if construction commenced on the stationary RICE on or after June 12, 2006.

As an area source, the three RICE engines will be subject to this rule. However, since the 3 natural gas RICE engines were constructed prior to June 12, 2006, the engines are considered ***existing*** stationary RICE and do not have requirements under this Maximum Achievable Control Technology (MACT), as specified by 40 CFR 63.6590(b)(3). Based on information submitted by ORM, the Baker Gas Plant is not subject to the provisions of 40 CFR 63, Subpart ZZZZ because the facility does not have any engines that are new or reconstructed after June 12, 2006 and is not a major source of HAPs. However, this subpart could apply to future engines.

D. ARM 17.8, Subchapter 5 - Air Quality Permit Application, Operation, and Open Burning Fees, including, but not limited to:

1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper

application fee is paid to the Department. A permit fee is not required for the current permit action because the permit action is considered an administrative change.

2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit (excluding an open burning permit) issued by the Department. This air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   An air quality operation fee is separate and distinct from an air quality permit application fee. The annual assessment and collection of the air quality operation fee, as described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions that pro-rate the required fee amount.

E. ARM 17.8, Subchapter 7 - Permit, Construction, and Operation of Air Contaminant Sources, including, but not limited to:

1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit modification to construct, modify, or use any air contaminant sources that have the potential to emit (PTE) greater than 25 tons per year of any pollutant. ORM has a PTE greater than 25 tons per year (TPY) of NO_X, CO, sulfur oxides (SO_X), and VOC; therefore, an air quality permit is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.

4. ARM 17.8.745 Montana Air Quality Permits--Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, modification, or use of a source. ORM was not required to submit an application for the current permit action because the permit action is considered an administrative permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. ORM was not required to notify the public of the current permit action because the current action is considered an administrative action.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and

the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. A BACT analysis was not required because the current permitting action is an administrative permit action.

8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving ORM of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq*.

10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.

11. ARM 17.8.760 Additional Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making decisions on those applications that require an environmental impact statement.

12. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or modified source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

13. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

14. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.

15. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

16. ARM 17.8.770 Additional Requirements for Incinerators. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215 MCA.

F. ARM 17.8, Subchapter 8 - Prevention of Significant Deterioration, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.

2. ARM 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow. This facility is not a major stationary source because it is not listed and the facility's PTE is below 250 tons per year of any pollutant (excluding fugitive emissions).

G. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any source having:

a. PTE greater than 100 tons/ year of any pollutant;

b. PTE greater than 10 tons/year of any one HAP, or PTE greater than 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

c. PTE greater than 70 tons/year of particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing MAQP #2736-10 for ORM, the following conclusions were made:

a. The facility's PTE is greater than 100 tons/year for VOC and SO_X;

b. The facility's PTE is less than 10 tons/year of any one HAP and less than 25 tons/year of all HAPs;

c. This source is not located in a serious PM_{10} nonattainment area;

d. The facility is subject to a current NSPS standard: 40 CFR 60, Subpart A and Subpart KKK, and potentially subject to 40 CFR 60, Subpart LLL;

e. This facility is not subject to any current NESHAP standards;

f. The source is not a Title IV affected source, or a solid waste combustion unit; and

g. The source is not an EPA designated Title V source.

Based on these facts, the Department determined that ORM's Baker Gas Plant is subject to the Title V Operating Permit Program.

III. BACT Determination

A BACT determination is required for any new or modified source. ORM shall install on the new or modified source the maximum air pollution control capability that is technologically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was not required for the current permit action because the current permit action is considered an administrative permit action.

IV. Emission Inventory

Tons/Year						
	PM	**$PM_{10}/PM_{2.5}$ (1)**	**NO_x**	**VOC**	**CO**	**SO_x**
448 bhp Waukesha F-3521G compressor engine	0.28	0.28	8.67	4.38	12.96	0.008
800 bhp White Superior 8G-825 compressor engine	0.53	0.53	15.46	7.71	23.17	0.016
1250 bhp Waukesha L-7042 GSI compressor engine	0.81	0.81	24.13	12.09	24.13	0.024
Two (2) Y-Grade horizontal storage tanks	---	---	---	---	---	---
Three (3) Propane horizontal storage tanks	---	---	---	---	---	---
Two (2) Butane horizontal storage tanks	---	---	---	---	---	---
Four (4) 400 barrel (bbl) Condensate/Natural Gasoline storage tanks	---	---	---	25.76	---	---
Y-Grade product loading	---	---	---	2.53	---	---
Propane product loading	---	---	---	0.73	---	---
Butane Product loading	---	---	---	0.16	---	---
Natural Gasoline product loading	---	---	---	8.74	---	---
8.5 MMScfd Ethylene Glycol Dehydration Unit with Still Vent and Flash Tank (2)	---	---	---	12.93		
6.5 MMBtu/hr Anderson Hot Oil Heater	0.21	0.21	2.71	0.15	2.28	0.016
2.0 MMBtu/hr Amine Reboiler	0.06	0.06	0.42	0.05	0.70	0.005
6.5 MMScfd Amine Regenerator (*emissions reported at Acid Gas Flare*)	---	---	---	---	---	---
0.5 MMBtu/hr Glycol Line Heater	0.02	0.02	0.07	0.01	0.18	0.001
Acid Gas Flare (combustion of gas from the Amine Regenerator)	0.74	0.74	0.72	2.27	3.94	177.56
Acid Gas Flare - Pilot	0.00	0.00	0.02	0.04	0.08	0.000
Guyed Utility Flare (combustion of vent gases during emergency upset conditions or process venting)	0.64	0.64	2.73	10.68	14.85	6.60
Guyed Utility Flare - Pilot	0.00	0.00	0.15	0.04	0.08	0.000
Fugitive Emissions subject to NSPS Subpart KKK LDAR monitoring (i.e. seals, valves, pumps, connections, and open-ended lines associated with process equipment)	---	---	---	15.73	---	---
TOTAL	3.29	3.29	55.08	104.00	82.37	184.23

(1) All PM emissions from sources of natural gas combustion are assumed to be in the $PM_{2.5}$ size fraction in accordance with AP-42 Table 3.2-3 and Table 1.4-2
(2) Emission inventory summary is based on the greater of two calculations below, using either the 5 MMScfd or 8.5 MMScfd throughput (BPE used 5 MMScfd because this is where the dehydration unit normally operates and it is the more conservative of the two)

448 bhp Waukesha F-3521G compressor engine (AFR controller, NSCR unit)
Brake Horsepower: 448 bhp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7250 Btu/bhp-hr (provided by BPE)
Calculations: 7250 Btu/bhp-hr * 1.94E-02 lb/MMBtu * 448 bhp * 8760 hr/yr * 0.0005 ton/lb = 0.28 ton/yr

NO_X Emissions:
Emission factor: 1.98 lb/hr (BACT Determination/Permit Limit)
Calculations: 1.98 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 8.67 ton/yr

VOC Emissions:
Emission factor: 1.00 lb/hr (BACT Determination/Permit Limit)
Calculations: 1.00 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 4.38 ton/yr

CO Emissions:
Emission factor: 2.96 lb/hr (BACT Determination/Permit Limit)
Calculations: 2.96 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 12.96 ton/yr

SO_X Emissions:
Emission factor: 5.88E-04 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7250 Btu/bhp-hr (provided by BPE)
Calculations: 7250 Btu/bhp-hr * 5.88E-04 lb/MMBtu * 448 bhp * 8760 hr/yr * 0.0005 ton/lb = 0.008 ton/yr

800-hp White Superior 8G-825 compressor engine (AFR controller, NSCR unit)
Brake Horsepower: 800 bhp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7750 Btu/bhp-hr (Maximum Design, BPE)
Calculations: 7750 Btu/bhp-hr * 1.94E-02 lb/MMBtu * 800 bhp * 8760 hr/yr * 0.0005 ton/lb = 0.53 ton/yr

NO_X Emissions:
Emission factor: 3.53 lb/hr (BACT Determination/Permit Limit)
Calculations: 3.53 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 15.46 ton/yr

VOC Emissions:
Emission factor: 1.76 lb/hr (BACT Determination/Permit Limit)
Calculations: 1.76 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 7.71 ton/yr

CO Emissions:
Emission factor: 5.29 lb/hr (BACT Determination/Permit Limit)
Calculations: 5.29 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 23.17 ton/yr

SO_X Emissions:
Emission factor: 5.88E-04 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7750 Btu/bhp-hr (Maximum Design, BPE)
Calculations: 7750 Btu/bhp-hr * 5.88E-04 lb/MMBtu * 800 bhp * 8760 hr/yr * 0.0005 ton/lb = 0.016 ton/yr

1250 bhp Waukesha L-7042 GSI compressor engine (AFR controller, NSCR unit, Johnson Mathey Catalytic Converter)
Brake Horsepower: 1250 hp
Hours of operation: 8760 hr/yr

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 1.94E-02 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7581 Btu/bhp-hr (provided by BPE)
Calculations: 7581 Btu/bhp-hr * 1.94E-02 lb/MMBtu * 1250 bhp * 8760 hr/yr * 0.0005 ton/lb = 0.81 ton/yr

NO_X Emissions:
Emission factor: 5.51 lb/hr (BACT Determination/Permit Limit)
Calculations: 5.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 24.13 ton/yr

VOC Emissions:
Emission factor: 2.76 lb/hr (BACT Determination/Permit Limit)
Calculations: 2.76 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 12.09 ton/yr

CO Emissions:
Emission factor: 5.51 lb/hr (BACT Determination/Permit Limit)
Calculations: 5.51 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 24.13 ton/yr

SO_X Emissions:
Emission factor: 5.88E-04 lb/MMBtu (AP-42, Table 3.2-3, 7/00)
Fuel Consumption: 7581 Btu/bhp-hr (provided by BPE)
Calculations: 7581 Btu/bhp-hr * 5.88E-04 lb/MMBtu * 1250 bhp * 8760 hr/yr * 0.0005 ton/lb = 0.024 ton/yr

Four (4) 400 barrel (bbl) Condensate/Natural Gasoline storage tanks
Hours of operation: 8760 hr/yr
Note: Working and breathing calculated using EPA TANKS 4.0.9d (provided by BPE, on file with the Department)
Flashing factor based on PROMAX run for Baker inlet condensate (provided by BPE, on file with the Department)

TK-7 Inlet Condensate tank
VOC Emissions

Working Loss:
Emission Factor: 1612.90 lb/yr (EPA Tanks, Version 4.0.9d)
Calculations: 1612.90 lb/yr * 0.0005 ton/lb = 0.81 ton/yr

Breathing Loss:
Emission Factor: 3001.49 lb/yr (EPA Tanks, Version 4.0.9d)
Calculations: 3001.49 lb/yr * 0.0005 ton/lb = 1.50 ton/yr

Flashing Loss:
Emission Factor: 11556.60 lb/yr (EPA Tanks, Version 4.0.9d)
Calculations: 11556.60 lb/yr * 0.0005 ton/lb = 5.78 ton/yr

Subtotal: TK-7 VOC Emissions = 0.81 ton/yr + 1.50 ton/yr + 5.78 ton/yr = 8.09 ton/yr

TK-8, TK-9, TK-10 Natural Gasoline tanks
VOC Emissions

Working Loss:
Emission Factor: 8781.32 lb/yr (EPA Tanks, Version 4.0.9d)
Calculations: 8781.32 lb/yr * 0.0005 ton/lb = 4.39 ton/yr

Breathing Loss:
Emission Factor: 3001.49 lb/yr (EPA Tanks, Version 4.0.9d)
Calculations: 3001.49 lb/yr * 0.0005 ton/lb = 1.50 ton/yr

Flashing Loss:
Emission Factor: 0 lb/yr (EPA Tanks, Version 4.0.9d)
Calculations: 0 lb/yr * 0.0005 ton/lb = 0.00 ton/yr

Subtotal: TK-8, TK-9, TK-10 VOC Emissions = (4.39 ton/yr + 1.50 ton/yr + 0.00 ton/yr) * 3 = 17.67 ton/yr

Total: TK-7, TK-8, TK-9, TK-10 VOC Emissions = 8.09 ton/yr + 17.67 ton/yr = 25.76

Product Loading
Loading Information

Unit ID	TL-1	TL-2	TL-3	TL-4**
Product Loaded	Y-Grade	Propane	Butane	Condensate/Natural Gas Liquid
Fill Method	Submerged	Submerged	Submerged	Submerged
Type of Service	Dedicated	Dedicated	Dedicated	Dedicated
Mode of Operation	Vapor Balance	Vapor Balance	Vapor Balance	Vapor Balance

Saturation Factor	1	1	1	1
Emission Factor (lb/1000 gal)*	253.25	97.18	32.73	11.66
Throughput (1000 gal)	20	15	10	5
Control Type	Closed System	Closed System	Closed System	Vapor Balance
Control Efficiency (%)	99.90	99.90	99.90	70.00

Note: * AP-42, Page 5.2-4, Equation 1 (6/08) for Petroleum Liquid Loading Losses
** Collection efficiency = 70.00% (AP-42, Page 5.2-6 for trucks not passing a MACT-level or NSPS-level annual leak test)

Y-Grade Loading Loss (lb/1000 gal) = 12.46 *(S*P*M/T), where:
1 = S, Saturation Factor
195.2 = P, True vapor pressure of liquid loaded (average psia)
53 = M, Molecular weight of vapor (lb/lb-mol)
49 = T, temperature of bulk liquid loaded (average ^{0}F + 460 = ^{0}R)

Propane Loading Loss (lb/1000 gal) = 12.46 *S*P*M/T, where:
1 = S, Saturation Factor
90 = P, True vapor pressure of liquid loaded (average psia)
44.11 = M, Molecular weight of vapor (lb/lb-mol)
49 = T, temperature of bulk liquid loaded (average ^{0}F + 460 = ^{0}R)

Butane Loading Loss (lb/1000 gal) = 12.46 *S*P*M/T, where:
1 = S, Saturation Factor
23 = P, True vapor pressure of liquid loaded (average psia)
58.13 = M, Molecular weight of vapor (lb/lb-mol)
49 = T, temperature of bulk liquid loaded (average ^{0}F + 460 = ^{0}R)

Condensate/Natural Gas Liquids Loading Loss (lb/1000 gal) = 12.46 *S*P*M/T, where:
1 = S, Saturation Factor
8.846 = P, True vapor pressure of liquid loaded (average psia)
53.6266 = M, Molecular weight of vapor (lb/lb-mol)
47.05 = T, temperature of bulk liquid loaded (average ^{0}F + 460 = ^{0}R)

Loading VOC Emissions

Unit ID	TL-1		TL-2		TL-3		TL-4	
	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr	lb/yr	ton/yr
	5065.08	2.53	1457.71	0.73	327.29	0.16	17485.81	8.74

Example: L_L = (1-control efficiency) *12.46(SPM/T)

Inputs (BPE): S = 1 (BPE)
P = 8.846 (BPE)
M = 53.6266 (BPE
T = 47.05 degrees Fahrenheit = 507.05 degrees Rankin (BPE)
Throughput (gal) = 5000

L_L = (1-0.70)*12.46 (1*8.846*53.6266/507.05)*5000 = 17485.81 lb/yr
= 17485.81 lb/yr * 0.0005 ton/lb = 8.74 ton/yr

8.5 MMScfd Ethylene Glycol Dehydration Unit with Still Vent and Flash Tank

The following emission summary has been estimated using the GRI-GLYCalc program (detailed input parameters are on file with the Department).

Note: Off-gases from the regenerator still column are routed to the Anderson Hot Oil Heater for thermal destruction. The still vent has a control valve that can be opened to atmosphere when the Anderson Hot Oil Heater is down. Off-gases from the flash tank are hard-piped to the inlet condensate separator.

Still vent emissions are routed to the Anderson Hot Oil Heater to be burned at 95% combustion efficiency. BPE conservatively assumed combustion efficiency at 50% because it is possible for still vent emissions to be vented to atmosphere if the heater is down for maintenance or repair.

Dehydration Unit with Still Vent and Flash Tank

Glycol Type:	Ethylene Glycol (EG)
Hours of Operation:	8760 hrs/yr
Dry Gas Flow Rate:	8.5 MMScfd (maximum throughput - BPE)
Control Device:	6.5 MMBtu/hr Anderson Hot Oil Heater
Control Efficiency:	50% (still vent); 100% (flash tank)

8.5 MMScfd dehydration unit

Controlled Regenerator Emissions	lb/hr	ton/yr
Total VOC Emissions	0.8137	3.5642
Total HAP Emissions	0.0071	0.0312

Uncontrolled Regenerator Emissions	lb/hr	ton/yr
Total VOC Emissions	1.6275	7.1284
Total HAP Emissions	0.0142	0.0623

Flash Tank Off-Gases

Closed System – Off-gases are hard-piped to the inlet condensate knock out drum.

Controlled Flash Separator Off-gases	lb/hr	ton/yr
Total VOC Emissions	0	0
Total HAP Emissions	0	0

Uncontrolled Flash Separator Off-gases	lb/hr	ton/yr
Total VOC Emissions	0.1190	0.5210
Total HAP Emissions	0.0001	0.0004

OR:

5.0 MMScfd dehydration unit

Controlled Regenerator Emissions	lb/hr	ton/yr
Total VOC Emissions	2.9524	12.9313
Total HAP Emissions	0.7275	3.1863

Uncontrolled Regenerator Emissions	lb/hr	ton/yr
Total VOC Emissions	5.9047	25.8627
Total HAP Emissions	1.4549	6.3726

Flash Tank Off-Gases

Closed System – Off-gases are hard-piped to the inlet condensate knock out drum.

Controlled Flash Separator Off-gases	lb/hr	ton/yr
Total VOC Emissions	0	0
Total HAP Emissions	0	0

Uncontrolled Flash Separator Off-gases	lb/hr	ton/yr
Total VOC Emissions	0.3807	1.6674
Total HAP Emissions	0.0069	0.0302

6.5 MMBtu/hr Anderson Hot Oil Heater (uncontrolled)

Hours of Operation: 8760 hrs/yr

Fuel Heating Value: 1050 Btu/scf (provided by BPE)

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)

Emission Factor: 7.6 lb/MMScf (AP-42, Table 1.4-2, 7/98)

Fuel Consumption: 6.5 MMBtu/hr (Maximum Design, BPE)

Calculations: 6.5 MMBtu/hr * 7.6 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.21 ton/yr

NO_X Emissions:

Emission Factor: 100 lb/MMScf (AP-42, Table 1.4-1, 7/98)

Fuel Consumption: 6.5 MMBtu/hr (Maximum Design, BPE)

Calculations: 6.5 MMBtu/hr * 100 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 2.71 ton/yr

VOC Emissions:

Emission Factor: 5.5 lb/MMScf (AP-42, Table 1.4-2, 7/98)

Fuel Consumption: 6.5 MMBtu/hr (Maximum Design, BPE)

Calculations: 6.5 MMBtu/hr * 5.5 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.15 ton/yr

CO Emissions:

Emission Factor: 84 lb/MMScf (AP-42, Table 1.4-1, 7/98)

Fuel Consumption: 6.5 MMBtu/hr (Maximum Design, BPE)

Calculations: 6.5 MMBtu/hr * 84 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 2.28 ton/yr

SO_X Emissions:
Emission Factor: 0.6 lb/MMScf (AP-42, Table 1.4-1, Table 1.4-2, 7/98)
Fuel Consumption: 6.5 MMBtu/hr (Maximum Design, BPE)
Calculations: 6.5 MMBtu/hr * 0.6 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.016 ton/yr

2.0 MMBtu/hr Amine Reboiler (controlled, low NOx)
Hours of Operation: 8760 hrs/yr
Fuel Heating Value: 1050 Btu/scf (provided by BPE)

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 7.6 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Fuel Consumption: 2.0 MMBtu/hr (Maximum Design, BPE)
Calculations: 2.0 MMBtu/hr * 7.6 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.06 ton/yr

NO_X Emissions:
Emission Factor: 50 lb/MMScf (AP-42, Table 1.4-1, 7/98)
Fuel Consumption: 2.0 MMBtu/hr (Maximum Design, BPE)
Calculations: 2.0 MMBtu/hr * 50 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.42 ton/yr

VOC Emissions:
Emission Factor: 5.5 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Fuel Consumption: 2.0 MMBtu/hr (Maximum Design, BPE)
Calculations: 2.0 MMBtu/hr * 5.5 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.05 ton/yr

CO Emissions:
Emission Factor: 84 lb/MMScf (AP-42, Table 1.4-1, 7/98)
Fuel Consumption: 2.0 MMBtu/hr (Maximum Design, BPE)
Calculations: 2.0 MMBtu/hr * 84 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.70 ton/yr

SO_X Emissions:
Emission Factor: 0.6 lb/MMScf (AP-42, Table 1.4-1, Table 1.4-2, 7/98)
Fuel Consumption: 2.0 MMBtu/hr (Maximum Design, BPE)
Calculations: 2.0 MMBtu/hr * 0.6 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.005 ton/yr

0.5 MMBtu/hr Glycol Line Heater (Controlled - Low NOx burners/Flue gas recirculation)
Hours of Operation: 8760 hrs/yr
Fuel Heating Value: 1050 Btu/scf (provided by BPE)

$PM_{10}/PM_{2.5}$ Emissions (filterable & condensable)
Emission Factor: 7.6 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Fuel Consumption: 0.5 MMBtu/hr (Maximum Design, BPE)
Calculations: 0.5 MMBtu/hr * 7.6 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.02 ton/yr

NO_X Emissions:
Emission Factor: 32 lb/MMScf (AP-42, Table 1.4-1, 7/98)
Fuel Consumption: 0.5 MMBtu/hr (Maximum Design, BPE)
Calculations: 0.5 MMBtu/hr * 32 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.07 ton/yr

VOC Emissions:
Emission Factor: 5.5 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Fuel Consumption: 0.5 MMBtu/hr (Maximum Design, BPE)
Calculations: 0.5 MMBtu/hr * 5.5 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.01 ton/yr

CO Emissions:
Emission Factor: 84 lb/MMScf (AP-42, Table 1.4-1, 7/98)
Fuel Consumption: 0.5 MMBtu/hr (Maximum Design, BPE)
Calculations: 0.5 MMBtu/hr * 84 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.18 ton/yr

SO_X Emissions:
Emission Factor: 0.6 lb/MMScf (AP-42, Table 1.4-1, Table 1.4-2, 7/98)
Fuel Consumption: 0.5 MMBtu/hr (Maximum Design, BPE)
Calculations: 0.5 MMBtu/hr * 0.6 lb/MMScf * 1MMScf/1050 MMBtu * 8760 hrs/yr * 0.0005 ton/lb = 0.001 ton/yr

Fugitive VOC Emissions

Source Type/Service	Number of Sources	Emission Factor (lb/hr/source) *	Control Efficiency (%)	TOC (lb/hr)	TOC (TPY)	VOC Wt % **
Connectors – Gas	5	4.41E-04	0.00	0.0022	0.0097	19.77
Flanges	125	8.60E-04	0.00	0.1075	0.4707	19.77
Open-Ended Lines – Gas	10	4.41E-03	0.00	0.0441	0.1931	19.77
Valves – Gas	120	9.92E-03	0.00	1.1904	5.2143	19.77
Total TOC (Inlet Gas Components Only) =				1.3442	5.8878	---
Connectors – Light Oil	24	4.63E-04	0.00	0.0111	0.0487	100.00
Flanges – Light Oil	318	2.43E-04	0.00	0.0771	0.3378	100.00
Open-Ended Lines – Light Oil	24	3.09E-03	0.00	0.0741	0.3244	100.00
Pump Seals – Light Oil	5	2.87E-02	0.00	0.1433	0.6276	100.00
Valves – Light Oil	422	5.51E-03	0.00	2.3258	10.1872	100.00
Total TOC (Light Oil Components Only) =				2.6314	11.5257	---
Connectors – Gas	5	4.41E-04	0.00	0.0022	0.0097	19.77
Flanges – Gas	776	8.60E-04	0.00	0.6672	2.9223	19.77
Open-Ended Lines – Gas	34	4.41E-03	0.00	0.1499	0.6566	19.77
Other – Gas	4	1.94E-02	0.00	0.776	0.3399	19.77
Valves – Gas	162	9.92E-03	0.00	1.6071	7.0393	19.77
Total TOC (Produced Gas Components Only) =				2.5041	10.9678	---
Pump Seals – Light Oil	7	2.87E-02	0.00	0.2006	0.8787	100.00
Total TOC (Produced Oil Components Only) =				0.2006	0.8787	---

* *Total organic compound (TOC) emission rates multiplied by VOC content of the gas stream (weight percent) to obtain VOC emissions. Source: Protocol for Equipment Leak Emissions Estimates, EPA Document 453/R-95-017, Table 2-4 (11/95).*

** *VOC Wt % from inlet gas stream analysis. Liquid streams assumed to be 100% VOC.*

VOC Emissions

Inlet Gas Components Only:

((5*4.41E-04 lb/hr) + (125*8.60E-04 lb/hr) + (10*4.41E-03 lb/hr) + (120*9.92E-03 lb/hr)) * 0.1977 = 0.27 lb/hr

Subtotal = 0.27 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.16 ton/yr

Light Oil Components Only:

((24*4.63E-04 lb/hr) + (318*2.43E-04 lb/hr) + (24*3.09E-03 lb/hr) + (5*2.87E-02 lb/hr) + (422*5.51E-03)) * 1.00 = 2.63 lb/hr

Subtotal = 2.63 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 11.52 ton/yr

Produced Gas Components Only:

((5*4.41E-04 lb/hr) + (776*8.60E-04 lb/hr) + (34*4.41E-03 lb/hr) + (4*1.94E-02) + (162*9.92E-03 lb/hr)) * 0.1977 = 0.49 lb/hr

Subtotal = 0.49 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 2.17 ton/yr

Produced Oil Components Only: (7*2.87E-02 lb/hr) * 1.00 = 0.20 lb/hr

Subtotal = 0.20 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.88 ton/yr

TOTAL Fugitive VOC Emissions = 1.16 ton/yr + 11.52 ton/yr + 2.17 ton/yr + 0.88 ton/yr = 15.73 ton/yr

Acid Gas Flare (acid and residual gas flaring)

Fuel Type: 3.1% H_2S in the fuel (BPE; concentrated amount in the acid gas vs. inlet H_2S content used in previous permit)
Acid Gas Heat Content: 18 Btu/scf (based on 588 Btu/scf for H_2S; BPE)
Acid Gas Throughput: 69,000 Mscf/yr (80% of total gas flared)

Residual Gas Heat Content: 1160 Btu/scf (July 2009 residue gas analysis; BPE)
Residual Gas Throughput: 17,250 Mscf/yr (20% of total gas flared)

Hours of Operation: 8460 hrs/yr (8760 hrs/yr minus 300 hrs/yr for inlet and plant downtime)
Total Gas Throughput: 86,250 Mscf/yr (calc: 69,000 Mscf/yr + 17,250 Mscf/yr; 8460 hrs/yr; BPE)
Combined Heat Value of Flared Stream: 247 Btu/scf (calc: 18 Btu/scf * 0.8 + 1160 Btu/scf * 0.20)

Total H_2S volume fed to flare: 2139 Mscf/yr (calculated as maximum acid gas throughput * %H_2S)
Note: all H_2S is assumed to oxidize to SO_2
Conversion: use 385.46 scf/lb-mole; based on standard conditions of 68 deg F and 14.7 psia (BPE)

$PM_{10}/PM_{2.5}$ Emissions (soot in concentration values, heavily smoking flares)
Emission Factor: 274 µg/L in exhaust gas (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Total Gas Throughput: 86,250 Mscf/yr (provided by BPE)
Calculations:
86,250 Mscf/yr * 1000 scf/1.0 Mscf * 28.31685 L/scf * 274 µg/L * 1g/10^6µg * 1 lb/453.6 g * 0.0005 ton/lb = 0.74 ton/yr

NO_X Emissions:
Emission factor: 0.068 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 247 Btu/scf * 86,250 Mscf/yr * 0.068 lb/MMBtu * 0.0005 ton/lb = 0.72 ton/yr

VOC Emissions:
Emission factor: 2.0% of VOC fed to flare (Flare VOC Destruction Efficiency = 98%)
Total VOC mass fed to flare: 226,898 lb/yr (sum of VOC in acid gas plus VOC in residual gas; BPE)
Total H_2S volume fed to flare: 2139 Mscf/yr (calculated as maximum acid gas throughput * %H_2S)
Note: all H_2S is assumed to oxidize to SO_2
Calculations: 226,898 lb/yr total gas * 0.02 * 0.0005 ton/lb = 2.27 ton/yr

CO Emissions:
Emission factor: 0.37 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 247 Btu/scf * 86,250 Mscf/yr * 0.37 lb/MMBtu * 0.0005 ton/lb = 3.94 ton/yr

SO_X Emissions:
Emission factor: 1.88 lb SO_2/ lb H_2S (ratio of molecular weights of SO_2/H_2S = 64/34)
Calculations:
2139 Mscf/yr*1000 scf/Mscf *1 lb-mole/385.46 scf*34 lb H_2S/mole*1.88 lb SO_2/lb H_2S*0.0005 ton/lb = 177.56 ton/yr

Acid Gas Flare (Pilot)

Fuel Type:	Residual Gas
Pilot Fuel Volume Throughput:	385.44 Mscf/yr (design rating 44 scf/hr * 1 Mscf/1000 scf * 8760 hrs/yr; BPE)
Pilot Fuel Heat Throughput:	447,110,400 Btu/yr (385.44 Mscf * 1160 Btu/scf)
Hours of Operation:	8760 hrs/yr
VOC, Mol% of Pilot Gas:	9.39% by volume (based on Jul 2009 residue gas analysis; BPE)
Composite Molecular Wt of VOCs in Residual Gas:	46.59 lb/lb-mole (based on Jul 209 residue gas analysis; BPE)
Mass VOC in Pilot Gas fed to Flare:	4,379.66 lb/yr (BPE)
Pilot Gas Heating Value:	1160 Btu/scf (July 2009 residue gas analysis; BPE)
Flare Destruction Efficiency:	98%

$PM_{10}/PM_{2.5}$ Emissions (non-smoking flares)
Emission Factor: 0 µg/L in pilot gas (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 385.44 Mscf/yr * 1000 scf/1.0 Mscf * 28.31685 L/scf * 0 µg/L * 1g/10^6µg * 1 lb/453.6 g * 0.0005 ton/lb = 0.00 ton/yr

NO_X Emissions:
Emission factor: 0.068 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 447,110,400 Btu/yr * 0.068 lb/MMBtu * 0.0005 ton/lb = 0.015 ton/yr

VOC Emissions:
Emission Factor: 5.5 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Calculations: 4379.66 lb/yr * 0.02 * 0.0005 ton/yr = 0.044 ton/yr

CO Emissions:
Emission factor: 0.37 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 447,110,400 Btu/yr * 0.37 lb/MMBtu * 0.0005 ton/lb = 0.083 ton/yr

SO_X Emissions:
Emission Factor: 0.6 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Calculations: 385.44 Mscf/yr * 0.6 lb/MMScf * 0.0005 ton/lb = 0.0001 ton/yr

Guyed Utility Flare (acid and residual gas flaring due to plant equipment downtime)
Fuel Type: flaring of inlet gas, ethane overheads, and plant gas when plant equipment is down
Volume of Flared Gas: 75,000 Mscf/yr (BPE)
= 2,123,763,750 L/yr (Mscf/yr * 1000 scf/Mscf * 28.31685 L/scf)
Heat Value to Flare: 80,250 MMBtu/yr
Mass VOC to Flare: 1,067,984 lb/yr (Mscf/yr * 1000 scf/Mscf * VOC% by volume * 1 mole/385.46 scf * VOC lb/mole)
Hours of Operation: 300 hrs/yr (total plant downtime)
Flared Gas Composite Properties:

VOC ($C3^+$) content:	10% by volume (Jul 2009 inlet gas analysis)
Molecular Weight Composite $C3^{+:}$	53 lb/lb-mole (Jul 2009 inlet gas analysis)
Heat Value:	1070 Btu/scf (Jul 2009 inlet gas analysis)
Flare VOC Destruction Efficiency:	98%

$PM_{10}/PM_{2.5}$ Emissions (soot in concentration values, heavily smoking flares)
Emission Factor: 274 µg/L in exhaust gas (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 75,000 Mscf/yr * 1000 scf/1.0 Mscf * 28.31685 L/scf * 274 µg/L * 1g/10^6µg * 1 lb/453.6 g * 0.0005 ton/lb = 0.64 ton/yr

NO_X Emissions:
Emission factor: 0.068 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 80,250 MMBtu/yr * 0.068 lb/MMBtu * 0.0005 ton/lb = 2.73 ton/yr

VOC Emissions:
Emission factor: 2.0% of VOC fed to flare (Flare VOC Destruction Efficiency = 98%)
Mass VOC fed to flare: 1,067,984 lb/yr
Calculations: 1,067,984 lb/yr * 0.02 * 0.0005 ton/lb = 10.68 ton/yr

CO Emissions:
Emission factor: 0.37 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 80,250 MMBtu/yr * 0.37 lb/MMBtu * 0.0005 ton/lb = 14.85 ton/yr

SO_X Emissions:
Emission Factor: 0.6 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Calculations: 75,000 Mscf/yr * 300 hrs/8760 hrs * 0.031(H_2S) * 1000 scf/Mscf * 1 lb-mole/385.46 scf * 34 lb H_2S/mole * 1.88 lb SO_2/lb H_2S * 0.0005 ton/lb = 6.60 ton/yr

Guyed Utility Flare (Pilot)

Fuel Type:	Residual Gas
Pilot Fuel Volume Throughput:	385.44 Mscf/yr (design rating 44 scf/hr * 1 Mscf/1000 scf * 8760 hrs/yr; BPE)
Pilot Fuel Heat Throughput:	447,110,400 Btu/yr (385.44 Mscf * 1160 Btu/scf)
Hours of Operation:	8760 hrs/yr
VOC, Mol% of Pilot Gas:	9.39% by volume (based on Jul 2009 residue gas analysis; BPE)
Composite Molecular Wt of VOCs in Residual Gas:	46.59 lb/lb-mole (based on Jul 209 residue gas analysis; BPE)
Mass VOC in Pilot Gas fed to Flare:	4,379.66 lb/yr (BPE)
Pilot Gas Heating Value:	1160 Btu/scf (July 2009 residue gas analysis; BPE)
Flare Destruction Efficiency:	98%

$PM_{10}/PM_{2.5}$ Emissions (non-smoking flares)
Emission Factor: 0 µg/L in pilot gas (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 385.44 Mscf/yr * 1000 scf/1.0 Mscf * 28.31685 L/scf * 0 µg/L * 1g/10^6µg * 1 lb/453.6 g * 0.0005 ton/lb = 0.00 ton/yr

NO_X Emissions:
Emission factor: 0.068 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 447,110,400 Btu/yr * 0.068 lb/MMBtu * 0.0005 ton/lb = 0.015 ton/yr

VOC Emissions:
Emission Factor: 5.5 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Calculations: 4379.66 lb/yr * 0.02 * 0.0005 ton/yr = 0.044 ton/yr

CO Emissions:
Emission factor: 0.37 lb/MMBtu (AP-42, Table 13.5-1, 9/91 – reformatted 1/95)
Calculations: 447,110,400 Btu/yr * 0.37 lb/MMBtu * 0.0005 ton/lb = 0.083 ton/yr

SO_X Emissions:
Emission Factor: 0.6 lb/MMScf (AP-42, Table 1.4-2, 7/98)
Calculations: 385.44 Mscf/yr * 0.6 lb/MMScf * 0.0005 ton/lb = 0.0001 ton/yr

V. Existing Air Quality

The facility is located in the SW ¼ of the SW ¼ of Section 6, Township 7 North, Range 60 East in Fallon County, Montana. The air quality of this area is classified as either better than National Standards or unclassifiable/attainment for the National Ambient Air Quality Standards (NAAQS) for criteria pollutants.

VI. Air Quality Impacts

The Department determined that there are no impacts from this administrative name change. The Department believes it will not cause or contribute to a violation of any ambient air quality standard.

VII. Ambient Air Impact Analysis Air Quality Impacts

Based on the updates associated with the administrative actions incorporated into this permit and the allowable emissions added to the facility under the current permit action, the Department believes that the amount of controlled emissions generated by this project will not cause or contribute to a violation of any set ambient air quality standard.

VIII. Taking or Damaging Implication Analysis

As required by 2-10-101 through 2-10-105, MCA, the Department conducted the following private property taking and damaging assessment.

YES	NO	
X		1. Does the action pertain to land or water management or environmental regulation affecting private real property or water rights?
	X	2. Does the action result in either a permanent or indefinite physical occupation of private property?
	X	3. Does the action deny a fundamental attribute of ownership? (ex.: right to exclude others, disposal of property)
	X	4. Does the action deprive the owner of all economically viable uses of the property?
	X	5. Does the action require a property owner to dedicate a portion of property or to grant an easement? [If no, go to (6)].
		5a. Is there a reasonable, specific connection between the government requirement and legitimate state interests?
		5b. Is the government requirement roughly proportional to the impact of the proposed use of the property?
	X	6. Does the action have a severe impact on the value of the property? (consider economic impact, investment-backed expectations, character of government action)
	X	7. Does the action damage the property by causing some physical disturbance with respect to the property in excess of that sustained by the public generally?
	X	7a. Is the impact of government action direct, peculiar, and significant?
	X	7b. Has government action resulted in the property becoming practically inaccessible, waterlogged or flooded?
	X	7c. Has government action lowered property values by more than 30% and necessitated the physical taking of adjacent property or property across a public way from the property in question?
	X	Takings or damaging implications? (Taking or damaging implications exist if YES is checked in response to question 1 and also to any one or more of the following questions: 2, 3, 4, 6, 7a, 7b, 7c; or if NO is checked in response to questions 5a or 5b; the shaded areas)

Based on this analysis, the Department determined there are no taking or damaging implications associated with this permit action.

IX. Environmental Assessment

This permitting action is considered an administrative action; therefore, an Environmental Assessment is not required.

MAQP Analysis Prepared By: C. Henrikson
Date: June 22, 2012