**MONTANA DEPARTMENT OF ENVIRONMENTAL QUALITY**
**OPERATING PERMIT TECHNICAL REVIEW DOCUMENT**

**Permitting and Compliance Division**
**1520 E. Sixth Avenue**
**P.O. Box 200901**
**Helena, Montana 59620-0901**

**ONEOK ROCKIES MIDSTREAM, LLC – Baker Gas Plant**
**SW¼ of the SW¼ of Section 6, Township 7 North, Range 60 East, in Fallon County, MT**
**ONEOK, Inc.**
**100 West Fifth Street**
**P.O. Box 871**
**Tulsa, Oklahoma 74103-4298**

The following table summarizes the air quality programs testing, monitoring, and reporting requirements applicable to this facility.

| **Facility Compliance Requirements** | Yes | No | Comments |
|---|---|---|---|
| Source Tests Required | X | | Semiannual |
| Ambient Monitoring Required | | X | |
| Continuous Opacity Monitoring System (COMS) Required | | X | |
| Continuous Emission Monitoring System (CEMS) Required | | X | |
| Schedule of Compliance Required | | X | |
| Annual Compliance Certification and Semiannual Reporting Required | X | | Annual and Semiannual |
| Monthly Reporting Required | | X | |
| Quarterly Reporting Required | | X | |
| **Applicable Air Quality Programs** | | | |
| ARM Subchapter 7 Montana Air Quality Permitting | X | | Montana Air Quality Permit (MAQP) #2736-10 posted PD on June 28, 2012 |
| New Source Performance Standards (NSPS) | X | | 40 CFR 60, Subpart KKK and 40 CFR 60, Subpart LLL, recordkeeping and reporting requirements, as applicable |
| National Emission Standards for Hazardous Air Pollutants (NESHAPS) | | X | Except for 40 CFR 61, Subpart M |
| Maximum Achievable Control Technology (MACT) | | X | |
| Major New Source Review (NSR) – includes Prevention of Significant Deterioration (PSD) and/or Non-attainment Area (NAA) NSR | | X | |
| Risk Management Plan Required (RMP) | | X | |
| Acid Rain Title IV | | X | |
| Compliance Assurance Monitoring (CAM) | X | | |
| State Implementation Plan (SIP) | X | | General SIP |

## TABLE OF CONTENTS

## SECTION I. GENERAL INFORMATION

### A. Purpose

This document establishes the basis for the decisions made regarding the applicable requirements, monitoring plan, and compliance status of emission units affected by the operating permit proposed for this facility. The document is intended for reference during review of the proposed permit by the Environmental Protection Agency (EPA) and the public. It is also intended to provide background information not included in the operating permit and to document issues that may become important during modifications or renewals of the permit. Conclusions in this document are based on information provided in the original Title V operating permit application submitted by Bear Paw Energy, LLC (BPE) and received on December 15, 1998, operating permit renewal applications received on January 20, 2004, and September 17, 2009, operating permit modifications issued May 17, 2002, April 18, 2003, July 16, 2005, operating permit administrative amendments issued November 22, 2003, February 22, 2007, November 7, 2007, the initial Montana Air Quality Permit (MAQP) issued June 28, 1993, in addition to MAQPs issued February 8, 1995, August 25, 1996, June 27, 1997, November 21, 1997, November 8, 1998, December 13, 2001, August 20, 2002 January 8, 2005, and May 25, 2010. An administrative amendment for a name change to ONEOK Rockies Midstream, LLC. was received on June 18, 2012.

### B. Facility Location

ONEOK owns and operates the Baker Gas Plant. The legal description of the facility is the SW¼ of the SW¼ of Section 6, Township 7 North, Range 60 East in Fallon County, Montana.

### C. Facility Background Information

**<u>MAQP Background</u>**

The Baker Gas Plant occupies a 20-acre rectangular site measuring approximately 900 feet by 950 feet. Local terrain is predominantly flat with a slight down slope from north to south. The surrounding vicinity is also predominantly flat. The prevailing winds are from the west. There are no schools, hospitals, residential areas, or parks located within a ½ mile radius of the plant.

The facility was originally permitted to Western Gas Resources (WGR). In May 1992, WGR applied for a permit to operate their existing natural gas processing plant and associated equipment and to construct a Challenger flare to be used for emergency situations to increase safety at the plant.

On June 28, 1993, WGR **MAQP #2736-00** became final and effective. The flare was constructed and placed in operation in October 1993. Also, as a requirement of the permit, WGR was required to install Non-Selective Catalytic Reduction (NSCR) units on the two compressor engines to control oxides of nitrogen ($NO_x$), carbon monoxide (CO), and Volatile Organic Compound (VOC) emissions. The 800 brake horsepower (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 and effective. 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 Baker Gas Plant 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 and effective. 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. The permit alteration was for the following VOC emission units:

- Fugitive VOC leaks from components in VOC service;
- 4.0 million standard cubic feet per day (MMScfd) ethylene glycol (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 and effective. 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; 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 ($SO_2$) emissions 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 did 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, which means a direct product loss to the company. MAQP #2736-03 was modified by removing the routing language. There was no change in the potential emissions because the emissions inventory did not calculate the tank emissions as being controlled by the flare. **MAQP #2736-04** replaced MAQP #2736-03.

On September 23, 1998, the Department received a complete application requesting a alteration to MAQP #2736-04. BPE 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. **MAQP #2736-05** 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 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. **MAQP #2736-06** 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 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 a hydrogen sulfide ($H_2S$) 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 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 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 the 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 current permit increased emissions from the facility by approximately 5.73 tpy.

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

The proposed changes 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. The administrative permit action updated the permit to reflect administrative changes, current permit language, potential to emit (PTE), and rule references used by the Department. Details for the administrative actions are provided in the permit analysis:

- Remove 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 (replaced by the Self Supported Air-Assisted Flare) to account for emissions during planned maintenance shutdowns (300 hours of total plant equipment downtime during planned maintenance activities);
- Remove the Challenger flare from the equipment list. The Challenger flare is out-of-service/abandoned;
- Remove methanol storage tank from the equipment list. This tank has been permanently removed from the facility;
- Add one 0.5 MMBtu/hr glycol line heater to equipment list. The heater was inadvertently left off the previous equipment list;
- Update process description; and
- Update 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.

On June 18, 2012, the Department received an administrative amendment request from BPE to MAQP #2736-09. BPE requested the Department to administratively change the company name to ONEOK Rockies Midstream, LLC (ORM). **MAQP #2736-10** replaces MAQP #2736-09.

## Title V Operating Permit Background

On December 15, 1998, the Department received an operating permit application for the Baker Gas Plant. The application was assigned number OP2736. The permit application was deemed administratively complete on January 3, 1999, and the application was deemed technically complete on February 3, 1999. **Operating Permit #OP2736-00** became final and effective on July 14, 1999.

On September 4, 2001, the Department received a permit application from Compliance Partners, Inc., on behalf of BPE, requesting a Montana air quality permit modification to MAQP #2736-05 and an operating permit modification to Operating Permit #OP2736-00. The application requested to increase the facility's throughput from 4.2 MMScfd a day to 8.5 MMScfd. The application was deemed complete upon submittal of additional information on October 12, 2001. The proposed alteration increased $SO_2$ emissions from 117.1 tons per year (TPY) to 235.3 TPY. The proposed 118.2 TPY emission increase was below New Source Review (NSR) threshold levels and does not trigger Prevention of Significant Deterioration (PSD). This permit action increased the facility's throughput from 4.2 MMScfd to 8.5 MMScfd. **Operating Permit #OP2736-01** replaced Operating Permit #OP2736-00 and MAQP #2736-06 replaced MAQP #2736-05.

On May 21, 2002, the Department received a request to modify Operating Permit #OP2736-01. The request was to switch the responsibilities of the 2 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 is 600 ppm. The permit action did not increase emissions from the facility. **Operating Permit #OP2736-02** replaced Operating Permit #OP2736-01.

On October 6, 2003, the Department received a request from BPE for an administrative amendment of Operating Permit #OP2736-02 to update Section V.B.3 of the General Conditions incorporating changes to federal Title V rules 40 CFR 70.6(c)(5)(iii)(B) and 70.6(c)(5)(iii)(C) (to be incorporated into Montana's Title V rules at ARM 17.8.1213) regarding Title V annual compliance certifications. **Operating Permit #OP2736-03** replaced Operating Permit #OP2736-02.

On January 20, 2004, the Department received a Title V renewal application from BPE. The application was deemed administratively complete on January 27, 2004, and technically complete on February 19, 2004. **Operating Permit #OP2736-04** replaced Operating Permit #OP 2736-03.
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 tons per year. Further, the proposed changes triggered the requirements of 40 CFR 60, Subpart KKK, Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants, as applicable, and the permit action was considered a significant modification in the Title V Program. **Operating Permit #OP2736-05** replaced Operating Permit #OP2736-04.

On December 22, 2006, the Department received notification of a change in the facility responsible official and contact personnel. The new responsible official is Roger G. Thorpe, Vice President, and the new facility contact person is Ms. Lynn Reed, P.E. The Department's Decision on the permit action updated the information accordingly and was considered an administrative amendment to the existing Title V operating permit. **Operating Permit #OP2736-06** replaced Operating Permit #OP2736-05.

On June 4, 2007, the Department received a request from BPE to update the permit to reflect current operating practices. In addition, the Department received notification that the Responsible Official had changed. The new responsible official is Craig A. Forsander. The Department's Decision on the current permit action updated the information accordingly and the permit action was considered an administrative amendment to the existing Title V operating permit. **Operating Permit #OP2736-07** replaced Operating Permit #OP2736-06.

On September 17, 2009, the Department received a renewal application from BPE (assigned Operating Permit #OP2736-08). **Operating Permit #OP2736-08** replaced Operating Permit #OP2736-07.

On June 6, 2011, the Department received a request from BPE to administratively amend the operating permit to allow incorporation of a recent de minimis change, in which the Guyed Utility Flare (EU009) was replaced with a Self Supported Air Assisted Flare. BPE requested the update to more accurately describe the current flare design and to avoid future confusion. **Operating Permit #OP2736-09** replaced Operating Permit #OP2736-08.

### D. Current Permit Action

On June 18, 2012, the Department received an administrative amendment request from BPE to #OP 2736-09. BPE requested the Department to administratively change the company name to ONEOK Rockies Midstream, LLC. A request was also made to change the responsible official to Geoffrey A. Sands. The administrative permit action updated the permit to reflect administrative changes, current permit language, and rule references used by the Department. **Operating Permit #OP2736-10** replaces Operating Permit #OP2736-09.

## E. Taking and Damaging Analysis

HB 311, the Montana Private Property Assessment Act, requires analysis of every proposed state agency administrative rule, policy, permit condition or permit denial, pertaining to an environmental matter, to determine whether the state action constitutes a taking or damaging of private real property that requires compensation under the Montana or U.S. Constitution. As part of issuing an operating permit, the Department is required to complete a Taking and Damaging Checklist. 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 pubic 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.

## F. Compliance Designation

The ORM Baker Gas Plant was last inspected on August 22, 2011. In addition to the on-site inspection, the Department conducted a review of reports/records submitted by BPE during the period covered (September 3, 2009, to September 15, 2011) for this Full Compliance Evaluation (FCE).

The Baker Gas Plant's 2011 1st Semester Semi-Annual Monitoring Report was received by the Department on August 15, 2011. BPE reported that the reference pressure drop across the catalyst for emitting unit (EU) 10 was not taken in January and February of 2011 as required by the compliance assurance monitoring (CAM) plan, Appendix E of Operating Permit #OP2736-09. The report states operator training was provided on March 8, 2011 and this deviation has been corrected.

The Baker Gas Plant's 2011 1st Semester Semi-Annual Monitoring Report also states that on three occasions, catalysts were cleaned and maintenance tests performed on EU10 without recording the maintenance test results. BPE stated that field personnel have been reminded to be diligent in documenting maintenance test results and that this deviation has been resolved. Also, BPE stated that the reference pressure drop across the catalyst exceeded the CAM Plan allowable 2 inches of $H_2O$ without corrective action taken. BPE explained that training has been provided to the field personnel regarding this issue.

Under Operating Permit #OP2736-09, Section II, E.1, BPE shall use a Leak Detection and Repair (LDAR) program, as described in 40 CFR 60, Subpart KKK, for each affected process unit (ARM 17.8.340). 40 CFR 60.482-7(d)(2) requires an attempt at repair to be made no later than five calendar days after each leak is detected. The 1st Semester Semi-Annual Monitoring Report stated that more than five calendar days passed before first attempts were made to repair leaking valves. BPE stated that field personnel have been reminded to make a repair attempt within five days of discovery of any leak requiring a process unit shutdown to attempt the repair. 40 CFR 60.486 (c)(5) requires recording in a log any leaks placed on "Delay of Repair" if a leak is not repaired within 15 calendar days after discovery of the leak. BPE reported in the 2011 that leaks discovered during monitoring were not placed on a Delay of Repair list within 15 calendar days after discovery of the leak. BPE stated that field personnel have been reminded to list leaks on a delay-of-repair list within 15 days after discovery of a leak if a process unit shutdown is required to attempt the repair.

Under Operating Permit #OP2736-09, Section III, A.15, it states "Pursuant to ARM 17.8.340, BPE shall comply with all applicable requirements of 40 CFR 60, Subpart LLL, as they apply to the units required to comply with the Standards of Performance for Onshore Natural Gas Processing: $SO_2$ Emissions. However, because BPE has demonstrated that the design capacity of the facility is less than 2 long tons/day of $H_2S$ in the acid gas (expressed as sulfur), only 40 CFR 60.647(c) is applicable to the facility (ARM 17.8.340 and 40 CFR 60, Subpart LLL)." 40 CFR 60.647(c) states "To certify that a facility is exempt from the control requirements of these standards, each owner or operator of a facility with a design capacity less that 2 LT/D of $H_2S$ in the acid gas (expresssed as sulfur) shall keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of $H_2S$ expressed as sulfur." The required analysis was not available on site during the August 22, 2011 inspection as required in 40 CFR 60.647(c).

Overall, the Department believes that the Baker Gas Plant has met the requirement to monitor compliance with MAQP #2736-09 and Operating Permit #OP2736-09 and the above violations will be addressed in a separate letter. At the time of this report, the facility appeared to be in compliance with the applicable permit conditions except as explained above.

## SECTION II. SUMMARY OF EMISSION UNITS

### A. Facility Process 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 $H_2S$ 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 Self Supported Air-Assisted 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.

## B. Emission Units and Pollution Control Device Identification

| Emissions Unit ID | Description | Pollution Control Device/Practice |
|---|---|---|
| EU001 | 448 bhp Waukesha Compressor Engine | Air-to-fuel ratio (AFR) controller and a non-selective catalytic reduction (NSCR) unit |
| EU002 | 800 bhp White Superior Compressor Engine | AFR controller and a NSCR unit |
| EU004 | Acid Gas Flare | 40 CFR 60.18 |
| EU005 | Fugitive Emissions | 40 CFR 60, Subpart KKK LDAR Monitoring |
| EU006 | 1. Ethylene Glycol Regenerator Vent (8.5 MMscfd)<br>2. Flash Tank | 1. Vent routed to the Anderson hot oil heater for thermal destruction<br>2. Flash tank vapors hard-piped to the inlet condensation knockout drum |
| EU007 | Y-Grade Product Loading (TL-1)<br>Propane Product Loading (TL-2)<br>Butane Product Loading (TL-3)<br>Condensate/Natural Gas Gasoline Product Loading (TL-4) | Closed System<br>Closed System<br>Closed System<br>Vapor Balance |
| EU008 | Four (4) 400 barrel (bbl) Condensate/Natural gas storage tanks (TK-7, TK-8, TK-9, TK-10) | Vertical fixed roof, vapor balance system, submerge-filled and pressure/vacuum vent |
| EU009 | Self Supported Air-Assisted Flare | 40 CFR 60.18 |
| EU0010 | 1250 bhp Waukesha Compressor Engine | AFR controller and a NSCR unit |
| EU012 | Amine Regenerator, 6.5 MMscf/d | Acid Gas Flare |
| EU013 | Two (2) Y-grade horizontal storage tanks (TK-1, TK-2) | Pressurized tanks, submerge-filled and pressure relief valve |
| EU014 | Three (3) Propane horizontal storage tanks<br>(TK-3, TK-4, TK-11) | Pressurized tanks, submerge-filled and pressure relief valve |
| EU015 | Two (2) Butane horizontal storage tanks (TK-5, TK-6) | Pressurized tanks, submerge-filled and pressure relief valve |

## C. Categorically Insignificant Sources/Activities

| Emissions Unit ID | Description |
|---|---|
| IEU01 | Anderson-Baird Hot Oil Heater, 6.5 MMBtu/hr |
| IEU02 | Amine Regenerator Heater, 2.0 MMBtu/hr |
| IEU03 | Methyl Mercaptan Storage Tank, 67 gal |
| IEU04 | Depropanizer Unit |
| IEU05 | Two Heat Exchangers |
| IEU06 | Glycol Line Heater (0.5 MMBtu/hr) |

## SECTION III. PERMIT CONDITIONS

### A. Emission Limits and Standards

The combined emissions from all compressor engine(s) comprising the 1250 bhp shall not exceed 5.51 pounds per hour (lb/hr) for $NO_X$, 5.51 lb/hr for CO, and 2.76 lb/hr for VOC.

The 448 bhp Waukesha compressor engine shall not exceed 1.98 lb/hr for $NO_X$, 2.96 lb/hr for CO, and 1.00 lb/hr for VOC.

The 800 bhp White Superior compressor engine shall not exceed the following: 3.53 lb/hr for $NO_X$, 5.29 lb/hr for CO, and 1.76 lb/hr for VOC.

All compressor engines will be operated with an AFR controller and a NSCR unit.

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.

The VOC product loading and receiving at the Baker Gas Plant shall be operated under a vapor balance system. All VOC 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. Upon completion of VOC product loadout, all lines used for loading shall be purged of VOC vapors. These VOC vapors shall be routed to a flare for thermal destruction.

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 vapor balanced, submerge filled, and equipped with a pressure relief valve.

Each flare has an opacity limit of 10% and a particulate limit of 0.10 grains per dry standard cubic foot (gr/dscf) of flue gas, adjusted to 12% $CO_2$ and calculated as if no auxiliary fuel had been used. ORM shall install and continuously operate a thermocouple and an associated recorder or any equivalent device to detect the presence of a flame on each flare.

ORM's Self Supported Air-Assisted Flare is limited to 300 hours of total plant equipment downtime during planned maintenance activities during any rolling 12-month period.

The Baker Gas Plant has maximum production rate limit of 3,102.5 MMScf during any rolling 12-month period.

All stack emission from the amine regenerator shall be routed to the Acid Gas flare. The reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart LLL are applicable to the Baker Gas Plant amine unit. However, because ORM has demonstrated that the design capacity is less than 2 long tons per day of $H_2S$ in the acid gas (expressed as sulfur), only 40 CFR 60.647(c) is applicable to the facility.

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.

ORM shall not cause or authorize the production, handling, transportation, or storage of any material, unless reasonable precautions to control emissions of particulate matter are taken. 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. 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.

## B. Monitoring Requirements

ARM 17.8.1212(1) requires that all monitoring and analysis procedures or test methods required under applicable requirements are contained in operating permits. In addition, when the applicable requirement does not require periodic testing or monitoring, periodic monitoring must be prescribed that is sufficient to yield reliable data from the relevant time period that is representative of the source's compliance with the permit.

The requirements for testing, monitoring, recordkeeping, reporting, and compliance certification sufficient to assure compliance do not require the permit to impose the same level of rigor for all emission units. Furthermore, they do not require extensive testing or monitoring to assure compliance with the applicable requirements for emission units that do not have significant potential to violate emission limitations or other requirements under normal operating conditions. When compliance with the underlying applicable requirement for an insignificant emissions unit is not threatened by lack of regular monitoring and when periodic testing or monitoring is not otherwise required by the applicable requirement, the status quo **(i.e., no monitoring)** will meet the requirements of ARM 17.8.1212(1). Therefore, the permit does not include monitoring for insignificant emission units.

The permit includes periodic monitoring or recordkeeping for each applicable requirement. The information obtained from the monitoring and recordkeeping will be used by the permittee to periodically certify compliance with the emission limits and standards. However, the Department may request additional testing to determine compliance with the emission limits and standards.

Overall, Operating Permit #OP2736-10 requires monitoring of emission units by way of inspections and maintenance on both uncontrolled emitting units and existing control equipment. Log entries indicating performance of any required inspections or maintenance will demonstrate compliance with the monitoring requirement.

## C. Test Methods and Procedures

The operating permit may not require testing for all sources if routine monitoring is used to determine compliance, but the Department has the authority to require testing if deemed necessary to determine compliance with an emission limit or standard. In addition, ORM may elect to voluntarily conduct compliance testing to confirm its compliance status.

Compliance with the opacity, particulate from fuel combustion, sulfur compounds in fuel (gaseous), and VOC limitations in the permit may be demonstrated by burning pipeline quality natural gas (as defined by ORM’s Federal Energy Regulatory Commission (FERC) gas tariff) on an ongoing basis.

The Department will use the portable analyzer testing results as a direct measure of compliance. Title V Operating Permit #OP2736-10 contains requirements for semiannual testing with a portable analyzer for $NO_x$ and CO on units EU001, EU002, and EU010. The permit stipulates that the portable analyzer shall be capable of achieving performance specifications equivalent to the traditional test methods in 40 CFR 60, Appendix A, or shall be capable of meeting the requirements of EPA Conditional Test Method 030 (or American Society for Testing and Materials (ASTM)

Method D6522-00) for the "Determination of Nitrogen Oxides, Carbon Monoxide, and Oxygen Emissions from Natural Gas-Fired Engines, Boilers and Process Heaters Using Portable Analyzers." ORM may use another testing procedure as approved in advance by the Department. All compliance source tests must be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106). ORM will then convert the $NO_x$ and CO emissions test results from parts per million (ppm) concentrations to a lb/hr emission rate. Stack gas flow rates shall be determined using EPA Test Methods in 40 CFR 60, Appendix A in order to monitor compliance with the emissions limitations in the permit.

### D. Recordkeeping Requirements

The permittee is required to keep all records listed in the operating permit as a permanent business record for at least 5 years following the date of the generation of the record.

### E. Reporting Requirements

Reporting requirements are included in the permit for each emissions unit and Section V of the operating permit "General Conditions" explains the reporting requirements. However, the permittee is required to submit semiannual and annual monitoring reports to the Department and to annually certify compliance with the applicable requirements contained in the permit. The reports must include a list of all emission limit and monitoring deviations, the reason for any deviation, and the corrective action taken as a result of any deviation. The information required in 40 CFR 60.647(c) is required to be kept on file for the life of the facility.

## SECTION IV. NON-APPLICABLE REQUIREMENT ANALYSIS

ORM did not identify any Air Quality ARM or Federal Regulations as non-applicable to the facility or to any specific emissions unit under the current operating permit renewal, application (ARM 17.8.1214). ORM shall comply with any new requirements that may become applicable during the permit term.

## SECTION V. FUTURE PERMIT CONSIDERATIONS

### A. MACT Standards

As of July 2, 2012, for Operating Permit #OP2736-10, this facility is an area source of HAPs based on information submitted by ORM. For area sources under 40 CFR 63, Subpart HH - *National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities*, the affected sources include each triethylene glycol (TEG) dehydration unit. ORM operates an EG unit, not a TEG unit, and therefore, is not subject to the area source provisions of Subpart HH. In addition, the ORM facility is not subject to 40 CFR 63, Subpart HHH - *National Emission Standards for Hazardous Air Pollutants from Natural Gas Transmission and Storage Facilities* because the facility is not a major source of HAPs. As an area source, ORM's three reciprocating internal combustion engines (RICE) are subject to 40 CFR 63, Subpart ZZZZ; however, based on information submitted by ORM, the Baker Gas Plant is not subject to the provisions of 40 CFR 63, Subpart ZZZZ at this time 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 Subpart ZZZZ could apply to future engines.

### B. NESHAP Standards

The Department is unaware of any proposed or pending NESHAP standard that may be promulgated that will affect the Baker Gas Plant.

### C. NSPS Standards

As of July 2, 2012, for Operating Permit #OP2736-09, 40 CFR 60, Subparts LLL and KKK are applicable to the Baker Gas Plant. However, because ORM has demonstrated that the design capacity of the facility is less than 2 long tons/day of $H_2S$ in the acid gas (expressed as sulfur), only 40 CFR 60.647(c), of Subpart LLL, is applicable to the facility.

### D. Risk Management Plan

If a facility has more than a threshold quantity of a regulated substance in a process, the facility must comply with 40 CFR 68 requirements no later than June 21, 1999; 3 years after the date on which a regulated substance is first listed under 40 CFR 68.130; or the date on which a regulated substance is first present in more than a threshold quantity in a process, whichever is later.

As of July 2, 2012, this facility exceeded the minimum threshold quantities for regulated substance(s) listed in 40 CFR 68.115. Consequently, this facility was required to submit a Risk Management Plan no later than June 21, 1999. A copy of the risk management plan is available from the EPA upon request.

### E. CAM Applicability

An emitting unit located at a Title V facility that meets the following criteria listed in ARM 17.8.1503 is subject to Subchapter 15 and must develop a CAM Plan for that unit:

- The emitting unit is subject to an emission limitation or standard for the applicable regulated air pollutant (other than emission limits or standards proposed after November 15, 1990, since these regulations contain specific monitoring requirements);

- The emitting unit uses a control device to achieve compliance with such limit; and

- The emitting unit has potential pre-control device emissions of the applicable regulated air pollutant that is greater than major source thresholds.

ORM currently has an emitting unit, EU010, which meets all the applicability criteria in ARM 17.8.1503 under Operating Permit #OP2736-10. Therefore, ORM is required to develop a CAM Plan for the Baker Gas Plant. The CAM Plan provided by ORM can be found in Appendix E of Operating Permit #OP2736-10

**F. Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule**

On May 7, 2010, EPA published the "light duty vehicle rule" (Docket # EPA-HQ-OAR- 2009-0472, 75 FR 25324) controlling greenhouse gas (GHG) emissions from mobile sources, whereby GHG became a pollutant subject to regulation under the Federal and Montana Clean Air Act(s). On June 3, 2010, EPA promulgated the GHG "Tailoring Rule" (Docket # EPA-HQ-OAR-2009-0517, 75 FR 31514) which modified 40 CFR Parts 51, 52, 70, and 71 to specify which facilities are subject to GHG permitting requirements and when such facilities become subject to regulation for GHG under the PSD and Title V programs.

Under the Tailoring Rule, any PSD action (either a new major stationary source or a major modification at a major stationary source) taken for a pollutant or pollutants other than GHG that was not final prior to January 2, 2011, would be subject to PSD permitting requirements for GHG if the GHG increases associated with that action were at or above 75,000 tons per year (tpy) of carbon dioxide equivalent ($CO_2e$). Similarly, if such action were taken, any resulting requirements would be subject to inclusion in the Title V Operating Permit.

Starting on July 1, 2011, PSD permitting requirements would be triggered for modifications that were determined to be major under PSD based on GHG emissions alone, even if no other pollutant triggered a major modification. In addition, sources that are not considered PSD major sources based on criteria pollutant emissions would become subject to PSD review if their facility-wide potential emissions equaled or exceeded 100,000 TPY of $CO_2e$ and 100 or 250 TPY of GHG on a mass basis depending on their listed status in ARM 17.8.801(22) and they undertook a permitting action with increases of 75,000 TPY or more of $CO_2e$ and greater than 0 TPY of GHG on a mass basis. With respect to Title V, sources not currently holding a Title V permit that have potential facility-wide emissions equal to or exceeding 100,000 TPY of $CO_2e$ and 100 TPY of GHG on a mass basis would be required to obtain a Title V Operating Permit.