AIR QUALITY PERMIT

Issued To:	Rocky Mountain Power, LLC Hardin Generating Station 2575 Park Lane, Suite 200 Lafayette, CO 80026	Permit: #3185-04 Application Complete: 08/03/07 Preliminary Determination Issued: 08/29/07 Department's Decision Issued: 10/05/07 Permit Final: 10/23/07 AFS #: 003-0018

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

SECTION I: Permitted Facilities

A. Plant Location

RMP owns and operates a stationary facility that produces electrical power for delivery to the existing power grid. The facility is known as the Hardin Generating Station and is located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The facility consists of a pulverized coal-fired boiler (PC-Boiler) and a steam turbine, which drives a 135 MVA class nameplate electric generator to produce a nominal 116-gross megawatts (MW) of electric power (approximately 11-MW of the power produced is used for plant auxiliary power). A complete list of the permitted equipment for the coal-fired steam-electric generating station is contained in the permit analysis.

B. Current Permit Action

On March 16, 2007, Rocky Mountain Power, Inc. (RMPI) submitted an MAQP application for a modification to MAQP #3185-03. The application was deemed complete on August 3, 2007, upon RMPI's submittal of additional information. Specifically, RMPI requested the following actions: 1) specify that the current sulfur dioxide (SO_2) short-term emission limit of 182.6 pounds per hour (lb/hr) does not apply during periods of PC-Boiler startup and shutdown or during spray dry absorber (SDA) atomizer change-outs; 2) establish an alternate SO_2 short-term emission limit for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs; 3) define startup, shutdown, and SDA atomizer change-out periods and establish any related conditions; 4) request that the optimization period requirement for PC-Boiler SO_2 emissions control efficiency be established as a permanent MAQP condition; and 5) replace the temporary particulate matter/particulate matter with an aerodynamic diameter of 10 microns or less (PM/PM_{10}) and SO_2 emission limits established to apply during a defined optimization period with the post-optimization-period limits expressed in MAQP #3185-03.

In addition, on June 26, 2007, RMPI notified the Department of Environmental Quality – Air Resources Management Bureau (Department) of a pending merger with and into Rocky Mountain Power, Inc. (a Delaware Company (RMPD)) and RMPD's intent to transfer MAQP #3185-03 to RMP upon closing. On August 3, 2007, the Department received notification that the merger had closed. Therefore, the current permit action also transfers the MAQP from RMPI to RMP.

Further, the Department placed a 3-hour SO_2 limit on the PC-Boiler stack to minimize visibility impacts, which also reduced impacts to the 3-hour SO_2 increment. The Department based the proposed 3-hour limit on RMP's past operating data.

Lastly, while RMP is subject to the applicable requirements of the Acid Rain Program contained in 40 CFR 72-78, the program is implemented under Title V of the Federal Clean Air Act. Therefore, the Department removed the condition requiring RMP to comply with the Acid Rain Program from the MAQP (ARM 17.8, Subchapter 8). Removing the requirement does not alleviate RMP from the responsibility of complying with the program and the requirement will be included in RMP's Title V Operating Permit (ARM 17.8, Subchapter 12), upon issuance. Removing the requirement for RMP to comply with the acid rain program simply clarifies that the Department's authority to implement the acid rain program is contained in ARM 17.8, Subchapter 12 (Title V Operating Permit Program). In addition, the monitoring requirements contained in 40 CFR 72-78 remain as applicable requirements in the MAQP.

SECTION II: Conditions and Limitations

A. General Plant Requirements

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

2. RMP shall not cause or authorize emissions to be discharged into the atmosphere from haul roads, access roads, parking lots, or the general plant property without taking reasonable precautions to control emissions of airborne particulate matter (ARM 17.8.308).

3. RMP shall treat all unpaved portions of the access roads, parking lots, and general plant area with chemical dust suppressant and/or clear, non-oily water which does not contain regulated hazardous waste as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.2 (ARM 17.8.749).

4. The annual heat input to the PC-Boiler shall not exceed 11,423,040 million British thermal units (MMBtu) per rolling 12-month time period (ARM 17.8.749).

5. RMP shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Da (ARM 17.8.340 and 40 CFR 60, Subpart Da).

6. RMP shall comply with all applicable standards and limitations, and the reporting, monitoring, recordkeeping, testing, and notification requirements contained in 40 CFR 60, Subpart Y (ARM 17.8.340 and 40 CFR 60, Subpart Y).

B. PC-Boiler Startup and Shutdown, and SDA Atomizer Change-Out Operations

1. PC-Boiler startup and shutdown, and SDA atomizer change-out operations shall be conducted as described in the *PC-Boiler Start-Up and Shutdown, and SDA atomizer change-out Procedures* included in Attachment 3 of MAQP #3185-04 or according to another PC-Boiler startup and shutdown, and SDA atomizer change-out plan as may be approved by the Department in writing (ARM 17.8.749).

2. PC-Boiler startup and shutdown, and SDA atomizer replacement operations, as defined in Section II.B.3 of MAQP #3185-04, shall not exceed the 182.6 lb/hr SO_2 emission limit contained is Section II.C.4 more than 6 hours during any rolling 24-hour time period (ARM 17.8.749 and ARM 17.8.752).

3. For MAQP conditions that refer to PC-Boiler startup and shutdown, and SDA atomizer change-outs, the following conditions apply (ARM 17.8.749):

   a. PC-Boiler startup periods begin when coal flow is detected in the PC-Boiler by the data acquisition and handling system (DAHS) and end when gross generator output is equal to 79 gross MW.

   b. PC-Boiler shutdown periods begin when gross generator output is less than 79 gross MW and end when coal flow is no longer detected in the PC-Boiler by the DAHS.

   c. If a PC-Boiler shutdown procedure is aborted, the PC-Boiler is in startup until the gross generator output is equal to 79 gross MW.

   d. SDA atomizer change-out periods begin when operation of the SDA is suspended for the purpose of replacing an atomizer and end when operation of the SDA is resumed after replacing an atomizer.

4. During PC-Boiler startup and shutdown, and SDA atomizer change-out operations, as defined in Section II.B.3 of MAQP #3185-04, SO_2, hydrochloric acid (HCl), hydrofluoric acid (HF), and sulfuric acid (H_2SO_4) mist emissions from the PC-Boiler stack shall be controlled by implementing proper work practices (ARM 17.8.752).

5. During PC-Boiler startup and shutdown, and SDA atomizer change-out operations, as defined in Section II.B.3 of MAQP #3185-04, SO_2 emissions from the PC-Boiler stack shall not exceed 1465 lb/hr based on a 1-hour average (ARM 17.8.752).

6. During PC-Boiler startup and shutdown, and SDA atomizer change-out operations, as defined in Section II.B.3 of MAQP #3185-04, SO_2 emissions from the PC-Boiler stack shall not exceed 990 lb/hr based on a 3-hour rolling average (ARM 17.8.749).

C. PC-Boiler

1. Carbon Monoxide (CO) emissions from the PC-Boiler shall be controlled by proper design and combustion. CO emissions from the PC-Boiler stack shall not exceed 0.15 lb/MMBtu (ARM 17.8.752).

2. Oxides of nitrogen (NO_x) emissions from the PC-Boiler shall be controlled by selective catalytic reduction (SCR). NO_x emissions from the PC-Boiler stack shall not exceed 0.09 lb/MMBtu based on a 30-day rolling average (ARM 17.8.752).

3. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, SO_2 emissions from the PC-Boiler shall be controlled with the use of a dry flue gas desulfurization (FGD) system, specifically characterized as an SDA (ARM 17.8.752).

4. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, SO_2 emissions from the PC-Boiler stack shall not exceed 182.6 lb/hr based on a 1-hour average (ARM 17.8.749 and ARM 17.8.752).

5. SO_2 emissions from the PC-Boiler stack shall not exceed 0.11 lb/MMBtu based on a 30-day rolling average (ARM 17.8.752).

6. The control efficiency for the SO_2 emission control equipment shall be maintained at a minimum of 90% based on a 30-day rolling average (as measured according to 40 CFR 60.49Da(b) (ARM 17.8.752).

7. PM/PM_{10} emissions from the PC-Boiler shall be controlled with the use of a fabric filter baghouse (FFB) while coal is being combusted in the PC-Boiler (ARM 17.8.752).

8. PM/PM_{10} emissions from the PC-Boiler stack shall not exceed 0.012 lb/MMBtu (filterable) (ARM 17.8.752).

9. PM/PM_{10} emissions from the PC-Boiler stack shall not exceed 0.024 lb/MMBtu (filterable and condensable) (ARM 17.8.752).

10. Volatile Organic Compounds (VOC) emissions from the PC-Boiler shall be controlled by good combustion practices. VOC emissions from the PC-Boiler stack shall not exceed 0.0034 lb/MMBtu (ARM 17.8.752).

11. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, HCl emissions from the PC-Boiler shall be controlled with the use of the dry FGD/SDA (ARM 17.8.752). Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, HCl emissions from the PC-Boiler stack shall not exceed 1.54 lb/hr (0.00118 lb/MMBtu) based on a 1-hour average (ARM 17.8.749).

12. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, HF emissions from the PC-Boiler shall be controlled with the use of the dry FGD/SDA (ARM 17.8.752). Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, HF emissions from the PC-Boiler stack shall not exceed 0.67 lb/hr (0.00051 lb/MMBtu) based on a 1-hour average (ARM 17.8.749).

13. Except during periods of startup, shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, H_2SO_4 mist emissions from the PC-Boiler shall be controlled by the use of dry FGD/SDA. Except during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, as defined in Section II.B.3 of MAQP #3185-04, H_2SO_4 emissions shall not exceed 8.2 lb/hr (0.0063 lb/MMBtu) based on a 1-hour average (ARM 17.8.752).

14. Mercury (Hg) emissions

    a. For the 36 months following commencement of commercial operations ("Hg Demonstration Period"), the RMP Hardin facility will be available as a testing facility for Hg control. During the Hg Demonstration Period, RMP will operate equipment and control equipment at the Hardin facility in a manner that demonstrates the capabilities of Hg emission control. Prior to the completion of the Hg Demonstration Period, RMP shall install and operate an activated carbon injection control system or, at RMP's request and as approved by the Department, an equivalent technology (equivalent in removal efficiency) ("Installed Technology") (BER order signed May 6, 2005).

b. Within the 18 months following the completion of the Hg Demonstration Period, RMP shall operate the Installed Technology to optimize the Installed Technology's performance for Hg emission reduction ("Hg Optimization Period"). Not later than 18 months after the completion of the Hg Demonstration Period, RMP shall submit to the Department an application for a Hg Best Available Control Technology (BACT) emission limit for the Installed Technology, which will utilize the Installed Technology as the base technology. If the Department determines the application to be deficient or incomplete, RMP shall submit information responsive to any noted deficiencies within a reasonable time period (BER order signed May 6, 2005).

15. The emissions of radionuclides from the PC-Boiler shall be controlled by an FFB. The PC-Boiler's PM_{10} emission limits shall be used as surrogate emission limits for radionuclides (ARM 17.8.752).

16. The emissions of trace metals from the PC-Boiler shall be controlled by an FFB. The PC-Boiler's PM_{10} emission limits shall be used as surrogate emission limits for trace metals (ARM 17.8.752).

17. The PC-Boiler stack shall stand no less than 250 feet above ground level (ARM 17.8.749).

18. The sulfur content of any coal fired at RMP shall not exceed 1% by weight calculated on a monthly average (ARM 17.8.749).

19. Coal fired in the PC-Boiler shall have a minimum heating value of 8000 Btu/lb calculated on a monthly average (ARM 17.8.749).

D. Cooling Tower

RMP is required to operate and maintain a mist eliminator on the cooling tower that limits PM_{10} emissions to no more than 0.001% of circulating water flow (ARM 17.8.752).

E. Coal Transfer, Coal Milling, Fuel Transfer, Lime Transfer, and Bottom and Fly Ash Transfer

1. Emissions from the following baghouses/bin vents shall not exceed 0.01 grains per dry standard cubic foot (grains/dscf) of particulate emissions (ARM 17.8.752):

   a. Coal unloading baghouse: RCF-BH-001
   b. Coal silo baghouse: RCF-BH-002
   c. Coal storage bunkers baghouse: RCF-BH-003
   d. SDA lime silo bin vent: FGT-BV-001
   e. FGD ash silo bin vent: WMH-BV-002
   f. Recycle ash silo bin vent: FGT-BV-002
   g. Water treatment lime silo baghouse: RWS-BH-001
   h. Soda ash silo baghouse: RWS-BH-002

2. RMP shall install and maintain enclosures surrounding the following process operations (ARM 17.8.752):

   a. Coal Transfer:

      i. Truck to below-grade hopper
      ii. Below-grade hopper to stockout conveyor
      iii. Coal storage silo to reclaim conveyor

iv. Reclaim conveyor to bunker feed conveyor
v. Bunker feed conveyor to coal bunkers
vi. Coal bunkers to coal pulverizers

b. Coal Pulverizers

c. Fuel Transfer: Coal pulverizers to PC-Boiler

3. Draft pressure from the PC-Boiler shall be present to provide particulate control for fuel transfer from coal pulverizers to the PC-Boiler (ARM 17.8.752).

4. RMP shall store onsite coal in the coal storage silo (ARM 17.8.749).

F. Temporary Auxiliary Boiler

1. The operation of the temporary auxiliary boiler shall not exceed 1000 hours per rolling 12-month time period (ARM 17.8.749).

2. The sulfur content of the No. 2 fuel oil used in the temporary auxiliary boiler shall not exceed 0.05% sulfur (ARM 17.8.752).

3. RMP shall not operate the temporary auxiliary boiler while the PC-Boiler is combusting coal (ARM 17.8.749).

G. Testing Requirements

1. RMP shall use the data from the continuous opacity monitoring system (COMS) to monitor compliance with the opacity limit contained in Section II.A.1, for the PC-Boiler (ARM 17.8.749).

2. RMP shall test the PC-Boiler for CO to monitor compliance with the CO emission limit contained in Section II.C.1 on an every 2-year basis from the initial source test date, or according to another testing/monitoring schedule/demonstration as may be approved by the Department (ARM 17.8.105 and 17.8.749).

3. RMP shall use the data from the NO_x Continuous Emission Monitoring System (CEMS) to monitor compliance with the NO_x emission limits contained in Section II.C.2, for the PC-Boiler (ARM 17.8.749).

4. RMP shall use the data from the SO_2 CEMS to monitor compliance with the SO_2 emission limits contained in Sections II.B.5, II.B.6, II.C.4, II.C.5, and II.C.6, for the PC-Boiler (ARM 17.8.749).

5. RMP shall test the PC-Boiler for PM/PM_{10} to monitor compliance with the PM/PM_{10} emission limits contained in Sections II.C.8 and II.C.9 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

6. RMP shall test the PC-Boiler for HCl to monitor compliance with the HCl emission limit contained in Section II.C.11 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

7. RMP shall test the PC-Boiler for HF to monitor compliance with the HF emission limit contained in Section II.C.12 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and 17.8.749).

8. RMP shall test the PC-Boiler for H_2SO_4 to monitor compliance with the H_2SO_4 limit contained in Section II.C.13 on an every 5-year basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

9. RMP shall test the PC-Boiler for Hg to monitor compliance with the Hg limit contained in Section II.C.14 on an annual basis from the initial source test date, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

10. RMP shall obtain written coal analyses that are representative for all coal received from each coal supplier. A daily sample (or samples, if necessary, with amounts used of each type, as appropriate) representing all coal received for that day shall be analyzed for, at a minimum, sulfur content, ash content, and Btu value (Btu/lb). A monthly composite sample representing all coal received during the month will be analyzed for, at a minimum, mercury, chlorine, and fluorine content (ARM 17.8.749).

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

12. The Department may require additional testing (ARM 17.8.105).

H. Operational Reporting Requirements

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

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

2. RMP shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745, that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location or fuel specifications, or would result in an increase in source capacity above its permitted operation 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 the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).

3. RMP shall document, by month, the total heat input for the PC-Boiler. Within 30 days following the end of each month, RMP shall calculate the total heat input for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.A.4. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

4. RMP shall document, by month, the hours of operation of the temporary auxiliary boiler. Within 30 days following the end of the month, RMP shall calculate the total hours of operation for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation in Section II.F.2. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

5. RMP shall document, by day, date, and time, all hours that the PC-Boiler is in startup and shutdown, as defined in Section II.B.3 of MAQP #3185-04, and all hours that the SDA is in atomizer change-out, as defined in Section II.B.3 of MAQP #3185-04. Each day, RMP shall sum the hours that the PC-Boiler is in startup and shutdown, as defined in Section II.B.3 of MAQP #3185-04, and the hours that the SDA is in atomizer change-out, as defined in Section II.B.3 of MAQP #3185-04, for the rolling 24-hour time periods of the previous day. The information will be used to verify compliance with the rolling 24-hour limitation in Section II.B.2. The information for each rolling 24-hour time period shall be submitted along with the annual emission inventory. The information for each rolling 24-hour time period shall also be submitted along with any quarterly SO_2 excess emission report but only the rolling 24-hour time periods within the applicable quarter need be submitted (ARM 17.8.749).

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

I. Continuous Emission Monitoring Systems

1. RMP shall install, operate, calibrate, and maintain CEMS for the following:

   a. A CEMS for the measurement of SO_2 shall be operated on the PC-Boiler stack (ARM 17.8.749 and 40 CFR Parts 72-78).

   b. A flow monitoring system to complement the SO_2 monitoring system shall be operated on the PC-Boiler stack (40 CFR Parts 72-78).

   c. A CEMS for the measurement of NO_x shall be operated on the PC-Boiler stack (ARM 17.8.749 and 40 CFR Parts 72-78).

   d. A COMS for the measurement of opacity shall be operated on the PC-Boiler stack (ARM 17.8.749 and 40 CFR Parts 72-78).

   e. A CEMS for the measurement of oxygen (O_2) or carbon dioxide (CO_2) content shall be operated on the PC-Boiler stack (ARM 17.8.749).

2. RMP shall determine CO_2 emissions from the PC-Boiler stack by one of the methods listed in 40 CFR 75.10 (40 CFR Parts 72-78).

3. All continuous monitors required by this MAQP and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance tests conducted in accordance with the requirements of 40 CFR 60, Subpart A; 40 CFR 60, Subpart Da; 40 CFR 60, Appendix B (Performance Specifications #1, #2, and #3); and 40 CFR Parts 72-78, as applicable (ARM 17.8.749 and 40 CFR Parts 72-78).

4. On-going quality assurance requirements for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749).

5. RMP shall inspect and audit the COMS annually, using neutral density filters. RMP shall conduct these audits using the applicable procedures and forms in the EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors (EPA-450/4-92-010, April 1992). The results of these inspections and audits shall be included in the quarterly excess emission report as described in Attachment 2 to this MAQP (ARM 17.8.749).

6. RMP shall maintain a file of all measurements from the CEMS, and performance testing measurements; all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, 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. RMP shall supply these records to the Department upon request (ARM 17.8.749).

7. RMP shall maintain a file of all measurements from the COMS, and performance testing measurements; all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, 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. RMP shall supply these records to the Department upon request (ARM 17.8.749).

SECTION III: General Conditions

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

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

C. Compliance with Statutes and Regulations – Nothing in this MAQP shall be construed as relieving RMP 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 MAQP revocation, penalties, or other enforcement action as specified in Section 75-2-401, *et seq*., MCA.

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on an MAQP by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

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

G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by RMP may be grounds for revocation of this MAQP, as required by that section and rules adopted thereunder by the Board.

Attachment 2

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS (EER)

PART 1 Complete as shown. Report total time during the reporting period in hours. The determination of plant operating time (in hours) includes time during unit start up, shut down, malfunctions, SDA atomizer change-outs, or whenever pollutants of any magnitude are generated, regardless of unit condition or operating load.

Excess emissions include all time periods when emissions, as measured by the CEMS, exceed any applicable emission standard for any applicable time period.

Percent of time in compliance is to be determined as:

(1 – (total hours of excess emissions during reporting period/total hours of CEMS availability during reporting period)) x 100

PART 2 Complete as shown. Report total time the point source operated during the reporting period in hours. The determination of point source operating time includes time during unit start up, shut down, malfunctions, or whenever pollutants (of any magnitude) are generated, regardless of unit condition or operating load.

Percent of time CEMS was available during point source operation is to be determined as:

(1–(CEMS downtime in hours during the reporting period[a] /total hours of point source operation during reporting period)) x 100

a - All time required for calibration and to perform preventative maintenance must be included in the CEMS downtime.

PART 3 Complete a separate sheet for each pollutant control device. Be specific when identifying control equipment operating parameters. For example: number of TR units, energizers for electrostatic precipitators (ESP); pressure drop and effluent temperature for baghouses; and bypass flows and pH levels for scrubbers. For the initial EER, include a diagram or schematic for each piece of control equipment.

PART 4 Use Table I as a guideline to report <u>all</u> excess emissions. Complete a separate sheet for each monitor. Sequential numbering of each excess emission is recommended. For each excess emission, indicate: 1) time and duration, 2) nature and cause, and 3) action taken to correct the condition of excess emissions. Do not use computer reason codes for corrective actions or nature and cause; rather, be specific in the explanation. If no excess emissions occur during the quarter, it must be so stated.

PART 5 Use Table II as a guideline to report all CEM system upsets or malfunctions. Complete a separate sheet for each monitor. List the time, duration, nature and extent of problems, as well as the action taken to return the CEM system to proper operation. Do not use reason codes for nature, extent or corrective actions. Include normal calibrations and maintenance as prescribed by the monitor manufacturer. Do not include zero and span checks.

PART 6 Complete a separate sheet for each pollutant control device. Use Table III as a guideline to report operating status of control equipment during the excess emission. Follow the number sequence as recommended for excess emissions reporting. Report operating parameters consistent with Part 3, Subpart e.

PART 7 Complete a separate sheet for each monitor. Use Table IV as a guideline to summarize excess emissions and monitor availability.

PART 8 Have the person in charge of the overall system and reporting certify the validity of the report by signing in Part 8.

Attachment 2

EXCESS EMISSIONS REPORT

PART 1 – General Information

a. Emission Reporting Period ____________________

b. Report Date ____________________

c. Person Completing Report ____________________

d. Plant Name ____________________

e. Plant Location ____________________

f. Person Responsible for Review and Integrity of Report ____________________

g. Mailing Address for 1.f. ____________________

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h. Phone Number of 1.f. ____________________

i. Total Time in Reporting Period ____________________

j. Total Time Plant Operated During Quarter ____________________

k. Permitted Allowable Emission Rates: Opacity ____________________

SO_2 __________ NO_x __________ TRS __________

l. Percent of Time Out of Compliance: Opacity ____________________

SO_2 __________ NO_x __________ TRS __________

m. Amount of Product Produced During Reporting Period ____________________

n. Amount of Fuel Used During Reporting Period ____________________

Attachment 2

PART 2 - Monitor Information: Complete for each monitor.

a. Monitor Type (circle one)

Opacity SO$_2$ NO$_x$ O$_2$ CO$_2$ TRS Flow

b. Manufacturer ______________________________

c. Model No. ______________________________

d. Serial No. ______________________________

e. Automatic Calibration Value: Zero______________ Span ______________

f. Date of Last Monitor Performance Test ______________________________

g. Percent of Time Monitor Available:

1) During reporting period ______________________________

2) During plant operation ______________________________

h. Monitor Repairs or Replaced Components Which Affected or Altered Calibration Values ______________________________

i. Conversion Factor (f-Factor, etc.) ______________________________

j. Location of monitor (e.g. control equipment outlet)______________________________

PART 3 - Parameter Monitor of Process and Control Equipment. (Complete one sheet for each pollutant.)

a. Pollutant (circle one):

Opacity SO$_2$ NO$_x$ TRS

b. Type of Control Equipment ______________________________

c. Control Equipment Operating Parameters (i.e., delta P, scrubber water flow rate, primary and secondary amps, spark rate)

____

d. Date of Control Equipment Performance Test ______________________________

e. Control Equipment Operating Parameter During Performance Test

____

____

____

____

PART 4 - Excess Emission (by Pollutant)

Use Table I: Complete table as per instructions. Complete one sheet for each monitor.

PART 5 - Continuous Monitoring System Operation Failures

Use Table II: Complete table as per instructions. Complete one sheet for each monitor.

PART 6 - Control Equipment Operation During Excess Emissions

Use Table III: Complete as per instructions. Complete one sheet for each pollutant control device.

PART 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

PART 8 - Certification for Report Integrity, by person in 1.f.

THIS IS TO CERTIFY THAT, TO THE BEST OF MY KNOWLEDGE, THE INFORMATION PROVIDED IN THE ABOVE REPORT IS COMPLETE AND ACCURATE.

SIGNATURE ____

NAME ____

TITLE ____

DATE ____

Attachment 2

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

Attachment 2

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Duration	Problem/Corrective Action

Attachment 2

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

	Time				
Date	From	To	Duration	Operating Parameters	Corrective Action

Attachment 2

TABLE IV

Excess Emission and CEMS Performance Summary Report

Pollutant (circle one): SO_2 NO_x TRS H_2S CO Opacity

Monitor ID

Emission data summary [1]	**CEMS performance summary** [1]
1. Duration of excess emissions in reporting period due to: a. Startup/shutdown b. Control equipment problems c. Process problems d. Other known causes e. Unknown causes 2. Total duration of excess emissions 3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$	1. CEMS[2] downtime in reporting due to: a. Monitor equipment malfunctions b. Non-monitor equipment malfunctions c. Quality assurance calibration d. Other known causes e. Unknown causes 2. Total CEMS downtime 3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$

[1] For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)
[2] CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Attachment 3

PC-Boiler Start-Up, Shutdown, and SDA Atomizer Change-Out Procedures
Permit #3185-04

PC-Boiler startup and shutdown, and SDA atomizer change-out operations shall be conducted as described in this attachment.

I. <u>PC-Boiler Startup Operations</u>

The PC-Boiler/generator system must be started gradually to allow system components to equilibrate and to avoid excessive thermal stresses on mechanical components. The amount of time required to complete a startup procedure will vary depending upon a variety of factors; however, typical procedures require less than 16 hours. RMP proposed a combined PC-Boiler Startup and shutdown and SDA atomizer change-out limit of no more than 6 hours per rolling 24-hour average while coal is being combusted in the PC-Boiler. During the startup process, the PC-Boiler steps through a series of changes to reach full load firing on coal. During this process, SO_2, HCl, HF, H_2SO_4 mist, PM/PM_{10}, radionuclides, trace metals, and NO_x emissions may vary until air pollution control equipment can be operated at a minimum continuous load on the PC-Boiler. The startup procedures are as follows:

1. Natural gas igniters are placed in service to preheat the PC-Boiler and boil out the superheater pendants. The time required to complete this step depends on the initial temperature of the PC-Boiler.

   - A cold boiler must fire for approximately 8 hours.
   - A warm boiler must fire for approximately 5 hours.
   - A hot boiler must fire for approximately 2 hours.

2. Once the superheater pendants are boiled out, the steam pressure and temperature are increased to the steam quality required to roll the steam turbine.

3. The steam turbine is then rolled up to 1,000 revolutions per minute (RPM) and held until the turbine is at the required metal temperatures.

4. The turbine can then roll up to sync speed (3,600 RPM).

5. Once at sync speed and with vibration indicators in the normal range, the turbine is placed online and the plant load increased to 7 MWs.

6. Plant load (plant output) for the next hour must be scheduled with a PowerEx dispatcher before continuing with the startup procedure.

7. The FFB can then be placed in service. In order to complete this step:

   - All 12 igniters must be firing on gas; and
   - The stack temperature must be above 175 degrees Fahrenheit.
   - The FFB logic then puts two compartments in service and monitors the stack temperature. During cooler weather the stack temperature will drop 10 to 15 degrees Fahrenheit each time a set of compartments is placed in service. It then takes approximately 20 minutes for the stack temperature to return to the 175 degree set point, at which time the next set of two compartments is placed in service.
   - Because there are six compartments, it takes approximately 40 to 50 minutes to get the FFB completely in service.

8. The first pulverizer can now be started and plant load increases up to approximately 40 MWs. Coal flow to the PC-Boiler is detected by the DAHS.

9. Plant load is scheduled at minimum load (79 MWs) with Power Ex dispatcher for approximately 1 hour.

10. Control systems are placed in auto and allowed to settle out. This step takes approximately 30 to 45 minutes to complete.

11. The second pulverizer is then started and plant load increases to the scheduled minimum load. Coal flow to the PC-Boiler is detected by the DAHS.

12. At this time the SCR and SDA can be placed in service.

    - The SCR average temperature must be at 590 degrees Fahrenheit between the inlet and outlet of the SCR. This minimum temperature can only be achieved when the plant is at or above 79 MWs.
    - The SDA inlet temperature must be between 250 and 300 degrees Fahrenheit before the atomizer can be placed in service (start spraying slurry).
        - If the SDA inlet temperature is not at setpoint, then outlet temperature will drop below 169 degrees Fahrenheit and the SDA spray valves will close, shutting down the atomizer.
        - This temperature setpoint is in place to protect the FFB from getting coated with wet fly ash and plugging the bags.

As soon as the plant is at minimum load (79 MWs) and all the air pollution control equipment is in service, the startup process is complete. At this time the unit can be loaded to the desired output.

II. PC-Boiler Shutdown Operations

The shutdown procedures are as follows:

1. The slide gate is closed on Coal Feeder C as load is decreased to approximately 92 MW. Coal is allowed to empty out of the feeder and the coal mill. The DAHS detects when coal flow to the PC-Boiler has stopped. Simultaneously, the lime/recycle ash flow to SDA is reduced as needed to maintain an SDA outlet temperature of between 172 and 175 degrees Fahrenheit.

2. The slide gate is closed on Coal Feeder B as load is decreased below 79 MW. Coal is allowed to empty out of the feeder and the coal mill. The DAHS detects when coal flow to the PC-Boiler has stopped. SDA lime/recycle ash flow is ramped down to zero flow while maintaining a baghouse inlet temperature of at least 169 degrees Fahrenheit, SCR ammonia injection is turned off.

3. The slide gate is closed on Coal Feeder A as load is decreased below 79 MW. Coal is allowed to empty out of the feeder and the coal mill. The DAHS detects when coal flow to the PC-Boiler has stopped. Simultaneously, natural gas is fired to stabilize the system.

4. When load reaches 10 MW, the gas flow to the PC-Boiler is turned off. The steam turbine is taken off line, the stop valve is closed, and when the turbine has stopped turning, the turbine is put on the turning gear.

Note: If the plant is going to be down for a short period of time, the slide gates are left open and the feeder is shut off, and the cal mill is ran until it is empty.

III. SDA Atomizer Change-Out Operations

Unscheduled Change-out

When lime slurry flow reductions are observed (approximately 30 – 40 gallons per minute), PC-Boiler SO_2 emissions increase, or an increase control valve opening indicates atomizer plugging, the in-service atomizer will be replaced with the standby atomizer. The removed atomizer wheel is cleaned and placed in ready standby position.

Scheduled Change-Out

Routine atomizer maintenance is scheduled no longer than 10 days after the last atomizer change-out. In that case, the in-service atomizer is removed and replaced with the standby atomizer. The removed atomizer wheel is cleaned and placed in ready standby position.

Atomizer Change-Out Process

1. The slurry flow, SO_2 emissions, and control valve position are noted.
2. Prior to removing the atomizer from service, scrubbing is increased if possible to build a thick cake on the fabric filter bags.
3. The slurry flow and the atomizer motor are secured.
4. The atomizer is removed from the in-service position.
5. The stand-by atomizer is installed.
6. The atomizer is started and the status of the slurry flow, SO_2 emissions, and control valve position is verified to ensure they have returned to normal.

Under each scenario, atomizer change-out should require no more than 30-45 minutes except that one to one and one-half hours may be required if no standby atomizer motor is available.

Permit Analysis
Rocky Mountain Power, LLC
Permit #3185-04

I. Introduction/Process Description

A. Permitted Equipment

Rocky Mountain Power, LLC (RMP) owns and operates a nominal 116-gross megawatt (MW) electrical power generation facility approximately 1.2 miles northeast of Hardin, Montana. The facility consists of a pulverized coal-fired boiler (PC-Boiler) and a steam turbine, which drives a 135 MVA class nameplate electric generator to produce a nominal 116-gross MW of electric power (approximately 11-MW of the power produced is used by RMP for plant auxiliary power). The legal description of the site location is the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The following equipment is permitted for this facility:

1. 1,304 million British thermal units per hour (MMBtu/hr) PC-Boiler (with associated steam turbine and electric generator) with a 250-foot stack
2. Cooling tower
3. Coal, lime, and ash handling systems:
    a. Coal unloading baghouse (RCF-BH-001) – 50,000 dry standard cubic feet per minute (dscfm)
    b. Coal silo baghouse (RCF-BH-002) – 7,500 dscfm
    c. Coal storage bunkers baghouse (RCF-BH-003) – 5,000 dscfm
    d. Spray dry absorber (SDA) lime silo bin vent (FGT-BV-001) – 1,000 dscfm
    e. Flue gas desulfurization (FGD) ash silo bin vent (WMH-BV-002) – 2,000 dscfm
    f. Recycle ash silo bin vent (FGT-BV-002) – 2,000 dscfm
    g. Water treatment lime silo baghouse (RWS-BH-001) – 1,000 dscfm
    h. Soda ash silo baghouse (RWS-BH-002) – 1,000 dscfm
4. Temporary auxiliary boiler

B. Source Description

1. PC-Boiler and Associated Emission Control

The permitted PC-Boiler is a 1968 wet-bottom, wall-fired boiler manufactured by Mitchell of the United Kingdom. The PC-Boiler is configured with 3 pulverizers and 12 burners with opposed firing. The maximum nominal heat input rate to the PC-Boiler is 1,304 MMBtu/hr, which will be used to produce up to approximately 900,000 pounds of steam per hour. Natural gas is used to initially fire the PC-Boiler during periods of startup and pulverized coal is introduced during the later stages of startup (see attachment 3 of Montana Air Quality Permit (MAQP) #3185-04). During normal operations, the PC-Boiler will be fueled with pulverized coal. The PC-Boiler combusts coal owned by the Tribe of Crow Indians from the Absaloka Mine. The mine, which is owned by Westmoreland Resources, Inc., is located approximately 30 miles east of Hardin.

PC-Boiler combustion gases (flue gases) are routed to a Selective Catalytic Reduction (SCR) unit for control of nitrogen oxides (NO_X). From the SCR unit, the flue gas is routed to a dry flue gas desulfurization (FGD) system (specifically characterized as a Spray Dry Absorber (SDA)) that uses a lime reagent for control of sulfur dioxide (SO_2) emissions. Other acid gases including sulfuric acid (H_2SO_4) mist, hydrochloric acid (HCl) and hydrofluoric acid (HF), and ionic mercury (Hg) is also removed as a co-benefit control.

There are periods of time (i.e., PC-Boiler Startup and Shutdown and SDA atomizer change-outs) that the SDA can not be operated because a minimum flue gas temperature is required for the control equipment to operate, which is achieved at approximately 79 MW of load. A fabric filter baghouse (FFB) is located downstream of the SDA for particulate matter/particulate matter with an aerodynamic diameter of 10 microns or less (PM/PM_{10}) control. Additional pollutants such as Hg, trace metals, and radionuclides will also be removed as a co-benefit control if present in the particulate form. From the FFB, the flue gas exits to the atmosphere.

2. Cooling Tower

A wet cooling tower is used to dissipate the heat from the steam turbine by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower is an induced, counter flow draft design equipped with cellular (honeycomb) drift eliminators. The maximum make-up water rate for the cooling tower is approximately 1,400 gallons per minute (gpm). Water will come from the Bighorn River. There will be no direct discharge to the waters of the state from the operation of the cooling tower. Blow-down is treated to maximize water recovery. Treatment includes a reverse osmosis unit followed by a condensate polisher (de-ionizer) and a small dehydrator. Discharge from the blow-down is reduced to less than 30 gpm, and is discharged to the makeup system for the lime slurry, which is injected into the SDA. If the discharged water cannot be immediately used, it is stored in a surge tank until it can be reused within the system.

3. Coal Storage and Handling

According to Westmoreland Resources, Inc., the coal will have an “as-received” moisture content of 24.5%. This high moisture content will serve to inhibit fugitive dust emissions during storage and handling activities. Coal is transported the 30 miles from the Absaloka Mine using over-the-road tractor-trailer transport vehicles. Coal is delivered around the clock at the rate of approximately 1-½ trucks per hour (3 trucks every 2 hours). Some of the empty coal trucks may be used to haul ash and/or scrubber sludge to the dedicated disposal site.

Coal delivery trucks deliver coal to an enclosed truck unloading station. The enclosure is a self-supported, metal-clad building with gravity louvers on the sidewalls and automated doors at the entry and exit ends for maximum containment of airborne PM. The building is of sufficient size to fully contain a delivery truck, trailer, and pup. Gravity-operated louvers on the enclosure walls normally provide openings for the design volume of airflow removed by a dust collection system provided for the building. When one of the enclosure doors is opened, the dampers close, and air is drawn through the door openings only. The overhead doors are interlocked such that only one door can be open at a time.

The trucks unload coal into below-grade receiving hoppers sized to accept the complete discharge from a trailer and pup. A grizzly with 6-inch square openings is provided on the hopper to prevent oversize materials from entering and plugging the conveying equipment. A rubber seal boot partially encloses the grizzly and hopper top to minimize fugitive dust emissions during the unloading process. Two variable speed stockout feeders transfer coal from the unloading hoppers onto an inclined, covered belt conveyor.

Fugitive dust collection for coal truck unloading operations is provided by a dust collector (RCF-BH-001) with a required efficiency of 0.01 grains per dry standard cubic foot (gr/dscf) and a fan that provides a nominal air flow rate of 50,000 actual cubic feet per minute (acfm). Coal dust collected by the baghouse is pneumatically conveyed to a coal storage silo. Ductwork connects the dust collector to the building enclosure, hopper rubber seal boot, and feeder transfer point hoods. Inflow air through the enclosure louvers or doors maintain a clean work environment within the enclosure. Inflow air through the hopper facilitates fugitive emissions collection during coal unloading. Additional ventilation is provided at the conveyor transfer points. Ventilation design will provide for positive ventilation (negative draft) of the building under worst-case conditions with one door fully open.

The stockout conveyor conveys coal from the receiving hoppers to the top of an active coal storage silo. The silo discharges at the bottom via a reclaim feeder to a covered belt conveyor. This reclaim conveyor transfers coal from the silo to coal bunkers located within the generation building. A fabric filter bin vent (RCF-BV-002) located on top of the silo controls dust emissions from silo loading with a maximum design outlet grain loading of 0.01 gr/dscf and 7,500 acfm air flow. It will also control fugitive dust emissions from material transfers between the reclaim feeder and reclaim conveyor. Dust pulsed from the bin vent fabric filters will fall directly into the silo.

4. Lime Handling Operations

As previously mentioned, the facility uses a lime SDA to control SO_2 and certain Hazardous Air Pollutant (HAP) emissions. Lime is delivered by truck at a rate of approximately 1 truck per day. Lime is used at a rate of 2,200 pounds per hour (lb/hr).

Pebble lime for the SDA is pneumatically unloaded from delivery trucks into a storage silo. The storage silo is equipped with a fabric filter bin vent (FGT-BV-001) to collect fugitive dust generated during loading. The bin vent is limited to a maximum outlet grain loading of 0.01 gr/dscf (with a nominal airflow rate of 1,000 acfm). The bottom of the lime storage silo is enclosed and houses the lime screw feeder, slaker equipment, screw equipment, screw conveyor, and agitated slurry storage tank.

5. Ash and Spent Lime Handling Operations

Combustion of coal in the PC-Boiler produces ash. Bottom ash from the PC-Boiler and ash collected from the economizer is mixed with water and fed via a system of conveyors to a load-out bunker located outside of the generation building. Front-end loaders transfer the wetted material to trucks for transport off-site. Particulate emissions from these operations to the atmosphere are negligible since the materials are wet. A pneumatic conveying system collects fly ash and spent lime from the SDA and PC-Boiler baghouse. It transfers the material to one of two storage silos. SDA material feeds to an FGD ash silo. Material from the baghouse is first directed to a recycle ash silo. Once this silo is filled, the material is routed to the FGD ash silo.

Particulate emissions resulting from loading the recycle ash silo are controlled by a fabric filter bin vent located on top of the silo. The bin vent (WMH-BV-002) is limited to a maximum outlet grain loading of 0.01 gr/dscf (with a nominal airflow rate of 2,000 acfm). Material collected in the recycle ash silo is mixed with cooling tower blowdown water and used to feed the SDA.

Material not required for recycle is conveyed to the FGD ash silo. Particulate emissions resulting from silo loading are controlled by a fabric filter bin vent located on top of the silo. The bin vent (WMH-BV-003) is limited to a maximum outlet grain loading of 0.01 gr/dscf, (with a nominal airflow rate of 2,000 acfm). Material is discharged from the silo to a screw feeder for either wet or dry loadout into trucks or railcars. An elevated structure supports the silo and loading equipment, allowing trucks and railcars to access beneath.

The loadout equipment is enclosed within a silo skirt. The dry loading spout is ventilated to the silo's bin vent.

6. Water Treatment Reagents Handling

Lime and soda ash is stored in separate silos for use in the water treatment system. Each silo is equipped with a bin vent to collect fugitive dust generated during lime loading. The bin vents (RWS-BV-001 – lime and RWS-BV-002 – soda ash) are limited to a maximum outlet grain loading of 0.01 gr/dscf, (with a nominal airflow rate of 1,000 acfm).

7. Temporary Auxiliary Boiler

The temporary auxiliary boiler is used to provide supplemental heat when the PC-Boiler is operating on natural gas for activities such as steam blows or freeze protection during tuning or startup of the PC-Boiler. The facility does not have a permanent auxiliary boiler to supply supplement steam during periods of downtime, so a temporary portable auxiliary boiler is used. The auxiliary boiler is a trailer-mounted boiler with a capacity of 10,000 lb/hr of steam (approximately 11.8 MMBtu/hr). The boiler is rated for a maximum of 85 gallons per hour of No. 2 fuel oil at full load. The auxiliary boiler is used for initial warming of the system at the maximum rate of 10,000 pounds per hour. During start up of the forced draft and induced draft fans the auxiliary boiler can be used at low loads to prevent freezing in the tubes. Once startup has progressed to the point that the PC-Boiler is fired on coal, there will be no need for the auxiliary boiler. The auxiliary boiler is not operated at the same time the PC-Boiler is combusting coal, thus there is no increase in yearly potential emissions.

C. Permit History

On June 11, 2002, **MAQP #3185-00** was issued to Rocky Mountain Power, Inc. (RMPI) to construct a 113-MW electrical power generation facility approximately 1.2 miles northeast of Hardin, Montana. The facility consisted of a PC-Boiler and a steam turbine, which would drive an electric generator to produce a nominal 113-MW of electric power (11-MW of the power produced would be used by RMP).

On November 29, 2003, **MAQP #3185-01** was issued to allow RMPI to move the plant location by 610 meters, 10 degrees clockwise from North; reduce the SO_2 emission rate limit; reduce the PC-Boiler stack height; correct PC-Boiler exhaust temperature; add HCl and HF emission limits; and include short term emission limits for SO_2. The legal description of the facility's location would remain the same except it will be in the Northwest ¼ of Section 12 rather than the Southwest ¼ of Section 12. The location of all buildings, property boundaries, and emission sources would remain unchanged relative to each other. The PC-Boiler stack height was changed from the previously permitted level of no less than 350 feet to at least 250 feet above ground level. The PC-Boiler exhaust temperature was assumed to be 325 degrees Fahrenheit (º F) in MAQP Application #3185-00, but would actually be approximately 160º F. The MAQP was amended to include enforceable limits on HCl and HF emissions to ensure that the Hardin facility remained an area source (as opposed to a major source) with respect to Hazardous Air Pollutants (HAPs). In addition, short-term limits on SO_2 were included in the MAQP to protect short-term ambient air quality standards and increments. No emission increases would result from the amendment, however, RMPI provided modeling to support the facility move, stack height change, and PC-Boiler exhaust temperature correction. MAQP #3185-01 replaced MAQP #3185-00.

On April 30, 2004, the Department of Environmental Quality (Department) received an MAQP application from RMPI, requesting a change in the currently permitted control equipment on the

PC-Boiler for SO_2 and PM_{10} emissions and changes in the facility's material handling systems, cooling system, and plant layout. The permitted system for SO_2 and PM_{10} emissions under MAQP #3185-01 included a wet venturi scrubber operated in conjunction with a multiclone. RMPI proposed to replace that with a lime SDA followed by an FFB. The changes in the cooling system and the consequential increase in potential PM_{10} emissions triggered review under the PSD program. The increased emissions would be a result of the potential increase of the level of total dissolved solids (TDS) in the cooling system feed water, a more accurate water balance (which minimizes the amount of water discharged to evaporation ponds), and the previously overestimated cooling tower mist eliminator control efficiency, which could not be guaranteed in the current configuration. In addition, RMPI requested to correct the current HF limit that was established under MAQP #3185-01. Previously established limits associated with NO_x, carbon monoxide (CO), and Volatile Organic Compound (VOC) emissions from the PC-Boiler were not reviewed in this action because the proposed modifications would not affect them. The application was deemed complete on October 4, 2004.

In response to comments, several emission limits changed: SO_2 from 0.12 lb/MMBtu on a rolling 30-day average to 0.11 lb/MMBtu on a rolling 30-day average, filterable PM/PM_{10} from 0.015 lb/MMBtu to 0.012 lb/MMBtu, and Hg from 3.54 lb per trillion Btu (lb/TBtu) to 5.8 lb/TBtu with a testing plan to evaluate the feasibility of lowering that limit. In addition, a total PM/PM_{10} limit (that includes filterable and condensable fractions) was added. Additional discussion regarding these changes was included in Section III – Best Available Control Technology (BACT) Determination for **MAQP #3185-02**.

The Department Decision (DD) of MAQP #3185-02 was appealed to the Montana Board of Environmental Review (Board) by RMPI, the Montana Environmental Information Center, William J. Eggers III, Margaret J. S. Eggers, and Tracy Small. A settlement agreement was signed by all parties (including the Department) and approved in a Board order signed on May 6, 2005. The order included the following changes (in summary):

- Clarification that if water is used for dust suppression on unpaved portions of access roads, parking lots, and general plant area only clear, non-oily water that contains no regulated hazardous waste shall be used.
- 18-month optimization periods for SO_2 and PM_{10} during which temporary emission limits would apply. Following the 18-month optimization periods, the SO_2 (including control efficiencies) and PM_{10} limits would revert back to the BACT limits established in the DD of MAQP #3185-02. Through an MAQP application, RMPI may demonstrate to the Department that other limits are appropriate using information from the optimization periods.
- A 36-month demonstration period for mercury (Hg) emissions during which RMPI would make the Hardin facility available as a test facility for Hg controls. By the end of that 36-month demonstration period, RMPI would install and operate an activated carbon injection system or equivalent technology for Hg control. An 18-month optimization period for the Hg control system would follow. Prior to the end of the 18-month optimization period, RMPI would submit an application to the Department with information from that Hg optimization period to determine an appropriate Hg BACT emissions limit.

In addition, in an unrelated action, the Department changed the rule reference on the requirement in the MAQP to comply with 40 Code of Federal Regulations (CFR) 60, Subpart Da from the Administrative Rules of Montana (ARM) 17.8.749 to ARM 17.8.340 and 40 CFR 60, Subpart Da. The change reflected information provided by RMPI (that was not available prior to the issuance of the DD) that reconstruction as defined under 40 CFR 60.15 had occurred for the PC-Boiler. This change was not a substantive change, and was being made at that time for convenience purposes. MAQP #3185-02 was issued final on May 16, 2005. MAQP #3185-02 replaced MAQP #3185-01.

On December 20, 2005, the Department received a complete MAQP application from RMPI to add a temporary auxiliary 11.8 million British thermal units per hour (MMBtu/hr) boiler necessary for startup of the PC- Boiler. The temporary auxiliary boiler was to be used to provide supplemental heat when the PC-Boiler is operating on natural gas for activities such as steam blows or freeze protection during tuning or startup of the PC-Boiler. Once startup progressed to the point that the PC-Boiler is fired on coal, there would be no need for the auxiliary boiler. The auxiliary boiler would not be operated at the same time the PC-Boiler is combusting coal, therefore overall potential emissions at the facility did not increase. **MAQP #3185-03** replaced MAQP #3185-02.

D. Current Permit Action

On March 16, 2007, RMPI submitted an MAQP application for a modification to MAQP #3185-03. The application was deemed complete on August 3, 2007, upon RMPI's submittal of additional information. Specifically, RMPI requested the following actions: 1) specify that the current SO_2 short-term emission limit of 182.6 lb/hr does not apply during periods of PC-Boiler startup and shutdown or during SDA atomizer change-outs; 2) establish an alternate SO_2 short-term emission limit for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs; 3) define PC-Boiler startup and shutdown, and SDA atomizer change-out periods and establish any related conditions; 4) request that the optimization period requirement for PC-Boiler SO_2 emissions control efficiency be established as a permanent MAQP condition; and 5) replace the temporary PM/PM_{10} and SO_2 emission limits established to apply during a defined optimization period with the post-optimization-period limits expressed in MAQP #3185-03.

In addition, on June 26, RMPI notified the Department of a pending merger with and into Rocky Mountain Power, Inc. (a Delaware Company (RMPD)) and RMPD's intent to transfer MAQP #3185-03 to RMP upon closing. On August 3, 2007, the Department received notification that the merger had closed. Therefore, the current permit action also transfers the MAQP from RMPI to RMP.

Further, the Department placed a 3-hour SO_2 limit on the PC-Boiler stack to minimize visibility impacts, which also reduced impacts to the 3-hour SO_2 increment. The Department based the proposed 3-hour limit on RMP's past operating data.

Lastly, while RMP is subject to the applicable requirements of the Acid Rain Program contained in 40 CFR 72-78, the program is implemented under Title V of the Federal Clean Air Act. Therefore, the Department removed the condition requiring RMP to comply with the Acid Rain Program from the MAQP (ARM 17.8, Subchapter 8). Removing the requirement does not alleviate RMP from the responsibility of complying with the program and the requirement will be included in RMP's Title V Operating Permit (ARM 17.8, Subchapter 12), upon issuance. Removing the requirement for RMP to comply with the acid rain program simply clarifies that the Department's authority to implement the acid rain program is contained in ARM 17.8, Subchapter 12 (Title V Operating Permit Program). In addition, the monitoring requirements contained in 40 CFR 72-78 remain as applicable requirements in the MAQP. **MAQP #3185-04** replaces MAQP #3185-03.

E. Additional Information

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

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 location of complete copies of all applicable rules and regulations or copies where appropriate.

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

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

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

   Initial performance tests were conducted for the PC-Boiler as directed by the New Source Performance Standards (NSPS), Subpart Da. Continuous emission monitoring systems (CEMS) are used to monitor ongoing NO_x compliance and SO_2 compliance. Continuous opacity monitoring systems (COMS) are used to monitor ongoing compliance with the opacity limitations. Based on the emissions from the PC-Boiler, the Department determined that initial testing for CO, PM_{10}, HCl, HF, and Hg was necessary. Furthermore, based on the emissions from the PC-Boiler, the Department determined that additional testing annually is necessary to monitor compliance with the Hg limit, additional testing every 2 years is necessary to monitor compliance with the CO limit, and additional testing every 5 years is necessary to monitor compliance with the PM_{10}, HCl, HF, and H_2SO_4 emission limits.

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

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

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

5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction of the total amount of air

contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner as to create a public nuisance.

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

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
6. ARM 17.8.221 Ambient Air Quality Standard for Visibility
7. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}

RMP must maintain compliance with the applicable ambient air quality standards.

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

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

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

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

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

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid, or gaseous fuel in excess of the amount set forth in this rule.

6. 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.

7. ARM 17.8.340 Standard of Performance for New Stationary Sources and Emission Guidelines for Existing Sources. This rule incorporates, by reference, 40 CFR Part 60, Standards of Performance for New Stationary Sources (NSPS). The owner or operator or any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the applicable standards and provisions of 40 CFR Part 60.

40 CFR 60, Subpart A – General Provisions. This subpart applies to all affected equipment or facilities subject to an NSPS subpart listed below.

40 CFR 60, Subpart Da - Standards of Performance for Electric Utility Steam Generating Units. This subpart would apply to the RMP PC-Boiler because it is an electric utility steam generating unit with a heat input capacity greater than 250 MMBtu/hr. The PC-Boiler was built in 1968, prior to the applicability date of September 18, 1978. However, based on information provided by RMP (submitted on April 5, 2005) regarding the upgrades made to the PC-Boiler, the Department determined that reconstruction (as defined under 40 CFR 60.15) has occurred; therefore, Subpart Da is applicable.

40 CFR 60, Subpart Dc - Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units. Although the RMP temporary auxiliary boiler is a steam generating unit with a maximum design heat input capacity that falls into the range of 100 MMBtu/hr or less, but greater than or equal to 10 MMBtu/hr; it was constructed in 1984 prior to the applicability date of June 9, 1989. Therefore, Subpart Dc does not apply to the temporary auxiliary boiler.

40 CFR 60, Subpart Y – Standards of Performance for Coal Preparation Plants. This subpart applies to the RMP facility because RMP was constructed after October 24, 1974, and the facility pulverizes or "crushes" more than 200 tons per day of coal.

8. ARM 17.8.341 Emission Standards for Hazardous Air pollutants. This rule incorporates, by reference, 40 CFR Part 61, National Emission Standards for Hazardous Air Pollutants (NESHAP). Since the emission of HAPs from the RMP coal-fired steam-electric generating facility is less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the RMP facility is not subject to the provisions of 40 CFR Part 61. In addition, 40 CFR Part 61 does not apply because it does not contain any requirements applicable to RMP.

9. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. This rule incorporates, by reference, 40 CFR Part 63, NESHAP for Source Categories. Since the emission of HAPs from the RMP coal-fired steam-electric generating facility is less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the RMP facility is not a major source of HAPs.

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

1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.402 Requirements. RMP must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). RMP made the appropriate demonstration of compliance with the ambient air quality standards.

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 MAQP application fee concurrent with the submittal of an MAQP application.

A permit application is incomplete until the proper application fee is paid to the Department. RMP submitted the appropriate MAQP application fee for the current permit action.

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 MAQP (excluding an open burning permit) issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.
   An air quality operation fee is separate and distinct from an MAQP application fee. The annual assessment and collection of the air quality operation fee, described above, shall take place on a calendar-year basis. The Department may insert into any final MAQP 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 MAQP or MAQP modification 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. RMP has the PTE greater than 25 tons per year of PM, PM_{10}, NO_X, SO_2, and CO; therefore, an MAQP is required.

3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the MAQP 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 an MAQP under the MAQP Program.

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that an MAQP application be submitted prior to installation, alteration, or use of a source. RMP submitted the required MAQP application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for an MAQP. RMP submitted an affidavit of publication of public notice for the March 8, 2007, issue of *The Billings Gazette*, a newspaper of general circulation in the Town of Billings in Yellowstone County, as proof of compliance with the public notice requirements.

6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the MAQP's issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the MAQP and the requirements of this subchapter. This rule also requires that the MAQP must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this MAQP analysis.

8. ARM 17.8.755 Inspection of Permit. This rule requires that MAQP's shall be made available for inspection by the Department at the location of the source.

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

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

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

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

13. ARM 17.8.764 Administrative Amendment to Permit. An MAQP may be amended for changes in any applicable rules and standards adopted by the 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 MAQP limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring an MAQP, or unless the owner or operator applies for and receives another MAQP 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. ARM 17.8.765 Transfer of Permit. This rule states that an MAQP 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. ARM 17.8.771 Mercury Emission Standards for Mercury-Emitting Generating Units. This rule identifies mercury emission limitation requirements, mercury control strategy requirements, and application requirements for mercury-emitting generating units.

16. ARM 17.8.772 Mercury Allowance Allocations under Cap and Trade Budget. This rule describes the Department's responsibilities with respect to mercury allowance allocations, timing of allowance allocations, and submittal of allowance allocations in conjunction with 40 CFR 60, Subpart HHHH for mercury-emitting generating units.

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 17.8.818 Review of Major Stationary Sources and Major Modifications--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification, with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

This facility is a listed source because it is a fossil-fuel fired steam-electric plant having more than 250 MMBtu/hr heat input. Furthermore, the facility's emissions are greater than 100 tons per year; therefore, the facility is a major source under PSD program. The Department and RMP disagree on whether the current permit action constitutes a major modification.

RMP believes that because they are not proposing to change the existing SO_2 BACT limit of 0.11 lb/MMBtu based on a 30-day rolling average that the net emissions increase is zero. However, the Department determined that because the existing BACT limit of 0.11 lb/MMBtu based on a 30-day rolling average cannot be relied upon to limit SO_2 emissions without the corresponding requirement to operate the SDA at all times, the determination of whether a significant SO_2 emissions increase is taking place must be made by looking at the proposed change from 182.6 lb/hr to RMP's proposed limit of 1465 lb/hr, not to exceed 6 hours during any rolling 24-hour time period. Therefore, the Department determined that the net emission increase for SO_2 is as follows:

(1465 lb/hr * 2190 hr/yr * 0.0005 ton/lb) – (182.6 lb/hr * 2190 hr/yr * 0.0005 ton/lb) = 1437 ton/year

Regardless of the determination of a net emission increase, the Department determined to require the PSD analysis whether the PSD program applied or not because RMP proposed to not operate control equipment during periods of PC-Boiler startup and shutdown, and SDA atomizer change-outs, which changes the previous BACT determination, and could affect the 3-hour and 24-hour SO_2 increments. HCl, HF, and H_2SO_4 potential emissions increases would be far less than SO_2 and potential controls are the same as SO_2; therefore, SO_2 analyses were used as surrogate analyses for these pollutants. Emission increases for PM/PM_{10}, trace metals, radionuclides, and NO_x would not be expected by the proposed action because the PC-Boiler would be expected to meet all existing limits for these pollutants during PC-Boiler startup and shutdown, and SDA atomizer change-outs.

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

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

   a. PTE greater than (>) 100 tons per year of any pollutant;

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

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

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA 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 MAQP #3185-04 for RMP, the following conclusions were made:

    a. The facility's PTE is less than (<) 100 tons per year for several criteria pollutants.

    b. The facility's PTE is < 10 tons per year for any one HAP and < 25 tons per year for all HAPs.

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

    d. This facility is subject to current NSPS standards (40 CFR 60, Subparts Da and Y).
    e. This facility is not subject to any current NESHAP standards.

    f. This facility is a Title IV affected source.

   Based on the above information, the RMP facility is a major source for Title V and, thus, a Title V Operating Permit is required.

III. BACT Determination

A BACT determination is required for each new or altered source. RMP 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.

RMP has proposed to increase the short-term SO_2 emission limitation from 182.6 lb/hour to 1,465 lb/hr (both on an hourly basis) during periods of PC-Boiler startup and shutdown and SDA atomizer change-outs because RMP currently cannot consistently comply with the 182.6 lb/hr limit. The 182.6 lb/hr limit is based on 0.14 lb/MMBtu (the 0.14 lb/MMBtu was a previous determination based on BACT and a decreased stack height as addressed in MAQP #3185-00 and #3185-01, respectively) and was included as a limit in the MAQP under the authority of ARM 17.8.749. The limit was converted from the BACT lb/MMBtu basis to a lb/hr basis to protect the short-term (i.e. hourly, 3-hour, and 24-hour) SO_2 National and Montana Ambient Air Quality Standards (NAAQS/MAAQS). The lb/hr limit in MAQP #3185-02 was not reduced to reflect the lower BACT 30-day rolling average lb/MMBtu limit in that permit action to allow RMP some operational flexibility to account for atomizer change-outs on the SDA. While RMP has requested to increase the short-term emission limits for SO_2 during periods of PC-Boiler startup and shutdown and SDA atomizer replacement, RMP requested to lower the 30-day rolling limit for SO_2 from 0.12 lb/MMBtu to 0.11 lb/MMBtu, which would include all operating times, including periods of PC-Boiler startup and shutdown and SDA atomizer replacements. The 30-day rolling limit for SO_2 was required by MAQP to be lowered to 0.11 lb/MMBtu unless RMP submitted an application demonstrating that a higher limit was appropriate. However, RMP determined that 0.11 lb/MMBtu on a 30-day rolling average is achievable.

A BACT analysis was submitted by RMP as part of MAQP Application #3185-02, which determined that the SDA was BACT for SO_2 and acid gas emissions. However, the analysis did not take into account all periods of time that the SDA could not be operated (i.e. PC-Boiler startup and shutdown). Therefore, RMP submitted a BACT analysis as part of MAQP Application #3185-04 to demonstrate that the SDA should still be considered BACT for SO_2, HCl, HF, and H_2SO_4 (all have the same control technologies) emissions from the PC-Boiler when considering that there are certain times that the SDA can not be operated and RMP proposed an alternate short-term SO_2 emission limit for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs.

The Department originally requested additional BACT analyses for PM/PM_{10}, trace metals, radionuclides, and NO_x emissions from the PC-Boiler; however, the Department determined that the intent of the existing BACT condition to operate the FFB to control PM/PM_{10}, trace metals, and radionuclide emissions was to control the emissions while coal is being combusted in the PC-Boiler because these emissions are insignificant when natural gas is fired. RMP provided information that the FFB is operated at all times that coal is being combusted in the PC-Boiler; therefore, the Department determined that it was appropriate to clarify the limit and that BACT was not changing and an additional BACT analysis was not necessary. In addition, RMP does not bypass the NO_x control equipment (SCR), NO_x emission limits are not being violated, and RMP has not requested to increase a NO_x emission limit, therefore, the Department determined that BACT is not changing and that an additional NO_x BACT analysis was not required.

RMP submitted a single BACT analysis for "normal" or steady state operations and periods that control equipment could not be operated (i.e. PC-Boiler startup and shutdown and control equipment maintenance periods). The Department organized the BACT analysis in a manner of determining BACT for "normal" or steady state operations and a second BACT analysis to analyze additional controls for periods that the selected BACT control equipment may not be able to be operated.

The Environmental Protection Agency's (EPA) Draft New Source Review Workshop Manual (October 1990) (NSR Manual) states that "historically, EPA has not considered the BACT requirement as a means to re-define the design of the source when considering available control technologies." However, the NSR Manual goes on to indicate "…this is an aspect of the New Source Review – Prevention of Significant Deterioration permitting process in which states have the discretion to engage in a broader analysis if they so desire." In this case, since part of the proposed project is the modification of a previously permitted and already constructed PC-Boiler, the Department believes that the analysis of potentially lower polluting processes including, but not limited to, integrated gasification combined cycle (IGCC) and circulating fluidized bed (CFB) coal combustion technologies, is not appropriate. In addition, these potentially lower polluting processes would not be used as add-on controls on a PC-Boiler. RMP included an evaluation of potentially lower polluting processes as part of their analysis, however the Department did not carry lower polluting processes through the analysis because of the afore mentioned reasons. RMP also evaluated the use of an electrostatic precipitator in conjunction with an FGD; however, because the FFB was previously determined to be BACT for controlling PM/PM_{10}, trace metals, and radionuclide emissions from the PC-Boiler and because BACT for those emissions is not changing, the Department did not carry the ESP/FGD option through the analysis.

1. PC-Boiler - SO_2 Emissions – Steady State Operations

   SO_x emissions from coal combustion consist primarily of SO_2 with a much lower quantity of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the organic and pyretic sulfur in the coal is oxidized during the combustion process. Boiler size, firing configuration, and boiler operations generally have little effect on the percent conversion of fuel sulfur to SO_2.

   The generation of SO_2 is directly related to the sulfur content and heating value of the fuel burned. The sulfur content and heating value of coal can vary dramatically depending on the source of the coal. RMP's PC-Boiler combusts subbituminous coal owned by the Tribe of Crow Indians from the Absaloka Mine. The mine, which is owned by Westmoreland Resources, Inc., is located approximately 30 miles east of Hardin. According to information provided in RMP's 2006 annual emission inventory, the average heating value of the coal for 2006 was 8,687 Btu/lb and the average sulfur content for 2006 was 0.62 percent. Without post-combustion controls, maximum SO_2 emissions from the PC-Boiler (based on the 2006 average heat content minus two standard deviations to account for variability (8,546 Btu/lb) and the

2006 average sulfur content plus two standard deviations to account for variability (0.70%)) firing this coal would be 1.64 lb/MMBtu. This emission rate was considered as the baseline emission rate for this BACT analysis because RMP used this methodology in proposing a short-term emission limit for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs.

While 0.7 % sulfur and 8546 Btu/lb are not representative of worst case coal conditions as required by MAQP #3185-03 (1% sulfur and 8000 Btu/lb), these values are representative of real operating data and RMP would need to fire coal in the PC-Boiler that meets or is very near these values or RMP would not be able to meet their BACT-determined SO_2 limit of 0.11 lb/MMBtu rolling 30-day average. 1% sulfur and 8000 Btu/lb were included as conditions in MAQP #3185-03 to require a minimum coal quality because RMP would not be able to predict or control future availability of lower sulfur fuels or the price of those fuels, because RMP would need some flexibility in coal conditions, and because the BACT determined limit of 0.11 lb/MMBtu per rolling 30 days would still dictate that RMP use lower sulfur content and higher Btu content coal. Further, other sources required to burn low sulfur coals are generally limited to coal with less than 1% sulfur content.

a. Identify Available Control Technologies

Viable strategies for the control of SO_2 emissions can be divided into pre-combustion and post-combustion categories. Pre-combustion methods include the use of lower sulfur coal (i.e. coal cleaning, switching to lower sulfur coals, or blending with lower sulfur coals), since SO_2 emissions are proportional to the sulfur content of the coal. Post-combustion methods include mainly FGD, also known as scrubbing, and techniques that can remove SO_2 formed during combustion. As previously mentioned, since part of the proposed project is the modification of a previously permitted and already constructed PC-Boiler, the Department determined that the analysis of potentially lower polluting processes including, but not limited to, IGCC and CFB coal combustion technologies, is not appropriate. In addition, IGCC and CFB would not be used as add-on control on a PC-Boiler. Also as previously mentioned, the Department does not consider ESP/FGD as an option because an FFB was previously determined to be BACT for controlling PM/PM_{10}, trace metals, and radionuclide emissions from the PC-Boiler and BACT for those pollutants is not changing.

i. <u>Coal Cleaning</u> – In some cases, various coal cleaning processes may be employed to reduce the fuel sulfur content. Physical coal cleaning removes mineral sulfur such as pyrite but is not effective in removing organic sulfur. Chemical cleaning and solvent refining processes are being developed to remove organic sulfur. Coal cleaning has generally been used on high mineral, high sulfur coal for power plants without FGD systems with some success. In some studies, coal cleaning processes have been noted to reduce the feed coal sulfur content by 1% in coal with sulfur contents up to 5%, therefore, achieving up to a 20% reduction in coal sulfur.

ii. <u>Fuel Switching</u> – A potential control for reducing SO_2 emissions from the proposed project is reducing the amount of sulfur contained in the coal. RMP combusts subbituminous coal from the Absaloka Mine. The coal is a subbituminous western coal with low sulfur content. Bituminous coals from mines in the eastern and midwestern U.S. generally have a higher heating value, but also have significantly higher sulfur content. Regionally available coals (i.e., from Montana, Wyoming, and North Dakota) contain sulfur in the range of 0.3% to over 3% by weight. Assuming a nominal higher heating value of 8,700 Btu per pound (an average value for subbituminous coals) and complete conversion of all fuel-bound sulfur to SO_2, uncontrolled SO_2 emissions from the PC-Boiler fired with these coals can range from 0.69 to over 6.9 lb/MMBtu (on a heat input basis).

iii. Fuel Blending - Another potential way of reducing SO_2 emissions from the proposed project would be to blend the Absaloka Mine coal with another coal source of lower sulfur content.

It may be possible to use an ultra-low sulfur coal strictly for periods of PC-Boiler startup and shutdown, and periods of control equipment maintenance. Ultra-low sulfur coal could be purchased or it could be processed to reduce sulfur or increase specific heat content. Reduced amounts of sulfur entering the PC-Boiler would result in lower sulfur emissions from the PC-Boiler stack. As previously mentioned, RMP combusts subbituminous coal from the Absaloka Mine. The coal is a subbituminous western coal with low sulfur content.

iv. Wet FGD/Scrubbing – Wet FGD technology is a well-established SO_2 control technology. Wet FGD systems are generally categorized as lime or limestone scrubbing systems. The scrubbing process and equipment for both lime scrubbing and limestone scrubbing are similar. Some FGD systems are designed to accommodate both lime and limestone.

(1). Wet Lime Scrubbing – The wet lime scrubbing process uses an alkaline slurry made by adding lime (CaO) to water. The alkaline slurry is sprayed in the absorber and reacts with SO_2 in the flue gas. Insoluble calcium sulfite ($CaSO_3$) and calcium sulfate ($CaSO_4$) salts are formed in the chemical reaction that occurs in the scrubber. The salts are removed as a solid waste by-product. The waste by-product is made up of mainly $CaSO_3$, which is difficult to dewater. Solid waste by-products from wet lime scrubbing are typically managed in dewatering ponds and landfills.

(2). Wet Limestone Scrubbing – Wet limestone scrubbers are very similar to wet lime scrubbers. However, the use of limestone ($CaCO_3$) instead of lime requires different feed preparation equipment and a higher liquid-to-gas ratio. The higher liquid-to-gas ratio typically requires a larger absorbing unit. The limestone slurry process also requires a ball mill to crush the limestone feed.

Forced oxidation of the scrubber slurry can be used with either the lime or limestone wet FGD system to produce gypsum solids instead of the calcium sulfite by-product. Forced oxidation of the scrubber slurry provides a more stable by-product and reduces the potential for scaling in the FGD. The gypsum by-product may be salable, reducing the quantity of solid waste that needs to be landfilled.

Wet lime/limestone scrubber systems can achieve SO_2 control efficiencies of approximately 96% when used for PC-Boilers burning higher sulfur bituminous coals, but potential efficiencies may be less for lower sulfur coals. The actual control efficiency of a wet FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the scrubber. Based on a maximum uncontrolled SO_2 emission rate of 1.64 lb/MMBtu, the wet lime/limestone scrubber technology could achieve a removal efficiency of approximately 94%.

v. Dual-Alkali Wet Scrubber – Dual-alkali wet scrubbers use a sodium-based alkali solution to remove SO_2 from combustion exhaust gas. The process uses both sodium-based and calcium-based compounds. The sodium-based reagent absorbs SO_2 from the exhaust gas, and the calcium-based solution (lime or limestone) regenerates the spent liquor. Calcium sulfites and sulfates are precipitated and discarded as sludge, while the regenerated sodium solution is returned to the absorber loop.

The dual-alkali process requires lower liquid-to-gas ratios than scrubbing with lime or limestone. The reduced liquid-to-gas ratios generally mean smaller reaction units, however, additional regeneration and sludge processing equipment is necessary.

The sodium-based scrubbing liquor, typically consisting of a mixture of sodium hydroxide, sodium carbonate, and sodium sulfite, is an efficient SO_2 control reagent. However, the high cost of the sodium-based chemicals may limit the feasibility of such an installation for generating units sized 100 MW or larger. In addition, the process generates a less stable sludge that can create material handling and disposal problems. The control efficiency is similar to the Wet lime/limestone FGD scrubbers (approximately 96% on higher sulfur coals). Again, the actual control efficiency of a dual-alkali wet scrubber depends on several factors, including the uncontrolled SO_2 concentration entering the scrubber. Based on a maximum uncontrolled SO_2 emission rate of 1.64 lb/MMBtu, the dual-alkali wet scrubber technology could achieve a removal efficiency of approximately 94%.

vi. Dry Flue Gas Desulfurization – An alternative to wet scrubbing that effectively removes SO_2 from combustion gases is dry scrubbing. Dry FGD systems produce a dry by-product that is removed in the particulate control equipment, versus wet FGD systems where the by-product is a slurry collected separately from the fly ash. Dry FGD systems are described below.

(1) Spray Dry Absorber – The typical SDA uses a lime slurry and water injected into a tower to remove SO_2 from the combustion gases. The towers must be designed to provide adequate contact and residence time between the exhaust gas and the slurry in order to produce a relatively dry by-product. The process equipment associated with a spray dryer typically includes an alkaline storage tank, mixing and feed tanks, an atomizer, spray chamber, particulate control device, and a recycle system. The recycle system collects solid reaction products and recycles them back to the spray dryer feed system to reduce alkaline sorbent use.

SDAs are the commonly used dry scrubbing method in large industrial and utility PC-Boiler applications. SDAs have demonstrated the ability to achieve up to 95% SO_2 reduction under normal operating conditions. Once again, the actual control efficiency depends on several factors, including the SO_2 concentration in the flue gas exhaust entering the spray dryer. Dry FGD systems can be as much as 95% efficient for flue gas streams resulting from combustion of high-sulfur coal. Based on a maximum uncontrolled SO_2 emission rate of 1.64 lb/MMBtu, the SDA technology could achieve a removal efficiency of approximately 93%.

(2). Circulating Dry Scrubber – Circulating dry scrubbers use a circulating fluidized bed of dry hydrated lime reagent to remove SO_2. Flue gas passes through a venturi at the base of a vertical reactor tower and is humidified by a water mist. The humidified flue gas then enters a fluidized bed of powdered hydrated lime where SO_2 is removed. The dry by product produced by this system is routed with the flue gas to the particulate removal system. Circulating Dry Scrubber systems can be as much as 90% efficient for flue gas streams resulting from combustion of high-sulfur coal. Based on a maximum uncontrolled SO_2

emission rate of 1.64 lb/MMBtu, the circulating dry scrubber technology could achieve a removal efficiency of approximately 88%, which is lower than the control efficiency of either the wet FGD or dry FGD-SDA.

(3). Dry Sorbent Injection – Dry sorbent injection involves the injection of powdered or hydrated sorbent (typically alkaline) directly into the flue gas exhaust stream. Dry sorbent injection systems are simple systems, and generally require a sorbent storage tank, feeding mechanism, transfer line and blower, and an injection device. The dry sorbent is typically injected countercurrent to the gas flow through a venturi orifice. An expansion chamber is often located downstream of the injection point to increase residence time and contact efficiency. Particulates generated in the reaction are controlled in the system's particulate control device.

Typical SO_2 control efficiencies for a dry sorbent injection system are approximately 50%, but if the sorbent is hydrated lime, then 80% or greater removal efficiency can be achieved. These systems are commonly referred to as lime spray dryers and the control efficiency is lower than the control efficiency of either the wet FGD or dry FGD-SDA.

b. Eliminate Technically Infeasible Options

Circulating dry scrubbers have seen limited application and have not been used on large PC-Boilers such as RMP's PC-Boiler. Circulating dry scrubbers on smaller PC-Boilers have shown high lime consumption rates and significant fluctuations in lime utilization based on inlet SO_2 loading. In addition, circulating dry scrubbers result in high particulate loading to the unit's particulate control device. Because of the high particulate loading, the pressure drop across RMP's existing BACT determined particulate control device (FFB) would be unacceptable. Therefore, circulating dry scrubbers are not considered technically feasible for RMP's PC-Boiler and are eliminated from further consideration.

c. Ranking of Control Technologies Based on Control Efficiencies

Control Technology	**Control Efficiency**
Wet FGD options (including lime, limestone, and dual alkali)	Up to 94%
Dry FGD – SDA	Up to 93%
Dry FGD – Dry Sorbent Injection	Up to 80%
Fuel Switching	Up to 50%
Fuel Blending	Up to 50%
Coal Cleaning	Up to 20%

d. Evaluation of Most Effective Controls

The two most effective controls, wet FGD and dry FGD-SDA, have very similar control efficiencies and will be compared to determine which method would be most appropriate for the PC-Boiler. The fuel switching, fuel blending, and coal cleaning options are considered in conjunction with each of the FGD options as the baseline for this BACT analysis. Fuel information is based on data from RMP's 2006 annual emission inventory and conditions in RMP's MAQP require RMP to burn low sulfur coal. In addition, on very low sulfur coals, the effectiveness of FGD systems flattens out due to the increased difficulty of controlling very small amounts of SO_2.

For this BACT analysis, it was assumed that the wet FGD system would consist of wet limestone scrubbing with forced oxidation. Wet lime and wet limestone scrubbing systems achieve about the same SO_2 control efficiency; however, the higher cost of lime makes wet limestone scrubbing the more economically reasonable option of the two. Using a maximum uncontrolled SO_2 emission rate of 1.64 lb/MMBtu and 9367 tons per year, the wet limestone scrubbing system could achieve a maximum 94% SO_2 removal, resulting in a controlled emission rate of 0.10 lb/MMBtu and 571 tons per year of SO_2 under ideal conditions. RMP provided information that the cost effectiveness of a wet FGD is $1,180 per ton of SO_2 removed, which is comparable to past estimates and is within the range provided in EPA's Air Pollution control Technology Fact Sheet for flue gas desulfurization – wet, spray dry, and dry scrubbers. However, using the baseline data of 1.64 lb/MMBtu and RMP's cost estimations, the cost effectiveness of a wet FGD calculated by the Department is $780 per ton of SO_2 removed.

Wet FGD systems would require an elevated flue gas temperature to evaporate the moisture before they could be turned on, such is the case with the existing SDA system. Consequently, as with the existing SDA, PC-Boiler SO_2 emissions would, by necessity, be largely uncontrolled for a period of time during startup and shutdown. In addition, like the existing SDA, wet FGD systems utilize nozzles and atomizers that would require periodic maintenance resulting in intermittent, limited periods of increased SO_2 emissions. Further, wet FGD systems may also be incompatible with an FFB, which has previously been determined to be BACT for particulate emissions.

Dry FGD-SDA systems, using a maximum uncontrolled SO_2 emission rate of 1.64 lb/MMBtu and 9367 tons per year, could achieve a maximum 93% SO_2 removal, resulting in a controlled emission rate of 0.11 lb/MMBtu and 628 tons per year of SO_2 under ideal conditions. The cost is estimated at $1,497 per ton of SO_2 removed. A wet FGD may be able to achieve slightly higher control efficiency and may be more cost effective; however, to require a wet FGD system in place of the existing dry FGD system would have a minimum incremental cost effectiveness of $30,100 per ton (the extra cost of new wet FGD divided by the additional emissions reduction).

Dry FGD-SDA was previously determined to be BACT for controlling SO_2 emissions from the PC-Boiler; however, periods of PC-Boiler startup and shutdown and SDA atomizer change-outs were not analyzed with respect to BACT. As previously stated, the existing dry FGD-SDA system requires an elevated flue gas temperature to evaporate the moisture before it can be turned on. Consequently, PC-Boiler SO_2 emissions would and are, by necessity, largely uncontrolled for a period of time during startup and shutdown. Further, as previously stated, dry FGD-SDA systems utilize nozzles and atomizers that would and do require periodic maintenance resulting in intermittent, limited periods of increased SO_2 emissions.

BACT analyses must include energy and environmental impacts of potential control technologies. Both wet and dry FGD systems require electricity to operate. Electricity is included in the cost estimates for the two systems. Energy demand for a wet FGD system is approximately 40% higher than for a dry system. Potential collateral environmental impacts can be categorized in the areas of water consumption, waste water handling, solid waste handling, and toxic emissions.

A wet FGD system would require approximately 20% more water than a dry system. A wet FGD system would produce a liquid waste stream containing dissolved and undissolved solids. The waste stream from a dry system would be in the form of a dry, coarse powder. In Permit Application #3185-00, RMP proposed that the wet FGD waste stream would be collected in a tank. From there, the undissolved solids would be separated from the liquid, and the liquid would then be recycled to the scrubber. As the facility design matured, RMP realized that a more feasible approach would be to collect the scrubber effluent in lined evaporation ponds. This option, however, involves increased risk of leaching that could lead to ground and/or surface water contamination. This has proven to be a persistent problem at other established generation facilities.

Both the wet and dry FGD systems would produce a solid waste stream containing ash and reacted and unreacted lime or limestone. As noted above, the waste stream from the dry system would be in the form of a dry, coarse powder. The solid portion of the wet scrubber effluent would be in the form of a high-solids, compact sludge. Beneficial uses potentially exist for both residues. The wet scrubber sludge, consisting primarily of gypsum, can be used as a construction material. The dry powder of the SDA can be used in road construction or as an additive in cement manufacturing. Economic variables, especially in the Hardin area, favor the beneficial use of a dry solid waste. Typically, facilities with a wet scrubber must be associated with a gypsum manufacturing facility on or near their property in order to minimize transportation costs. These costs would otherwise eliminate the economic feasibility of selling the material. Those facilities must also be near a viable market for gypsum. Conversely, it is much more likely that the sale of a dry FGD residue from RMP would be economically practical given the reduced transportation costs and market proximity. Assuming a beneficial use could not be found for either a wet or a dry waste stream, both would be disposed of in a municipal waste facility or in nearby surface impoundments. In that case the dry system would have the advantage of producing less waste than the wet system. This is due to a lower moisture content and because the SDA uses lime, which is more effective than the limestone used in the wet scrubber, thereby requiring a lower feed rate.

The use of wet FGD would potentially result in visibility impacts both locally and on a more widespread basis (because of the high-moisture plume). Wet FGD systems also emit some level of mist that escapes from the slurry spray system. This mist poses negative environmental impacts related to acid gas emissions and fine particulate emissions that would not be collected by the BACT-determined FFB. Dry FGD systems avoid these problems because they do not produce mist and because emissions from the absorber must pass through a filter cake of alkaline material collected in the downstream BACT determined FFB before exhausting to the atomosphere. Locally, the high moisture plume would be quite visible on days with cool weather or humid conditions. The dry FGD system still has some moisture, but in general, has a drier plume.

Wet FGD provides some control of H_2SO_4 emissions, however, in tests reviewed by EPA in the December, 1997 Utility Report to Congress (RTC), wet FGD was found to be 25% effective in controlling H_2SO_4 emissions while dry FGD was found to be 90% effective in controlling H_2SO_4 emissions.

Similar results exist for other acid gases. In combination with an FFB, dry FGD was also found to be more effective at controlling Hg and other metals than a wet FGD system. According to RMP, the configuration of the RMP facility is proving to be an ideal design for mercury removal. The SDA inlet duct configuration allows sufficient contact time for the activated carbon and flue gas before entering the SDA. After passing through the SDA and collecting on the FFB, the mercury continues to be absorbed as the carbon and ash is collected on the filter bags. Recent testing conducted at RMP is showing instances of greater than 90% removal of Hg.

Although coal cleaning, fuel switching, and fuel blending would not be evaluated by themselves due to other options with much higher control efficiency, these options could be combined with FGD methods. As previously mentioned, coal cleaning has mostly been utilized for high-sulfur eastern coals with high pyrite contents. Little research was found for low-sulfur western subbituminous coals. No cost information was found regarding coal cleaning in combination with FGD.

With respect to fuel switching or fuel blending, RMP cannot predict or control future availability of lower sulfur fuels or the price of those fuels. Other sources required to burn low sulfur coals are generally limited to coal with less than 1% sulfur content (also a requirement in MAQP #3185-04 and representative of Absaloka Coal). As previously stated, the use of low sulfur coal (i.e. fuel switching, fuel blending, and coal cleaning) were considered in conjunction with each of the FGD options, as the baseline for this BACT analysis is based on information from RMP's 2006 annual emission inventory and conditions in RMP's MAQP require RMP to burn low sulfur coal (less than 1% sulfur). Therefore, there is no justification, either economically or environmentally, to require RMP to use a coal with lower sulfur content. However, RMP is not prohibited from coal cleaning, fuel switching, or fuel blending, as long as established emission limits can be achieved.
Therefore, coal cleaning, fuel switching, and fuel blending, on their own and in combination with other control technologies are eliminated from consideration as a requirement under BACT for SO_2 emissions from the PC-Boiler.

e. Select BACT

The Department determined that wet FGD systems do not constitute BACT for the PC-Boiler for a variety of reasons. Although wet FGD systems are technically feasible and cost effective, they can result in negative collateral environmental impacts. For example, wet FGD systems can result in the formation of condensable particulate matter and acid gases, neither of which would be controlled with the existing particulate control (FFB). Creation of hazardous air pollutants is of great concern to the community of Hardin and the Department. Wet FGD systems would also require an elevated flue gas temperature to evaporate the moisture before they could be turned on, which would result in periods of time the SO_2 emissions would be largely uncontrolled during PC-Boiler startup and shutdown. Wet SDA systems would also require periodic maintenance to the nozzles and atomizers which would result in periods of increased SO_2 emissions. In addition, the wet FGD systems would require additional water and energy. Also, the solid waste by-product from the scrubbing process would need to be managed in dewatering ponds and/or a landfill. Conversely, the Department determined that the control provided by a dry FGD system is consistent with other recently permitted similar sources and that the negative collateral environmental effects, in this case, from using a wet FGD system compared with a dry FGD system are too great to justify designating that a wet FGD system constitutes BACT.

While a dry FGD-SDA system would have fewer negative collateral environmental effects, in this case, than a wet FGD system, dry FGD-SDA systems also would require an elevated flue gas temperature to evaporate the moisture before they could be turned on, which would result in periods of time that the SO_2 emissions would be largely uncontrolled during PC-Boiler startup and shutdown. Dry FGD-SDA systems would also require periodic maintenance to the nozzles and atomizers which would result in periods of increased SO_2 emissions.

The Department investigated the sulfur percentage of the Absaloka Mine coal (≈ 0.61%) in comparison with the sulfur percentage of the coal for other recently permitted similar sources and their associated limits and for recently permitted sources with similar control equipment that have operated effectively for some period of time. Control of SO_2 becomes progressively more difficult and less effective on lower sulfur coals. Based upon this information, the Department determined that an SO_2 emission limit of 182.6 lb/hr (equivalent to 0.14 lb/MMBtu) on an hourly basis (to protect the hourly ambient standard), as previously permitted under ARM 17.8.749 is one component of BACT for "normal" or steady state operations. In addition, the Department determined that 0.11 lb/MMBtu based on a 30-day rolling average remains the appropriate BACT determination after considering times that the SDA can not be operated (i.e. PC-Boiler startup and shutdown and SDA atomizer change-outs.

MAQP #3185-02 established an 18-month SO_2 optimization period that defined SO_2 emission limits as 0.12 lb/MMBtu and 90% control efficiency with both limits based on a 30-day rolling average. After the 18-month optimization period, MAQP #3185-02 required BACT limits of 0.11 lb/MMBtu and 92% control efficiency with both limits based on a 30-day rolling average, unless RMP submitted an application that included information that different limits are necessary. MAQP Application #3185-04 requested an SO_2 BACT limit of 0.11 lb/MMBtu based on a 30-day rolling average. However, RMP requested that the SO_2 control efficiency remain at 90% per rolling 30-day average rather than increase to 92% per rolling 30-day average.
RMP provided data and information gathered during the SO_2 optimization period that indicates that a minimum SO_2 control efficiency of 92% is not technically achievable on a continuous basis. The data analysis was based on operational data collected from July 2006, through February 2007. The data analysis indicated that while sulfur removal is highly efficient, normal variations in operating conditions can be expected to result in SO_2 removal efficiencies of less than 92%. Due to the data analysis provided and because requiring a higher control efficiency would actually encourage RMP to burn higher sulfur containing coal to ensure their ability to comply with a higher control efficiency requirement, the Department agreed with RMP and determined that an SO_2 control efficiency of 90% is the appropriate BACT control efficiency in this case.

In addition to the need to comply with this MAQP limit, RMP has multiple, compelling reasons to limit pollutant emissions, particularly SO_2 emissions. RMP's corporate policy and the Clean Air Act Amendments Title IV (Acid Rain Requirements) requirements to purchase SO_2 allowances impose strong incentives to aggressively limit emissions to levels below the MAQP limit. As a newly constructed source subject to Acid Rain rules, RMP must purchase an allowance for every ton of SO_2 emitted. With a limited supply of allowances and increasing demand resulting from the power industry expansion, the cost of allowances has been escalating. Therefore, RMP has many incentives not only to comply with the BACT limit as required, but also to further limit SO_2 production.

The above BACT analysis demonstrates that operating the dry FGD-SDA system and complying with 182.6 lb/hr on an hourly basis during "normal" or steady state operations is the appropriate BACT determination. In addition, the above BACT analysis demonstrates that complying with the 0.11 lb/MMBtu and 90% control efficiency, with both limits on a 30-day rolling average, at all times (including periods of PC-Boiler startup and shutdown and SDA atomizer replacements) is the appropriate BACT determination.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

2. PC-Boiler - SO_2 Emissions – Startup and Shutdown and Control Equipment Maintenance

Because the BACT determined SDA can not be operated at certain times (i.e. PC-Boiler startup and shutdown and SDA atomizer replacement) the Department required RMP to conduct a

BACT analysis to determine if it is technically feasible and economically reasonable to control emissions at those times. RMP presented the information as a single BACT analysis and the Department organized the information as two analyses because the Department believes the information is clearer with the information presented separately.

a. Identify Available Control Technologies

The following control strategies have been identified for control of PC-Boiler SO_2 emissions specifically during periods of startup, shutdown, and atomizer change-out.

i. Use of Low Sulfur Coal (i.e. coal cleaning, fuel switching, and fuel blending)

It may be possible to use an ultra-low sulfur coal strictly for periods of PC-Boiler startup and shutdown, and periods of control equipment maintenance. Ultra-low sulfur coal could be purchased or it could be processed to reduce sulfur or increase specific heat content. As discussed in Section 1 of the BACT analysis, RMP combusts subbituminous coal from the Absaloka Mine. The coal is a subbituminous western coal with low sulfur content. Bituminous coals from mines in the eastern and midwestern U.S. generally have a higher heating value, but also have significantly higher sulfur content. Regionally available coals (i.e., from Montana, Wyoming, and North Dakota) contain sulfur in the range of 0.3% to over 3% by weight.

ii. Use of Auxiliary Heat

A very low sulfur fuel such as natural gas could be combusted in a duct burner to heat the flue gas to the temperature required for SDA operation until coal combustion alone achieves the required temperature. A related technique would be to fire the PC-Boiler on natural gas alone until the required exhaust gas temperature is reached.

iii. Installation and operation of redundant controls

A redundant SDA atomizer could be installed and operated when the primary atomizer was being removed for maintenance. Alternately, an entire redundant SDA system could be installed and the exhaust gas routed to it when the primary system required atomizer maintenance. These techniques are potentially available only for control of emissions during atomizer change-out. Redundant systems would be subject to the same exhaust gas temperature limitations as the primary system during periods of PC-Boiler startup and shutdown.

iv. Implementation of proper work practices

PC-Boiler SO_2 emissions during periods of startup, shutdown, and SDA atomizer change-out can be minimized by minimizing the frequency and duration of these events. Such work practices include generally operating all equipment in accordance with manufacturer recommendations, firing the PC-Boiler on natural gas as long as possible during startup prior to introduction of coal, maintaining the PC-Boiler system so as to achieve maximum heat transfer efficiency, maintaining and operating the PC-Boiler-generator system properly so as to avoid shutdowns, closely monitoring exhaust temperature and commencing SDA operation as soon as the requisite temperature is reached, and optimizing the SDA system to minimize atomizer change-out time and frequency.

b. Eliminate Technically Infeasible Options

Both variations of the use of auxiliary heat are technically infeasible. Using a natural gas-fired duct burner to heat the exhaust gas to the temperature required for SDA operation, besides being highly energy inefficient and producing additional pollutant emissions, is technically infeasible due to safety concerns. Any combustion source located downstream of the PC-Boiler has the potential to ignite accumulation of unburned coal, potentially causing baghouse fires or duct explosions.

Burning natural gas longer during startup in order to achieve SDA-required exhaust temperatures prior to combusting coal is technically infeasible because of the gas supply and PC-Boiler design restrictions. The PC-Boiler is designed to combust the maximum amount of natural gas available from the gas distribution system. Even if more natural gas was available, its potential combustion rate in the PC-Boiler would be limited by the capacity of the PC-Boiler for gas combustion. Natural gas is fired using igniters that are integrated into the low NO_x coal burners. The gas igniters are intended to ignite the coal burners and stabilize the flame; they were not intended to provide a significant portion of the PC-Boiler's heat input and have limited combustion capability.

Installation and operation of a redundant SDA atomizer is technically infeasible because of the configuration of the SDA. The atomizer is located in the center of the cone-shaped SDA vessel. The flue gas enters in a radial direction around the atomizer to achieve maximum mixing and gas-solid contact required for maximum control efficiency. This optimized design does not provide sufficient space to add a second atomizer. A redundant atomizer located at any other location would provide limited control efficiency and would disrupt the gas-flow regime so as to reduce the effectiveness of the primary atomizer.

c. Ranking of Control Technologies Based on Control Efficiencies

Control Technology	Control Efficiency
Use of low sulfur coal	50%
Installation and Operation of Redundant SDA	48%
Implementation of proper work practices	2%

d. Evaluation of Most Effective Controls

Uncontrolled emissions due to startup, shutdown, and SDA atomizer replacement are difficult to determine because only short term emission increases result from the activities. RMP currently complies with the 30-day rolling BACT emission rate of 0.11 lb/MMBtu and 90% control efficiency (also on a 30- rolling average using the SDA). RMP has proposed a PC-Boiler SO_2 startup and shutdown and SDA atomizer replacement limit of 1465 lb/hr based on a 1 hour average with the caveat that the 1,465 lb/hr limit shall not exceed 6 hours during any rolling 24-hour time period that coal is combusted in the PC-Boiler. Using these proposed limits to calculate annual emissions would result in approximately 1,604 tons per year. However, this is not a realistic approach because operating data demonstrates that RMP is complying with the 0.11 lb/MMBtu BACT limit on a rolling 30-day average (628 tons per year). Therefore, RMP assumed one startup/shutdown event every 2 months with each startup lasting 6 hours and each shutdown lasting 1 hour to estimate potential emissions related to PC-Boiler startup and shutdown. The calculation would be as follows:

<u>Startup</u>
1465 lb/hr * 6 events/yr * 6 hr/event * 0.0005 ton/lb = 26 ton/yr

<u>Shutdown</u>
1465 lb/hr * 6 events/yr * 1 hr/event * 0.0005 ton/lb = 5 ton/yr

Startup/shutdown
26 ton/yr + 5 ton/yr = 31 ton/year

RMP assumed one atomizer change-out every ten operating days for 350 operating days per year and each event lasting 1 hour with the results multiplied by a 10% contingency factor for unanticipated maintenance requirements. The calculation would be as follows:

1465 lb/hr * (350 days/yr * 0.1 change-out/day) * 1.10 *0.0005 ton/lb = 28 ton/yr

Adding the PC-Boiler startup and shutdown emissions to the SDA atomizer replacement emissions results in annual emissions of 59 tons per year.

A redundant SDA system would only control emissions during periods of atomizer replacement because a redundant atomizer would have the same limitations regarding PC-Boiler startup and shutdown. Therefore, a redundant SDA atomizer would potentially reduce SO_2 emissions associated with SDA atomizer replacements by 93% or 26 tons per year. Considering the combined total of 59 tons per year, a redundant SDA atomizer would potentially reduce SO_2 emissions associated with PC-Boiler startup, shutdown, and SDA atomizer change-outs by approximately 44%.
RMP provided a cost estimate of $10,000 to $50,000 per MMBtu/hr in 2001 dollars. This cost estimate is based on EPA's Air Pollution Control Fact Sheet for Flue Gas Desulfurization – Wet, Spray Dry, and Dry Scrubbers (EPA-45/F-03-034). Assuming the lowest value and multiplying by the PC-Boiler's nominal heat input capacity of 1304 MMBtu/hr yields an annualized cost of approximately $13,000,000, resulting in a cost effectiveness of approximately $500,000 per ton of SO_2 removed.

RMP is currently required by its MAQP to combust low-sulfur coal with a maximum sulfur content of one percent by weight. It is not practical to supply a specific coal to the PC-Boiler for the purpose of combusting only during certain events whose timing often cannot be predicted. This is because a large amount of coal resides in the feed system. This coal would have to be purged from the system and the ultra-low sulfur coal fed through the supply system before any reduction in emissions would result. In most cases, insufficient time is available to clear out and recharge the coal supply stream. RMP provided information that the cost would be approximately $5,000,000 for a redundant coal storage and supply system to provide ultra low-sulfur coal. Using the EPA OAQPS air pollution control cost estimating methodology, this capital cost equates to an approximate annual cost of $519,000. Assuming a conservatively high (RMP is already required to burn coal less than 1% sulfur) control efficiency of 50% would result in 30 tons per year of SO_2 emissions resulting from PC-Boiler startup and shutdown and SDA atomizer change-outs, which would result in a cost effectiveness of approximately $17,300 per ton of SO_2 removed.

RMP is currently implementing proper work practices. As previously stated, such work practices include generally operating all equipment in accordance with manufacturer recommendations, firing the PC-Boiler on natural gas as long as possible during startup prior to introduction of coal, maintaining the PC-Boiler system so as to achieve maximum heat transfer efficiency, maintaining and operating the PC-Boiler-generator system properly so as to avoid shutdowns, closely monitoring exhaust temperature and commenting SDA operation as soon as the requisite temperature is reached, and optimizing the SDA system to minimize atomizer change-out time and frequency. In estimating the SO_2 emissions from periods of PC-Boiler startup and shutdown and SDA atomizer replacement, RMP estimated an approximate control efficiency of 2% for implementing over-scrubbing techniques prior to such events. Therefore, the Department used 2% control efficiency for utilizing proper work practices; however, 2% is a conservatively low number because over-scrubbing is only one aspect of proper work practices but assigning a more accurate control efficiency would be very difficult, if not impossible, to determine. Using 2% control efficiency, such work practices would result in approximately 1 ton per year SO_2 reduction.

d. Select BACT

The preceding BACT analysis demonstrates that all the identified control technologies for controlling SO_2 emissions during PC-Boiler startup and shutdown and SDA atomizer replacements, except for implementing proper work practices, are either technically infeasible or economically impractical and are therefore eliminated from consideration. RMP proposed implementing proper work practices and complying with a 1,465 lb/hr limit on an hourly basis for no more than 6 hours in any rolling 24-hour period (while coal is combusted in the PC-Boiler) as BACT. The previously determined BACT limits of 0.11 lb/MMBtu and 90% control efficiency, with both limits on a 30-day rolling average, apply at all times, including periods of PC-Boiler startup and shutdown and SDA atomizer replacement. The Department considered including assumptions (i.e. % sulfur in coal) RMP used in calculating the 1,465 lb/hr limit as BACT requirements; however, the Department determined that it was not necessary because RMP needs the flexibility in sulfur content due to coal uncertainties and because the PC-Boiler has an SO_2 CEMS to monitor the emissions. Therefore, 1% sulfur and 8,000 Btu/lb remain as applicable requirements in MAQP #3185-04 under the authority of ARM 17.8.749; however, all of the established emission limits would effectively require RMP to use coal that is very near the baseline values used in this analysis (0.7% sulfur and 8546 Btu/lb) in order to comply with those limits. Further, other sources required to burn low sulfur coals are generally limited to coal with less than 1% sulfur content.

RMP stated that they have expended extensive effort and incurred considerable costs upgrading the SDA system to minimize the frequency and duration of atomizer change-out events. Two of the primary modifications have been the design and procurement of new, more durable atomizer wheels, and configuration of a second atomizer with all necessary electrical and auxiliary equipment hooked up in a "hot-standby" mode so it can be placed in the spray tower in the shortest possible time. RMP is striving to limit upset conditions that result in PC-Boiler shutdown and startup events as the facility is a baseload facility, and downtime is extremely costly both in terms of lost revenue and additional labor and materials.

The Department agreed with RMP's proposal and determined that implementing proper work practices and complying with a 1,465 lb/hr limit on an hourly basis for no more than 6 hours in any rolling 24-hour period is BACT. In addition, the previously determined BACT limits of 0.11 lb/MMBtu and 90% control efficiency, with both limits on a 30-day rolling average, apply at all times, including periods of PC-Boiler startup and shutdown and SDA atomizer replacement.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

3. PC-Boiler – H_2SO_4, HCl, and HF Emissions

Since the SDA is the primary control system for PC-Boiler emissions of H_2SO_4, HCl, and HF (acid gases), the BACT analyses presented above for SO_2 emissions control applies to these pollutants as well. RMP proposed to keep the existing BACT limits for "normal" or steady state operations and RMP proposed implementing proper work practices, as described in the

SO_2 PC-Boiler startup and shutdown and SDA atomizer replacement BACT analysis, as BACT during periods of PC-Boiler startup and shutdown and SDA atomizer replacement. The single significant difference between the BACT proposal for SO_2 and for acid gases is the identification of a BACT emission rate limit for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs because there is no practical method available for measuring emissions of these pollutants during these periods. All standard measurement procedures are based on an assumption of steady state operation.

RMP proposed implementing proper work practices during periods of PC-Boiler startup and shutdown and SDA atomizer replacement without imposition of specific related emission limits as BACT for acid gas emissions form the PC-Boiler. Complying with the limits established for SO_2 during periods of PC-Boiler startup and shutdown and SDA atomizer replacement, including the CEMS monitoring the established SO_2 emission rates, will also demonstrate compliance for acid gases. Because there is no practical method available for measuring emissions of these pollutants during periods of PC-Boiler startup and shutdown and SDA atomizer change-outs, the Department agreed with RMP and determined that implementing proper work practices without imposition of specific related emission limits constitutes BACT for periods of PC-Boiler startup and shutdown and SDA atomizer replacements. In addition, the Department determined that the existing BACT limits for acid gases still constitute BACT for "normal" or steady state operations.

The control options selected have controls and control costs comparable to other recently permitted similar sources and are capable of achieving the appropriate emission standards.

IV. Emission Inventory

					Ton/Year				
Source	PM/PM_{10}	NO_x	CO	VOC	SO_x	HCl	HF	H_2SO_4	Hg
PC-Boiler	68.54	514.04	856.73	19.42	628.27	6.75	2.93	35.98	0.027
Cooling Tower	45.04								
Baghouse and Bin Vents	26.11								
Truck Traffic Fugitives	0.26	0.09	0.18	0.04	0.13				
Temporary Auxiliary Boiler*	0.09	0.85	0.21	0.01	0.30				
Totals	139.95	514.13	856.91	19.46	628.40	6.75	2.93	35.98	0.027

*The emissions from the temporary auxiliary boiler are not included in the total plant emissions because the temporary auxiliary boiler is prohibited from operating when the PC-Boiler is combusting coal. Therefore, those emissions would not occur at the same time and are not additive.

PC-Boiler Emissions

Size = 116 MW
Hours of Operation = 8,760 hr/yr
Heat Input = 1304 MMBtu/hr
Fuel Heating Value = 8,700 Btu/lb of coal

PM/PM_{10} Emissions
Emission Factor: 0.012 lb PM/MMBtu {Manufacturer's Guarantee, BACT Limit}
Calculations: 0.012 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 68.54 ton/yr

NO_x Emissions
Emission Factor: 0.09 lb NO_x/MMBtu {Manufacturer's Guarantee, BACT Limit}
Calculations: 0.09 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 514.04 ton/yr

CO Emissions
Emission Factor: 0.15 lb CO/MMBtu {Manufacturer's Guarantee, BACT Limit}
Calculations: 0.15 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 856.73 ton/yr

VOC Emissions
Emission Factor: 0.0034 lb VOC/MMBtu {BACT Limit}

Calculations: 0.0034 lb VOC/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 19.42 ton/yr

SO_x Emissions
Emission Factor: 0.11 lb/MMBtu {BACT Limit}
Calculations: 0.11 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 628.27 ton/yr

HCl Emissions
Emission Factor: 0.00118 lb/MMBtu {Permit Limit}
Calculations: 0.00118 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 6.75 ton/yr

HF Emissions
Emission Factor: 0.00051 lb/MMBtu {Permit Limit}
Calculations: 0.00051 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 2.93 ton/yr

H_2SO_4 Emissions
Emission Factor: 0.0063 lb/MMBtu {Permit Limit}
Calculations: 0.0063 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 35.98 ton/yr

Hg Emissions
Emission Factor: 0.00000475 lb/MMBtu {Worst case, assume no control}
Calculations: 0.00000475 lb/MMBtu * 1304 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 0.027 ton/yr

Cooling Tower Emissions
Water intake rate = 1,400 gpm
Total liquid drift = 0.001% of circulating water flow
Design circulating water rate = 68,500 gpm
Total dissolved solids (TDS) intake = 1,250 ppm
Concentration cycles = up to 24
Circulating TDS = 30,000 lb TDS/10^6 lb H_2O
Hours of Operation = 8,760 hr/yr

PM_{10} Emissions
Calculations: 0.001 lb drift/100 lb H_2O * 68,500 gal H_2O/min * 60 min/hr * 8.34 lb/gal * 30,000 lb TDS/10^6 lb H_2O * 8760 hr/yr * 0.0005 ton/lb = 45.04 ton/yr

Baghouse and Bin Vent Emissions
Coal unloading (RCF-BH-001) flow rate = 50,000 dscfm
Coal silo (RCF-BH-002) flow rate = 7,500 dscfm
Coal storage bunkers (RCF-BH-003) flow rate = 5,000 dscfm
SDA lime silo (FGT-BV-001) flow rate = 1,000 dscfm
FGD ash silo (WMH-BV-003) flow rate = 2,000 dscfm
Recycle ash silo (FGT-BV-002) flow rate = 2,000 dscfm
Water treatment lime silo (RWS-BH-001) flow rate = 1,000 dscfm
Soda ash silo (RWS-BH-002) flow rate = 1,000 dscfm
Hours of operation = 8,760 hr/yr

PM/PM_{10} Emissions
Emission Factor: 0.01 gr/dscf {Permit limit}

RCF-BH-001 Calculations: 50,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 18.77 ton/yr

RCF-BH-002 Calculations: 7,500 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 2.82 ton/yr

RCF-BH-003 Calculations: 5,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 1.88 ton/yr
FGT-BV-001 Calculations: 1,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.38 ton/yr

WMH-BV-003 Calculations: 2,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.75 ton/yr

FGT-BV-002 Calculations: 2,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.75 ton/yr

RWS-BH-001 Calculations: 1,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.38 ton/yr

RWS-BH-002 Calculations: 1,000 dscf/min * 0.01 gr/dscf * 1 lb/7000 gr * 60 min/hr * 8760 hr/yr * 0.0005 ton/lb = 0.38 ton/yr

Truck Traffic Fugitives

Assumptions:

Distance of each round trip = 0.5 mile
Total trips = 2 trips/hr, every hour of the year
Driving surface = paved

PM/PM_{10} Emissions (Fugitives)

Emission Factor: 0.06 lb/VMT {Calculated from AP-42 Equation, 13.2.1 (10/97)}
Calculations: 0.06 lb/VMT * 0.5 VMT/trip * 2 trips/hr *8760 hr/yr * 0.0005 ton/lb = 0.26 ton/yr

Temporary Auxiliary Boiler Emissions

Hours of Operation = 1,000 hr/yr (Permit Limit)
Heat Input = 11.8 MMBtu/hr
Maximum fuel rate = 85 gal/hr of No. 2 fuel oil

PM/PM_{10} Emissions

Emission Factor: 2 lb PM/ 1000 gal fuel {AP-42, Table 1.3-1}
Calculations: 2 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.09 ton/yr

NO_x Emissions

Emission Factor: 20 lb NOx/ 1000 gal fuel {AP-42, Table 1.3-1}
Calculations: 20 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.85 ton/yr

CO Emissions

Emission Factor: 5 lb CO/ 1000 gal fuel {AP-42, Table 1.3-1}
Calculations: 5 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.21 ton/yr

VOC Emissions

Emission Factor: 0.252 lb VOC/1000 gal fuel {AP-42, Table 1.3-3}
Calculations: 0.252 lb/1000 gal fuel * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.02 ton/yr

SO_x Emissions

Emission Factor: 142 * S lb/ 1000 gal {Permit Limit for fuel sulfur content ≤ 0.05%}
Calculations: 142 * 0.05 lb/1000 gal * 85 gal/hr * 1000 hr/yr * 0.0005 ton/lb = 0.30 ton/yr

V. Existing Air Quality

The facility is located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The air quality of this area is classified as either "Better than National Standards" or unclassifiable/attainment of the MAAQS and NAAQS for criteria pollutants.

VI. Ambient Air Impact Analysis

RMP proposed a 1-hour average emission rate of 1465 lb/hr from the facility during periods of PC-Boiler startup and shutdown and atomizer change-oust. RMP also proposed that the facility be limited to not more than 6 hours of that peak emission rate during a rolling 24-hour period, resulting in an effective 24-hour rolling average emission limit of 503.2 lb/hr. Based on review of RMP's emission control technology, the Department is proposing the following permit limits to apply during periods of PC-Boiler startup and shutdown and atomizer change outs:

- 1-hour average: 1465 lb/hr
- 3-hour average: 990 lb/hr

- 24-hour average, effective: 384.5 lb/hr (not an MAQP limit but is the maximum 24-hr average emission rate when considering 990 lb/hr for 6 hrs and 182.6 lb/hr for 18 hours).

The permitted emission rates for steady-state operation of the facility are unchanged by this permitting action. Those limits are 182.6 lb/hr on a 1-hour average and 0.11 lb/MMBtu on a 30-day rolling average. For modeling purposes, the effective 3-hour and 24-hour emission limits for the steady-state operating conditions are also 182.6 lb/hr.

The Department re-ran some of the submitted modeling files using the proposed emission limits to obtain final modeling results. Other results contained in this analysis are based on a ratio of the Department proposed limits and RMP's modeled emission rates.

The proposed short-term SO_2 emission rates were modeled to demonstrate compliance with the 1-hour and 24-hour MAAQS, the 3-hour and 24-hour NAAQS, and the 3-hour and 24-hour Class I and Class II PSD increments. The modeling generally followed the methodology outlined in the New Source Review Workshop Manual, EPA, October 1990, Draft and Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), November 9, 2005.

Bison performed the NAAQS/MAAQS and PSD Class II modeling using EPA's AERMOD model and the PRIME downwash algorithm. The Department ran representative AERMOD modeling files to verify the modeling results. The Department has reviewed the GEP-BPIP input and output files, and verified that the PC-Boiler stack height is below Good Engineering Practice (GEP) stack height. The AERMOD modeling used 1 year of on-site meteorological data collected by RMP at a site approximately 0.6 miles south of the facility. The met data period was from May 16, 2002, through June 11, 2003. The on-site data was processed using AERMET; Billings NWS data was input as surface data, to substitute missing data elements from the on-site data. Upper air data from the Great Falls station was also used in AERMET.

Modeled receptor elevations were derived from digital elevation model (DEM) files of the United States Geological Survey (USGS) 7.5-minute series (1:24,000 scale) topographical maps. Bison has provided the DEM files used in AERMAP to establish receptor elevations and hill heights. The modeling receptor grid complies with the Department's modeling guidance. A total of 3638 fenceline and grid receptors were used. Receptors were placed at 100-meter (m) spacing along the fenceline and out to a distance of 1 kilometer (km). For a distance of 1 km to 3 km from the fenceline, receptors were located at 250-m spacing. From 3 km to 10 km, receptors were placed at 500-m intervals. All receptors locations were expressed using the Universal Transverse Mercator (UTM) coordinates, Zone 13. Locations were in the NAD27 datum.

NAAQS/MAAQS COMPLIANCE DEMONSTRATION

EPA's modeling guideline requires that the full impact analysis include emissions from all sources located within 50 km of the outermost boundary of the SIA (see Figure C-5 of EPA's New Source Review Workshop Manual, EPA, October 1990, Draft). RMP performed cumulative impact modeling to determine compliance with the 1-hour and 24-hour SO_2 MAAQS and the 3-hour and 24-hour SO_2 NAAQS. Modeled boiler stack parameters and emission rates for the RMP PC-Boiler are included in the August 21, 2007, Memorandum from Diane Lorenzen to Dave Aguirre and the memorandum is contained in Department files. The stack parameters and emission rates are consistent with the existing facility configuration. SO_2 emissions from a number of other facilities were included in the cumulative impact modeling. Stack parameters and emission rates for the cumulative impact sources are also listed in the previous mentioned memorandum.

Modeling results are compared to the applicable MAAQS and NAAQS in Table 1. The NAAQS modeling results are dominated by the sources in Billings and the contribution of RMP to the peak impacts is very small. Therefore the values in Table 1 are the same values shown in RMP's modeling results submitted July 26, 2007. Modeled concentrations show the modeled cumulative impacts, and include relevant background values. As shown in Table 1, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 1: NAAQS/MAAQS Compliance Demonstration

Pollutant	Avg. Period	Modeled Conc.[a] (μg/m^3)	Background Conc. (μg/m^3)	Ambient Conc. (μg/m^3)	NAAQS (μg/m^3)	% of NAAQS	MAAQS (μg/m^3)	% of MAAQS
SO_2	1-hr	684	35	719	------	------	1,300	55
	3-hr	632	26	658	1,300	51	------	-----
	24-hr	58.5	11	69.5	365	19	262	26

[a] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-6th-high.

CLASS II PSD INCREMENT COMPLIANCE DEMONSTRATION

RMP modeled the proposed emissions from the RMP PC-Boiler to determine the extent of significant impacts from the facility. Annual emissions were modeled to demonstrate non-significant impact, even though the permitting action does not propose a change in annual emission rates. The modeled RMP impacts are compared to the applicable Class II significant impact levels (SIL's) in Table 2. The radius of impact (ROI) for each pollutant and averaging period is also included in Table 2. The area within the ROI is referred to as the significant impact area (SIA). The values in Table 2 have been updated to reflect the Department's proposed 3-hour emission limit and the effective 24-hour emission limit.

Table 2: Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. (μg/m^3)	Class II SIL[a] (μg/m^3)	Significant (y/n)	Radius of Impact (km)
SO_2	3-hr	179	25	Y	59
	24-hr	21.0	5	Y	44
	Annual	0.46	1	N	NA

[a] All concentrations are 1st-high for comparison to SILs.

RMP's modeled impacts exceed the 3-hour and 24-hour SO_2 SILs, triggering the requirement for cumulative impact modeling. RMP's cumulative PSD increment modeling included Rocky Mountain Ethanol (RME), Colstrip Energy Limited Partnership (CELP), PPL Colstrip Units 3 & 4, and the Yellowstone Energy Limited Partnership (YELP) project in Billings. These are all SO_2 increment-consuming sources located within 50 km of the SIA.

The cumulative modeling for PSD increment consumption was based on the annual average SO_2 emissions from the off-site sources. The Department determined that the PSD increment modeling approach is consistent with Montana's PSD regulations contained in ARM 17.8.801 *et. seq*. The PSD increment modeling emission rates are listed in afore mentioned memorandum.

RMP's Class II increment modeling results are compared to the applicable PSD increments in Table 3. Background concentrations are not included in the PSD increment compliance demonstration. Table 3 values have been updated to reflect the Department's proposed 3-hour emission limit and the effective 24-hour emission limit.

Table 3: Class II PSD Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Modeled Conc. (μg/m^3)$^{(a)}$	Class II Increment	% Class II Increment Consumed	Peak Impact Location (UTM Zone 13)

				($\mu g/m^3$)		
SO_2	3-hr	On-site 02-03	152	512	30	(305500, 5066500)
	24-hr	On-site 02-03	21.8	91	24	(297800, 5069300)

CLASS I PSD INCREMENT COMPLIANCE DEMONSTRATION

Class I increment modeling was performed using the CALPUFF modeling system. CALPUFF is an appropriate model for receptors beyond 10 km and as far out as 200 km. The closest receptor on the NCIR is 46 km from the RMP facility and other Class I areas are up to 200 km from the RMP site. The CALPUFF analysis following EPA-approved versions of the CALPUFF primary programs and pre- and post-processors:

Geophysical Data Processors
- TERREL (Version 3.684, Level 070327)
- CTGCOMP (Version 3.684, Level 070327)
- CTGPROC (Version 3.684, Level 070430)
- MAKEGEO (Version 3.684, Level 070327)

Meteorological preprocessors
- SMERGE (Version 5.57, Level 070327
- EXTRACT (Version 3.684, Level 070327)
- PMERGE (Version 3.684, Level 070327)
- READ62 (Version 3.684, Level 070327)

Main Models
- CALMET (Version 5.8, Level 070623)
- CALPUFF (Version 5.8, Level 070623)

Postprocessors
- CALPOST (Version 5.8, Level 070622)
- PRTMET (Version 5.8, Level 070627)
- CALSUM (Version 5.8, Level 051122)
- POSTUTIL (Version 5.8, Level 070627)

Bison modeled the impacts of the RMP PC-Boiler at receptors at the following four Class I areas:
- UL Bend Wilderness Area
- Yellowstone National Park
- North Absaroka Wilderness Area
- Northern Cheyenne Indian Reservation (NCIR)

The CALPUFF modeling was based on 3 years of MM5 data from 2001-2003 and corresponding surface, upper air and precipitation data. Meteorological data processing using CALMET followed the methodology specified in Montana's draft BART modeling protocol.

Montana's permit modeling guidance lists tentative SIL's for Class I areas of 1 $\mu g/m^3$ on a 3-hour average, 0.2 $\mu g/m^3$ on a 24-hour average, and 0.1 $\mu g/m^3$ on an annual average. If the impacts from the project alone are above these levels, cumulative impact modeling may be necessary to fully assess impacts. For this application, the impacts from the RMP PC-Boiler exceeded the significance levels at all four Class I areas modeled. The Department did not require cumulative impact analysis at UL Bend, Yellowstone or North Absaroka because of the large distances between those Class I areas and the facility. Cumulative impact analysis was included for the NCIR Class I area.

The NCIR Class I cumulative increment modeling included the main power boilers at RMP, RME, CELP, Colstrip Units 3 & 4, and YELP. RMP's Class I SO_2 modeling results are compared to the applicable PSD increments in Table 3. The 3-hour and 24-hour Class I PSD increment compliance results in Table 3 have been adjusted based on a ratio of the emission rate in the application and the emission limit the Department is proposing in the MAQP.

Table 3: Class I PSD Increment Compliance Demonstration

Class I Area	Pollutant/ Period	Met Data Year	Modeled Conc. ($\mu g/m^3$)[a]	Class I Increment ($\mu g/m^3$)	% Class I Increment	Modeled Sources
UL Bend Wilderness Area	SO_2, 3-hr	2001	2.97	25	12	RMP Boiler
	SO_2, 24-hr	2001	0.26	5	5.2	
	SO_2, Annual	2001	0.0032	2	0.16	
Yellowstone National Park	SO_2, 3-hr	2003	0.99	25	4.0	RMP Boiler
	SO_2, 24-hr	2003	0.110	5	2.2	
	SO_2, Annual	2002	0.0007	2	0.035	
North Absaroka Wilderness Area	SO_2, 3-hr	2002	2.17	25	8.7	RMP Boiler
	SO_2, 24-hr	2002	0.34	5	6.7	
	SO_2, Annual	2003	0.0022	2	0.11	
Northern Cheyenne Indian Reservation	SO_2, 3-hr	2002	14.65	25	59	RMP Boiler
	SO_2, 24-hr	2002	1.91	5	38	
	SO_2, Annual	2002	0.05	2	2.5	
Northern Cheyenne Indian Reservation	SO_2, 3-hr	2002	17.75	25	71	RMP, RME, Colstrip 3&4, CELP, YELP
	SO_2, 24-hr	2002	2.64	5	53	
	SO_2, Annual	No cumulative model because RMP not significant.				

[a] Compliance with short-term standards is based on high-second-high impact.

VISIBILITY MODELING FOR CLASS I AREAS

RMP submitted an analysis of impacts on visibility in the three mandatory Class I areas listed above. CALPUFF modeling results were processed using the CALPOST program. CALPOST compares visibility impacts from the modeled source(s) to pre-existing visual range at the affected Class I areas and calculates a reduction in background extinction, ΔB_{ext}. The value of ΔB_{ext} is expressed either as a percent change or in units of deciviews (dv).

Visual range is defined as the actual distance at which a person can discern an ideal dark object against the horizon sky. Change in the visual range is used to describe the intensity of the modeled visibility impacts, using the modeled ΔB_{ext} value. A change of 0.5 dv represents a 2% threshold contrast ration and is theoretically the lowest visually perceptible brightness contrast a person can see.

Bison provided analyses of the modeling results using two different methods to obtain visibility extinction values: CALPOST Method 2 and CALPOST Method 6. In Method 2, an hourly relative humidity (RH) factor is applied to observed and modeled sulfate and nitrate to determine extinction. This method is highly conservative because Montana often has very low background extinction values and the hourly RH factor can result in high predicted extinction from the plume as a result of the RH factor. Method 6 uses a monthly average RH factor, which moderates the impacts of RH extremes and typically results in a lower calculated extinction percentage.

Bison submitted CALPOST results from both Method 2 and Method 6 using the maximum modeled visibility impact and the 98th percentile modeled visibility impacts. The Department has focused this analysis on the maximum modeled impacts; the 98th percentile modeling results can be viewed in the

permit application materials. Modeling results using RMP's proposed SO_2 emission rates can be viewed in the permit application materials.
The visibility impact analysis results presented in the tables below are based on the Department's proposed SO_2 emission limits for PC-Boiler startup and shutdown and atomizer change outs. Visibility impacts from RMP using the permit-allowable steady-state emission limits are also listed for comparison.

Table 4: RMP Visibility Results, CALPOST Method 2

Class I Area	Met Data Year	Modeled Using SUSD* Limits			Modeled using Steady-state Limits		
		Max. ΔB_{ext} 24-hr Average	Days $\Delta B_{ext} \geq 0.5$	Days $\Delta B_{ext} \geq 1.0$	Max. ΔB_{ext} 24-hr Average	Days $\Delta B_{ext} \geq 0.5$	Days $\Delta B_{ext} \geq 1.0$
Yellowstone National Park	2001	0.233	0	0	0.156	0	0
	2002	0.547	1	0	0.341	0	0
	2003	0.778	1	0	0.478	0	0
UL Bend Wilderness Area	2001	1.43	6	2	0.929	3	0
	2002	0.939	3	0	0.575	1	0
	2003	1.07	4	1	0.670	2	0
North Absaroka Wilderness Area	2001	0.767	2	0	0.496	0	0
	2002	1.02	6	1	0.637	1	0
	2003	1.35	3	1	0.883	2	0

* SUSD Indicates limits applicable during startup, shutdown and atomizer change out.

Guidelines for evaluating visibility impacts were first provided in the 2000 Draft Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I report. The guidelines in the 2000 FLAG report, which are based on CALPOST Method 2 results, identify a visibility change of $\%\Delta B_{ext} \geq 5\%$ ($\Delta B_{ext} \geq 0.5$ dv) from the project alone as the level at which a cumulative analysis would be warranted.

The results in Table 4 also show that the RMP PC-Boiler alone would cause an impact of $\Delta B_{ext} \geq 0.5$ dv for 8 days using the current steady-state permit limits. RMP provided cumulative impact modeling in August 2004 for the steady-state permit limits, and it was accepted by the Department. The results in Table 4 show that the RMP PC-Boiler alone would cause an impact of $\Delta B_{ext} \geq 0.5$ dv for 26 days using the Department's proposed start up, shutdown and atomizer change out limits. The Department did not require cumulative impact modeling for visibility because the results from the 2004 modeling were dominated by the cumulative impact sources and those results are not expected to change.

The 2000 Draft Flag Phase I guidelines state that the FLM's are likely to object to the MAQP if the $\%\Delta B_{ext}$ from the project is greater than $\geq 10\%$ ($\Delta B_{ext} \geq 1.0$ dv). As shown in Table 4, the single source impact for RMP with the Department's proposed limits would exceed 1.0 dv on 5 days with the start up, shutdown and atomizer change out limits, and would not exceed 1.0 dv on any days with the steady-state limits. These results are based on CALPOST Method 2 analyses.

The FLAG workgroup has proposed revising the FLAG Phase I report and the visibility guidelines to rely on the results of CALPOST Method 6 rather than Method 2. Table 5 contains RMP impact analyses processed with Method 6 for both the steady-state and startup, shutdown and atomizer change out conditions.

Table 5: RMP Visibility Results, CALPOST Method 6

Class I Area	Met Data Year	Modeled Using SUSD* Limits			Modeled using Steady-state Limits		
		Max. ΔB_{ext} 24-hr Average	Days $\Delta B_{ext} \geq$ 0.5	Days $\Delta B_{ext} \geq$ 1.0	Max. ΔB_{ext} 24-hr Average	Days $\Delta B_{ext} \geq$ 0.5	Days $\Delta B_{ext} \geq$ 1.0
Yellowstone National Park	2001	0.211	0	0	0.140	0	0
	2002	0.280	0	0	0.223	0	0
	2003	0.229	0	0	0.180	0	0
UL Bend Wilderness Area	2001	0.861	2	0	0.558	2	0
	2002	0.331	0	0	0.260	0	0
	2003	0.477	0	0	0.378	0	0
North Absaroka Wilderness Area	2001	0.333	0	0	0.212	0	0
	2002	0.475	0	0	0.382	0	0
	2003	0.375	0	0	0.303	0	0

* SUSD Indicates limits applicable during startup, shutdown and atomizer change out.

The CALPOST Method 6 analyses show that the RMP emissions are expected to cause a visibility change greater than 0.5 dv on two days at the UL Bend Wilderness Area. With the Department proposed emission limits, the CALPOST Method 6 results do not show that RMP will have an impact over 1.0 dv on any days at any of the Mandatory Class I areas. The CALPOST Method 6 results were based on the annual monthly relative humidity adjustment factors.

The modeling results in Table 5 show that impacts at the UL Bend Wilderness area are the most critical and that year 2001 produces the highest impacts. The following is a list of the high-first-high through the high-eighth-high modeled impacts using Method 6. The high-eighth-high value is essentially the 98th percentile value.

Table 6: Detailed Method 6 Results for UL Bend Wilderness Area, 2001 (ΔB_{ext})

Limits	H1H	H2H	H3H	H4H	H5H	H6H	H7H	H8H
SUSD*	0.861	0.750	0.477	0.463	0.371	0.335	0.380	0.290
Steady-state	0.558	0.483	0.326	0.310	0.245	0.209	0.193	0.180

* SUSD Indicates limits applicable during startup, shutdown and atomizer change out.

DEPARTMENT ASSESSMENT OF VISIBILITY IMPACTS

Visibility impact assessment is required under ARM 17.8.1103 which states that the visibility requirements are applicable to the owner or operator of a proposed major stationary source, as defined by ARM 17.8.802(22). ARM 17.8.1106 (1) requires that "the owner or operator of a major

stationary source … demonstrate that the actual emissions (including fugitive emissions) will not cause or contribute to adverse impact on visibility within any federal Class I area or the Department shall not issue a permit."
ARM 17.8.1101 defines "adverse impact on visibility" as visibility impairment which the Department determines does or is likely to interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within a federal Class I area. The determination must be made on a case-by-case basis taking into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility. "Visibility impairment" is defined as any humanly perceptible change in visual range, contrast or coloration from that which would have existed under natural conditions. Natural conditions include fog, clouds, windblown dust from natural sources, rain, naturally ignited wildfires, and natural aerosols.

The Department considered all of the visibility modeling results presented above to evaluate the visibility impacts from RMP's proposed MAQP changes. The Department has reviewed RMP's visibility impact analyses to determine if the proposed MAQP changes at the facility are expected to have an adverse impact on visibility. Each of the following paragraphs compares RMP's projected visibility impacts to the parameters listed in Montana's visibility regulation.

Geographic Extent: The Method 6 CALPOST results in Table 5 show that the RMP impacts exceed 0.5 dv on two days in 2001. On both of those days, all of the 134 receptors in the UL Bend Wilderness Area had modeled visibility change be greater than 0.5 dv. Therefore the extent of the impacts is the entire area of the UL Bend wilderness area.

Intensity: The highest modeled ΔB_{ext} value for RMP alone is 0.861 dv using Method 6.

Duration: The visibility impact assessment period is a 24-hour day. The modeled ΔB_{ext} values did not exceed the guidelines for any two consecutive days. Modeled ΔB_{ext} values exceeded 0.5 dv on January 11 and January 23 in the 2001 data set.

Frequency: The modeled ΔB_{ext} values from RMP exceeded 0.5 dv on 2 of the 1095 days modeled, which is 0.2% of the modeled days.

Time of Visibility Impairment: Modeled ΔB_{ext} values exceeding the FLAG guidelines were modeled in January, when the area experiences approximately 10 hours of daylight.

Correlation with Times of Visitor Use of the Federal Class I Area(s): Most visitation of the UL Bend Wilderness area occurs during hunting, fishing and bird-watching seasons. Use of the area is limited in January due to cold weather and snow cover.

Frequency and Occurrence of Natural Conditions that Reduce Visibility: The UL Bend Wilderness area almost always has snow, with gray overcast skies in the month of January.

DEPARTMENT DETERMINATION ON VISIBILITY IMPACT

RMP has provided a visibility impact assessment as required under ARM 17.8.1103. The Department has reviewed the assessment and evaluated the results on a case-by-case basis as required. The visibility impact assessment demonstrates that the proposed short-term emission limit changes for the RMP boiler will not cause or contribute to adverse impact on visibility within any mandatory Class I area.

The geographic extent of the modeled visibility impacts is fairly large on the peak days, but this is expected due to the wide expanse of the modeling domain. The intensity of visibility impacts, as reflected in the modeled ΔB_{ext} values from RMP are less than 0.5 dv (the FLM level of concern) for >99% of the days modeled and are all less than 1.0 dv.

The Department has concluded that visibility impact assessment results do not indicate that the project will interfere with visitor's enjoyment of the wilderness visual experience. Modeled visibility impacts that could be perceptible based on FLM guidelines were modeled in January, when visitor use in the UL Bend Wilderness area is limited by cold weather and short days.

The Department has determined that the change in short-term allowable SO_2 emissions from the RMP boiler will not cause or contribute to an adverse impact on visibility. The proposed emissions will not result in visibility impairment which the Department determines does or is likely to interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within a federal Class I area. This determination has taken into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility.

VII. Taking or Damaging Implication Analysis

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

VIII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was completed for this project. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued To: Rocky Mountain Power, LLC.
Hardin Generating Station
2575 Park Lane, Suite 200
Lafayette, CO 80026

Air Quality Permit Number: 3185-04

Preliminary Determination Issued: August 29, 2007
Department Decision Issued: October 5, 2007
Permit Final: October 23, 2007

1. *Legal Description of Site*: The facility is located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana.

2. *Description of Project*: The proposed project would not include the addition of any new emissions units. The project would consist of clarifying existing BACT conditions and emission limits for SO_2, acid gases, and PM/PM_{10} emissions during "normal" or steady state operations. In addition, the proposed project would establish additional BACT conditions and emission limits for SO_2 and acid gases during periods of PC-Boiler startup and shutdown and SDA atomizer change-outs.

3. *Objectives of Project*: The objectives of the project would be to establish BACT conditions and emission limits for SO_2 and acid gases during periods of PC-Boiler startup and shutdown and SDA atomizer change-outs. RMP did not previously go through BACT for periods of PC-Boiler startup and shutdown and SDA atomizer change-outs and RMP currently is not complying with certain existing conditions which do not provide any relief during periods of PC-Boiler startup and shutdown and SDA atomizer change-outs.

4. *Alternatives Considered*: In addition to the proposed action, the Department also considered the "no-action" alternative. The "no-action" alternative would deny issuance of the air quality preconstruction permit to the proposed facility. However, the Department does not consider the "no-action" alternative to be appropriate because RMP demonstrated compliance with all applicable rules and regulations as required for MAQP issuance. Therefore, the "no-action" alternative was eliminated from further consideration.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions, including a BACT analysis, would be included in MAQP #3185-04.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this MAQP as part of the MAQP development. The Department determined that the MAQP conditions are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Terrestrial and Aquatic Life and Habitats			✓			Yes
B	Water Quality, Quantity, and Distribution			✓			Yes
C	Geology and Soil Quality, Stability and Moisture			✓			Yes
D	Vegetation Cover, Quantity, and Quality			✓			Yes
E	Aesthetics				✓		Yes
F	Air Quality		✓				Yes
G	Unique Endangered, Fragile, or Limited Environmental Resources			✓			Yes
H	Demands on Environmental Resource of Water, Air and Energy			✓			Yes
I	Historical and Archaeological Sites				✓		Yes
J	Cumulative and Secondary Impacts			✓			Yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

There would be no impacts to terrestrial and aquatic life and habitats due to facility construction from the proposed project because the RMP facility is an existing facility and no new emission units or projects that would require ground or water disturbance are a part of the proposed project. Terrestrials (such as deer, antelope, rodents) would continue to use the general area of the facility. The area around the facility is fenced to limit access to the facility. The fencing likely does not restrict access by all animals that frequent the area, but it surely discourages some animals from entering the facility property. The area to the south is currently used for industrial purposes and would remain an industrial area. Surrounding that industrial area is some agricultural activity as well as single-family dwellings. The area to the north and west of the facility is agricultural with additional single-family dwellings (within 100 yards of the facility). The other industrial sources, such as a Cenex bulk storage facility and the abandoned Holly Sugar processing facility (directly to the south of the RMP facility) are located within a few hundred feet of the facility boundary.

Aquatic life and habitats would realize a minor impact from the proposed project due to facility operation because short-term emissions of SO_2 and annual emissions of acid gases would be increasing during periods of PC-Boiler startup and shutdown and SDA atomizer change-outs. However, annual potential emissions of SO_2 and PM/PM_{10} would actually decrease because the 30-day average emission limits would be lowered. The resulting air emissions from the proposed project to any water body or land mass would be minor.

The air quality modeling analysis (see section 7.F of this EA) of the air emissions from this facility indicates that the cumulative impacts from the RMP emissions on land or surface water would be moderate and would consume only a small portion of the ambient air quality standards. The cumulative, moderate air impact would probably correspond to a small amount of deposition because of the type of emissions involved and the dispersion characteristics in the area (wind speed, wind direction, atmospheric stability, stack temperature, etc.). The air impacts from the proposed project and the short term emission increases in SO_2 emissions, and the emission increases in acid gas emissions would be minor. The proposed project, and the facility as a whole, would be in compliance with the NAAQS and MAAQS, which are designed to be protective of human health (primary standards), public welfare, and the environment (secondary standards), including terrestrial and aquatic life. Overall, impacts to terrestrial and aquatic life and habitats would be minor.

B. Water Quality, Quantity and Distribution

The proposed project would result in minor impacts to water quality, quantity, and distribution in the area because little or no impact to the surrounding surface water would result from the short-term emissions increase of SO_2 and annual emissions increase of acid gases. In fact, annual emissions of SO_2 and PM/PM_{10} emissions would actually be decreasing because the 30-day rolling average emission limits for these pollutants would be lowered. The facility would continue to use water from the Bighorn River to operate the cooling tower, and the facility would continue to use the City of Hardin water and sewage facilities for other water demands and sewage discharge. However, no changes to water usage or sewer discharge are part of the proposed project so there would be no additional impacts.

As described in Section 7.F of this EA, the maximum, cumulative impacts from the air emissions from this facility would be moderate. However, based on the dispersion characteristics in the area in combination with the level of air emissions, the corresponding deposition of the air pollutants in the area would be minor. The modeled emissions from the RMP facility show compliance with the NAAQS and MAAQS, both primary and secondary standards. The secondary standards are applicable to these impacts, as they protect public welfare, including protection against damage to water resources.

The proposed project does not include any changes in the amount of water drawn from the Bighorn River and no change to the method of water discharged from the facility. There would continue to be no direct discharge to the waters of the state of Montana from the operation of the cooling tower. Therefore there would be no impacts associated with the proposed project due to water withdrawal and discharge/evaporation.

C. Geology and Soil Quality, Stability and Moisture

The impacts to the geology and soil quality, stability, and moisture from this facility would be minor because the proposed project would not change the footprint of the facility as it was previously permitted. No new emissions units or construction is proposed and the amount of resulting deposition of the air emissions would be small. Soil stability would not be impacted by the proposed project because construction is not required. The facility would continue to not discharge any material directly to the soil in the immediate area. Some of the air emissions from the facility may deposit on local soils, but that deposition would result in only a minor impact to local areas because of the air dispersion characteristics of the area (see Section 7.F of this EA).

D. Vegetation Cover, Quantity, and Quality

The proposed project would result in minor impacts on the vegetative cover, quantity, and quality in the immediate area because the proposed project would not change the footprint of the facility as it was previously permitted. No new emissions units or construction is proposed and the amount of resulting deposition of the air emissions from the proposed project would be relatively small. Approximately 30 acres have been or would be disturbed for the entire facility construction and its perimeter and the proposed project would not change the disturbed acres. As described in Section 7.F of this EA, the cumulative modeled air impacts from the air emissions from this facility would be moderate. As described in that section, based on the air dispersion characteristics in the area, the corresponding deposition of the air pollutants on the surrounding vegetation would be minor. Modeling for the RMP facility shows compliance with the NAAQS and MAAQS, both primary and secondary standards. The secondary standards are applicable to these impacts, as they protect public welfare and the environment, including protection against damage to vegetation. The air impacts from the proposed project and its short-term increase in SO_2 and acid gas emissions would be minor.

E. Aesthetics

There would be no impacts to the aesthetics of the area from the proposed project because the facility is an existing facility the appearance of the plant would not change as part of the proposed project. In addition, noise and odors would remain the same as currently exist.

F. Air Quality

RMP proposed a one-hour average emission rate of 1465 lb/hr from the facility during periods of PC-Boiler startup and shutdown and atomizer change-outs. RMP also proposed that the facility be limited to not more than 6 hours of the peak emission rate during a rolling 24-hour period, resulting in an effective 24-hour rolling average emission limit of 503.2 lb/hr. Based on review of RMP's emission control technology, the Department is proposing the following permit limits to apply during periods of PC-Boiler startup and shutdown and atomizer change outs:

- 1-hour average: 1465 lb/hr
- 3-hour average: 990 lb/hr
- 24-hour average, effective: 384.5 lb/hr (not an MAQP limit but is the maximum 24-hr average emission rate when considering 990 lb/hr for 6 hrs and 182.6 lb/hr for 18 hours).

The permitted emission rates for steady-state operation of the facility are unchanged by this permitting action. Those limits are 182.6 lb/hr on a one-hour average and 0.11 lb/MMBtu on a 30-day rolling average. For modeling purposes, the effective 3-hour and 24-hour emission limits for the steady-state operating conditions are also 182.6 lb/hr.

The Department re-ran some of the submitted modeling files using the proposed emission limits to obtain final modeling results. Other results contained in this analysis are based on a ratio of the Department proposed limits and RMP's modeled emission rates.

The proposed short-term SO_2 emission rates were modeled to demonstrate compliance with the 1-hour and 24-hour MAAQS, the 3-hour and 24-hour NAAQS, and the 3-hour and 24-hour Class I and Class II PSD increments. The modeling was performed in accordance with the methodology outlined in the New Source Review Workshop Manual, EPA, October 1990, Draft and Appendix W of 40 CFR Part 51, Guideline on Air Quality Models (revised), November 9, 2005.

Bison performed the NAAQS/MAAQS and PSD Class II modeling using EPA's AERMOD model and the PRIME downwash algorithm. The Department ran representative AERMOD modeling files to verify the modeling results. The Department has reviewed the GEP-BPIP input and output files, and verified that the PC-Boiler stack height is below Good Engineering Practice (GEP) stack height.

NAAQS/MAAQS COMPLIANCE DEMONSTRATION

EPA's modeling guideline requires that the full impact analysis include emissions from all sources located within 50 km of the outermost boundary of the SIA (see Figure C-5 of EPA's New Source Review Workshop Manual, EPA, October 1990, Draft). RMP performed cumulative impact modeling to determine compliance with the 1-hour and 24-hour SO_2 MAAQS and the 3-hour and 24-hour SO_2 NAAQS. Modeled boiler stack parameters and emission rates for the RMP PC-Boiler are included in the August 21, 2007, Memorandum from Diane Lorenzen to Dave Aguirre and the memorandum is contained in Department files. The stack parameters and emission rates are consistent with the existing facility configuration. SO_2 emissions from a number of other facilities were included in the cumulative impact modeling. Stack parameters and emission rates for the cumulative impact sources are also listed in the previous mentioned memorandum.

Modeling results are compared to the applicable MAAQS and NAAQS in Table 1. The NAAQS modeling results are dominated by the sources in Billings and the contribution of RMP to the peak impacts is very small. Therefore the values in Table 1 are the same values shown in RMP's modeling results submitted July 26, 2007. Modeled concentrations show the modeled cumulative impacts, and include relevant background values. As shown in Table 1, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 1: NAAQS/MAAQS Compliance Demonstration

Pollutant	Avg. Period	Modeled Conc.[a] (μg/m³)	Background Conc. (μg/m³)	Ambient Conc. (μg/m³)	NAAQS (μg/m³)	% of NAAQS	MAAQS (μg/m³)	% of MAAQS
SO_2	1-hr	684	35	719	------	------	1,300	55
	3-hr	632	26	658	1,300	51	------	-----
	24-hr	58.5	11	69.5	365	19	262	26

[a] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-6th-high.

The modeling results contained in Table 1 show that the SO_2 emissions from RMP's facility, as a whole, comply with the NAAQS and MAAQS.

RMP modeled the proposed emissions from the RMP PC-Boiler to determine the extent of significant impacts from the facility. Annual emissions were modeled to demonstrate non-significant impact, even though the permitting action does not propose a change in annual emission rates. The modeled RMP impacts are compared to the applicable Class II SILs in Table 2. The ROI for each pollutant and averaging period is also included in Table 2. The area within the ROI is referred to as the SIA. The values in Table 2 have been updated to reflect the Department's proposed 3-hour emission limit and the effective 24-hour emission limit.

Table 2: Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. (μg/m³)	Class II SIL[a] (μg/m³)	Significant (y/n)	Radius of Impact (km)
SO_2	3-hr	179	25	Y	59
	24-hr	21.0	5	Y	44
	Annual	0.46	1	N	NA

[a] All concentrations are 1st-high for comparison to SIL's.

RMP's modeled impacts exceed the 3-hour and 24-hour SO_2 SILs, triggering the requirement for cumulative impact modeling. RMP's cumulative PSD increment modeling included RME, CELP, PPL Colstrip Units 3 & 4, and the YELP project in Billings. These are all SO_2 increment-consuming sources located within 50 km of the SIA.

The cumulative modeling for PSD increment consumption was based on the annual average SO_2 emissions from the off-site sources. The Department determined that the PSD increment modeling approach is consistent with Montana's PSD regulations contained in ARM 17.8.801 *et. seq*.

RMP's Class II increment modeling results are compared to the applicable PSD increments in Table 3. Background concentrations are not included in the PSD increment compliance demonstration. Table 3 values have been updated to reflect the Department's proposed 3-hour emission limit and the effective 24-hour emission limit.

Table 3: Class II PSD Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Modeled Conc. ($\mu g/m^3$)[(a)]	Class II Increment ($\mu g/m^3$)	% Class II Increment Consumed	Peak Impact Location (UTM Zone 13)
SO_2	3-hr	On-site 02-03	152	512	30	(305500, 5066500)
	24-hr	On-site 02-03	21.8	91	24	(297800, 5069300)

The modeling results contained in Table 3 demonstrate that the SO_2 emissions from RMP's facility, as a whole, comply with the Class II PSD SO_2 increments.

Class I increment modeling was performed using the CALPUFF modeling system. CALPUFF is an appropriate model for receptors beyond 10 km and as far out as 200 km. The closest receptor on the NCIR is 46 km from the RMP facility and other Class I areas are up to 200 km from the RMP site. The CALPUFF analysis following EPA-approved versions of the CALPUFF primary programs and pre- and post-processors:

Bison modeled the impacts of the RMP PC-Boiler at receptors at the following four Class I areas:

- UL Bend Wilderness Area
- Yellowstone National Park
- North Absaroka Wilderness Area
- NCIR

The CALPUFF modeling was based on 3+ years of MM5 data from 2001-2003 and corresponding surface, upper air and precipitation data. Meteorological data processing using CALMET followed the methodology specified in Montana's draft BART modeling protocol.

Montana's permit modeling guidance lists tentative SIL's for Class I areas of 1 $\mu g/m^3$ on a 3-hour average, 0.2 $\mu g/m^3$ on a 24-hour average, and 0.1 $\mu g/m^3$ on an annual average. If the impacts from the project alone are above these levels, cumulative impact modeling may be necessary to fully assess impacts. For this application, the impacts from the RMP PC-Boiler exceeded the significance levels at all four Class I areas modeled. The Department did not

require cumulative impact analysis at UL Bend, Yellowstone or North Absaroka because of the large distances between those Class I areas and the facility. Cumulative impact analysis was included for the NCIR Class I area.
The NCIR Class I cumulative increment modeling included the main power boilers at RMP, RME, CELP, Colstrip Units 3 & 4, and YELP. RMP's Class I SO_2 modeling results are compared to the applicable PSD increments in Table 3. The 3-hour and 24-hour Class I PSD increment compliance results in Table 3 have been adjusted based on a ratio of the emission rate in the application and the emission limit the Department is proposing in the MAQP.

Table 3: Class I PSD Increment Compliance Demonstration

Class I Area	Pollutant/ Period	Met Data Year	Modeled Conc. ($\mu g/m^3$)[a]	Class I Increment ($\mu g/m^3$)	% Class I Increment	Modeled Sources
UL Bend Wilderness Area	SO_2, 3-hr	2001	2.97	25	12	RMP Boiler
	SO_2, 24-hr	2001	0.26	5	5.2	
	SO_2, Annual	2001	0.0032	2	0.16	
Yellowstone National Park	SO_2, 3-hr	2003	0.99	25	4.0	RMP Boiler
	SO_2, 24-hr	2003	0.110	5	2.2	
	SO_2, Annual	2002	0.0007	2	0.035	
North Absaroka Wilderness Area	SO_2, 3-hr	2002	2.17	25	8.7	RMP Boiler
	SO_2, 24-hr	2002	0.34	5	6.7	
	SO_2, Annual	2003	0.0022	2	0.11	
Northern Cheyenne Indian Reservation	SO_2, 3-hr	2002	14.65	25	59	RMP Boiler
	SO_2, 24-hr	2002	1.91	5	38	
	SO_2, Annual	2002	0.05	2	2.5	
Northern Cheyenne Indian Reservation	SO_2, 3-hr	2002	17.75	25	71	RMP, RME, Colstrip 3&4, CELP, YELP
	SO_2, 24-hr	2002	2.64	5	53	
	SO_2, Annual	No cumulative model because RMP not significant.				

[a] Compliance with short-term standards is based on high-second-high impact.

The modeling results contained in Table 3 demonstrate that the SO_2 emissions from RMP's facility, as a whole, comply with the Class II PSD SO_2 increments.

RMP submitted an analysis of impacts on visibility in the three mandatory Class I areas listed above. CALPUFF modeling results were processed using the CALPOST program. CALPOST compares visibility impacts from the modeled source(s) to pre-existing visual range at the affected Class I areas and calculates a reduction in background extinction, ΔB_{ext}. The value of ΔB_{ext} is expressed either as a percent change or in units of deciviews (dv).

RMP provided a visibility impact assessment as required under ARM 17.8.1103. The Department has reviewed the assessment and evaluated the results on a case-by-case basis as required. The visibility impact assessment demonstrates that the proposed short-term emission limit changes for the RMP boiler will not cause or contribute to adverse impact on visibility within any mandatory Class I area.

The geographic extent of the modeled visibility impacts is fairly large on the peak days, but this is expected due to the wide expanse of the modeling domain. The intensity of visibility impacts, as reflected in the modeled ΔB_{ext} values from RMP are less than 0.5 dv (the FLM level of concern) for >99% of the days modeled and are all less than 1.0 dv.

The Department has concluded that visibility impact assessment results do not indicate that the project will interfere with visitor's enjoyment of the wilderness visual experience. Modeled visibility impacts that could be perceptible based on FLM guidelines were modeled in January, when visitor use in the UL Bend Wilderness area is limited by cold weather and short days.

The Department has determined that the change in short-term allowable SO_2 emissions from the RMP boiler will not cause or contribute to an adverse impact on visibility. The proposed emissions will not result in visibility impairment which the Department determines does or is likely to interfere with the management, protection, preservation, or enjoyment of the visual experience of visitors within a federal Class I area. This determination has taken into account the geographic extent, intensity, duration, frequency, and time of visibility impairment, and how these factors correlate with times of visitor use of the federal Class I area, and the frequency and occurrence of natural conditions that reduce visibility.

In summary, the RMP facility (as a whole, including the proposed the short term SO_2 emission increase) would result in moderate air quality impacts as a cumulative effect because of the amount of air pollutants emitted and the good dispersion characteristics of the stack and the area. The air quality modeling was performed for the facility as a whole, including the proposed project and the modeling demonstrated that the emissions from the RMP facility would comply with the NAAQS/MAAQS, PSD Class I and Class II increments, and would not adversely affect visibility at federal Class I areas.

For the proposed project, the air quality impacts would be minor because while short-term SO_2 emissions would increase, annual SO_2 emissions would decrease; although, the annual decrease in SO_2 emissions was required by the existing MAQP. In addition, the air impacts from the proposed project and its short-term increase in acid gas emissions would be minor.

G. Unique Endangered, Fragile, or Limited Environmental Resources

For the original permitting action (#3185-00), the Department contacted the Montana Natural Heritage Program of the Natural Resource Information System (NRIS) to identify any species of special concern in the immediate area of the RMP facility. The Natural Heritage Program files identified four species of special concern in the 1-mile buffer area surrounding the section, township, and range of the facility. The four animal species identified were the *haliaeetus leucocephalus* (bald eagle), *heterodon nasicus* (western hognose snake), *sorex merriami* (merriam's shrew), and *sorex preblei* (preble's shrew). A bald eagle nest is estimated to be located approximately 0.5-mile north-northeast of the property boundary from the RMP site. A western hognose snake was sighted approximately 2 miles southwest of the RMP site. The sightings of merriam's shrew and preble's shrew are historic sightings (both dated 1884) located approximately 2.5 miles southeast of the RMP site. None of the species identified were located within the same section, township, and range of the RMP site.

As the facility site would be fenced, most terrestrials would stay away from the facility itself. In addition, the RMP site would probably not be a habitat area for animals as it had been an industrial site for some time prior to being purchased by RMP. Although, as described in Section 7.B. of this EA, the cumulative impact on air quality would be moderate, the facility would not violate any ambient standards. The RMP facility would be required to operate in compliance with the NAAQS and MAAQS, both primary and secondary standards. The secondary standards are applicable in this case, as they protect public welfare, including protection against damage to animal species.

To determine the impact on the bald eagle population for previous permitting actions, the Department consulted the U.S. Department of Interior, Bureau of Reclamation Montana Bald Eagle Management Plan (MBEMP). With the identified nest being slightly more than 0.5 mile away from the RMP property boundary, the RMP site would fall into a MBEMP "Zone III" Classification, representing home range for the bald eagles. Zone III is classified as the area from 0.5 mile to 2.5 miles in radius from the nest site (Zone II from 0.25 to 0.5 miles, Zone I from 0 to 0.25 miles). Zone III represents most of the home range used by eagles during nesting season, usually including all suitable foraging habitat within 2.5 miles of all nest sites in the breeding area that have been active within 5 years. The objectives in Zone III areas include maintaining suitability of foraging habitat, minimizing disturbance within key areas, minimizing hazards, and maintaining the integrity of the breeding area. The nest is located in a group of cottonwood trees located in the marshy area next to the Bighorn River. That area would remain unchanged by the facility operation, except for a possible cumulative moderate impact by air pollutants, as described in Section 7.F of this EA. The proposed change would not impact the nest area, except, as described above, a possible impact from the short-term increase in SO_2 emissions and the annual increase in acid gas emissions. Therefore, the impact on bald eagles would be minor.

RMP would be responsible for compliance with any applicable statutes and regulations, including the Bald Eagle Protection Act, the Migratory Bird Treaty Act, and the Endangered Species Act.

The proposed project would have no impact on limited, non-renewable resources because the amount of coal and natural gas required by the facility would not change from previously analyzed levels.

H. Demands on Environmental Resource of Water, Air and Energy

As described in Section 7.B of this EA, cumulative impacts to the water resource would not change as a result of the proposed action. Therefore, there would be no impacts to the demands on the environmental resource of water from the proposed project.

As described in Section 7.F of this EA, the impact on the air resource in the area from the modification would be minor because of the amount of the proposed increase in short-term SO_2 emissions and the proposed increase in annual emissions and the good dispersion characteristics of the stack and the area. Ambient air modeling for NO_x, CO, PM, PM_{10}, were conducted as part of previous permit actions at "worst case" conditions and demonstrated that the cumulative emissions from the facility would not exceed any ambient air quality standard. In addition, as part of the MAQP application for the proposed project, SO_2 emissions representing the short-term emission increases in SO_2 emissions were conducted for the facility at "worst case" conditions and demonstrates that the cumulative emissions from the RMP facility would not exceed any ambient air quality standard. In addition, MAQP #3185-04 would contain conditions limiting the emissions from the facility.

There would be no impacts to the demands on the environmental resource of energy from the proposed project because the propose project would not affect the energy demands of the facility.

I. Historical and Archaeological Sites

There would be no impacts on historical and archaeological sites because the proposed project would take place at an existing facility and would not disturb any ground. Prior to any construction by RMP, the site contained no visible standing structures and was within an area that had been previously used for industrial and/or agricultural purposes. The RMP plant site was previously used as a support facility for Holly Sugar Corporation. In addition, the site location is in an area that would likely not have been used for any significant historical or archaeological activity. Directly to the south of the facility are a Cenex bulk storage facility and the buildings associated with Holly Sugar Corporation. Due to the previous use of the site, if any historical structures once existed on the property, they would probably have been destroyed prior to or during the construction of the Holly Sugar facility.

The physical location of the site also indicates that it was not likely a location for significant historical or archaeological activity. The RMP site location is located in the plains next to the river marsh area of the Bighorn River. The nearest portion of the Bighorn River to the site location is approximately 0.25 miles away.

During the analysis for Permit #3185-00, the Department contacted the Montana Historical Society – State Historic Preservation Office (SHPO) in an effort to identify any historical, archaeological, or paleontological sites or findings near the proposed project. SHPO's records indicate that there are currently no previously recorded cultural properties within the project site. Because of the fact that industrial activities and land disturbances have occurred in the area, SHPO commented that the likelihood of finding undiscovered or unrecorded historical properties would be practically zero. SHPO further commented "a recommendation for a cultural resource inventory is unwarranted at this time."

J. Cumulative and Secondary Impacts

Overall, the cumulative impacts from the proposed project on the physical and biological aspects of the human environment would be minor. Although the overall air impact from RMP by itself would be moderate, no other significant industrial sources exist in the area. Any area sources that contribute to "background" levels of air emissions were included in the PSD increment modeling, mentioned in Section 7.F. of this EA. As previously mentioned, the modeling analysis indicated that the emissions from the RMP facility would not violate any Class I or Class II PSD increment, would comply with the NAAQS/MAAQS, and would not adversely affect visibility at federal class I areas. That "moderate" air quality impact, from the facility as a whole, could also impact the bald eagle population. However, only minor impacts would be seen from the proposed project.

The proposed project would be associated with an increase in short-term SO_2 emissions of 1,282 lb/hr during periods of PC-Boiler startup, shutdown, and SDA atomizer change-outs, may actually slightly decrease the overall impacts from SO_2 emissions on the physical and biological impacts of the human environment because the 30 day average SO_2 emission limit would decrease from 0.14 lb/MMBtu to 0.11 lb/MMBtu, which would include periods of the increased shot-term emission limit. As a part of the BACT analyses performed for the proposed project, SO_2 and acid gas emission limits were established for "normal" or steady state operations as well as SO_2 emission limits for periods of PC-Boiler startup, shutdown and SDA atomizer change-outs. While no emission limits were established for acid gases for periods of PC-Boiler startup, shutdown and SDA atomizer change-outs, the Department determined that complying with the SO_2 emission limits would serve as a surrogate to acid gas compliance.

8. The following table summarizes the potential economic and social effects of the proposed project on the human environment. The "no-action" alternative was discussed previously.

		Major	Moderate	Minor	None	Unknown	Comments Included
A	Social Structures and Mores				✓		Yes
B	Cultural Uniqueness and Diversity				✓		Yes
C	Local and State Tax Base and Tax Revenue				✓		Yes
D	Agricultural or Industrial Production			✓			Yes
E	Human Health			✓			Yes
F	Access to and Quality of Recreational and Wilderness Activities			✓			Yes
G	Quantity and Distribution of Employment				✓		Yes
H	Distribution of Population				✓		Yes
I	Demands for Government Services			✓			Yes
J	Industrial and Commercial Activity				✓		Yes
K	Locally Adopted Environmental Plans and Goals				✓		Yes
L	Cumulative and Secondary Impacts				✓		Yes

SUMMARY OF COMMENTS ON POTENTIAL ECONOMIC AND SOCIAL EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed project at the existing RMP facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores); the proposed project would not change the nature or use of the site. The proposed project would be consistent with the permitted RMP facility and the former and current use of the larger area surrounding the facility (the former Holly Sugar processing plant and the current Cenex bulk storage facility). The proposed project would not affect the greater surrounding area (predominately agricultural and/or associated with the outskirts of the City of Hardin).

B. Cultural Uniqueness and Diversity

The proposed project would not cause a change in the cultural uniqueness and diversity of the area because no physical changes are proposed at the site that was previously used for industrial activity (the Holly Sugar processing plant), and a Cenex bulk storage facility currently operates directly south of the proposed site.

As described in Section 7.F of this EA, the proposed project would not cause or contribute to a violation of ambient air quality standards. Therefore, unique cultures nearby (including the Tribe of Crow Indians and the Northern Cheyenne Tribe) would not be affected by this project. As the Northern Cheyenne Indian Reservation is a PSD Class I area, a Class I increment analysis was performed for that area. Based on that analysis and associated modeling results, the proposed project would not create a situation in which any increments would be exceeded. Therefore, the proposed project would cause no change in the cultural uniqueness and diversity of the area.

C. Local and State Tax Base and Tax Revenue

The proposed project would have no effect on the state tax base and tax revenue because it would not change the amount of taxes owed by the RMP facility and would not create additional employment opportunities with RMP or surrounding businesses.

D. Agricultural or Industrial Production

The impacts to agricultural and industrial production in the area from the proposed project would be minor because no physical alterations or additions would occur and the resulting deposition from air emissions would be minor.

The RMP plant site is next to a Cenex bulk storage facility and the old Holly Sugar processing plant. Therefore, the area is accustomed to industrial use.

As described in Section 7.F of the EA, the cumulative air quality impacts from this facility would be moderate. However, because of the air dispersion characteristics, the resulting deposition of the pollutants from the RMP facility would be minor. In addition, the fact that the facility was modeled to show compliance with the NAAQS and MAAQS (protect public health and promote public welfare) indicates that the impacts from the proposed modification would be minor.

E. Human Health

As described in Section 7.F of the EA, the impacts from this proposed project on human health would be minor because the air emissions would be greatly dispersed before humans would be exposed. Also, as described in Section 7.F, the modeled impacts from this facility, taking into account other dispersion characteristics, are well below the MAAQS and the NAAQS. The MAQP for the facility would incorporate conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

Besides the criteria pollutants, the impacts from all other HAPs would also be greatly minimized by the dispersion characteristics of the facility and the area (wind speed, wind direction, relative atmospheric stability, stack temperature, facility emissions, etc.). The Department reviewed control technologies for HAPs from coal combustion in the BACT analysis for Permit #3185-02, and has incorporated emission limits and control technology requirements, as appropriate. Impacts from other common activities (such as fueling a vehicle for example) would have a greater impact on human health from HAPs because of the concentrations at the point of exposure.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed project would result in only a minor impact on the access to and quality of recreational and wilderness activities because the air emissions from the facility would be required to be in compliance with the NAAQS and MAAQS and would disperse before impacting the recreational areas (see Section 7.F of EA). The recreational activities in the area are approximately ¼ to 1½ miles away. Furthermore, the RMP site is located on land previously used as an industrial site. The land use would not change. The property will continue to be private. No recreational or wilderness activities exist within the RMP property boundaries. The RMP facility would have no impact on the access to and quality of wilderness activities.

Recreational activities exist in the area surrounding the RMP site location. The closest recreational opportunity is the Arapooish fishing access point/recreation area (approximately ¾ mile southeast of the RMP property), and the Bighorn River (approximately ¼-mile away from the RMP property at its closest point). Based on the modeling analysis performed for the RMP facility (see Section 7.F of the EA) and the distance between the recreational sites and the RMP project site, the impacts to the previously mentioned recreational opportunities and other recreational opportunities in the area would be minor.

G. Quantity and Distribution of Employment

There would be no effect on the employment of the area from the proposed project because no new employees would be hired as a result of the proposed project.

H. Distribution of Population

The proposed project would have no effect on the normal population distribution in the area above the 45 full-time positions previously associated with the facility.

I. Demands for Government Services

Demands on government services from the proposed project would be minor because the facility would require some, but not extensive, government services. RMP would be a tax paying entity for both state and local tax bases.

The acquisition of the MAQP and compliance verification with the MAQP as well as any other state issued permits would also require minor services from the government.

J. Industrial and Commercial Activity

The proposed project would represent no change in industrial activity in the area. The proposed project would only change emission limits associated with periods of PC-Boiler startup and shutdown and SDA atomizer change-outs. The facility, under ideal conditions, would operate 24 hours a day and 7 days per week generating electricity. Other industrial activity in the area includes the Cenex bulk storage facility, just south of the proposed RMP site.

K. Locally Adopted Environmental Plans and Goals

The nearest nonattainment areas with respect to air quality are the Laurel SO_2 Nonattainment Area and associated SO_2 state implementation plan area (including Billings, approximately 45 miles to the west) and the Lame Deer PM_{10} Nonattainment Area (approximately 46 miles to the east). Based on the air quality modeling performed, the proposed project and the RMP facility as a whole would not significantly impact either of those nonattainment areas and therefore, would have no effect on any locally adopted environmental goals and plans associated with those two areas.

The Department is unaware of any other locally adopted environmental plans and goals that would be affected by the proposed project at the RMP facility.

L. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from the proposed project on the social and economic aspects of the human environment would be minor because the project would occur on the previously permitted RMP site, would not affect cultural and social values or recreational opportunities, would require minimal government resources, and would not increase employment above what was previously associated with the RMP facility. In addition, the proposed project would have only a minor impact on human health.

Recommendation: No Environmental Impact Statement (EIS) is required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The current permitting action is for a modification at the existing RMP facility. MAQP #3185-04 includes conditions and limitations to ensure the facility will operate in compliance with all applicable rules and regulations. In addition, there are no significant impacts associated with this proposal.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System - Montana Natural Heritage Program, Montana Department of Revenue

Individuals or groups contributing to this EA: Department of Environmental Quality (Air Resources Management Bureau; Air, Energy, and Pollution Prevention Bureau; and Water Protection Bureau), Montana Historical Society – State Historic Preservation Office; Natural Resource Information System - Montana Natural Heritage Program; Department of Revenue

EA prepared by: Dave Aguirre
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