Air Quality Permit

Issued to: Montana Refining Company 1900 10th Street North East Great Falls, MT 59404	Permit #2161-18 Administrative Amendment (AA) Received: 05/14/04 Department Decision on AA: 07/02/04 Permit Final: 07/20/04 AFS#: 013-0004

An air quality permit, with conditions, is hereby granted to the Montana Refining Company (MRC) pursuant to Sections 75-2-204 and 211 of the Montana Code Annotated (MCA), as amended, and the Administrative Rules of Montana (ARM) 17.8.740, *et seq*., as amended, for the following:

SECTION I: Permitted Facilities

A. Plant Location/Description

MRC operates a petroleum refinery and all refinery equipment located at the NE¼ of Section 1, Township 20 North, Range 3 East, in Cascade County, Montana. The facility includes, but is not limited to, the following equipment:

Emission Point Source

1. Fluid Catalytic Cracking Unit (FCCU)
2. Crude Furnace/Reboiler (Crude heater)
3. Deisobutanizer Reboiler
4. Reformer Heater
5. Vacuum Heater
6. Naphtha Hydrodesulfurization (HDS) Heater
7. Diesel HDS Heater
8. Asphalt Tank #50 Heater
9. Asphalt Tank #110 Heater
10. Asphalt Tank #112 Heater
11. Asphalt Tank #55 Heater
12. Asphalt Tank #56 Heater
13. #1 & #2 Boilers (routed to one stack)
14. Waste Water Treatment Plant
15. Blowdowns
16. Bulk Loading – Gasoline
17. Storage Tanks:
    - Tank #122 - Gasoline
    - Tank #123 - Gasoline
    - Tank #125 - Gasoline
    - Tank #126 - Gasoline
    - Tank #8 - Asphalt
    - Tank #9 - Asphalt
    - Tank #52 - Gasoline
    - Tank #57 - Gasoline
    - Tank #124 - Crude Oil
    - Tank #36 -Kerosene, Jet Fuel
    - Tank #46 -Kerosene, Jet Fuel
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Emission Point Source

- Tank #47 -Kerosene, Jet Fuel
- Tank #48 -Kerosene, Jet Fuel
- Tank #53 -Kerosene, Jet Fuel
- Tank #63 -Kerosene, Jet Fuel
- Tank #127 - Heavy Naphtha
- Tank #44 - Heavy Oil
- Tank #45 - Heavy Oil
- Tank #111 - Heavy Oil
- Tank #116 - #2 Diesel
- Tank #128 - Raw Diesel
- Tank #35 – Sodium Hydrosulfide (NaHS) Product, Caustic, No volatile organic compounds (VOC) Content
- Tank 24,128a – Asphalt
- Tank 24,128b – Asphalt
- Tank 109,946c – Asphalt

18. Emergency Flare
19. Hydroflouric (HF) Alkylation Unit
20. NaHS Unit
21. FCCU Preheater
22. Reactor Catalytic Heater
23. Diesel/Gas Oil HDS Heater
24. Hydrogen Plant Reformer Heater
25. Fugitive Volatile Organic Compound (VOC) Emissions from Sources #24 and #25
26. 3,500-barrel per day Asphalt Polymerization Unit that includes:
    - (3) 1000-barrel modified asphalt storage tanks (fixed-roof, vented)
    - (3) 750-thousand British thermal units per hour (MBtu/hr) fire-tube tank heater (natural gas fired)
    - (1) 715-barrel modified asphalt reactor tank (fixed-roof, vented)
    - (1) 800-gallon asphalt wetting tank (fixed-roof, vented)
    - Process valves and pumps in asphalt, modified asphalt, and tall oil service

B. Current Permit Action

On May 14, 2004, the Department of Environmental Quality (Department) received a letter from MRC requesting changes to Permit #2161-17. The proposed change includes adding the ability to burn sweet gas in heaters at the HF Alkylation Unit, and at Tanks 102, 135, 137, 138, and 139. The sweet gas will have a hydrogen sulfide (H_2S) limit equivalent to the 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS), Subpart J limit of 0.10 grains per dry standard cubic foot (gr/dscf) H_2S. The continuous refinery fuel gas monitoring system for H_2S installed on the fuel gas system that supplies the heaters would be used to determine compliance with the limit. Since the emissions from switching the fuel to sweet gas are less than 15 tons/year, the Department added the fuel switch under de minimis, ARM 17.8.745. The current permit action updates the permit to reflect the changes.

SECTION II: Limitations and Conditions

A. Emission Control Requirements:

MRC shall install, operate and maintain the following equipment and practices as specified (ARM 17.8.749 and ARM 17.8.752):

1. The refinery flare shall be utilized for emergency use only.

2. The diesel/gas oil HDS heater and hydrogen plant reformer heater shall be fired with only purchased natural gas and shall not be fired with refinery gas or refinery Liquefied Petroleum Gas (LPG). The purge (vent) gas used, as fuel in the hydrogen plant reformer heater shall be sulfur free (ARM 17.8.752).

3. Storage Tanks:

   a. Storage tanks #52, #53, and #57 shall be equipped with double seal internal floating roofs (ARM 17.8.752).

   b. Storage tanks #122, #123, #124, #125, and #126 shall be equipped with dual-seal external floating roofs (ARM 17.8.752).

   c. Storage tanks #127 and #128 shall be equipped with dual-seal external floating roofs. The primary seals shall be visually inspected for holes every 5-years and the secondary seals shall be visually inspected for holes annually (ARM 17.8.752).

   d. Storage tanks #8, #9, #55, #56, #69, #130, #132, #133, WT-1901, and RT-1901 shall be used for asphalt, modified asphalt, or tall oil service (ARM 17.8.749).

   e. Storage tanks 24 128a, 24, 128b, and 109946c shall be used for asphalt (ARM 17.8.749).

   f. H_2S content of fuel gas burned in the tank heaters for Tanks #102, #135, #137, #138, and #139 shall not exceed 0.10 gr/dscf, based on a rolling 3-hour average. The tank heaters shall burn only natural gas until the H_2S fuel gas monitoring system is installed and approved by the Department. The tank heaters shall burn only natural gas or sweet gas (ARM 17.8.749).

4. The HF Alkylation Unit shall be operated and maintained as follows:

   a. All valves used shall be high quality valves containing high quality packing.

   b. All open-ended valves shall be of the same quality as the valves described above. They shall have plugs or caps installed on the open end.

   c. All pumps used in the alkylation plant shall be fitted with the highest quality state-of-the-art mechanical seals.

   d. All pumps shall be monitored and maintained as described in 40 CFR 60.482-2 and all control valves shall be monitored and maintained as described in 40 CFR 60.482-7. All other potential sources of VOC leaks shall be inspected quarterly for evidence of leakage by visual or other detection methods. Repairs shall be made promptly as described in 40 CFR 482-7d. Records of monitoring and maintenance shall be maintained on site for a minimum of 2-years.

   e. All process drains shall consist of water seal traps with covers.

   f. All equipment shall be operated and maintained as described in 40 CFR 60.692-2, 60.692-6, and 60.693-1. Inspection reports shall be made available for inspection upon request.

   g. H_2S content of the fuel gas burned in the 20-MMBtu/hr Alkylation Heater shall not exceed 0.10 gr/dscf, rolling 3-hr average. The Alkylation Heater shall burn only natural gas until the H_2S fuel gas monitoring system is installed and approved by the

Department. The tank heaters shall burn only natural gas or sweet gas (ARM 17.8.749).

5. The Asphalt Polymerization Unit shall be operated and maintained as follows:

   a. All open-ended valves shall have plugs or caps installed on the open end (ARM 17.8.752).

   b. All pumps in the asphalt polymerization unit shall be equipped with standard single seals (ARM 17.8.752).

   c. All pumps and valves in heavy liquid service, pressure relief devices in light liquid or heavy liquid service, and flanges and other connectors shall meet the standards described in 40 CFR 60.482-8. Repairs shall be made promptly as described in 40 CFR 60.482-7e (ARM 17.8.752).

   d. The three 750-MBtu/hr fire-tube tank heaters #130, #132, and #133 shall be fired with natural gas only (ARM 17.8.752).

   e. MRC shall not cause to be discharged into the atmosphere from any asphalt tank or modified asphalt tank exhaust gases with opacity of 20% or greater, averaged over any 6 consecutive minutes (ARM 17.8.752).

6. MRC shall comply with all applicable requirements of ARM 17.8.340, which references 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS):

   a. Subpart A - General Provisions shall apply to all equipment or facilities subject to an NSPS Subpart as listed below.

   b. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the following affected facilities, as described:

      i. FCCU regenerator: for carbon monoxide (CO), the requirements of Subpart J shall apply by December 20, 2002; and for sulfur dioxide (SO_2), the requirements of Subpart J shall apply by December 20, 2004 (MRC Consent Decree).

      ii. Heaters and boilers: the requirements of Subpart J shall apply by no later than December 31, 2006.

      By no later than December 31, 2006, MRC shall install, certify, calibrate, maintain, and operate a fuel gas Continuous Emission Monitoring System (CEMS) in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F (MRC Consent Decree).

   c. Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels shall apply to all volatile organic storage vessels (including petroleum liquid storage vessels) for which construction, reconstruction or modification commenced after July 23, 1984. This shall include, but not be limited to, the storage tanks listed in Section II.A.3.a. and b. These requirements shall be as specified in 60.112b, 60.113b, 60.115b, and 60.116b.

   d. Subpart GGG - Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries shall apply to the NaHS Unit, Diesel/Gas Oil HDS Unit, Hydrogen Plant, and any other equipment as appropriate:

i. All valves used shall be high quality valves containing high quality packing.

ii. All open-ended valves shall be of the same quality as the valves described above. They shall have plugs or caps installed on the open end.

iii. A monitoring and maintenance program as described under New Source Performance Standards (40 CFR Part 60, Subpart VV) shall be instituted.

e. Subpart QQQ - Standards of Performance for VOC Emissions from Petroleum Refining Wastewater Systems shall apply to the HTU, Hydrogen Unit, and any other equipment as appropriate:

i. All process drains shall consist of water seal traps with covers.

ii. All equipment shall be operated and maintained as required in 40 CFR Part 60, Subpart QQQ.

7. Pressure Vessels - All pressure vessels in HF Acid service, except storage tanks, shall be vented to the flare system.

8. Cooling Towers - Cooling water shall be monitored twice per shift for changes, specifically pH and hydrocarbon content. The appearance of the towers and related equipment shall be inspected at least once per shift.

9. The wastewater overhead stream from the HTU Sour Water Stripper (SWS) unit shall be incinerated in the #1 and #2 boilers only. The total SO_2 emissions from the incineration of the sour water overhead and any fuel gas shall not exceed the emission limitation of Section II.B.1.b and c.

10. MRC shall comply with all applicable standards, limitations, reporting, recordkeeping, and notification requirements of ARM 17.8.342, as specified by 40 CFR Part 63, National Emission Standards for Hazardous Air Pollutants (NESHAP) for Source Categories:

a. Subpart A - General Provisions applies to all equipment or facilities subject to a NESHAP for source category subpart as listed below.

b. Subpart CC - NESHAP from Petroleum Refineries shall apply to, but not be limited to, the bulk loading rack, miscellaneous process vents, storage vessels, wastewater, and equipment leaks.

11. The bulk loading gasoline and distillates truck loading rack shall be operated and maintained as follows:

a. MRC's tank truck loading rack shall be equipped with a vapor collection system designed to collect the organic compound vapors displaced from cargo tanks during gasoline product loading (ARM 17.8.342).

b. MRC’s collected vapors shall be routed to the Vapor Combustion Unit (VCU) at all times. In the event the VCU is inoperable, MRC may continue to load distillates, provided the Department is notified in accordance with the requirements of ARM 17.8.110 (ARM 17.8.752).

c. The vapor collection and liquid loading equipment shall be designed and operated to prevent gauge pressure in the gasoline cargo tank from exceeding 4,500 Pascals (Pa) (450 millimeters [mm] of water) during product loading. This level shall not be exceeded when measured by the procedures specified in the test methods and procedures in 40 CFR 60.503(d) (ARM 17.8.342).

d. No pressure-vacuum vent in the permitted terminal's vapor collection system shall begin to open at a system pressure less than 4,500 Pa (450 mm of water) (ARM 17.8.342).

e. The vapor collection system shall be designed to prevent any VOC vapors collected at one loading position from passing to another loading position (ARM 17.8.342).

f. Loadings of liquid products into gasoline cargo tanks shall be limited to vapor-tight gasoline cargo tanks, using the following procedures (ARM 17.8.342):

    i. MRC shall obtain annual vapor tightness documentation described in the test methods and procedures in 40 CFR 63.425(e) for each gasoline cargo tank that is to be loaded at the truck loading rack;

    ii. MRC shall require the cargo tank identification number to be recorded as each gasoline cargo tank is loaded at the terminal;

    iii. MRC shall cross-check each tank identification number obtained during product loading with the file of tank vapor tightness documentation within two weeks after the corresponding cargo tank is loaded;

    iv. MRC shall notify the owner or operator of each non-vapor-tight cargo tank loaded at the truck loading rack within 3 weeks after the loading has occurred; and

    v. MRC shall take the necessary steps to ensure that any non-vapor-tight cargo tank will not be reloaded at the truck loading rack until vapor tightness documentation for that cargo tank is obtained which documents that:

        aa. The gasoline cargo tank meets the applicable test requirements in 40 CFR 63.425(e) to this permit;

        bb. For each gasoline cargo tank failing the test requirements in 40 CFR 63.425(f) or (g), the gasoline cargo tank must either:

            1. Before the repair work is performed on the cargo tank, meet the test requirements in 40 CFR 63.425 (g) or (h), or

            2. After repair work is performed on the cargo tank, before or during the tests in 40 CFR 63.425 (g) or (h), subsequently passes, the annual certification test described in 40 CFR 63.425(e).

g. MRC shall ensure that loadings of gasoline cargo tanks at the truck loading rack are made only into cargo tanks equipped with vapor collection equipment that is compatible with the terminal's vapor collection system (ARM 17.8.342).

h. MRC shall ensure that the terminal and the cargo tank vapor recovery systems are connected during each loading of a gasoline cargo tank at the truck loading rack (ARM 17.8.342).

i. MRC shall install and continuously operate a thermocouple and an associated recorder, or an ultraviolet flame detector and relay system, that will render the loading rack inoperable if a flame is not present at the VCU flare tip, or any other equivalent device, to detect the presence of a flame (ARM 17.8.342 and ARM 17.8.752).

j. MRC shall monitor and maintain all pumps, shutoff valves, relief valves, and other piping and valves associated with the gas loading rack as described in 40 CFR 60.482-1 through 60.482- 10.

k. The VCU stack shall be at least 35 feet above grade (ARM 17.8.749).

12. The following units shall not combust fuel gas with a sulfur concentration in excess of 160 parts per million (ppm) by volume on a dry basis: reformer heater; kerosene heater; naptha heater; and the FCCU preheater.

13. The crude stack height shall be at least 150 feet above ground level (ARM 17.8.749).

14. The temporary diesel generators shall comply with the following;

a. MRC shall maintain the stack on each temporary generator at least 75 feet above ground level (ARM 17.8.749).

b. MRC shall not operate the temporary generators, permitted under Permit #2161-14, after a suitable power contract has been obtained. In no case shall the temporary generators be operated for a time period exceeding 2 years after initial start-up of the first generator (ARM 17.8.749).

c. MRC shall operate the 5 generators permitted under Permit #2161-14 using low sulfur diesel fuel (ARM 17.8.752).

B. Emission Limitations:

1. Plant-wide Refinery and #1 and #2 Boilers Stack

a. Annual SO_2 Emission Limitations

i.	Plant wide	1515 tons/year
ii.	#1 & #2 Boilers	355 lb/hr average over a 3-hour period
iii.	#1 & #2 Boilers	648 tons/year averaged over a 1-year period (148 lb/hr averaged over 1 year) (ARM 17.8.749)

b. Daily SO_2 Emission Limitations

i.	Plant wide	4.15 tons/day
ii.	#1 & #2 Boilers	174 lb/hr averaged over a 24-hour period

c. Plant-wide refinery CO emissions shall not exceed 12.9 tons/day or 4700 tons/year.

d. Nitrogen oxide (NO_x) emissions from the #1 and #2 boiler stack shall not exceed 76.50 lb/hr or 335 tons/year (ARM 17.8.752).

e. CO emissions from the #1 and #2 boiler stack shall not exceed 1.00 lb/hr or 4.4 tons/year (ARM 17.8.752).

f. The #1 and #2 boilers' opacity shall not exceed 40% averaged over any 6-consecutive minutes (ARM 17.8.304).

2. Diesel/Gas Oil HDS Furnace Stack

a. NO_x emissions shall not exceed the limit of 0.07 pounds per million British thermal units (lb/MMBtu), 1.42 lb/hr, or 6.2 tons/year (ARM 17.8.752).

b. CO emissions shall not exceed the limit of 0.79 lb/hr or 3.5 tons/year (ARM 17.8.752).

c. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

3. Hydrogen Plant Reformer Furnace Stack

a. NO_x emissions shall not exceed the limit of 0.07 lb/MMBtu, 1.90 lb/hr, or 8.3 tons/year (ARM 17.8.752).

b. CO emissions shall not exceed the limit of 0.93 lb/hr or 4.1 tons/year (ARM 17.8.752).

c. Opacity shall not exceed 20% averaged over any 6 consecutive minutes (ARM 17.8.304).

4. Gasoline Loading Rack

a. The total VOC emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 milligrams per liter (mg/L) of gasoline loaded (ARM 17.8.342 and ARM 17.8.752).

b. The total CO emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 10.0 mg/L of gasoline loaded (ARM 17.8.752).

c. The total NO_x emissions to the atmosphere from the VCU due to loading liquid product into cargo tanks shall not exceed 4.0 mg/L of gasoline loaded (ARM 17.8.752).

d. MRC shall not cause or authorize to be discharged into the atmosphere from the enclosed VCU:

i. Any visible emissions that exhibit an opacity of 10% or greater (ARM 17.8.752); and

ii. Any particulate emissions in excess of 0.10 grains per dry standard cubic foot (gr/dscf) corrected to 12% carbon dioxide (CO_2) (ARM 17.8.752).

5. Temporary Diesel Generators (5 – 1600-kilowatt generators)

MRC shall not cause or authorize to be discharged into the atmosphere, from each portable generator stack:

a. NO_x emissions in excess of 49.82 lb/hr (ARM 17.8.752);

b. CO emissions in excess of 9.16 lb/hr. CO emissions from the temporary generators shall be included when determining compliance with the refinery CO emission limits contained in Section II.B.1.c. (ARM 17.8.752);

c. SO_2 emissions in excess of 17.36 lb/hr. SO_2 emissions from the temporary generators shall be included when determining compliance with the plant wide SO_2 emission limits contained in Section II.B.1.a.i. and Section II.B.1.b.i. (ARM 17.8.752); and

d. Visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

6. FCCU

MRC shall not cause or authorize to be discharged into the atmosphere, from the FCCU (MRC Consent Decree):

a. Particulate Matter (PM) emissions in excess of 15.0 lb/hr; and

b. CO emissions in excess of 500 parts per million volumetric dry (ppmvd), corrected to 0% oxygen (O_2) on a 1-hour average basis; and 100 ppmvd, corrected to 0% O_2 on a 365-day rolling average basis.

C. Monitoring Requirements:

1. HTU SWS

a. MRC shall analyze the inlet wastewater streams of the HTU SWS unit for H_2S and ammonia (NH_3) concentrations in accordance with standard Methods for the Examination of Water and Wastewater, latest edition, 4500-S^{2-}D/4500S^{2-}E for H_2S and 4500-NH_3 for NH_3, or an equivalent test method as approved by the Department. The chemical analysis frequency for the HTU SWS unit shall be twice per 7 days of continuous operation or at least once if operated less than 3 days. The inlet wastewater stream flow rate shall be continuously monitored and recorded by a flow rate meter. The outlet wastewater stream flow rate shall be assumed to be equivalent to the inlet flow rate and the effluent concentration will be assumed to be zero for calculating emissions. Emissions of SO_2 and NO_x from the incineration of waste water gases in boilers #1 and #2 shall be determined by utilizing the engineering measurement procedures outlined in Attachment 2. Reporting of the SO_2 and NO_x emissions data shall be performed in accordance with Section II.F (ARM 17.8.749).

b. MRC shall achieve 95% data availability from the flow rate monitoring system of the HTU SWS unit inlet wastewater streams, as demonstrated by the flow rate monitoring system of the HTU SWS unit inlet wastewater streams. This condition became effective April 15, 1998 (ARM 17.8.749).

c. MRC shall inspect and audit the HTU SWS unit flow rate monitor quarterly. MRC shall develop and implement a standard operating procedures manual and a Quality Assurance (QA) plan for the HTU SWS unit flow rate monitor. The standard operating procedures manual and quality assurance plan for the HTU SWS shall be submitted to the Department for approval by April 15, 1998. MRC shall conduct these audits using the approved procedures and forms (ARM 17.8.749).

2. Old SWS

a. MRC shall analyze the inlet wastewater streams of the Old SWS unit for H_2S and NH_3 concentrations in accordance with standard Methods for the Examination of Water and Wastewater, latest edition, 4500-S^{2-}D/4500S^{2-}E for H_2S and 4500-NH_3 for NH_3, or an equivalent test method as approved by the Department. The chemical analysis frequency for the Old SWS unit shall be twice per 7 days of continuous operation or at least once if operated less than 3 days. The inlet wastewater stream flow rate shall be continuously monitored and recorded by a flow rate meter. The outlet wastewater stream flow rate shall be assumed to be equivalent to the inlet flow rate and the effluent concentration will be assumed to be zero for calculating emissions. Emissions of SO_2 from the incineration of waste water gases in the crude unit shall be determined by utilizing the engineering measurement procedures outlined in Attachment 2. Reporting of the SO_2 emissions data shall be performed in accordance with Section II.F (ARM 17.8.749).

b. MRC shall inspect and audit the Old SWS unit flow rate monitor quarterly. MRC shall develop and implement a standard operating procedures manual and a QA plan for the Old SWS unit flow rate monitor. The standard operating procedures manual and QA plan for the Old SWS shall be submitted to the Department for approval within 180 days after issuance of Permit #2161-13. MRC shall conduct these audits using the approved procedures and forms (ARM 17.8.749).

3. Boiler #1 and #2

a. MRC shall operate and maintain an H_2S monitoring system for boiler #1 and #2 to monitor and record the H_2S concentration and fuel gas flow to boilers #1 and #2, to verify continuous SO_2 offsets required. The H_2S monitoring system shall include a continuous H_2S concentration monitor, a continuous fuel gas flow rate meter for each boiler, and a data acquisition and handling system. The continuous H_2S concentration monitor shall comply with the provisions of Attachment 4, Quality Assurance Requirements for MRC Continuous H_2S Concentration Monitoring System (CCMS) that shall be used for Compliance Determinations. MRC shall perform an initial Cylinder Gas Audit (CGA) on the continuous H_2S concentration monitor by April 15, 1998, and submit the reports to the Department by April 20, 1998 (ARM 17.8.749).

b. MRC shall achieve 95% data availability from the H_2S monitoring system. MRC shall maintain compliance with applicable limitations, as demonstrated by the H_2S monitoring system, 95% of the time boilers #1 and #2 are operating. The monitoring and analyzed data will be used to demonstrate compliance with the applicable SO_2 and NO_x emission limitations for boilers #1 & #2.

4. MRC shall install and operate continuous fuel gas flow rate meters for the vacuum heater and for the crude heater. Flowmeters shall be equipped with a data acquisition system and shall be used in conjunction with the H_2S monitor to calculate sulfur emissions from the vacuum heater and the crude heater.

5. MRC shall inspect and audit the flow rate monitors quarterly. MRC shall conduct these audits using the appropriate procedures and forms. The results of these inspections and audits shall be included in the quarterly SO_2 and NO_x emission report.

6. MRC shall develop and implement a standard operating procedures manual and a QA plan for flow rate monitors. These documents shall be submitted to the Department for approval within 30 days prior to an initial start-up date.

7. MRC shall perform a weekly gas chromatograph analysis of the sweet fuel gas drum to ensure the sulfur content does not exceed the limit set for the units in Section II.A.12.

8. MRC shall install and use SO_2 and O_2 CEMS to monitor performance of the FCCU by December 20, 2002. MRC shall install, certify, calibrate, maintain and operate the above-mentioned CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13 and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F (MRC Consent Decree).

9. MRC shall install and use NO_x and O_2 CEMS to monitor performance of the FCCU by December 20, 2002. MRC shall install, certify, calibrate, maintain and operate the above-mentioned CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13 and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F (MRC Consent Decree).

10. MRC shall install and use CO and O_2 CEMS to monitor performance of the FCCU by December 20, 2002. MRC shall install, certify, calibrate, maintain and operate the above-mentioned CEMS in accordance with the requirements of 40 CFR §§ 60.11, 60.13 and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F (MRC Consent Decree).

D. Emission Testing:

1. The FCCU shall be tested for SO_2 and CO and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.B. The testing shall occur in 1998, 2000, 2002, and 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 17.8.106).

2. Boilers #1 and #2 shall be tested for NO_x and CO, concurrently, and the results submitted to the Department in order to demonstrate compliance with the emission limits contained in Section II.B.1.d and e. The testing shall occur in 1998, 2002, and 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 17.8.106).

3. MRC shall comply with all test methods and procedures as specified by subpart R 63.425 (a) through (c), and 63.425 (e) through (h). This shall apply to, but not be limited to, the bulk gasoline and distillate truck loading rack, the vapor processing system, and all gasoline equipment.

   a. The gasoline truck loading VCU shall be initially tested for total organic compounds and compliance demonstrated with the emission limitation contained in Section II.B.4. within 180 days of initial start up. Additional testing shall occur on an every-5-year basis or according to another testing/monitoring schedule as may be approved by the Department. MRC shall perform the test methods and procedures as specified in 40 CFR 63.425, Subpart R (ARM 17.8.105 and 17.8.342).
   b. The gasoline truck loading VCU shall be initially tested for CO and NO_x, concurrently, and compliance demonstrated with the emission limitations contained in Section II.B.4.b and c within 180 days of initial startup (ARM 17.8.105).

4. Fuel flow rates, production information, and any other data the Department believes is necessary shall be recorded during the performance of source tests (ARM 17.8.749).

5. Compliance with the emission limit in Section II.B.6.a shall be demonstrated by conducting a 3-hour performance test representative of normal operating conditions for PM emissions by December 31 of each calendar year beginning with December 31, 2001. If any performance test undertaken pursuant this section is not representative of normal operating conditions, MRC shall conduct a subsequent performance test representative of normal operating conditions by no later than 90 days after the test that was not representative (MRC Consent Decree).

6. All compliance source tests shall be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

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

E. Compliance Determination:

1. Compliance with the plant-wide SO_2 emission limitations contained in Section II.B.1 a and b shall be determined using the summation of the following:

   a. Calculated emissions from the HTU SWS and the Old SWS required by Section II.C.1 and II.C.2;

   b. Data from the sour refinery fuel gas system continuous H_2S concentration monitor and continuous fuel gas flow rate meters required by Section II.C; and

   c. FCCU actual fresh feed and recycles rates (bbl/hour) and the emission factor (lb/bbl) developed from the most recent compliance source test.

2. <u>Boilers #1 and #2</u>

   a. Compliance with boiler #1 and #2 SO_2 emission limitations contained in Section II.B.1.a and b shall be determined using the sum of the following:

      i. The calculated emissions from the HTU SWS and the Old SWS required by Section II.C.1 and 2; and

      ii. The data from the H_2S monitoring system required by Section II.C.3.

   b. In addition to the testing required in Section II.D, compliance determinations for the NO_x emission limits for boilers #1 and #2 shall be determined using the sum of the following:

      i. Actual fuel burning rates and the emission factors developed from the most recent compliance source test conducted while firing refinery fuel gas; and

      ii. The calculated emissions from the HTU SWS and the Old SWS required by Section II.C.1 and 2.

   c. In addition to the testing required in Section II.D, compliance determinations for the CO emission limits for boilers #1 and #2 shall be determined using the actual fuel burning rates and the emission factors developed from the most recent compliance source test.

3. Diesel/Gas Oil HDS Heater

   Compliance determinations for NO_x and CO emission limits for the diesel/gas oil HDS heater shall be based upon actual fuel burning rates and emission factors developed from the most recent compliance source test.

4. Hydrogen Plant Reformer Heater

   Compliance determinations for NO_x and CO emission limits for the hydrogen plant reformer heater shall be based upon actual fuel burning rates and the emission factors developed from the most recent compliance source test.

5. Compliance with the opacity limitations shall be determined according to 40 CFR, Part 60, Appendix A, and Method 9 Visual Determination of Opacity of Emissions from Stationary Sources.

F. Reporting and Recordkeeping Requirements:

1. Plant-wide Refinery
   MRC shall provide quarterly Emission Reports to demonstrate compliance with Section II.B.1. using data required in Section II.E.1. The quarterly report shall also include the following (ARM 17.8.749):

   a. FCC catalyst recirculation rates (tons/hour), FCCU actual fresh feed rates (bbl/day), FCCUs recycle rates (bbl/day), and the emission factor (lb/bbl) developed from the most recent compliance source test.

   b. Emission estimates for SO_2 from FCCU actual fresh feed and recycle rates (bbl/day) and the emission factor (lb/bbl) developed from the most recent compliance source test.

   c. Report the sum of SO_2 emissions from Section II.E.1. for each month of the quarter.

   d. Operating times for the old SWS unit during the reporting period.

   e. All chemical analyses of the old SWS unit waste water stream as required by Attachment 2.

   f. The total hourly flow rates of the wastewater stream flow into the old SWS unit as required by Attachment 2.

   g. Emission estimates for SO_2 from material balance, engineering calculation data as described in Attachment 2.

   h. Monitoring downtime that occurred during the reporting period.

2. #1 and #2 Boilers

   MRC shall provide quarterly Emission Reports to demonstrate compliance with Section II.B.1. using data required in Section II.E.2. The quarterly report shall also include the following (ARM 17.8.749):

a. Operating times for #1 and #2 boilers and the HTU SWS unit during the reporting period.

b. The total hourly flow rates of the fuel gas flow to the #1 and #2 boilers.

c. The hourly averaged H_2S concentrations of the fuel gas to the #1 and #2 boilers.

d. All chemical analyses of the HTU SWS unit waste water stream as required by Attachment 2.

e. The total hourly flow rates of the wastewater stream flow into the HTU SWS unit as required by Attachment 2.

f. Emission estimates for SO_2 from material balance, engineering calculation data as described in Attachment 2.

g. Emission estimates for NO_x from material balance, engineering calculation data as described in Attachment 2. The NO_x emission rate shall be reported as an hourly average.

h. Emission estimates for NO_x from actual fuel burning rates and the emission factors developed from the most recent compliance source test. The NO_x emission rates shall be reported as an hourly average.

i. Report the total NO_x emissions from the incineration of the wastewater streams from the HTU SWS and from fuel gas firing for each month of the quarter.

j. Monitoring downtime that occurred during the reporting period.

3. The results of the inspections and audits required in Section II.C.5. shall be included in the quarterly report (ARM 17.8.749).

4. All Emission Reports shall be submitted within 45 days following the end of the calendar quarter (ARM 17.8.749).

5. MRC shall supply the Department with the following reports, as required, by 40 CFR Part 60 New Source Performance Standards (ARM 17.8.340):

a. Subpart Kb - MRC shall furnish the Department with initial and annual reports for each storage vessel that is subject to this subpart. These reports shall include information described in 40 CFR Part 60 NSPS, Subpart Kb.

b. Subpart GGG - MRC shall submit an initial report to the Department beginning 6 months after the initial start-up date and semiannual reports, thereafter, of all affected facilities. These reports shall include information described in 40 CFR Part 60 NSPS, Subpart GGG.

c. Subpart QQQ - MRC shall submit to the Department semiannually a certification that all required inspections have been carried out in accordance with this subpart. These reports shall include information described in 40 CFR Part 60 NSPS, Subpart QQQ.

6. MRC shall supply the Department with the following reports, as required, by 40 CFR

Part 63 NESHAP (ARM 17.8.342):

a. Subpart CC - MRC shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63, 63.428 (b) and (c), (g)(1), and (h)(1) through (h)(3) of Subpart R.

b. Subpart CC - MRC shall keep all records and furnish all reports to the Department as required by 40 CFR Part 63.654.

7. MRC shall maintain a file of all measurements from the continuous H_2S concentration monitor, continuous fuel gas flow rate meter, HTU SWS, and old SWS unit flow rate meters, including, but not limited to: compliance data; performance testing measurements; all flow rate meter performance evaluations; all flow rate meter calibrations, checks, and audits. Adjustments and maintenance performed on these systems or devices shall be recorded in a permanent form suitable for inspection. The file shall be retained on site for at least 5-years following the date of such measurements and reports. MRC shall supply these records to the Department upon request (ARM 17.8.749).

G. Operational Reporting Requirements

1. MRC 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 and sources identified in Section I of this permit.

   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 for calculating operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. MRC shall notify the Department of any construction or improvement project conducted, pursuant to ARM 17.8.745, that would include a change of 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 or the addition of a new emission unit. 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 information requested in ARM 17.8.745 (ARM 17.8.745).

3. MRC shall document, by month, the hours of operation of each temporary generator. By the 25th day of each month, MRC shall total the hours of operation of each temporary generator and have this information available for representatives of the Department. A written report, including the previous 12-month total hours of operation of each portable generator, shall be submitted annually to the Department no later than March 1 and may be submitted along with the annual Emission Inventory (ARM 17.8.749).

H. Notification Requirements

MRC shall provide the Department with written notification of the following dates within the specified time periods (ARM 17.8.749):

1. Pretest information forms must be completed and received by the Department no later than 25 working days prior to any proposed test date, according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

2. The Department must be notified of any proposed test date 10 working days before that date according to the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

3. 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 limitations or can be expected to last for a period greater than 4 hours (ARM 17.8.110).

4. Actual start-up date of each temporary generator within 15 days after actual start-up.

I. Ambient Monitoring

MRC shall conduct ambient air monitoring as described in Attachment 1.

SECTION III: General Conditions

A. Inspection - The recipient shall allow the Department's representatives access to the source at all reasonable times for the purpose of making inspections, surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.

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

C. Compliance with Statutes and Regulations - Nothing in this permit shall be construed as relieving the permittee 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 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 Department's decision on the application is not final unless 15 days have elapsed and there is no request for a hearing under this section. The filing of a request for a hearing postpones the effective date of the Department's decision until the conclusion of the hearing and issuance of a final decision by the Board.

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 Department personnel at the location of the permitted source.

G. Permit Fees - Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, the continuing validity of this permit is conditional upon the payment by the permittee of an annual operation fee, as required, by that section and rules adopted thereunder by the Board.

H. Construction Commencement - Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked.

Summary of Attachments

Attachment 1	AMBIENT AIR MONITORING PLAN
Attachment 2	ESTIMATE OF EMISSIONS DUE TO INCINERATION OF SOUR WATER STRIPPER OFF GASES
Attachment 3	FUEL GAS FLOWMETER CALIBRATION AND QUALITY ASSURANCE PROCEDURES
Attachment 4	QUALITY ASSURANCE REQUIREMENTS FOR MONTANA REFINING COMPANY'S (MRC) CONTINUOUS H_2S CONCENTRATION MONITORING SYSTEM (CCMS) USED FOR COMPLIANCE DETERMINATION

ATTACHMENT 1

AMBIENT AIR MONITORING PLAN

Montana Refining Company
Permit #2161-18

1. This ambient air-monitoring plan is required by Air Quality Permit #2161-18, which applies to MRC's crude oil refinery located at 1900 Tenth Street, in Great Falls, Montana. The Department may modify this monitoring plan. All requirements of this plan are considered conditions of the permit.

2. MRC shall operate and maintain one air monitoring site northeast of the refinery. The exact location of the monitoring site must be approved by the Department and meet all the siting requirements contained in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, and Parts 53 and 58 of the Code of Federal Regulations, or any other requirements specified by the Department.

3. MRC shall continue air monitoring for at least 2 years after installation of the monitor described in Section 2 above. The Department will review the air monitoring data and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions from the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

4. MRC shall monitor the following parameters at the site and frequencies described below:

AIRS # and Site Name	UTM Coordinates	Parameter	Frequency
30-013-2001	Zone 12	SO_2[1]	Continuous
	N 5263700	Wind Speed and	"
	E 478600	Direction, Standard	"
		Deviation of Wind	"
		Direction (sigma theta)	"

[1]SO_2= sulfur dioxide

5. Data recovery for all parameters shall be at least 80% computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met.

6. Any ambient air monitoring changes proposed by MRC must be approved, in writing, by the Department.

7. MRC shall utilize air monitoring and Quality Assurance (QA) procedures that are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions, the EPA Quality Assurance Manual, including revisions, 40 CFR Parts 53 and 58 of the Code of Federal Regulations, and any other requirements specified by the Department.

8. MRC shall submit quarterly data reports within 45 days after the end of the calendar quarter and an annual data report within 90 days after the end of the calendar year. The annual report may be substituted for the fourth quarterly report if all the quarterly information is included in the report.

9. The quarterly report shall consist of a narrative data summary and a data submittal of all data

points in AIRS format. This data may be submitted in ASCII files on diskette, in IBM-compatible format, or on AIRS data entry forms. The narrative data summary shall include:

a. A topographic map of appropriate scale with UTM coordinates and a true north arrow showing the air monitoring site location in relation to the refinery and the general area,

b. A hard copy of the individual data points,

c. The quarterly and monthly means for wind speed,

d. The first and second highest 24-hour concentrations for SO_2,

e. The first and second highest 3-hour concentrations for SO_2,

f. The first and second highest hourly concentrations for SO_2,

g. The quarterly and monthly wind roses,

h. A summary of the data collection efficiency,

i. A summary of the reasons for missing data,

j. A precision and accuracy (audit) summary,

k. A summary of any ambient air standard exceedances, and

l. Calibration information.

10. The annual data report shall consist of a narrative data summary containing:

a. A topographic map of appropriate scale with UTM coordinates and a true north arrow showing the air monitoring site location in relation to the refinery and the general area,

b. A pollution trend analysis,

c. The annual means for SO_2 and wind speed,

d. The first and second highest 24-hour concentrations for SO_2,

e. The first and second highest 3-hour concentrations for SO_2,

f. The first and second highest hourly SO_2 concentrations,

g. The annual wind rose,

h. An annual summary of data collection efficiency,

i. An annual summary of precision and accuracy (audit) data,

j. An annual summary of any ambient standard exceedance, and

k. Recommendations for future monitoring.

11. The Department may audit (or may require MRC to contract with an independent firm to audit) the air monitoring network, the laboratory performing associated analyses, and any data handling

procedures at unspecified times. On the basis of the audits and subsequent reports, the Department may recommend or require changes in the air monitoring network and associated activities in order to improve precision, accuracy, and data completeness.

ATTACHMENT 2

ESTIMATE OF EMISSIONS DUE TO INCINERATION OF SOUR WATER STRIPPER OFF GASES

Required Data[1]:

1. Feed Flow Rate - Totalized Flowmeter.

2. Feed H_2S Concentration - Standard Methods 18th ED 4500-S^{2-}D, or other method approved by the Department.

3. Feed NH_3 Concentration - Standard Methods 18th ED 4500-NH_3C, or other method approved by the Department.

Calculations:

1. (Feed Flow Rate, lb/hour)*(Feed Sulfide Concentration) = lb/hour H_2S Incinerated

2. (Feed Flow Rate, lb/day)*(Feed Ammonia Concentration) = lb/day NH_3 Incinerated

3. lb/hour H_2S Incinerated * 64/34 = lb/hour SO_2 Emitted

4. lb/day NH_3 Incinerated * 46/17 * 0.5 = lb/day NO_2 Emitted

[1] The effluent (bottoms) stream flow rates from the SWS units are not required to be monitored. The effluent (bottoms) waste water stream flow rate shall be assumed to be equivalent to the inlet flow rate for calculating SO_2 and NOx emissions.

[2] Sampling and analysis of sour water stripper (SWS) effluent from the HTU SWS (for analysis of sulfide and ammonia) and from the old SWS (for analysis of sulfide) are not required. The effluent concentrations will be assumed to be zero for calculating SO_2 and NOx emissions.

ATTACHMENT 3

FUEL GAS FLOWMETER CALIBRATION AND QUALITY ASSURANCE PROCEDURES

1. Use the procedures in the following standards for flowmeter calibration or flowmeter design, as appropriate to the type of flowmeter:

   ASME MFC-4M-1986 (Reaffirmed 1990), "Measurement of Gas Flow by Turbine Meters,"

   American Gas Association Report No. 3, "Orifice Metering of Natural Gas and Other Related Hydrocarbon Fluids, Part 1: General Equations and Uncertainty Guidelines" (October 1990 Edition), Part 2: "Specification and Installation Requirements" (February 1991 Edition) and Part 3: "Natural Gas Applications" (August 1992 edition), (excluding the modified flow-calculation method in Part 3)

   ASME MFC-7M-1987 (Reaffirmed 1992), "Measurement of Gas Flow by Means of Critical Flow Venturi Nozzles,"

2. The Department may also approve other ASME standards or other procedures for flowmeter calibration or flowmeter design. Document other procedures, the equipment used, and the accuracy of the procedures in the monitoring plan. If the flowmeter accuracy exceeds 2.0% of the upper range value, the flowmeter does not qualify for use.

3. Alternatively, a fuel flowmeter used for the purposes of this part may be calibrated or recalibrated at least annually by comparing the measured flow of a flowmeter to the measured flow from another flowmeter that has been calibrated or recalibrate during the previous 365 days, using a standard listed in item 1 or 2 or of this Attachment. Any secondary elements, such as pressure and temperature transmitters, must be calibrated immediately prior to the comparison. Perform the comparison over a period of no more than 7 consecutive unit operating days. Compare the average of three fuel flow readings for each meter at each of three different flow levels, corresponding to (1) normal full operating load, (2) normal minimum operating load, and (3) a load point approximately equally spaced between the full and minimum operating loads. Calculate the flowmeter accuracy at each of the three flow levels using the following equation:

   $ACC = [R - A]/URV * 100$

   Where:
   ACC= Flowmeter accuracy as a percentage of the upper range value.
   R= Average of the three flow measurements of the reference flowmeter.
   A= Average of the three measurements of the flowmeter being tested.
   URV= Upper range value of fuel flowmeter being tested (i.e., maximum measurable flow).

4. If the flowmeter accuracy exceeds 2.0% of the upper range value at any of the three flow levels, either recalibrate the flowmeter until the accuracy is within the performance specification, or replace the flowmeter with another one that is within the performance specification. Notwithstanding the requirement for annual calibration of the reference flowmeter, if a reference flowmeter and the flowmeter being tested are within 1.0% of the flow rate of each other during all in-place calibrations in a calendar year, then the reference flowmeter does not need to be calibrated before the next in-place calibration. This exception to calibration requirements for the reference flowmeter may be extended for periods up to 5 calendar years.

5. Recalibrate each fuel flowmeter to a flowmeter accuracy of 2.0% of the upper range value prior to

use under this part at least annually, or more frequently if required by manufacturer specifications. Perform the recalibration using the procedures in item 1, 2, or 3 of this Attachment.

6. For orifice-, nozzle-, and venturi-type flowmeters, recalibrate the flowmeter, following each calendar quarter using the procedures in item 7 of this Attachment. In addition, re-calibrate the flowmeter whenever the fuel flowmeter accuracy, during a calibration or test, is greater than 1.0% of the upper range value, or whenever a visual inspection of the orifice, nozzle, or venturi identifies corrosion since the previous visual inspection.

7. For orifice-, nozzle-, and venturi-type flowmeters that are designed according to the standards in item 1 of this Attachment, satisfy the calibration requirements of this Attachment by calibrating the differential pressure transmitter or transducer, static pressure transmitter or transducer, and temperature transmitter or transducer, as applicable, using equipment that has a current certificate of traceability to NIST standards. In addition, conduct a visual inspection of the orifice, nozzle, or venturi at least annually.

ATTACHMENT 4

QUALITY ASSURANCE (QA) REQUIREMENTS FOR MONTANA REFINING COMPANY'S (MRC) CONTINUOUS H_2S CONCENTRATION MONITORING SYSTEM (CCMS) USED FOR COMPLIANCE DETERMINATION

1.0 Applicability and Principle

1.1 Applicability

These procedures are used to evaluate the effectiveness of quality control (QC) and (QA) procedures and the quality of data produced by MRC's H_2S CCMS that is used, in part, for determining compliance with the SO_2 emission limitations on a continuous basis as specified in the permit. These QA/QC procedures have been written using 40 CFR 60, Appendix F, and Performance Specification 2 and 7 in Appendix B as guidance. The QA/QC procedures in 40 CFR 60, Appendix F, cannot be used for MRC's CCMS because the H_2S concentration in the refinery fuel gas exceeds the maximum H_2S concentration of 300 ppm for which the procedures can be effectively applied.

This procedure specifies the minimum QA requirements necessary for the control and assessment of the quality of CCMS data submitted to the Department of Environmental Quality (Department).

The CCMS used by MRC shall be a Houston Atlas Model 722R/102 hydrogen sulfide analyzer with sample metering valve, or equivalent. The continuous fuel gas flow rate meter shall meet the specifications outlined in the permit and the Fuel Gas Flowmeter Calibration and Quality Assurance Procedures outlined in Attachment 3.

Data collected as a result of QA/QC measures required in this procedure are to be submitted to the Department. The data is to be used by both the Department and MRC in assessing the effectiveness of the CCMS QA/QC procedures in the maintenance of acceptable CCMS operation and valid emission data.

1.2 Principle

The QA procedures consist of two distinct and equally important functions. One function is the assessment of the quality of the CCMS data by estimating accuracy. The other function is the control and improvement of the quality of the CCMS data by implementing QC policies and corrective actions. These two functions form a control loop: when the assessment function indicates the data quality is inadequate, the control effort must be increased until the data quality is acceptable. In order to provide uniformity in the assessment and reporting of data quality, this procedure explicitly specifies the assessment methods for response drift and accuracy.

2.0 Definitions

2.1 <u>CCMS</u>. The total equipment required for the determination of a fuel gas H_2S concentration, including the data recorder.

2.2 <u>Data Recorder</u>. That portion of the CCMS that provides a permanent record of the analyzer output.

2.3 <u>Span Value</u>. The upper limit of a gas concentration measurement range for the H_2S CCMS used and that can be certified. In the case of MRC's monitor, the span value is 100,000 ppm H_2S (10% H_2S).

2.4 Zero and High-Level Values. The CCMS response values related to the source specific span value. Determination of zero and high-level values are, in the case of MRC's monitor, defined as 0 ppm H_2S (0% H_2S) and 50,000 ppm H_2S (5% H_2S), respectively.

2.5 Calibration Drift (CD). The difference in the CCMS output reading from a reference value after a period of operation during which no unscheduled maintenance, repair or adjustment took place. A certified cylinder gas shall supply the reference value.

2.6 Relative Accuracy (RA). The absolute mean difference between the gas concentration or emission rate determined by the CCMS and the value determined by the SO_2 emission tests plus the 2.5% error confidence coefficient of a series of tests divided by the mean of the SO_2 emission tests or the applicable emission limit.

2.7 Hourly Average. Hourly average means an arithmetic average of all valid and complete data points (complete monitor cycle) in the hour. Ten valid and complete data points are required to determine an hourly average.

2.8 Valid. Valid means data that is obtained from a monitor or meter serving as a component of the CCMS that meets the applicable specifications, operating requirements, and QA/QC requirements of this Attachment.

3.0 QC Requirements

MRC must develop and implement a QC program. As a minimum, the QC program must include written procedures that should describe in detail, complete, step-by-step procedures and operations for each of the following activities:

1. Calibration of CCMS.
2. CD determination and adjustment of CCMS.
3. Preventive maintenance of CCMS (including spare parts inventory).
4. Data recording, calculations, and reporting.
5. Accuracy audit procedures including sampling and analysis methods.
6. Program of corrective action for malfunctioning CCMS.

As described in Section 5.2, whenever excessive inaccuracies occur for 3 consecutive months, the source owner or operator must revise the current written procedures or modify or replace the CCMS to correct the deficiency causing the excessive inaccuracies. These written procedures must be kept on record and available for inspection by the Department.

4.0 Calibration Drift Assessment

4.1 CD Requirement

MRC must check, record, and quantify the zero (or low-level value between 0 and 20% of span value) and span (50 to 100% of span value) calibration drifts at least once daily (approximately 24 hours) in accordance with the method prescribed by the manufacturer. The CCMS calibration must, as minimum, be adjusted whenever the daily zero (or low-level) CD or the daily high-level CD exceeds 5% of the scale (5,000 ppm H_2S, 0.50 % H_2S).

4.2 Recording Requirement for Automatic CD Adjusting Monitors.

Monitors that automatically adjust the data to the corrected calibration values (e.g., microprocessor control) must be programmed to record the unadjusted concentration measured in the CD prior to resetting the calibration, if performed, or record the amount of adjustment.

4.3 Criteria for Excessive CD

If either the zero (or low-level) or high-level CD result exceeds 5,000 ppm H_2S for 5, consecutive, daily periods, the CCMS is out-of-control. If either the zero (or low-level) or high-level CD result exceeds 10,000 ppm H_2S during any CD check, the CCMS is out-of-control. If the CCMS is out-of-control, then take necessary corrective action. Following corrective action, repeat the CD checks.

4.3.1 Out-Of-Control Period Definition

The beginning of the out-of-control period is the time corresponding to the completion of the 5^{th}, consecutive, daily CD check with a CD in excess of 5,000 ppm H_2S, or the time corresponding to the completion of the daily CD check preceding the daily CD check that results in a CD in excess of 10,000 ppm H_2S. The end of the out-of-control period is the time corresponding to the completion of the CD check following corrective action that results in the CD's at both the zero (or low-level) and high-level measurement points being within the corresponding allowable CD limit (i.e., 5% of scale and 10% of scale).

4.3.2 CCMS Data Status During Out-of-Control Period

During the period the CCMS is out-of-control, the CCMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required in the permit.

4.4 Criteria for Out-of-Range

If the monitor measures a fuel gas H_2S concentration in excess of 100,000 ppm H_2S (10% H_2S) at any time, the CCMS is out-of-range. If the CCMS is out of range, perform the necessary corrective action. Following corrective action, repeat the CD checks. A manual zero/span shall be conducted after an out of range as verification of proper operation.

4.4.1 Out-Of-Range Period Definition

The beginning of the out-of-range period is the time corresponding to the first monitor reading in excess of 100,000 ppm H_2S. The end of the out-of-range period is the time corresponding to the last monitor reading in excess of 100,000 ppm H_2S following corrective action that results in the monitor reading being below 100,000 ppm H_2S.

4.4.2 CCMS Data Status During Out-of-Range Period

During the period the CCMS is out-of-range, the CCMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required in the permit.

4.5 Data Recording and Reporting

The source owner must retain all measurements from the CCMS on file for at least 5-years. However, emission data obtained on each successive day while the CCMS is out of control or out of range may not be included as part of the minimum monthly data requirement of the permit nor be used in the calculation of reported emissions for that period.

5.0 Data Accuracy Assessment

5.1 Auditing Requirements

The CCMS must be audited at least once each calendar quarter. Successive quarterly audits shall occur no closer than 2 months from the previous audit. The audits shall be conducted as follows:

5.1.1 Cylinder Gas Audit (CGA).

A CGA shall be conducted at least once each calendar quarter. To conduct a CGA:

a. Challenge the CCMS with an audit gas of known concentration at two points within the following ranges:

   1. 15% - 20% of span value (15,000 - 20,000 ppm H_2S, 1.5% - 2% H_2S)
   2. 30% - 35% of span value (30,000 - 35,000 ppm H_2S, 3.0% - 3.5% H_2S)

   Challenge the CCMS three times at each audit point, and use the average of the three responses in determining accuracy. Use separate audit gas cylinders for audit points 1 and 2. Do not dilute gas from an audit cylinder when challenging the CCMS. The monitor should be challenged at each audit point for a sufficient period of time to assure adsorption-desorption of the CCMS sample transport surfaces has stabilized. The difference between the actual concentration of the audit gas and the concentration indicated by the monitor is used to assess the accuracy of the CCMS.

b. Operate the monitor in its normal sampling mode (i.e., pass the audit gas through all filters, scrubbers, conditioners, and other monitor components used during normal sampling, and as much of the sampling probe as is practical). At a minimum, the audit gas should be introduced at a point upstream of the sample filter/fast sweep assembly and sample cooler and, if possible, pass the audit gas through the probe, sample line, and liquid knock out pots.

c. Use audit gases that have been certified by comparison to National Institute of Standards and Testing (NIST) gaseous Standard Reference Materials (SRM's) or NIST/Environmental Protection Agency (EPA) approved gas manufacturers' Certified Reference Materials (CRM's) (See Citation 1) following EPA Traceability Protocol No. 1 (See Citation 2) or other gases approved by the Department. As an alternative to Protocol No. 1 audit gases, CRM's may be used directly as audit gases. A list of gas manufacturers that have prepared approved CRM's is available from EPA at the address shown in Citation 1. Procedures for preparation of CRM's are described in Citation 1. Procedures for preparation of EPA Traceability Protocol No. 1 materials are described in Citation 2.

5.1.2 Other Alternative Audits

Other alternative audit procedures may be used as approved by the Department.

5.2 Excessive Audit Inaccuracy

If the relative accuracy, using the CGA exceeds the criteria in section 5.2.3, the CCMS is out of control. If the CCMS is out of control, take necessary corrective action to eliminate the problem. Following corrective action, the source owner or operator must audit the CCMS with a CGA to determine if the CCMS is operating within the specifications. If audit results show the CCMS to be out of control, the CCMS operator shall report both the audit showing the CCMS to be out of control and the results of the audit following corrective action showing the CCMS to be operating within specifications.

5.2.1 Out-Of-Control Period Definition

The beginning of the out-of-control period is the time corresponding to the completion of the sampling for the CGA. The end of the out-of-control period is the time corresponding to the completion of the sampling of the subsequent successful audit.

5.2.2 CCMS Data Status During Out-Of-Control Period

During the period the monitor is out of control, the CCMS data may not be used in calculating emission compliance nor be counted towards meeting minimum data availability as required in the permit.

5.2.3 Criteria for Excessive Audit Inaccuracy

The criteria for excessive inaccuracy for the CGA, is +/- 15.0% of each average audit value (i.e., 15% of span, +/- 2,250 ppm @ 15,000 ppm; 20% of span, +/- 3,000 ppm @ 20,000 ppm; 30% of span, +/- 4,500 ppm @ 30,000 ppm; and 35% of span, +/- 5,250 ppm @ 35,000 ppm).

5.3 Criteria for Acceptable QC Procedure

Repeated excessive inaccuracies (i.e., out-of-control conditions resulting from the quarterly audits) indicate the QC procedures are inadequate or that the CCMS is incapable of providing quality data. Whenever excessive inaccuracies occur for 2 consecutive quarters, the source owner or operator must revise the QC procedures (see Section 3) or modify or replace the CCMS.

6.0 Calculations for CCMS Data Accuracy

Use the following equation to calculate the accuracy for the CGA. Each component of the CCMS must meet the acceptable accuracy requirement.

$$A = [(Cm-Ca)/Ca] \times 100$$

Where:
A = Accuracy of the CCMS, %.
Cm = Average CCMS response during audit, ppm H_2S.
Ca = Average audit value (CGA certified value), ppm H_2S.

Example calculations for the CGA are available in Citation 3.

7.0 Reporting Requirements

At the reporting interval specified in the permit, report for the CCMS the accuracy results from Section 6 and the CD assessment results from Section 4. Report the drift and accuracy information as a Data Assessment Report (DAR), and include one copy of this DAR for each quarterly audit with the report of emissions required in the permit.

As a minimum, the DAR must contain the following information:

1. Source owner or operators name and address.

2. Identification and location of the CCMS.

3. Manufacturer and model number of the CCMS.

4. Assessment of CCMS data accuracy and date of assessment as determined by the CGA described in Section 5, including the accuracy for the CGA, the cylinder gases certified values, the CCMS responses, and the calculation results as defined in Section 6. If the accuracy audit results show the CCMS to be out of control, the CCMS operator shall report both the audit results showing the CCMS to be out of control and the results of the audit following corrective action showing the CCMS to be operating within specifications.

5. Results from the CGA as described in Section 5.

6. Summary of all corrective actions taken when CCMS was determined out of control or out of range, as described in Sections 4 and 5.

An example of a DAR format is shown in Figure 1.

8.0 Bibliography

1. "A Procedure for Establishing Traceability of Gas Mixtures to Certain National Bureau of Standards Standard Reference Materials." Joint publication by NBS and EPA-600/7-81-010. Available from the U.S. Environmental Protection Agency. Quality Assurance Division (MD-77), Research Triangle Park, NC 27711.

2. "Traceability Protocol for Establishing True Concentrations of Gases Used for Calibration and Audits of Continuous Source Emission Monitors (Protocol Number 1)" June 1978. Section 3.0.4 of the Quality Assurance Handbook for Air Pollution Measurement Systems. Volume III. Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U.S. Environmental Protection Agency. Office of Research and Development Publications, 26 West St. Clair Street, Cincinnati, OH 45268.

3. Calculation and Interpretation of Accuracy for Continuous Emission Monitoring Systems (CCMS). Section 3.0.7 of the Quality Assurance Handbook for Air Pollution Measurement Systems, Volume III, Stationary Source Specific Methods. EPA-600/4-77-027b. August 1977. U.S. Environmental Protection Agency. Office of Research and Development Publications, 26 West St. Clair Street, Cincinnati, OH 45268.

Figure 1 - EXAMPLE FORMAT FOR DATA ASSESSMENT REPORT (DAR)

A. General Information

Period Ending Date: ______________________________ Year
Company Name: Montana Refining Company

Plant Name: Great Falls Refinery

Source Unit No.: Refinery Fuel Gas System (Sour Fuel Mix Drum)

CCMS Manufacturer: Houston Atlas

Model No.: Model 722R/102

CCMS Serial No.: 5656

CCMS Type: Hydrogen sulfide (H_2S) analyzer with sample metering valve

CCMS sampling location: at its current location, upstream of boilers #1 and #2
CCMS span value: 100,000 ppm H_2S (10.0%)

CCMS Data Available (%): ________________ Time in Compliance (%):

Date of Previous Audit:

CCMS Repairs or replaced components that affected or altered calibration values (include description and dates):

Responsible Official: ____________________________________ Date:

B. Accuracy Assessment Results from Cylinder Gas Audit (Complete A below for the CCMS).

If the quarterly audit results show the CCMS to be out-of-control, report the results of both the quarterly audit and the audit following corrective action showing the CCMS to be operating properly.

Montana Refining Company Hydrogen sulfide (H_2S) CCMS	Audit point 1 15% - 20% of span value	Audit point 2 30% - 35% of span value
Date of audit		
Cylinder ID number		
Date of certification		
Type of certification[2]		
Initial Cylinder Press. (psi)		
Final Cylinder Press. (psi)		
Ca = Certified audit value (ppm)		
CCMS response value (ppm) Run # 1		

[2] Example: EPA Protocol 1, CRM, or other

CCMS response value (ppm) Run # 2		
CCMS response value (ppm) Run # 3		
Sum of Runs 1, 2, and 3		
Average CCMS response (ppm), Cm = Sum/3		
Accuracy percent, [(Cm-Ca)/Ca]*100		
Out of Control? (|Accuracy| > 15%)		
Comments:		

Technician: ____ Date:

C. Monitor Out-of Control Status Documentation

Montana Refining Company - H_2S CCMS Out-of Control Status Documentation

Date and time of CD check or audit:

Type of assessment (check one): ______ CD check ______ Accuracy Audit

Type of CD check (zero or span):

CCMS response (%H_2S):

Reference value (%H_2S):

Calibration drift (%of scale):
Audit inaccuracy (% of reference value):

Date and time of beginning of out-of-control period:
Problem:

Date and time of corrective action:
Corrective action taken:

Date and time of CD check or audit after corrective action:
CCMS response after corrective action (%H_2S):

Calibration drift after corrective action (%of scale):
Audit inaccuracy after corrective action (% of reference value):
Date and time of end out-of-control period:
Number of hours of data invalidated:
Technician: ____ Date:

Permit Analysis
Montana Refining Company
Permit #2161-18

I. Introduction/Process Description

A. Permit History:

On December 2, 1985, the Montana Department of Health and Environmental Sciences and Montana Refining Company (MRC) signed a stipulation requiring MRC to obtain an air quality permit, and stipulated that a permit emission limitation of 4,700 tons per year (tons/year) carbon monoxide (CO) would constitute compliance with ambient CO standards. MRC submitted this permit application with the intentions of permitting its existing refining operations, including all equipment not already permitted.

On October 20, 1985, MRC was granted a general permit for their petroleum refinery and major refinery equipment located in Great Falls, Cascade County, Montana. The application was given **Permit #2161**.

The first alteration to their original permit was given **Permit #2161-A** and was issued on May 31, 1989. This alteration involved the addition of a deisobutanizer reboiler.

The second alteration was given **Permit #2161-A1** and was issued on March 12, 1990. This project involved the installation of one 30,000-barrel gasoline storage tank and one 40,000-barrel crude oil storage tank at the present facility. Both tanks were installed with external floating roof control.

The third alteration was given **Permit #2161-A3** and was issued on December 18, 1990. This alteration consisted of the installation of a Hydrofluoric (HF) Acid Alkylation Unit, internal floating roofs at existing storage tanks, which had fixed roofs, and a safety flare.

The fourth alteration was given **Permit #2161-04** and was issued on June 16, 1992. This alteration consisted of the installation of a sodium hydrosulfide (NaHS) unit at the existing Great Falls Refinery.

The NaHS unit receives refinery fuel gas (540,000 standard cubic foot per day (scf/day) maximum rated capacity) containing hydrogen sulfide (H_2S) and reacts with a sodium hydroxide caustic solution to remove virtually 100% of the H_2S by converting it to NaHS, a saleable product.

The resultant sweet fuel gas is burned, as before, in other process heaters. However, since the fuel gas contains virtually no H_2S, sulfur dioxide (SO_2) emissions from the process heaters, assuming no other changes, were decreased by nearly 60%. There was no decrease in permitted SO_2 emissions from this permit because the refinery wanted to retain the existing permitted SO_2 emission limitations so it could charge less expensive, higher sulfur crude oil.

In the basic process, off-gases from product desulfurizing processes (fuel gases) are contacted with a caustic solution in a gas contractor. The resultant reaction solution is continually circulated until the caustic solution is essentially used up; NaHS product is then sent to storage. Make-up caustic is added to the process as required. The process requires a gas contractor, process heat exchanger, circulation pump, storage tanks for fresh caustic and NaHS product, 12 pipeline valves, 4 open-ended valves, 21 flanges, and other process control equipment.
The only process emissions are fugitive Volatile Organic Compounds (VOC) from

equipment (valves and flanges) in fuel gas stream service. To estimate unit VOC emissions, emission factors developed by the Environmental Protection Agency (EPA) for equipment in gas vapor service with measured emissions from 0 to 1,000 parts per million (ppm) are used. With an aggressive monitoring and maintenance program, fugitive VOC emissions from valves and flanges are within this 0 to 1,000-ppm range. Total annual fugitive VOC emissions from the sodium hydrosulfide units are estimated to be 20 pounds per year.

The tank that is to be used to store NaHS product was in jet fuel service. When taken out of jet fuel service, this tank (#35) is no longer a source of VOC emissions; the reduction in VOC emissions will be 2,270 pounds per year (lb/yr). Considering the 2,270-lb/yr decrease due to tank #35 service change, the refinery realized a net decrease in annual VOC emissions of 2,250 lb/yr or 1.1 tons/year.

The fifth alteration was given **Permit #2161-05** and was issued on October 15, 1992. This permit alteration was for the construction and operation of two 20,000-barrel capacity aboveground storage tanks at its Great Falls Refinery. The new tanks contain heavy naphtha (#127) and raw diesel (#128).

Each tank was constructed of metal sections welded together that rest on a concrete ring wall foundation. External floating roofs with dual seals are installed on each tank for VOC control.

On April 6, 1993, MRC was granted **Permit # 2161-06** to construct and operate a hydrodesulfurization (HDS) unit and hydrogen plant. This sixth alteration was required to go through New Source Review (NSR) - Prevention of Significant Deterioration (PSD) review for NO_x and was deemed complete on February 22, 1993. The HDS project was designed to process 5,000 barrels per day (bbl/day) of diesel/gas oil and to reduce the sulfur content to 0.05 weight percent. The reduction of sulfur in diesel fuel and gasoline were mandated by the 1990 Clean Air Act Amendments and were accomplished by October 1993, and 1995, respectively. The desulfurizer unit operated by MRC was limited in size and throughput capacity to approximately 1,400 barrels per day.

The HDS project consisted of an HDS process unit and heater, hydrogen plant with reformer heater, and the removal of storage tanks #40 through #43. Tanks #40 and #41, which processed gas oil, were discontinued. Tanks #42 and #43 that process raw diesel were also discontinued. Tanks #44 and #111 were changed to gas oil use and Tank #45 which serviced JP-4 was changed to gas oil use.

On July 28, 1993, **Permit #2161-07**, a modification to MRC's Air Quality Permit #2161-06, was issued to change the emission control requirements of Section II.A.4.d.i., titled "Pressure Vessels."

In a system where the valves relieve to atmosphere, rupture discs can prevent emissions in the event of relief valve leakage. In HF systems, they can provide some protection from acid corrosion on the relief valve and acid salt formation. Except where HF acid is present, rupture discs do not provide any additional protection nor do they prevent any release of air contaminates in a closed relief system.

In heavy liquid service, rupture discs can be safety hazards by partial failure or leaking and changing, over time, the differential pressure required providing vessel protection. Therefore, only pressure vessels in HF Acid service shall be equipped with rupture discs upstream of the relief valves and all except storage tanks shall be vented to the flare system.
Also, the allowable particulate emission limitation for MRC's FCCU was corrected to

reflect the maximum allowable emissions based on the process weight rule (Administrative Rules of Montana (ARM) 17.8.310). The maximum allowable emissions were calculated to be 234.53 tons/year using a catalyst circulation rate of 125 tons/hour.

MRC requested a permit modification, **Permit #2161-08,** to remove the alkylation unit and tanks #127 and #128 from New Source Performance Standards (NSPS) status because they were erroneously classified as affected facilities under NSPS when originally permitted. This request for modification was submitted on August 11, 1993, and issued on January 6, 1994.

When MRC applied for the preconstruction permit to build the HF Alkylation Unit in 1990, it was presumed, since this unit was new to MRC, it automatically fell under NSPS as new construction. Subsequently, it has been determined that if a source is moved as a unit from a location where operation occurred (Garden City, Kansas) to another location, it must meet the definition of reconstruction or modification in order to trigger NSPS applicability.

The alkylation plant was originally constructed in Garden City, Kansas during 1959 - 1960 and moved, in its entirety, to Great Falls and installed. Since the unit was originally constructed before the NSPS-affected date of January 5, 1981, it does not meet the criteria for construction date of a new source under 40 Code of Federal Regulations (CFR), Subpart GGG or Subpart QQQ.

The project did not meet the criteria under reconstruction because no capital equipment was replaced when the unit was relocated. The replacement work performed, as the unit was moved, amounted to pump seals, valve packing, bearings, small amounts of corroded piping, and some heat exchanger tubes and bundles, all of which are done routinely as maintenance. The VOC emitters, such as valve packing and pump seals, were upgraded to meet Best Available Control Technology (BACT).

Along the same line, tanks #127 and #128 were originally constructed at Cody, Wyoming in 1960 and relocated to Great Falls in 1993. The only change was the modification of the roof seals to double seals to meet BACT. This cost of modification was a total of $15,000 for both tanks as compared to more than $500,000 if two new tanks were to be built.

Also, on October 28, 1993, MRC submitted a permit application to alter the existing permit. This modification and alteration of the existing permits were assigned Permit #2161-08. MRC proposed to construct and operate a 3,500 barrel-per-day asphalt polymerization unit. The unit enabled MRC to produce a polymerized asphalt product that would meet future federal specifications for road asphalt, as well as supply polymerized asphalt to customers that wished to use the product.

The proposed unit consisted of two circuits: the asphalt circuit and the hot oil circuit. In the asphalt circuit, polymerization occurs in a 1,000-barrel steel, vented mix tank. Product blending and storage occurs in 3 steel, vented 1,000 barrel tanks identified as A, B, and C on the attached flow diagram. Existing Tanks #55 and #56 (3,000 barrels each) remained in asphalt service and are used for storage. In addition to the above equipment, the asphalt circuit also consisted of 4 pumps and approximately 47 standard valves. All the above equipment became part of the asphalt service and, except for Tanks #55 and #56, was new.

To maintain the asphalt at the optimum temperature in the storage and blending tanks, a hot circuit was utilized. Hot oil (heavy fuel oil) was heated in an existing permitted process heater (Tank #56 heater) and circulated through coils in the process tankage. No change in the method of operation of the heater was anticipated. A steel, vented hot-oil storage/supply tank was utilized to maintain the required amount of hot oil in the unit. In addition to the process heater and storage/supply tank, the hot-oil circuit consisted of one pump and approximately 56 standard valves. The above equipment was used in hot-oil service and, except for the heater, was new.

An annual emissions increase of 7.3 tons/year of VOC was expected due to operation of the unit. It was anticipated that the unit would be operated only 6 months of the year. The VOC emissions resulted from the vented hot-oil tank and the valves and pump in hot-oil service.

Permit #2161-09 was issued on September 6, 1994, and included a change in the method of heating 3 previously permitted polymer modified asphalt tanks. As previously permitted, these tanks were heated utilizing circulating hot oil. The tanks were heated individually using natural gas fired fire-tube heaters. The use of natural gas eliminated the hot-oil circuit, including the hot-oil storage tank, entirely.

Since the initial permit application for the modified asphalt unit, several small design changes occurred involving the addition of a new 800-gallon wetting tank for asphalt service. An output line from existing Tank #69 (Tall Oil) was also added. This output line added approximately twelve new valves and one new pump, all in Tall Oil service, to the unit. All other valves and pumps were designated to be in asphalt service.

All VOC emissions from equipment and tanks in asphalt service were assumed to be negligible, since asphalt has negligible vapor pressure at the working temperatures seen in the unit.

Permit #2161-10, for the installation of an additional boiler (Boiler #3) to provide steam for the facility, was never issued as a final permit. On May 28, 1997, the Department of Environmental Quality (Department) received a letter requesting the withdrawal of the permit application and the withdrawal was granted to MRC. A summary of this permitting action is included in the analysis for Permit #2161-11.

Permit #2161-11 was issued on January 23, 1998, for the installation of a vapor collection system and enclosed flare for the reduction of Hazardous Air Pollutants (HAP) resulting from the loading of gasoline. This was done in order to comply with the gasoline loading rack provisions of 40 CFR 63, Subpart CC - National Emission Standards (NES) for Petroleum Refineries. A Vapor Combustion Unit (VCU) was added to the truck loading rack. The gasoline vapors are collected from the trucks during loading then routed to an enclosed flare where combustion occurs. The result of this project was an overall reduction in the amount of VOC and HAPs emitted, and a slight increase in CO and NO_x emissions.

Because MRC's bulk gasoline and distillate truck loading rack VCU was defined as an incinerator under Montana Code Annotated (MCA) 75-2-215, a determination that the emissions from the VCU would constitute a negligible risk to public health was required prior to the issuance of a permit to the facility. MRC and the Department identified the following HAP's from the flare that was used in the health risk assessment. These constituents are typical components of MRC's gasoline.

1. Benzene
2. Toluene

3. Ethyl Benzene
4. Xylenes
5. Hexane
6. 2,2,4-Trimethlypentane
7. Cumene
8. Napthalene
9. 1,3-Butadiene

The reference concentrations for Benzene, Toluene, Ethyl Benzene, and Hexane were obtained from EPA's IRIS database. The risk information for the remaining HAPs was contained in the January 1992 CAPCOA Risk Assessment Guidelines. The ISCT3 modeling performed by MRC for HAPs identified above demonstrated compliance with the negligible risk requirement.

MRC requested, via a letter dated August 13, 1997, changes to administratively and technically correct Permit #2161-09. These changes were necessary as a result of the withdrawal of Permit #2161-10. The changes included correctly stating opacity limits relating to asphalt storage tanks, removing references to procedural rules, changing monitoring requirements for the HTU Sour Water Stripper (SWS) and changing performance specifications for the continuous H_2S monitoring system.

The Department issued Draft Modification #2161-11 on November 6, 1997, to address the permit changes that were requested by MRC. The Department received comments on November 13, 1997, from MRC and later met on November 17, 1997, to discuss the draft modification. Because MRC had applied for a permit alteration on October 21, 1997, for the loading rack VCU, the draft modification was addressed in the permit alteration request.

The Department issued Preliminary Determination #2161-11 on November 26, 1997. The Department received comments from MRC on December 4, 1997, December 10, 1997, December 15, 1997, and December 30, 1997. The Department responded to these comments via faxes on December 8, 1997, December 11, 1997, and December 16, 1997. On December 23, 1997, the Department was prepared to issue a Department Decision, but MRC requested, via telephone, that the decision not be issued until after the holidays. The decision was required to be issued by January 8, 1998, to meet the mandated time frames for issuing a Department Decision.

Permit #2161-12 was not issued. MRC applied for a modification on February 18, 1998, and this action was given #2161-12. On February 27, 1998, the Department notified MRC that the permitting actions requested would require an alteration and that a complete preconstruction permit application would be required.

Permit #2161-13 placed enforceable emission limits on the facility, both plantwide and the #1 and #2 boilers. The emission limits showed, through the use of EPA approved models, to protect the National Ambient Air Quality Standards (NAAQS) for SO_2.

The continuous gas flowmeters installed on the vacuum heater and the crude heater were placed in the permit. Also, the #1 and #2 boiler limits were updated to allow MRC more flexibility in their operations. The limits were originally placed on the boilers to keep MRC below the PSD permitting threshold. The new limits maintained MRC's status below the PSD permitting threshold.

The monitoring location was identified in Attachment 1 Ambient Air Monitoring Plan. The current location was determined to be inappropriate after reviewing the modeling analysis, and the new location was approximately 1.2 km from its present location. The monitoring location was chosen based on the modeling analysis that was submitted and is required to provide monitored confirmation of compliance with the Montana SO_2 Standards.

The method numbers for examination of water and wastewater were updated in Section II.C. and Attachment 2. The conditions in Permit #2161-13 were incorporated into the Operating Permit and the compliance demonstration methodology for those conditions was evaluated at the time of the Operating Permit's issuance. Permit #2161-13 replaced Permit #2161-11.

On August 4, 2001, the Department issued **Permit #2161-14** for the installation and operation of five 1600-kW diesel-powered, temporary generators. These generators were necessary because of the current high cost of electricity. The generators would only operate for the length of time necessary for MRC to acquire a permanent, more economical, supply of power. Further, the generators are limited to a maximum operating period of 2 years.

Because these generators would only be used when commercial power is cost prohibitive, the amount of emissions expected during actual operation is minor. In addition, because the permit limits the operation of these generators to a time period of less than 2-years, the installation and operation qualifies as a "temporary source" under the PSD permitting program. Therefore, the proposed project does not require compliance with the Administrative Rules of Montana (ARM) 17.8.804, 17.8 820, 17.8.822, and 17.8.824. Even though the portable generators are considered temporary, the Department requires compliance with BACT and public notice requirements; therefore, compliance with ARM 17.8.819 and 17.8.826 will be ensured. Finally, MRC is responsible for complying with all applicable ambient air quality standards. Permit #2161-14 replaced Permit #2161-13.

On August 17, 2002, the Department issued **Permit #2161-15** to eliminate the summer boiler SO_2 emission limits (both the plant-wide and 24-hour average) and redefine the winter limits as year-round limits. The seasonal limits were originally placed in the permit to allow MRC more flexibility when operating the boilers. Both the winter and summer scenarios were supported by ambient air quality modeling performed prior to Permit #2161-13 being issued. The winter limit being redefined as a year-round limit does not represent an increase in SO_2 emissions from the boilers or any other emitting point. In addition, the Department removed requirements to determine and report NO_x emissions both from the crude heater (due to the old SWS) and refinery wide, as these sources are not subject to NO_x emissions limitations. The requirements appeared to have been inadvertently applied through an administrative error. MRC already provides refinery-wide NO_x emissions as part of its annual Emission Inventory submission to the Department. Permit #2161-15 replaced Permit #2161-14.

On March 19, 2003, the Department issued **Permit #2161-16** to include certain limits and standards associated with the Consent Decree lodged on December 20, 2001. In addition, the permit was updated with new rule references under ARM 17.8, Subchapter 7. Permit #2161-16 replaced Permit #2161-15.

The Department received a request to modify Air Quality Permit #2161-16 on July 10, 2003, to change the emission testing schedule for the gasoline truck loading vapor combustion unit (Section II.D.3.a) to be consistent with MRC's current operating permit. MRC also requested the Department clarify the 7,000-barrel per day (bbl/day) limit of crude charge (referenced in MRC's Title V Operating Permit) is no longer valid. Should MRC's normal processing exceed 7,000 bbl/day, MRC would be required to comply with ARM 17.8.324, as applicable. In a letter received by the Department on September 30, 2003, MRC also requested to add three new asphalt tanks with associated natural gas heaters. Since the emissions from the three tanks were less than 15 tons/year, the Department added the tanks under de minimis, ARM 17.8.745. The current permit action updated the permit to reflect the changes. **Permit #2161-17** replaced Permit #2161-16.

B. Current Permit Action

On May 14, 2004, the Department received a letter from MRC requesting changes to Permit #2161-17. The proposed change includes adding the ability to burn sweet gas in heaters at the HF Alkylation Unit, and at Tanks 102, 135, 137, 138, and 139. The sweet gas will have a H_2S limit equivalent to the 40 CFR Part 60, Standards of Performance for NSPS, Subpart J limit of 0.10 grains per dry standard cubic foot (gr/dscf) H_2S. The continuous refinery fuel gas monitoring system for H_2S installed on the fuel gas system that supplies the heaters would be used to determine compliance with the limit. Since the emissions from switching the fuel to sweet gas are less than 15 tons/year, the Department added the fuel switch under de minimis, ARM 17.8.745. The current permit action updates the permit to reflect the changes. **Permit #2161-18** replaces Permit #2161-17.

C. Additional Information

Additional information, such as applicable rules and regulations, BACT 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 locations 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 is 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. MRC shall also comply with the testing and monitoring requirements of this permit.

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 Montana Clean Air Act, 75-2-101, *et seq*., MCA.

   MRC shall comply with all 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. 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. 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. No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

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

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 17.8.221 Ambient Air Quality Standard for Visibility
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

MRC 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. (1) This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed on or before November 23, 1968, that exhibit an opacity of 40% or greater averaged over 6 consecutive minutes. (2) 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 17.8.322 Sulfur Oxide Emissions - Sulfur in Fuel. (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. The Great Falls Refinery is a small refinery (under 10,000 BPD crude oil charge) and is, therefore, exempt from this rule, provided that they meet the other provisions of this rule.

3. 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 truck 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. MRC is subject to this rule when MRC's normal processing exceeds 7,000 bbl/day of crude charge.
4. ARM 17.8.340 Standard of Performance for New Stationary Sources. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60, NSPS. The applicable NSPS Subparts include, but are not limited to:

a. Subpart A - General Provisions apply to all equipment or facilities subject to an NSPS Subpart as listed below.

b. Subpart J - Standards of Performance for Petroleum Refineries shall apply to the following affected facilities, as described per the MRC Consent Decree:

   i. FCCU regenerator: for CO, the requirements of Subpart J shall apply by December 20, 2002; and for SO_2, the requirements of Subpart J shall apply by December 20, 2004 (MRC Consent Decree).

   ii. Heaters and boilers: the requirements of Subpart J shall apply by no later than December 31, 2006. MRC shall install, certify, calibrate, maintain, and operate a fuel gas continuous emission monitor Continuous Emission Monitoring System (CEMS) in accordance with the requirements of 40 CFR §§ 60.11, 60.13, and Part 60 Appendix A, and the applicable performance specification test of 40 CFR Part 60 Appendices B and F (MRC Consent Decree).

c. Subpart J - Standards of Performance for Petroleum Refineries does <u>not</u> apply to the following units:

Equipment	Year of Mfg.	Fuel Type
D/GO HDS heater	1993	Natural gas
Hydrogen heater	1982	Natural gas
FCCU	1957	Refinery fuel gas
FCC preheater	1961	Sweet refinery fuel gas
Alky /heater	1979	Natural gas/Sweet refinery fuel gas
Boilers #1 & 2	1946	Refinery fuel gas
Reformer furnace	1962	Sweet refinery fuel gas
Vacuum unit	1954	Refinery fuel gas
Naphtha HDS heater	1961	Sweet refinery fuel gas
Kerosene HDS heater	1961	Sweet refinery fuel gas
Asphalt heaters	1963	Sweet refinery fuel gas
Crude furnace/reboiler*	1983	Refinery fuel gas
Emergency flare**	1990	Refinery fuel gas

* In 1983 two existing crude heaters were replaced with one crude furnace/reboiler with the same combined heat capacity. Reconstruction means the replacement of components of an existing facility to such an extent that the fixed capital cost of the new component exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility [40 CFR Part 60.15(b)]. Therefore, the crude furnace/reboiler is exempt from NSPS, Subpart J.

** The use of the emergency flare to burn off only process upset gases or fuel gas that is released to the flare due to relief valve leakage or other emergency malfunction exempts the flare from the requirement detailing the maximum H_2S of any fuel gas burned in a fuel gas combustion device (40 CFR Part 60.104(a)(1), Subpart J). For this reason, the emergency flare is exempt from NSPS Subpart J.

d. Subpart Kb - Volatile Organic Liquid Storage Vessels (including Petroleum

Liquid Storage Vessels) for which Construction, Reconstruction or Modification Commenced After July 23, 1984.

Note: The five tanks, listed below, used in the asphalt polymerization unit are exempt from the provisions of Subpart Kb because the true vapor pressure (TVP) of the Volatile Organic Liquid (VOL) stored is less than 3.5 kilopascals (Kpa) (0.5076 pounds per square inch atmosphere (psia)).

Asphalt Polymerization Unit

Tank	Capacity	TVP (psia)
wetting tank (1)	800 gal	negligible
reactor tank (1)	715 bbl	negligible
asphalt storage (3)	1,000 bbl	negligible

e. Subpart GGG - Equipment Leaks of VOC in Petroleum Refineries shall not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

f. Subpart QQQ - VOC Emissions from Petroleum Refinery Wastewater Systems does not apply to the following units:

Equipment	Year of Mfg.	Year of Install.
HF Alkylation Unit	1960	1990

g. All other applicable subparts and referenced test methods.

5. 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. Subpart A - General Provisions applies to all National Emission Standards for Hazardous Air Pollutants (NESHAP) source categories subject to a Subpart as listed below.

   b. Subpart CC - NESHAP Pollutants from Petroleum Refineries shall apply to, but not be limited to, the Bulk Truck Loading Rack.

D. ARM 17.8, Subchapter 4 - Stack Height and Dispersion Techniques, including, but not limited to:

ARM 17.8.401 Definitions and ARM 17.8.402, Requirements. MRC must demonstrate compliance with the ambient air quality standards based on the use of Good Engineering Practices (GEP) stack height.

E. 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 permit 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. The current permit action is considered an administrative amendment and does not require an application fee.

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; and the air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.

   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 prorate the required fee amount.

F. 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 alteration to construct, alter or use any air contaminant sources that have the Potential To Emit (PTE) greater than 25 tons per year of any pollutant. MRC has a PTE greater than 25 tons per year of Particulate Matter (PM), SO_2, NO_x, CO, 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, alteration or use of a source. The current permit action is an administrative amendment, and therefore, does not require the submittal of a permit application.

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. <u>ARM 17.8.752 Emission Control Requirements</u>. 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. The required BACT analysis is included in Section IV of this permit analysis.

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

9. <u>ARM 17.8.756 Compliance with Other Requirements</u>. This rule states that nothing in the permit shall be construed as relieving MRC 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. <u>ARM 17.8.759 Review of Permit Applications</u>. 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. <u>ARM 17.8.762 Duration of Permit</u>. 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 altered 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.

12. <u>ARM 17.8.763 Revocation of Permit</u>. 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 Federal Clean Air Act (FCAA), rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

13. <u>ARM 17.8.764 Administrative Amendment to Permit</u>. 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.

14. <u>ARM 17.8.765 Transfer of Permit</u>. 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.

15. <u>ARM 17.8.770 Additional Requirements for Incinerators</u>. This rule specifies the additional information that must be submitted to the Department for incineration facilities subject to 75-2-215, MCA.

G. ARM 17.8, Subchapter 8 - Prevention of Significant Deterioration of Air Quality, 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 17.8.81 Review of Major Stationary Sources and Major Modification--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.

   MRC's existing petroleum refinery in Great Falls is defined as a "major stationary source" because it is a listed source with the PTE more than 100 tons of several pollutants (PM, SO_2, NO_x, CO, and VOCs). The current permit action is considered an administrative amendment.

H. ARM 17.8, Subchapter 9 - Permit Requirements for Major Stationary Sources or Modifications Located within Nonattainment Areas, including, but not limited to:

ARM 17.8.904 When Air Quality Preconstruction Permit Required. This rule requires that major stationary sources or major modifications located within a nonattainment area must obtain a preconstruction permit in accordance with the requirements of this subchapter, as well as the requirements of Subchapter 7. The current permit action is considered an administrative amendment.

I. 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 stationary source having:

   a. PTE > 100 tons/year of any pollutant;

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

   c. PTE > 70 tons/year of PM_{10} in a serious PM_{10} nonattainment area.

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. (1) Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204 (1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #2161-18 for MRC, the following conclusions were made:

   a. The facility's PTE is greater than 100 tons/year for several pollutants.

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

   c. This source is not located in a serious PM_{10} nonattainment area.
   d. This facility is subject to NSPS requirements.

   e. This facility is subject to current NESHAP standards.

f. This source is not a Title IV affected source, nor a solid waste combustion unit.

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

Based on these facts, the Department determined that MRC is a major source of emissions as defined under Title V. MRC's Title V Operating Permit was issued final on November 20, 2001.

III. Emission Inventory (Increases)

	Ton/yr					
Source	**PM**	**PM_{10}**	**NO_x**	**VOC**	**CO**	**SO_x**
Tank 102						0.09
Tank 135						0.70
Tank 137						0.16
Tank 138						0.16
Tank 139						0.58
20-MMBtu/hr Alky Heater						3.26
Total						**4.95**

A Complete emissions inventory is on file with the Department

IV. BACT Analysis

A BACT determination is required for each new or altered source or stack. MRC shall install on the new or altered source, the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The current permit action is an administrative amendment and does not require a BACT analysis.

V. Existing Air Quality

As of July 8, 2002, Cascade County is designated as an Unclassifiable/Attainment area for National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. MRC was located outside, but adjacent to, a CO Nonattainment area in downtown Great Falls. On December 2, 1985, the Montana Department of Health and Environmental Sciences and MRC signed a stipulation requiring MRC to obtain an air quality permit and stipulating that a permit emission limitation of 4700 tons/year CO, when considered in conjunction with control measures on other sources such as automobiles, would achieve compliance with ambient CO standards. This permit limits plantwide CO emissions to 4700 tons/year. The current emission inventory, including emissions from the temporary diesel fired generators, shows potential CO emissions greater than the plant wide limit of 4700 tons/year. However, permit action (#2161-15) required that MRC include generator CO emissions when demonstrating compliance with the plant wide limit, thus maintaining compliance with CO NAAQS, MAAQS, and the City of Great Falls Carbon Monoxide Limited Management Plan.

In 1993, the Department conducted preliminary ambient air quality modeling for SO_2 using the COMPLEX1 and ISC2 models and meteorological data collected from the Great Falls Airport assuming 7 tons per day of SO_2 emissions. The results of the model demonstrate that, at 7 tons per day of emissions, this facility causes a violation of the state and federal SO_2 ambient standards. As a result, MRC was limited to 5.25 tons per day of plantwide refinery SO_2 emissions (Permit #2161-06) in the first step of a plan to achieve attainment. In April 1998, MRC submitted additional modeling to demonstrate compliance with the NAAQS for SO_2. In June 1999, this modeling, and the preconstruction permit application were determined to be complete. The permitting action established limitations that demonstrate compliance with the NAAQS and MAAQS for SO_2. The facility is now limited to 4.15 tons per day of plantwide refinery SO_2 emissions. An ambient air-monitoring plan will continue to be used to monitor SO_2 emissions. MRC's total potential emissions, including emissions from the temporary diesel fired generators, show potential SO_2 emissions greater than the plant wide limits previously discussed. However, Permit #2161-15 requires that MRC include generator SO_2 emissions when demonstrating compliance with the plant wide limit, thus maintaining compliance with SO_2 NAAQS and MAAQS as previously demonstrated.

VI. Air Quality Impacts

The Department determined that there would be no impacts from this permitting action. The Department believes it will not cause or contribute to a violation of any ambient air quality standard.

VII. Taking or Damaging Implication Analysis

As required by 2-10-101 through 105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VIII. Environmental Assessment

The current permit action is considered an administrative amendment and does not require an Environmental Assessment.

Permit Analysis prepared by: Chris Ames
Date: June 30, 2004