Air Quality Permit

Issued To: Rocky Mountain Power, Inc. Hardin Generation Project 400 North Fourth Street Bismarck, ND 58501	Permit #3185-02 Application Complete: 10/04/04 Preliminary Determination Issued: 11/08/04 Department Decision Issued: 12/22/04 Permit Final: 05/16/05 AFS Number: 003-0018

An air quality permit, with conditions, is hereby granted to Rocky Mountain Power, Inc. (RMP) pursuant to Sections 75-2-204 and 211, 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 submitted Permit Application #3185 to construct and operate a stationary facility to produce electrical power for delivery to the existing power grid located in the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The proposed facility will consist of a pulverized coal-fired (PC-fired) boiler and a steam turbine, which will drive a 135 MVA class nameplate electric generator to produce a nominal 116-gross megawatts (MW) of electric power (about 11-MW of the power produced will be used on average 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 April 30, 2004, the Department of Environmental Quality (Department) received a permit application from RMP, requesting a change in the currently permitted control equipment on the PC-fired boiler for sulfur dioxide (SO_2) and particulate matter with an aerodynamic diameter of 10 micrometers or less (PM_{10}) emissions and changes in the facility's material handling systems, cooling system, and plant layout. The currently permitted system for SO_2 and PM_{10} emissions includes a wet venturi scrubber operated in conjunction with a multiclone. RMP is proposing to replace that system with a lime spray dry absorber (SDA) followed by a fabric filter baghouse. The changes in the cooling system and the consequential increase in potential PM_{10} emissions triggers review under Prevention of Significant Deterioration (PSD) of Air Quality. 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 cannot be guaranteed in the current configuration. In addition, RMP requested to correct the current hydrofluoric acid (HF) limit that was established under Permit #3185-01. Previously established limits associated with oxides of nitrogen (NO_x), carbon monoxide (CO), and Volatile Organic Compound (VOC) emissions from the Boiler were not reviewed in this action because the proposed modifications would not affect them. The application was deemed complete on October 4, 2004. The Department Decision (DD) of Permit #3185-02 was appealed to the Montana Board of Environmental Review (BER) by RMP, 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 BER 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 Best Available Control Technology (BACT) limits established in the DD of Permit #3185-02. Through a permit application, RMP 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 RMP would make the Hardin facility available as a test facility for Hg controls. By the end of that 36-month demonstration period, RMP 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, RMP 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 has changed the rule reference on the requirement in the permit to comply with 40 Code of Federal Regulations (CFR) 60, Subpart Da from ARM 17.8.749 to ARM 17.8.340 and 40 CFR 60, Subpart Da. The change reflects information provided by RMP (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-fired Boiler. This change is not a substantive change, and is being made now for convenience purposes.

Section II: Limitations and Conditions

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 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).

7. RMP shall comply with all applicable standards and limitations, and the reporting, recordkeeping, and notification requirements of the Acid Rain Program contained in 40 CFR 72-78 (40 CFR 72-78).

B. PC-fired Boiler (Boiler)

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

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

3. SO_2 emissions from the Boiler shall be controlled with the use of a dry flue gas desulfurization (FGD) system, specifically characterized as a Spray Dry Absorber (SDA) (ARM 17.8.752).

   a. SO_2 emissions from the Boiler stack shall not exceed 182.6 lb/hr based on a 1-hour average (ARM 17.8.749).

   b. For 18 months following commencement of commercial operations ("SO_2 Optimization Period") (the emission limits in this subsection (b) are established for this SO_2 Optimization Period, and are not intended to be relied upon as an SO_2 BACT determination)(BER order signed on May 6, 2005):

      i. SO_2 emissions from the Boiler stack shall not exceed 0.12 lb/MMBtu based on a 30-day rolling average.

      ii. 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 60.47a(b)).

      iii. Except for the limit set forth in Section III.B.3.a, above, exceedances of the SO_2 emission limit associated with the atomizer change out or startup and shutdown activities (as defined in 40 CFR 60.2) during the SO_2 Optimization Period are not violations of the emission limit set forth above provided:

         (a) Exceedances of the SO_2 emission limit associated with atomizer change out and the startup and shutdown activities constitute no more than 36 hours during the affected 30-day rolling period and no more than 260 hours during the 18-month period;

         (b) SO_2 emissions do not exceed 0.14 lb/MMBtu based on a 30-day rolling average; and

         (c) RMP maintains and operates the equipment and control technology in a manner that is consistent with good practices for minimizing emissions.

   c. After the SO_2 Optimization Period:

      i. SO_2 emissions from the Boiler stack shall not exceed the SO_2 BACT limit of 0.11 lb/MMBtu based on a 30-day rolling average (ARM 17.8.752), unless RMP submits an application to the Department for a modification to the SO_2 BACT limit and, after the applicable review process, it is demonstrated through data and information gathered during the SO_2 Optimization Period that a different SO_2 BACT limit is necessary, in which case the SO_2 BACT limit shall be adjusted accordingly (BER order signed May 6, 2005).

ii. The control efficiency for the SO_2 emission control equipment shall be maintained at a minimum of 92% based on a 30-day rolling average (as measured according to 40 CFR 60.47a(b)) (ARM 17.8.752), unless RMP submits an application to the Department for a modification to the control efficiency for SO_2 emission control equipment and, after the applicable review process, it is demonstrated through data and information gathered during the SO_2 Optimization Period that a different control efficiency for SO_2 emission control equipment is necessary, in which case the control efficiency for SO_2 emission control equipment shall be adjusted accordingly (BER order signed May 6, 2005).

4. PM/PM_{10} emissions from the Boiler shall be controlled with the use of a fabric filter baghouse (FFB) (ARM 17.8.752).

   a. For the 18 months following commencement of commercial operations ("PM/PM_{10} Optimization Period"), the filterable PM/PM_{10} emissions from the Boiler stack shall not exceed 0.015 lb/MMBtu (BER order signed May 6, 2005). After the PM/PM_{10} Optimization Period, PM/PM_{10} emissions from the Boiler stack shall not exceed the filterable PM/PM_{10} BACT limit of 0.012 lb/MMBtu (ARM 17.8.752), unless RMP submits an application to the Department for a modification to the filterable PM/PM_{10} BACT limit and, after the applicable review process, it is demonstrated through data and information gathered during the PM/PM_{10} Optimization Period that a different filterable PM/PM_{10} BACT limit is necessary, in which case the filterable PM/PM_{10} BACT limit shall be adjusted accordingly (BER order signed May 6, 2005).

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

5. VOC emissions from the Boiler shall be controlled by good combustion practices. VOC emissions from the Boiler stack shall not exceed 0.0034 lb/MMBtu (ARM 17.8.752).

6. Hydrochloric acid (HCl) from the Boiler shall be controlled with the use of the dry FGD/SDA (ARM 17.8.752). HCl emissions from the Boiler stack shall not exceed 1.54 lb/hr (0.00118 lb/MMBtu) based on a 1-hour average (ARM 17.8.749).

7. HF from the Boiler shall be controlled with the use of the dry FGD/SDA (ARM 17.8.752). HF emissions from the Boiler stack shall not exceed 0.67 lb/hr (0.00051 lb/MMBtu) based on a 1-hour average (ARM 17.8.749).

8. Sulfuric Acid (H_2SO_4) Mist emissions from the Boiler shall be controlled by the use of dry FGD/SDA. 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).

9. 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 an Hg 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).

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

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

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

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

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

C. 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).

D. 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/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
      ii. 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 boiler

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

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

E. 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 Boiler (ARM 17.8.749).

2. RMP shall test the Boiler for CO within 180 days of initial start-up of the Boiler, or according to another testing/monitoring schedule as may be approved by the Department, to demonstrate compliance with the CO emission limit contained in Section II.B.1. The testing shall continue on an every 2-year basis, 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 CEMS to monitor compliance with the NO_x emission limits contained in Section II.B.2 for the 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.3 for the Boiler (ARM 17.8.749).

5. RMP shall test the Boiler for PM/PM_{10} within 180 days of initial start-up of the Boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the PM/PM_{10} emission limits contained in Section II.B.4. The testing shall continue on an every 5-year basis, 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 Boiler for HCl within 180 days of initial start-up of the Boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the HCl emission limit contained in Section II.B.6. The testing shall continue on an every 5-year basis, 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 Boiler for HF within 180 days of initial start-up of the Boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the HF emission limit contained in Section II.B.7. The testing shall continue on an every 5-year basis, 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 Boiler for H_2SO_4 within 180 days of initial start-up of the Boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the H_2SO_4 limit contained in Section II.B.8. The testing shall continue on an every 5-year basis, or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105 and ARM 17.8.749).

9. RMP shall test the Boiler for Hg within 180 days of initial start-up of the Boiler, or according to another testing/monitoring schedule as may be approved by the Department, to monitor compliance with the Hg limit contained in Section II.B.9. The testing shall continue on an annual basis, 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).

F. 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 Section I of 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 for calculating 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 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. 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).

G. Continuous Emission Monitoring Systems (CEMS)

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-fired Boiler stack (ARM 17.8.749 and 40 CFR 72-78).

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

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

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

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

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

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

H. Notification

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

1. Commencement of construction of the SDA and FFB within 30 days after commencement of construction;

2. Anticipated start-up date of the PC-fired Boiler postmarked not more than 60 days nor less than 30 days prior to start up; and

3. Actual start-up date of the PC-fired Boiler within 15 days after the actual start-up of the Boiler.

Section III: General Conditions

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

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

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

D. Enforcement - Violation of requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement as specified in Section 75-2-401, *et seq.*, MCA, and ARM 17.8.763.

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

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

G. Construction Commencement - Construction must begin within 18 months of permit issuance and proceed with due diligence until the project is complete or the permit shall expire and be revoked (ARM 17.8.762).

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

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, 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.

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 ______________________________

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)

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d. Date of Control Equipment Performance Test ______________________________

e. Control Equipment Operating Parameter During Performance Test

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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 ______________________________

TABLE I

EXCESS EMISSIONS

Date	Time From	Time To	Duration	Magnitude	Explanation/Corrective Action

TABLE II

CONTINUOUS MONITORING SYSTEM OPERATION FAILURES

Date	Time From	Time To	Duration	Problem/Corrective Action

TABLE III

CONTROL EQUIPMENT OPERATION DURING EXCESS EMISSIONS

Date	Time From	Time To	Duration	Operating Parameters	Corrective Action

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.

Permit Analysis
Rocky Mountain Power, Inc.
Permit #3185-02

I. Introduction/Process Description

A. Permitted Equipment

Rocky Mountain Power, Inc. (RMP) was permitted under Permit #3185 to construct 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 (PC-fired) boiler and a steam turbine, which will drive a 135 MVA class nameplate electric generator to produce a nominal 116-gross MW of electric power (11-MW of the power produced will be used on average 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-fired 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

B. Source Description

1. Boiler and Associated Emission Control

The permitted boiler is a 1968 wet-bottom, wall-fired boiler manufactured by Mitchell of the United Kingdom. The boiler is configured with 3 pulverizers and 12 burners with opposed firing. The maximum nominal heat input rate to the boiler will be 1,304 MMBtu/hr, which will be used to produce up to approximately 900,000 pounds of steam per hour. Natural gas will be used to fire the boiler during periods of start-up. During normal operations, the boiler will be fueled with pulverized coal. At this time, RMP anticipates the boiler will combust 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. Using the heat content of 8,700 Btu per pound (lb) of Absaloka Mine coal, as provided by Westmoreland Resources, Inc., the coal-firing rate will be approximately 75 tons per hour (ton/hr) and 656,500 tons per year (tpy).

Boiler combustion gases (flue gases) would be routed to a Selective Catalytic Reduction (SCR) unit for control of nitrogen oxides (NO_X). From the SCR unit, the flue gas would then be 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). Other acid gases including sulfuric acid (H_2SO_4), hydrochloric acid (HCl) and hydrofluoric acid (HF), and ionic mercury (Hg) will also be removed as a co-benefit control. A fabric filter baghouse (FFB) would be located downstream of the SDA for particulate matter (PM) 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 would exit to the atmosphere.

2. Cooling Tower

A wet cooling tower will be 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 proposed cooling tower will be an induced, counter flow draft design equipped with cellular (honeycomb) drift eliminators. The maximum make-up water rate for the proposed cooling tower will be 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 this cooling tower. Blow-down will be treated to maximize water recovery. Treatment will include a reverse osmosis unit followed by a condensate polisher (de-ionizer) and a small dehydrator. Discharge from the blow-down will be reduced to less than 30 gpm, and will be discharged to the makeup system for the lime slurry, to be injected into the SDA. If the discharged water cannot be immediately used, it will be 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 will be transported the 30 miles from the Absaloka Mine using over-the-road tractor-trailer transport vehicles. Coal will be 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 planned dedicated disposal site.

Coal delivery trucks will deliver coal to an enclosed truck unloading station. The enclosure will be 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 will be of sufficient size to fully contain a delivery truck, trailer, and pup. Gravity-operated louvers on the enclosure walls will 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 will close, and air will be drawn through the door openings only. The overhead doors will be interlocked such that only one door can be open at a time.

The trucks will 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 will be provided on the hopper to prevent oversize materials from entering and plugging the conveying equipment. A rubber seal boot will partially enclose the grizzly and hopper top to minimize fugitive dust emissions during the unloading process. Two variable speed stockout feeders will transfer coal from the unloading hoppers onto an inclined, covered belt conveyor.

Fugitive dust collection for coal truck unloading operations will be 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 will be pneumatically conveyed to a coal storage silo. Ductwork will connect the dust collector to the building enclosure, hopper rubber seal boot, and feeder transfer point hoods. Inflow air through the enclosure louvers or doors will maintain a clean work environment within the enclosure. Inflow air through the hopper will facilitate fugitive emissions collection during coal unloading. Additional ventilation will be 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 will convey coal from the receiving hoppers to the top of an active coal storage silo. The silo will discharge at the bottom via a reclaim feeder to a covered belt conveyor. This reclaim conveyor will transfer 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 will control 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 proposed facility will use a lime SDA to control SO_2 and certain Hazardous Air Pollutant (HAP) emissions. Lime will be delivered by truck at a rate of approximately 1 truck per day. Lime will be used at a rate of 2,200 lb/hr.

Pebble lime for the SDA will be pneumatically unloaded from delivery trucks into a storage silo. The storage silo will be 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 will be enclosed and will house 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 boiler will produce ash. Bottom ash from the boiler and ash collected from the economizer will be mixed with water and fed via a system of conveyors to a load-out bunker located outside of the generation building. Front-end loaders will transfer the wetted material to trucks for transport off-site. Particulate emissions from these operations to the atmosphere will be negligible since the materials would be wet. A pneumatic conveying system will collect fly ash and spent lime from the SDA and boiler baghouse. It will transfer the material to one of two storage silos. SDA material will feed to an FGD ash silo. Material from the baghouse will first be directed to a recycle ash silo. Once this silo is filled, the material will be routed to the FGD ash silo.

Particulate emissions resulting from loading the recycle ash silo will be 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 will be mixed with cooling tower blowdown water and used to feed the SDA.

Material not required for recycle will be conveyed to the FGD ash silo. Particulate emissions resulting from silo loading will be 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 will be discharged from the silo to a screw feeder for either wet or dry loadout into trucks or railcars. An elevated structure will support the silo and loading equipment, allowing trucks and railcars to access beneath. The loadout equipment will be enclosed within a silo skirt. The dry loading spout will be ventilated to the silo's bin vent.

6. Water Treatment Reagents Handling

Lime and soda ash will be stored in separate silos for use in the water treatment system. Each silo will be 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).

C. Permit History

On June 11, 2002, **Permit #3185-00** was issued to RMP to construct a 113-MW electrical power generation facility approximately 1.2 miles northeast of Hardin, Montana. The facility would consist of a PC-fired boiler and a steam turbine, which would drive an electric generator to produce a nominal 113-MW of electric power (8.5-MW of the power produced would be used by RMP).

On November 29, 2003, **Permit #3185-01** was issued to allow RMP to move the plant location by 610 meters, 10 degrees clockwise from North; reduce the SO_2 emission rate limit; reduce the boiler stack height; correct 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 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 boiler exhaust temperature was assumed to be 325º F in Permit Application #3185-00, but would actually be approximately 160º F. The permit 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 permit to protect short-term ambient air quality standards and increments. No emission increases would result from the amendment, however, RMP provided modeling to support the facility move, stack height change, and boiler exhaust temperature correction. Permit #3185-01 replaced Permit #3185-00.

D. Current Permit Action

On April 30, 2004, the Department of Environmental Quality (Department) received a permit application from RMP, requesting a change in the currently permitted control equipment on the PC-fired boiler for SO_2 and particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) emissions and changes in the facility's material handling systems, cooling system, and plant layout. The currently permitted system for SO_2 and PM_{10} emissions includes a wet venturi scrubber operated in conjunction with a multiclone. RMP is proposing 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 triggers review under Prevention of Significant Deterioration (PSD) of Air Quality. 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 cannot be guaranteed in the current configuration. In addition, RMP requested to correct the current HF limit that was established under Permit #3185-01. Previously established limits associated with oxides of nitrogen (NO_x), carbon monoxide (CO), and Volatile Organic Compound (VOC) emissions from the 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 is included in Section III – BACT Determination.

The Department Decision (DD) of Permit #3185-02 was appealed to the Montana Board of Environmental Review (BER) by RMP, 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 BER 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 Best Available Control Technology (BACT) limits established in the DD of Permit #3185-02. Through a permit application, RMP 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 RMP would make the Hardin facility available as a test facility for Hg controls. By the end of that 36-month demonstration period, RMP 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, RMP 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 has changed the rule reference on the requirement in the permit 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 reflects information provided by RMP (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-fired Boiler. This change is not a substantive change, and is being made now for convenience purposes.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the ARM and are available, upon request, from the

Department. Upon request, the Department will provide references for the location of complete copies of all applicable rules and regulations, or copies where appropriate.

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

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

2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emissions 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 are required for the PC-fired Boiler as directed by the New Source Performance Standards (NSPS), Subpart Da. Continuous emission monitoring systems (CEMS) will be used to monitor ongoing NO_x compliance and SO_2 compliance. Continuous opacity monitoring systems (COMS) will be used to monitor ongoing compliance with the opacity limitations. Based on the emissions from the PC-fired Boiler, the Department determined that initial testing for CO, PM_{10}, HCl, HF, and Hg is necessary. Furthermore, based on the emissions from the PC-fired 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 in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

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

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 an 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 20% for all fugitive emission sources and that reasonable precaution is taken to control emissions of airborne particulate. (2) Under this section, 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 17.8.340 Standard of Performance for New Stationary 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-fired Boiler because it is an electric utility steam generating unit with a heat input capacity greater than 250 MMBtu/hr. The PC-fired 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 Boiler, the Department has determined that reconstruction (as defined under 40 CFR 60.15) has occurred; therefore, Subpart Da is applicable.

   40 CFR Part 60, Subpart Y – Standards of Performance for Coal Preparation Plants. This subpart applies to the RMP facility because RMP would be constructed after October 24, 1974, and the facility will pulverize or "crush" more than 200 tons/day of coal.

5. 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.

6. 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 and would not be subject to the case-by-case MACT provisions under Section 112(g) of the Federal Clean Air Act. However, if the proposed Utility Maximum Achievable Control Technology (MACT) is finalized with the same applicability requirements, the RMP facility will be subject to the Utility MACT.

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 air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. RMP submitted the appropriate permit 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 air quality permit, excluding an open burning permit, issued by the Department; and the air quality operation fee is based on the actual, or estimated actual, amount of air pollutants emitted during the previous calendar year.

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

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

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

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a

person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. RMP has the PTE greater than 25 tons per year of PM, PM_{10}, NO_X, SO_2, and CO; therefore, a permit is required.

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

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

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration or use of a source. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. RMP submitted an affidavit of publication of public notice for the May 2, 2004, issue of the *Billings Gazette*, a newspaper of general circulation in the city 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 permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.

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

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

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving 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 air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the permit, which in no event may be less than 1 year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of

Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).

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

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

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 the New Source Review (NSR)-Prevention of Significant Deterioration (PSD) program. This permit action constitutes a major modification because the cooling tower emissions, as calculated in this application, constitute an increase in PM/PM_{10} potential emissions of 45.8 tons per year, exceeding the PSD significance threshold for those pollutants.

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

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

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

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

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

2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. Title V of the

FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3185-02 for RMP, the following conclusions were made:

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

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

c. This facility 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.

g. This facility is not an EPA designated Title V 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 source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. A BACT analysis was submitted by RMP in Permit Application #3185-02, addressing the proposed modification to the SO_2 and PM_{10} control technology for the PC-fired Boiler (including an analysis of H_2SO_4 emissions). The Department also included Hg, acid gas, and radionuclide emissions under the BACT analysis for the proposed changes to control technology on the PC-fired Boiler because those emissions would be affected by that change in control technology. A BACT analysis was completed for PM_{10} emissions that would result from a modified material handling system (including fuel handling and storage, lime handling and storage, and ash handling and storage) and to address the proposed cooling tower modifications.

The Department reviewed the proposed control methods, previous BACT determinations (via the RACT/BACT/LAER Clearinghouse, federal agency databases, and state agency decisions), and ongoing control proposals (via federal agencies and state agencies), before making the following BACT determination.

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 PC-fired Boiler, the Department determined 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, IGCC and CFB would not be used as add-on control on a PC-fired Boiler.

A. PC-fired Boiler

1. SO_2 Emissions

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 anticipates the Boiler will combust 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 an analysis of the average quality coal sample provided by Westmoreland Resources, Inc., this coal will have an average heating value of approximately 8,741 Btu/lb and an average sulfur content of 0.61 percent. Without post-combustion controls, maximum SO_2 emissions from the boiler (based on a worst-case minimum heat content of 8636 Btu/lb and maximum sulfur content of 0.76%) firing this coal would be 1.76 lb/MMBtu. This emission rate was considered as the baseline emission rate for this BACT analysis.

a. Identification of 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 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 flue gas desulfurization (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 PC-fired 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-fired Boiler.

i. Coal Cleaning – 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. Fuel Switching – A potential control for reducing SO_2 emissions from the proposed project is reducing the amount of sulfur contained in the coal. As previously mentioned, RMP anticipates combusting 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 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.

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 - Limestone scrubbers are very similar to 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 boilers burning higher sulfur bituminous coals. The actual control efficiency of a wet FGD system depends on several factors, including the uncontrolled SO_2 concentration entering the system.

v. Dual-Alkali Wet Scrubber - Dual-alkali scrubbing is a desulfurization process that uses 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 a unit on a >100 MW utility boiler. 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).

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. Two types of dry FGD systems are described below.

(1) Spray Dry Absorber (SDA) - The typical spray dry absorber uses a slurry of lime and water injected into the 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 typical dry scrubbing method in large industrial and utility boiler applications. SDAs have demonstrated the ability to achieve greater than 90% SO_2 reduction. 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 94% efficient for flue gas streams resulting from combustion of high-sulfur coal. Based on a maximum uncontrolled SO_2 emission rate of 1.76 lb/MMBtu, the spray dry absorber technology would achieve a removal efficiency of approximately 92%.

(2) Dry Sorbent Injection - Dry sorbent injection involves the injection of powdered absorbent 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. An expansion chamber is often located downstream of the injection point to increase residence time and 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%. The control efficiency of the dry sorbent system is lower than the control efficiency of either the wet FGD or spray dry absorber FGD.

b. Eliminate Technically Infeasible Options

All of the above technologies are technically feasible for a PC-fired Boiler.

c. Ranking of Control Technologies Based on Control Efficiencies

Control Technology	Control Efficiency
Wet FGD options (including lime, limestone, and dual alkali)	Up to 96%
Dry FGD – SDA	Up to 94%
Dry FGD – Dry Sorbent Injection	Up to 50%
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, both very similar control efficiencies will be compared to determine which method would be most appropriate for the RMP Boiler. The fuel switching, fuel blending, and coal cleaning options will not be considered in conjunction with the FGD options as the coal sulfur content may only be decreased slightly (if at all) based on those methods because of the current proposed use of 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 1.76 lb/MMBtu and 9992 tons per year, the wet limestone scrubbing system could achieve a maximum 96% SO_2 removal, resulting in a controlled emission rate of 0.07 lb/MMBtu and 400 tons per year of SO_2 under ideal conditions. The cost is estimated at $1395 per ton of SO_2 removed.

Dry FGD-SDA systems, using a maximum uncontrolled SO_2 emission rate of 1.76 lb/MMBtu and 9992 tons per year, could achieve a maximum 94% SO_2 removal, resulting in a controlled emission rate of 0.11 lb/MMBtu and 600 tons per year of SO_2 under ideal conditions. The cost is estimated at $918 per ton of SO_2 removed. The incremental cost difference between the two methods is $23,855 per ton (the extra cost of the Wet FGD divided by the increase in emissions reduction).

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 (not including a Wet Electrostatic Precipitator (WESP) as mentioned in the BACT analysis for H_2SO_4) would require approximately 20% more water than the dry system. With the addition of a WESP to the wet system, incremental water consumption would increase to 23%. A wet FGD system would produce a liquid waste stream containing dissolved and undissolved solids. The waste stream from an SDA 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. The cost of this waste handling was not included in the economic analysis presented by RMP (and summarized above).

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 (RMP is planning on disposing of the solid waste, boiler ash and scrubber waste, in a dry form in a dedicated disposal site). 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 would use 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) in addition to creating condensable particulate matter that would not be collected by the proposed FFB. Locally, the high moisture plume would be quite visible on days with cool weather or humid conditions. The dry FGD system still has moisture, but in general, has a drier plume.

Wet FGD provides some control of H_2SO_4 emissions (this option is further evaluated in the H_2SO_4 section), 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.
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. In addition, cost effectiveness information was based on high-sulfur eastern coals being combusted in power plants without FGD technology (in fact, coal cleaning was used to avoid installation of what was considered expensive FGD for moderate SO_2 reduction). 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 Permit #3185-02 and representative of Absaloka Coal). 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 switching or coal 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 on the Boiler.

e. Select BACT

The Department determined that wet FGD systems do not constitute BACT for the Boiler for a variety of reasons. Although wet FGD systems are technically feasible, they are more costly and can result in 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 proposed particulate control (baghouse). Creation of hazardous air pollutants is of great concern to the community of Hardin and the Department. 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 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 (with or without WESP, as further described in the PM_{10} and H_2SO_4 sections) system constitutes BACT. Therefore, a dry FGD system (in this case, an SDA) constitutes BACT.

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 (see table below, note: this table does not represent the only information reviewed for this BACT determination, it is only a representation of some material reviewed) and for recently permitted sources with similar control equipment that have operated effectively for some period of time (information from EPA's Acid Rain database). 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 remains appropriate. The limit is expressed as a lb/hr limit to allow for flexibility (to decrease load to minimize SO_2 emissions) during periods of atomizer changeout on the SDA system. Initially, the Department determined that 0.12 lb/MMBtu on a 30-day rolling average was appropriate. RMP's analysis indicated that 0.14 lb/MMBtu on a 30-day rolling average was appropriate based on 92% control on worst-case coal quality (the average coal sulfur plus three standard deviations and the average heat input minus three standard deviations or 1.76 lb SO_2/MMBtu uncontrolled). However, RMP's application states that 94% is achievable, which is consistent with other source determinations, particularly on higher sulfur coals. In addition, worst-case coal is not a certainty and would be averaged out over a 30-day period. The Department agrees with commenters that it seems uncharacteristic to establish a BACT limit that is applicable at all times on the basis of a worst-case scenario. RMP indicated a worst-case coal seam would prevent any averaging; however, as previously discussed, RMP's current coal contract is not a certainty and could include provisions for coal specifications. Alternatively, coal blending could be used to ensure a particularly coal quality.

At worst-case coal conditions (as described above), 92% control would be 0.14 lb/MMBtu and 94% control would be 0.11 lb/MMBtu. At average coal conditions, (yielding an uncontrolled SO_2 value of 1.39 lb SO_2/MMBtu), 92% control would be 0.11 lb/MMBtu. The Department agrees that SO_2 removal becomes steadily more difficult as the sulfur levels drop in the coal combusted, and believes that a 92% BACT limit is appropriate to ensure high removal efficiencies even when the facility is operating at less than maximum capacity. Based on this information, the SO_2 numerical limit has been changed to 0.11 lb/MMBtu on a rolling 30-day average. The averaging time will allow for statistical variability within coal specifications and SDA operation.

Date of permit	**Permitted facility**	**Location**	**SO_2 limit (lb/MMBtu)**	**Type of SO_2 control**	**PM_{10} limit (lb/MBtu) (control technology)**
8/17/99	Kansas City Power and Light – Hawthorne Station	Missouri	0.12 on a 30-day rolling avg	Dry FGD	0.018 (FFB)
3/24/01 (draft)	EnviroPower of Illinois	Illinois	0.25 on a 30-day rolling avg	CFB	0.015 (FFB)
5/04/01	Kentucky Mountain Power	Kentucky	0.13 lb/MMBtu on a 30-day rolling avg	CFB	0.015 (FFB)
10/29/01	AES-Puerto Rico	Puerto Rico	0.022 on a 30-day rolling avg	CFB/dry FGD	0.015 (ESP)
12/21/01	Tuscon Electric – Springerville Generating Station	Arizona	0.6 on a 30-day rolling avg	Dry FGD	0015 (FFB)
9/25/02	Black Hills Corp/ WYGEN 2	Wyoming	0.10 on a 30-day rolling avg 0.15 on a 3-hour block	Dry FGD	0.012 (FFB)
10/08/02	Sand Sage Power – Holcomb Unit 2	Kansas	0.12 on a 30-day rolling avg	Dry FGD	0.018 (FFB)
10/11/02	Thoroghbred	Kentucky	0.167 on a 30-	Wet FGD	0.018

	Generating Station		day rolling avg		(WESP)
12/17/02	Cornbelt Energy – Prairie Energy Power Plant	Illinois	0.15 on a 30-day rolling avg	Wet FGD	0.02 (ESP)
6/17/03	MidAmerican Energy Company	Iowa	0.1 on a 30-day rolling avg.	Dry FGD	0.025 (includes backhalf, FFB)
7/21/03	Roundup Power Project	Montana	0.15 on a 1-hour avg 0.12 on a 24-hour avg	Dry FGD	0.015 (FFB)
8/20/03	Plum Point Energy – Plum Point Station	Arkansas	0.16 on a 3-hour avg	Dry FGD	0.018 (FFB)
10/10/03	Indeck – Elwood	Illinois	0.15 on a 30-day rolling avg	CFB	0.015 (FFB)
2/05/04 (draft)	Santee Cooper – Cross Generating Station	South Carolina	0.13 on a 365-day average	Wet FGD	0.018 (ESP)
3/30/04	Hastings Utilities – Whelan Energy	Nebraska	0.12 on a 30-day rolling avg	Dry FGD	Not listed
10/15/04	Intermountain Power -New Unit 3	Utah	0.09 on a 30-day rolling avg	Wet FGD	0.012 (FFB)

In addition to the need to comply with this permit 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 permit 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.

2. PM/PM_{10} Emissions

PM composition and emission levels are a complex function of boiler firing configuration, boiler operation, pollution control equipment, and coal properties. Uncontrolled PM emissions from coal-fired boilers include the ash from combustion of the fuel as well as unburned carbon resulting from incomplete combustion. In pulverized coal systems, combustion is almost complete; thus, the emitted PM is primarily composed of inorganic ash residues. The baseline maximum uncontrolled filterable PM/PM_{10} emissions from the Boiler, as provided by RMP, would be 15.87 lb/MMBtu at the maximum heat rate of 1,304 MMBtu/hr.

a. Identification of Control Technologies

The primary methods for PM/PM_{10} control are post-combustion methods. Available methods include wet venturi scrubbers, multiclone mechanical collectors, electrostatic precipitators (ESPs), and FFBs.

i. <u>Wet Venturi Scrubbers</u> – accelerate the gas stream to atomize an injected scrubbing liquid and provide gas-liquid contact. Particles in the gas stream are captured by the liquid and settle out in a slurry or wet sludge. Control efficiencies range between 95 and 99%.

ii. Multiclones (or cyclone mechanical separators) – use inertia to remove particles from a gas stream. Multiclones are generally used to remove relatively larger particles to reduce inlet loading of particulate matter to downstream collection devices. Control efficiencies range between 90 and 95%.

As neither the wet venturi scrubber nor the multiclone can achieve the currently permitted emission limit (0.015 lb/MMBtu - baseline), they will be evaluated together at an efficiency of approximately 99%.

iii. ESPs – remove particulate matter from the flue gas by charging particles with high direct current and attracting the particles to charged collection plates. The collected particulate matter is removed from the plates by rapping the electrodes in a dry ESP or by washing the plates in a wet ESP. Dry ESPs may be used downstream of a dry FGD unit to collect the dry FGD media and the ash formed during fuel combustion. They do not, however, enhance SO_2 or SO_3 control. Dry ESPs are not suited for use downstream of wet FGD systems due to the high moisture content of the gas stream, and the resulting stickiness of the particles. Wet ESPs can be used downstream of a wet FGD unit to capture both residual flue gas particulate and sulfuric acid mist that may have formed in the wet FGD unit.

Because of their modular design, ESPs can be applied to a wide range of system sizes and would have no adverse effect on combustion system performance. The operating parameters that influence ESP performance include fly ash mass loading, particle size distribution, fly ash electrical resistivity, and precipitator voltage and current. Other factors that determine ESP collection efficiency are collection plate area, gas flow velocity, and cleaning cycle. Data for ESPs applied to coal-fired sources show fractional collection efficiencies of approximately 95% for fine particles (less than 0.1 micrometers in diameter) and greater than 99% for coarse particles (greater than 10 micrometers in diameter). These data show a reduction in collection efficiency for particle diameters between 0.1 and 10 micrometers (approximately 95% control efficiency).

iv. FFBs – Fabric filtration has been widely applied to coal combustion sources and consists of a number of filtering elements (bags) along with a bag cleaning system contained in a main shell structure incorporating dust hoppers. Fabric filters use fabric bags as filters to collect particulate matter. The particulate-laden gas enters a fabric filter compartment and passes through a layer of filter bags. The collected particulate forms a cake on the bag that enhances the bag's filtering efficiency. Excessive caking would increase the pressure drop across the fabric filter at which point the filters must be cleaned. FFBs are generally not used downstream of a wet FGD system because of high moisture content in the wet FGD effluent gas stream. When used downstream of a dry FGD system, they provide additional sulfur oxide control. The alkaline filter cake continues to react with and remove gaseous SO_2 and SO_3 as they pass through the filters. The filters also serve to capture acid gas mist that may have formed in the exhaust system.

The particulate removal efficiency of fabric filters is dependent upon a variety of particle and operational characteristics. Particle characteristics that affect the collection efficiency include particle size distribution, particle cohesion characteristics, and particle electrical resistivity. Operational parameters that may affect fabric filter collection efficiency include bag material, air-to-cloth ratio, and operating pressure loss. In addition, certain filter properties (e.g., structure of the fabric and fiber composition) can affect the system's particle collection efficiency. Fabric filters are capable of collection efficiencies greater than 99% when appropriately sized and operated.

b. Eliminate Technically Infeasible Options

All of the options listed above are technically feasible for a PC-fired Boiler.

c. Ranking of Control Technologies Based on Control Efficiencies

Control Technology	Control Efficiency
FFB	>99%
ESPs (wet or dry)	>99%
Multiclone and Wet Venturi Scrubber	99%

d. Evaluation of Most Effective Controls

Only the FFB and the ESPs will be evaluated as the multiclone and wet venturi scrubber in combination are below the control efficiencies achieved by either an FFB or an ESP.

The FFB is slightly more effective in overall control efficiency over the range of particle sizes than an ESP. Both FFB and ESP systems would create a solid waste stream, with a wet ESP creating a wet waste stream. No significant environmental, energy, or economic impacts were identified as being associated with the use of an FFB or ESP, although an ESP would require more energy use than an FFB. In addition, when FFBs are used downstream of a dry FGD system, they provide additional sulfur oxide control. The filters also serve to capture acid gas mist that may have formed in the exhaust system.

Specifically with respect to FFBs, the choice of bag material is critical. The Department requested information regarding bag material from RMP in response to comments received. The operation of the FFB and composition of the bag material directly affect the final removal efficiency of the SDA. The two control devices work together by building a layer of scrubber cake on the filter bags to enhance and maximize the removal efficiency of SO_2. The bag material RMP is proposing to use is Polyphenylene Sulfide (PPS) or also known as “Ryton”. The PPS bag is a felt design that is made to allow a layer of scrubber cake to attach and create a buildup on the bag to capture additional SO_2. The PPS bags are more resilient to the cleaning cycles of the pulse jet system and can withstand the temperature and constituents in the flue gas. Other designs such as a Polytetrafluoroethylene (PTFE), or “Gore-Tex”, are considered membrane bags that use a thin Teflon layer on the bag material to capture the particulate matter. PTFE bags removal efficiency is generally slightly greater with less pressure drop across the bags. However, they do not hold as thick a layer of the scrubber cake as the PPS bags, which is critical to the overall SO_2 and acid gas removal efficiency. The vendor will not maintain its SO_2 and acid gas removal guarantees with the use of PTFE bags. The vendor would recommend dual density PPS bags to gain particulate removal efficiency, while retaining the scrubber cake layer so the SO_2 and acid gas removal would not be impacted. Conservatively assuming a $50.00 per bag increase in bag replacement costs and accounting for the increased pressure drop, the incremental cost to reduce the particulate emissions from 0.015 lb/MMBtu to 0.012 would be approximately $6,158 per ton. The incremental cost is similar to costs borne by other sources to reach the same emissions limit.

e. Select BACT

Therefore, as the most effective option, the Department has determined the use of an FFB constitutes BACT. At an inlet loading rate of 15.87 lb/MMBtu, to achieve a limit of 0.012 lb/MMBtu would require an FFB control efficiency of 99.92%. The filterable PM/PM_{10} limit of 0.012 lb/MMBtu is consistent with other recently permitted sources (see table below for a representation of sources reviewed, again this does not and is not intended to reflect the universe of information reviewed). Therefore, the Department determined that a PM/PM_{10} emission limit of 0.012 lb/MMBtu (filterable or front-half only) is appropriate. In addition, based on similar sources, a total PM/PM_{10} limit of 0.024 lb/MMBtu (filterable and condensables) is appropriate. An opacity limit of 20% was required under ARM 17.8.304.

Date of permit	**Permitted facility**	**Location**	**Filterable PM/PM_{10} limit (lb/MBtu)**	**Type of PM/PM_{10} control**
8/17/99	Kansas City Power and Light – Hawthorne Station	Missouri	0.018	FFB
3/24/01 (draft)	EnviroPower of Illinois	Illinois	0.015	FFB
5/04/01	Kentucky Mountain Power	Kentucky	0.015	FFB
10/29/01	AES-Puerto Rico	Puerto Rico	0.015	ESP
12/21/01	Tuscon Electric – Springerville Generating Station	Arizona	0.015	FFB
9/25/02	Black Hills Corp/ WYGEN 2	Wyoming	0.012	FFB
10/08/02	Sand Sage Power – Holcomb Unit 2	Kansas	0.018	FFB
10/11/02	Thoroughbred Generating Station	Kentucky	0.018	WESP
12/17/02	Cornbelt Energy – Prairie Energy Power Plant	Illinois	0.02	ESP
6/17/03	MidAmerican Energy Company	Iowa	0.025 (includes backhalf)	FFB
7/21/03	Roundup Power Project	Montana	0.015	FFB
8/20/03	Plum Point Energy – Plum Point Station	Arkansas	0.018	FFB
10/10/03	Indeck – Elwood	Illinois	0.015	FFB
2/05/04 (draft)	Santee Cooper – Cross Generating Station	South Carolina	0.018	ESP
3/30/04	Hastings Utilities – Whelan Energy	Nebraska	Not listed	Not listed
10/15/04	Intermountain Power–New Unit 3	Utah	0.012	FFB

3. Sulfuric Acid Mist Emissions

Sulfuric acid mist is one of the PSD pollutants listed in ARM 17.8.801(27)(a). Sulfuric acid mist is typically generated when SO_3 in the flue gas reacts with water to form sulfuric acid. The combustion of coal will result in the formation of sulfuric acid. Its formation is dependent upon several factors, including residence time within specific temperature ranges and flue gas moisture content. If exhaust system conditions do not favor full conversion of SO_3 gases to sulfuric acid mist, some amount of SO_3 may escape as a gas into the atmosphere. There, it may or may not be converted to a mist, depending on ambient conditions. Because sulfuric acid mist is created in several steps, control strategies can be approached in a variety of ways that may be applied individually or in combination. Control strategies generally focus on reducing the amount of SO_3 in the flue gas, capturing sulfuric acid mist aerosol particles, and controlling exhaust system conditions to limit mist formation. Maximum uncontrolled emissions from the RMP Boiler are estimated at 0.063 lb/MMBtu at 1304 MMBtu/hr heat input.

a. Identification of Control Technologies

Available control technologies for sulfuric acid mist emissions from a PC-fired Boiler are listed below (full descriptions of these technologies are listed in the SO_2 and PM_{10} sections).

i. <u>Wet FGD</u> – Wet FGD systems are limited in their ability to control sulfuric acid mist emissions for two reasons. First, the moisture inherent in the system, combined with the sudden cooling created by the slurry spray, tends to create sulfuric acid mist. Second, because the sulfuric acid mist aerosol particles are extremely small, they are not effectively captured by the washing action of the wet FGD. A wet FGD system would be expected to control sulfur acid mist emissions with up to approximately 25% efficiency.

ii. <u>Wet FGD followed by wet ESP</u> – Although wet ESPs can control sulfuric acid mist aerosol particles with a very high efficiency, not all of the SO_3 in the gas stream is converted to sulfuric acid mist. This results in an overall sulfuric acid mist control efficiency for this system of approximately 90%. Employment of an FFB downstream of a wet scrubber is not technically feasible. The high moisture content of the flue gas exiting the scrubber would cause the filter cake to agglomerate, making effective filter cleaning extremely difficult.

iii. <u>Dry FGD followed by FFB or ESP</u> – Dry FGD systems, including SDAs, are generally capable of controlling SO_3 and sulfuric acid mist with an efficiency of at least 90%. A particulate control device is required following a dry FGD system to collect the injected reagent particles. While ESPs and FFBs provide very similar levels of particulate control, FFBs have the potential to enhance SO_2 and SO_3 removal efficiency as the exhaust gas passes through a filter cake containing alkaline ash and unreacted reagent.

b. Eliminate Technically Infeasible Options

All of the options listed above are technically feasible for a PC-fired Boiler.

c. Ranking of Control Technologies Based on Control Efficiencies

Control Technology	Control Efficiency
Dry FGD followed by FFB or ESP	90%
Wet FGD followed by wet ESP	90%
Wet FGD	25%

d. Evaluation of Most Effective Controls

As discussed above, both the dry FGD/SDA followed by an FFB or ESP and a wet FGD followed by a wet ESP have about 90% control of sulfuric acid mist. However, dry FGD has less probability of creating sulfuric acid mist than wet FGD, and FFBs have the potential to enhance SO_2 and SO_3 removal efficiency as the exhaust gas passes through a filter cake containing alkaline ash and unreacted reagent. In addition, other environmental, energy, and economic impacts are discussed in Sections III.A.1 and III.A.2 of this permit analysis (BACT determinations for SO_2 and PM_{10} from the Boiler). Therefore, post-exhaust formation of mist would be decreased with dry FGD followed by an FFB.

e. Select BACT

The Department determines that dry FGD/SDA followed by an FFB constitutes BACT for sulfuric acid mist. Based on that control, RMP proposed a sulfuric acid mist limit of 0.0063 lb/MMBtu (equating to 90% control). The Department determined that 0.0063 lb/MMBtu is appropriate and also constitutes BACT for sulfuric acid mist.

4. Acid Gas Emissions (specifically HCl and HF)

Two priority Hazardous Air Pollutants (HAPs), HF and HCl, are characterized as acid gases. Acid gases represent the large majority of potential HAPs from RMP. Based on emission calculations, HCl and HF would constitute approximately 97% of all HAPs emitted from the Boiler. The amount of HCl and HF generated in the Boiler would be dependent on the chlorine, fluorine, and ash content of the coal. HCl and HF emissions were limited by request of RMP in Permit Action #3185-01 in order to keep the Hardin facility below the major source threshold for HAPs. Acid gases were considered in this BACT determination with respect to appropriate control technology and the appropriateness of the previously established limits.

a. Identification of Control Technologies

In EPA's Utility RTC, the following air pollution control devices were evaluated with respect to acid gases: dry FGD and FFB, wet FGD units, FFBs alone, and ESPs alone.

These options (previously described in Sections III.A.1 and III.A.2 BACT determinations for SO_2 and PM_{10} from the Boiler) will be evaluated with respect to acid gases.

b. Eliminate Technically Infeasible Options

All of the options listed above are technically feasible for a PC-fired Boiler.

c. Ranking of Control Technologies Based on Control Efficiencies

In EPA's Utility RTC, EPA reviewed existing data on the removal efficiencies of HCl and HF by conventional air pollution control devices. EPA's test report data specified the following:

Control Technology	Control Efficiency
Dry FGD followed by FFB (14% bypass)	82%
Wet FGD (15% bypass)	80%
FFB	44%
ESP	<6%

d. Evaluation of Most Effective Controls

As an FFB or an ESP alone provides control efficiency significantly less than that provided by dry FGD followed by an FFB or wet FGD, they will not be considered further.

Since the top BACT option for acid gases would be the same control technology that was required in the BACT analysis for SO_2 and PM_{10}, the costs of using this technology to control the acid gases would be economically reasonable. Similar source control strategy analyses (MACT Analysis: Montana Roundup Power Project Permit #3182-00) indicate that the installation and operation of the dry FGD/SDA with an FFB for the sole purpose of controlling HCl emissions would result in unreasonable cost effectiveness. Because dry FGD/SDA with an FFB control will reduce the emissions of SO_2 and PM/PM_{10}, respectively, in addition to reducing the emissions of acid gases, the use of dry FGD/SDA with an FFB control becomes an economically reasonable method for acid gas control. Without the added benefit of reducing SO_2 and PM/PM_{10} emissions, the use of a dry FGD/SDA with an FFB would not be economically reasonable for controlling acid gas emissions.

If the wet FGD were required for SO_2 control, it too would be economically reasonable for acid gas control. A wet FGD in combination with a wet ESP would realize similar control values as the dry FGD/SDA with an FFB. Both types of control systems would result in a co-benefit control of acid gas emissions.

e. Select BACT

In summary, the Department analyzed the use of a dry FGD/SDA with an FFB and a wet FGD/wet ESP system as possible acid gas control strategies for the Boiler. Both of the previously mentioned control strategies are capable of HCl emission reductions. However, since (from the SO_2 and PM_{10} BACT determinations) the dry FGD/SDA with an FFB result in essentially equivalent co-benefit control of acid gas emissions as the wet FGD/wet ESP system, the Department determined that the use of a dry FGD/SDA system with an FFB constitutes BACT for acid gases. The emission limits previously established are 1.54 lb/hr for HCl (equivalent to 0.00118 lb/MMBtu) and 0.67 lb/hr for HF (equivalent to 0.00051 lb/MMBtu), which appear to be similar in the level of stringency as compared to other sources (most of the other limits were established as MACT limits). Therefore, as appropriate limits already exist, no additional limit will be established under BACT for acid gases.

5. Hg Emissions

Hg is a trace metal emission resulting from the combustion of fuel containing Hg. Although baghouses effectively control most trace metals, Hg requires additional consideration because it can be emitted as a mixture of solid and gaseous forms. Hg in boiler flue gas would be in an elemental form (Hg^0), an ionic form (Hg^{2+}), or a particulate form (Hg(p)). The relative concentration of each form of Hg in the flue gas is termed Hg speciation. Each form of Hg has different physical and chemical characteristics, and conventional pollution control devices have varying control efficiencies for each of the forms. Hg speciation for a coal-fired boiler would depend upon the combustion characteristics of the boiler as well as the characteristics of the feed coal.

Hg emissions from a power plant are a function of several factors including fuel Hg content, fuel chlorine content, boiler type and operation, flue gas composition, and the type of emission controls used for criteria pollutants. According to EPA's Utility RTC, the Hg concentration of coal ranges from an average of approximately 2.5 pounds per trillion British thermal units (lb/TBtu) to approximately 20 lb/TBtu. The average Hg concentration of U.S. coal is reported in the Utility RTC to be approximately 7.7 lb/TBtu. Based on Absaloka Mine coal analyses, the Hg concentration of the fuel used for RMP operations is expected to be approximately 4.6 lb/TBtu.

During combustion, Hg readily volatilizes from the fuel and is found predominantly in the vapor phase, as either elemental Hg or ionic Hg. Hg speciation testing indicates that the distribution of ionic Hg (most likely Hg (II) chloride ($HgCl_2$)) and elemental Hg varies with coal type and boiler characteristics. Preliminary tests suggest that the chlorine concentration in the coal and the type of coal (e.g. bituminous, subbituminous, or lignite) may be associated with a particular speciation of Hg in the flue gas. Specifically, test results indicate that flue gas from subbituminous coals will contain significantly more elemental Hg than flue gas from bituminous coals, while higher concentrations of ionic Hg may be associated with bituminous coals, especially those with high chlorine concentrations. The following information was collected in response to comments on the Roundup Power Project case-by-case MACT determination. The EPA's Information Collection Request (ICR) testing results (tests conducted in 1999-2000) for coal-fired power plants including the Mecklenburg, Logan, and SEI plants (for bituminous coal with average chlorine content of 1100 ppm) have indicated that Hg collection efficiency upwards of 97% is possible (with existing controls at those facilities). Similar Hg testing for emissions from Craig, Rawhide, and NSP Sherburne (for subbituminous coal with an average chlorine content of 170 ppm) have indicated that a Hg collection efficiency of only about 36% is possible with the existing controls at those facilities (the 36% represents one source, average removal is 24.2% based on information in the EPA MACT tool). However, as EPA stated with respect to use of the MACT tool, that information (from the MACT tool) does not include or represent any EPA determination of presumptive MACT, nor does it reflect any decision(s) by the Agency on MACT floors, subcategorization, or other aspects of the MACT standard. The ICR tests and measurements, typically a three-run series of manual samples taken over 1 or 2 days of testing, are limited by the emission test method's accuracy and precision, by the short duration of the test, and by differences from one run to the next and one unit to the next. Together, these factors bring into question the accuracy of the results of the tests as a measure of a particular units performance over time (preamble, Proposed National Emission Standards for Hazardous Air Pollutants for New and Existing Stationary Sources: Electric Utility Steam Generating Units).

According to the Absaloka Mine coal analyses provided by RMP, the coal that would be used at the RMP facility has an average chlorine content of about 100 ppm. Chlorine content of coal appears to be an indicator of the amount of oxidized Hg that will be present in flue gas (i.e. the higher the chlorine content, the higher chance that the Hg will tend toward oxidized Hg and the lower the chlorine content, the higher the chance that the Hg will tend toward elemental Hg). National testing and research efforts have indicated that elemental Hg appears to be the most difficult form of Hg to control. Some facilities see no Hg control realized from co-benefit controls.

a. Identification of Control Technologies

Several studies have been conducted and more are underway to identify control technologies that may effectively reduce Hg emissions. The following technologies are in the research/development stage and are not currently commercially available (with vendor guarantees for control efficiencies). The particulate form of Hg will be controlled as a trace metal or particulate making baghouse control a highly effective control strategy for this form of Hg. Some of the more promising Hg control technologies for elemental Hg and ionic Hg that have been identified by EPA include the following.

- Sorbent Injection (including Activated Carbon Injection);
- FGD Systems;
- Enhanced FGD Systems; and
- Combination of Conventional Pollutant Control Systems.

The following text provides an analysis of the above-cited control options.

i. Sorbent Injection – Sorbent injection is considered a potential control technology to enhance Hg removal from boiler flue gas. This technology involves the injection of a sorbent (activated carbon, chemically-treated carbon, non-carbons, and proprietary sorbents like TOXECON™ and TOXECON II™) into the flue gas duct upstream of a particulate control device or, in some cases, midway through an ESP. Hg is adsorbed to the surface of the sorbent and subsequently removed in the downstream particulate control device. Preliminary data from various pilot-scale and bench-scale studies suggest several factors may affect the efficiency of sorbent injection, including: (1) the temperature of the flue gas; (2) the speciation of Hg in the flue gas; and (3) the flue gas composition.

Pilot-scale studies of Activated Carbon Injection (ACI) upstream of a baghouse suggest that Hg removal efficiencies and the required amount of activated carbon are apparently temperature dependent. These tests suggest that more Hg is removed and less carbon is needed at lower flue gas temperature if the carbon is injected upstream of the particulate control. In many cases, flue gas temperatures must be maintained above a specific level to avoid acid condensation and, consequently, equipment corrosion.

Studies indicate that ACI may enhance removal of elemental Hg in a dry FGD/SDA with an FFB system. Removal may be further enhanced with the injection of iodide-impregnated or sulfur-impregnated activated carbon ahead of the system. The first full-scale demonstration project for ACI (Presque Isle Plant, Michigan) was initiated by the U.S. Department of Energy in April 2004 and is expected to be completed in 2009.

Under a recent maximum achievable control technology determination (40 CFR Part 63), the MidAmerican facility in Iowa was required by permit to use a sorbent injection system. According to the technical support document for that permit dated April 21, 2003, "The results of a review of the population of electric utility steam generating units showed that there were currently no units that have installed and are continuously operating any control system specifically for the removal of Hg from exhaust gases. However, the control equipment employed to remove other pollutants like SO_2 and PM/PM_{10} does remove some of the Hg from the exhaust gas. The available data on Hg removal is limited…Since there are no existing units operating with control specifically for Hg control, but rather are simply removing Hg as a co-benefit to the control of SO_2 and PM/PM_{10}, the Department has concluded that the co-benefits from the SO_2 and PM/PM_{10} control is the MACT floor."

That same document goes on to state "One technology has been identified as a potential beyond-the-floor control for Hg. That technology is sorbent injection…The applicant has agreed to install a sorbent injection system to remove the Hg from the exhaust of this unit."

ii. <u>FGD Systems</u> – Ionic Hg is water-soluble, and therefore FGD systems may effectively remove ionic Hg from boiler flue gas. EPA's preliminary results from tests of wet and dry FGD systems indicate that up to 90% or more of the ionic Hg was captured by these systems. Elemental Hg typically is not removed effectively by FGD systems, although in pilot-scale tests, the removal efficiency of FGD systems varied widely. Results from EPA's case-by-case MACT tool also show this wide variation in removal efficiencies between elemental Hg and ionic Hg. For example, the case-by-case MACT tool (based on the ICR test data) predicted that a bituminous PC-fired boiler with SDA, baghouse, and SCR controls would remove 97% of the flue gas Hg, while a subbituminous PC-fired boiler with SDA, baghouse, and SCR controls would remove 23% of the flue gas Hg. The wide range in results suggests that the Hg speciation in the flue gas streams tested varied significantly and/or that other, poorly understood factors affect Hg removal mechanisms.

Studies on Hg control generally state that for western subbituminous coals speciation of Hg in the flue gas may tend toward ionic Hg. The Department's BACT determination requiring a dry FGD/SDA system to control SO_2 emissions should provide effective control of the ionic Hg in the flue gas. More research is required before the level of elemental Hg oxidation can be estimated.

iii. <u>Enhanced FGD Systems</u> – Another category of Hg control involves the enhancement of existing FGD systems to improve the Hg removal rate. As discussed above, existing FGD systems should effectively remove oxidized (ionic) Hg from flue gas; therefore, methods to improve the capture of elemental Hg are being investigated by EPA and the scientific community. The primary options under investigation involve converting the elemental Hg to an oxidized form upstream of the FGD system for subsequent capture in the FGD system.

Similar investigations are also underway regarding the conversion of vapor-phase elemental Hg to more soluble ionic Hg. The primary process to oxidize elemental Hg involves passing the flue gas across a catalyst upstream of the FGD system. Conventional SCR systems may provide some oxidation of elemental

Hg, and the effectiveness of a number of other catalysts is being studied. The effects of flue gas temperature and residence time on the oxidation potential of different catalysts and coal-based flue gases are also being evaluated.

Based on information reviewed by the Department, enhanced FGD Hg control technologies are still in the demonstration phase.

iv. Combination of Conventional Pollutant Control Systems - RMP proposed the use of dry FGD/SDA and FFB for control of SO_2 and PM_{10} emissions and is already required to use an SCR unit for NO_x control and good combustion practices for VOC and CO control. The effectiveness of this combination of conventional control systems to reduce Hg emissions will depend on the speciation of Hg in the flue gas. Since western subbituminous coals tend to have Hg that speciates toward the ionic form (which is water soluble), the dry FGD/SDA with an FFB should provide some Hg control. Similar systems in the ICR data firing subbituminous coal had an average Hg control of 24.2%.

b. Eliminate Technically Infeasible Options

The paper, "Control of Hg Emissions for Coal-Fired Electric Utility Boilers" presented by EPA's Office of Research and Technology on the state of Hg control technology as of January 1, 2004, concluded that while activated carbon injection appears promising as a Hg control technology, more data and research into Hg speciation, effects of flue gas composition, and the interaction of flue gas and Hg species at various conditions are needed to understand the factors that affect Hg removal specifically for subbituminous and lignite coals (Hg removal appears to be more effective for bituminous coals). The Department's research into the use of activated carbon injection, in this case, has yielded the same conclusion – additional testing and research is necessary to determine the effects that Hg speciation, flue gas composition, and the interaction of flue gas and Hg species at various conditions will have on Hg collection efficiency. Also, activated carbon injection is not required under EPA's recently proposed utility MACT, providing further justification for not requiring this control strategy as BACT, in this case. As previously mentioned, the first full-scale demonstration project for ACI was initiated earlier this year. As it has not been demonstrated at this time on a full-scale coal-fired power plant, the Department eliminates ACI and, for the same reason, sorbent injection, as being technically infeasible (based on not being commercially available with a vendor guarantee) at this time.

FGD systems are technically feasible for a PC-fired Boiler, but will be considered as a part of the combination of conventional pollution control systems.

The Department determined that enhanced FGD is not currently an available control strategy and thus is not a suitable candidate for a full-scale Hg BACT control system at this time. Therefore, enhanced FGD is eliminated from further consideration.

c. Ranking of Control Technologies Based on Control Efficiencies
d. Evaluation of Most Effective Controls

The combination of conventional pollution control systems is the only option that remains technically feasible for a full-scale coal-fired power plant; therefore no ranking is necessary.

e. Select BACT

The Department determined that the combination of required criteria pollutant controls (co-benefit controls), specifically the SCR unit, dry FGD/SDA, and FFB constitutes BACT for Hg for the RMP facility. The case-by-case MACT tool (which is based on EPA's ICR testing database) predicts that approximately 23% control for an SCR unit, dry FGD/SDA, and FFB may be achievable; however this data is not based on continuous monitoring, and it represents very limited testing. This source is not subject to case-by-case MACT because it is not a major source for HAPs, but it will be subject to the Utility MACT (if and when promulgated) because it qualifies as an affected source. Because of the wide variation in the data available with respect to Hg control and the gap in information concerning how different species of Hg (specifically elemental) can be controlled, the Department has determined that the Hg limit will start at a published value (deemed to be achievable by EPA) and shall be established as a more stringent limit, if appropriate, based on testing at RMP over a three-year period and coal analysis. The ceiling for the Hg limit shall be the limit that RMP would be subject to if and when the Utility MACT is promulgated: 5.8 lb/TBtu. This limit, however, will be measured on a one-hour instead of an annual average. The Department's intent is to establish the lowest achievable limit.

6. Radionuclide Emissions

Nearly all natural materials, including coal, contain trace quantities of radioactivity. When coal is burned to produce steam in the production of electricity, radionuclides are entrained in the combustion gases. The radionuclide content of coal is not much different than for other natural materials. Radionuclides emitted from a coal-fired boiler are emitted primarily as particulate matter. Therefore, pollution control systems designed to reduce particulate matter, such as PM_{10} emissions, will also effectively reduce emissions of radionuclides. The Utility RTC states that particulate matter control devices at coal-fired utilities reduce radionuclide emissions by more than 95%.

a. Identification of Control Technologies

The two main control technologies are the FFB and ESP, as previously described in Section III.A.2 – PM_{10} BACT for the Boiler. Other, less effective control technologies are also described in that section.

b. Eliminate Technically Infeasible Options

Both options are technically feasible on a PC-fired Boiler.

c. Ranking of Control Technologies Based on Control Efficiencies
d. Evaluation of Most Effective Controls

Both options have the capability of controlling radionuclides (as particulates) at efficiencies of greater than 99%, although FFBs generally are slightly more effective, particularly for smaller particulate matter. Both FFB and ESP systems would create a solid waste stream, with a wet ESP creating a wet waste stream. No significant environmental, energy, or economic impacts were identified as being associated with the use of an FFB or ESP, although an ESP would require more energy use than an FFB. In addition, when FFBs are used downstream of a dry FGD system, they provide additional sulfur oxide control. The filters also serve to capture acid gas mist that may have formed in the exhaust system.

e. Select BACT

Because the FFB system will result in slightly greater emission reductions than the ESP system, the Department determined that the FFB system constitutes BACT for radionuclides. The Department also determined that the PM/PM_{10} emission limit in Permit #3185-02 for PM/PM_{10} would act as a surrogate BACT emission limit for radionuclides, as stated in the permit. If 99.92% control is achieved for PM/PM_{10}, it is reasonable to assume that constituents of that PM would be similarly controlled.

7. Trace Metal Emissions

Trace metals contained in coal are emitted during the combustion process. The quantity of any given metal emitted, in general, depends on:

- The physical and chemical properties of the metal itself
- The concentration of the metal in the coal
- The combustion conditions
- The type of particulate and SO_2 control devices used

Depending on the metal's physical and chemical properties and the boiler combustion conditions, some metals could be emitted in the gas phase, while others will be emitted as particulates and will tend to concentrate in either fly ash or bottom ash. Metals emitted from coal combustion include: arsenic, beryllium, cadmium, chromium, manganese, and lead. Based on the physical and chemical properties of the metals listed as priority HAPs, most arsenic, beryllium, cadmium, chromium, manganese, and lead would be emitted as particulate oxides. EPA identified in the Utility RTC that these pollutants exist primarily in particulate form.

a. Identification of Control Technologies

High-efficiency particulate control devices readily control HAP metals that exist primarily in particulate form. Both FFBs and ESPs will provide significant particulate matter control.

b. Eliminate Technically Infeasible Options

Both options are technically feasible on a PC-fired Boiler.

c. Ranking of Control Technologies Based on Control Efficiencies
d. Evaluation of Most Effective Controls

Both options have the capability of controlling metal HAPs (as particulates) at efficiencies of greater than 99%, although FFBs generally are slightly more effective, particularly for smaller particulate matter. Both FFB and ESP systems would create a solid waste stream, with a wet ESP creating a wet waste stream. No significant environmental, energy, or economic impacts were identified as being associated with the use of an FFB or ESP, although an ESP would require more energy use than an FFB. In addition, when FFBs are used downstream of a dry FGD system, they provide additional sulfur oxide control. The filters also serve to capture acid gas mist that may have formed in the exhaust system.

e. Select BACT

Because the FFB system will result in slightly greater emission reductions than the ESP system, the Department determined that the FFB system constitutes BACT for metal HAPs. The Department also determined that the PM/PM_{10} emission limit in Permit #3185-02 for PM/PM_{10} would act as a surrogate BACT emission limit for metal HAPs, as stated in the permit. If 99.92% control is achieved for PM/PM_{10}, it is reasonable to assume that constituents of that PM would be similarly controlled.

B. Cooling Towers – PM_{10} Emissions

RMP proposed changes to the design and operation of the RMP cooling system. The proposed changes would result in an estimated potential increase of 39.8 tons of PM_{10} emissions per year. PM_{10} emissions are based on the total dissolved solids in the cooling water and the amount of that water that evaporates into the atmosphere. Because the cooling tower will provide direct contact between the cooling water and the air passing through the tower, some of the cooling water may become entrained in the air stream and carried out of the tower as “drift” droplets. When the drift droplets evaporate, dissolved solids can crystallize and become PM_{10} emissions.

1. Identification of Control Technologies

Based on other previously permitted, similar sources, the available control technologies are drift/mist eliminators (that reduce the amount of cooling water lost to the atmosphere) and good operating practices (generally including limiting excess water and air flow).

2. Eliminate Technically Infeasible Options

Both options are technically feasible for the RMP facility.

3. Ranking of Control Technologies Based on Control Efficiencies
4. Evaluation of Most Effective Controls

The mist eliminator, as proposed by RMP, would be designed to limit mist emissions to no more than 0.001% of circulating water flow. Good operating practices would be less effective.

5. Select BACT

The Department determined that a mist eliminator designed to limit mist emissions to no more than 0.001% of the circulating water flow constitutes BACT for PM_{10} emissions at the cooling tower.

C. Material Handling – PM_{10} Emissions

RMP proposed additions and modifications to the systems designed to store and transport coal, lime, and waste/byproduct streams.

1. Identification of Control Technologies

Control technology for material handling PM_{10} emissions on material handling point sources include FFBs and bin vents. FFBs are more appropriate for larger sources; bin vents are more appropriate for smaller sources (with respect to air flow).

2. Eliminate Technically Infeasible Options

   Both of the options mentioned above are technically feasible for the RMP facility.

3. Ranking of Control Technologies Based on Control Efficiencies
4. Evaluation of Most Effective Controls

   RMP proposed FFBs on the following sources: coal unloading, coal silo, coal storage bunkers, water treatment lime silo, and soda ash silo with an emission limit of 0.01 gr/dscf for both PM and PM_{10}. RMP proposed bin vents on the following sources: SDA lime silo, FGD ash silo, and recycle ash silo with an emission limit of 0.01 gr/dscf for both PM and PM_{10}. Both options are extremely effective at that minimum control efficiency and would represent the highest-ranking control technology for those types of sources, respectively.

5. Select BACT

   Based on the review of appropriate controls for material handling and the proposals made by RMP, the Department determines that baghouses on the coal unloading, coal silo, coal storage bunkers, water treatment lime silo, and soda ash silo with a minimum control efficiency of 0.01 gr/dscf constitutes BACT for those sources. The Department determines that bin vents on the SDA lime silo, FGD ash silo, and recycle ash silo with a minimum control efficiency of 0.01 gr/dscf constitutes BACT for those sources.

IV. Emission Inventory

	Ton/Year								
Source	PM/PM_{10}	NO_x	CO	VOC	SO_x	HCl	HF	H_2SO_4	Hg
PC-fired 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				
Totals	139.95	514.13	856.91	19.46	628.40	6.75	2.93	35.98	0.027

<u>PC-fired Boiler Emissions</u>

Size = 113 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, Permit 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 NOx/MMBtu {Manufacturer's Guarantee, Permit 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, Permit 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 {Permit 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 {Permit 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

<u>Cooling Tower Emissions</u>

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

<u>Baghouse and Bin Vent Emissions</u>

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

V. Ambient Air Quality Impacts

The plant site 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 Montana and National Ambient Air Quality Standards (MAAQS and NAAQS) for criteria pollutants.

A. Review of Modeling Analysis

Air quality dispersion modeling (which factors in such parameters as wind speed, wind direction, atmospheric stability, stack temperature, stack emissions, etc.) was conducted for the RMP facility by Bison Engineering, Inc (Bison). The airborne concentrations of NO_x, SO_2, CO and PM_{10} were modeled to demonstrate compliance with the MAAQS and NAAQS and the 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 51, Guideline on Air Quality Models (revised), August 12, 1996. The air dispersion modeling analysis was independently reviewed by the Department.

As required by EPA modeling guidelines (used for this type of air quality permitting), the model must incorporate at least one year of on-site meteorological data or five years on nearby off-site data (data that has been through the appropriate quality assurance/quality control process). The ISC-PRIME model was used along with seven years of surface meteorological data (1984, 1986-1991) collected at the Billings International Airport National Weather Station, and local meteorological data collected on site (north of Hardin) during 2002-2003 and the corresponding upper air data collected at the Great Falls International Airport National Weather Station. The receptor grid was generated from digital elevation model (DEM) files using the six 7.5 minute United States Geological Survey (USGS) topographical maps. The receptor spacing placement was as follows: 100 meters along the fenceline and out to 2000 meters, 250-meter spacing from 2000 to 5000 meters, and 500-meter spacing from 5,000 to 16,000 meters from the fenceline. Downwash was calculated using the EPA's Building Profile Input Program (BPIP).

As in the original application submittal of January 2002, modeling was conducted for PM_{10}, CO, SO_2, and NO_x emissions from RMP. All of the pollutants' modeled concentrations were below the monitoring de minimis concentrations except for PM_{10} and SO_2. RMP submitted one year's worth of on-site ambient monitoring data for PM_{10} and SO_2 to the Department. The modeling significance level was exceeded for all the pollutants in this analysis except CO thus a full impact analysis was required for PM_{10}, SO_2, and NO_2 to demonstrate compliance with the NAAQS, MAAQS, and PSD increments. The largest identified radius for determining the significant impact area (SIA) for this project was the 24-Hour SO_2

averaging period, which extended 16.3 kilometers. Significance levels are listed in 40 CFR 51, Appendix S. CO was below the modeling significance level so no additional modeling was conducted for CO emissions. The ambient analysis only included RMP because no major stationary sources exist within any of the significant impact areas (SIAs) or within 50 kilometers beyond the SIAs.

The NAAQS/MAAQS analysis demonstrated that the emissions from this facility would be below the ambient air quality standards. A comparison of the modeled impacts from RMP with the MAAQS is shown in the following table. The RMP impacts were compared with the MAAQS because the MAAQS are the same or more stringent than the NAAQS for the previously mentioned pollutants and averaging times. As displayed in the following table, the impacts from the RMP project on the air quality in comparison to the ambient air quality standards is minor. The ambient air quality standards are designed to protect public health with an adequate margin of safety (primary standard) and to promote public welfare (secondary standard).

Ambient Air Quality Analysis Modeling Results

Pollutant	Avg. Period	Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Ambient Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS	MAAQS ($\mu g/m^3$)	% of MAAQS
PM_{10}	24-hr	10.1	54	64.1	150	42.7	150	42.7
	Annual	2.07	15	17.07	50	34.1	50	34.1
NO_2	1-hr	103	75	178	------	------	564	31.6
	Annual [a]	1.91	6	7.91	100	7.9	94	8.4
SO_2	1-hr[b]	142	35	177	------	------	1,300	13.6
	3-hr	68.1	26	94.1	1,300	7.24	------	-----
	24-hr	19.6	11	30.6	365	8.3	260	11.8
	Annual	2.98	3	5.98	80	7.5	52	11.5

[a] Neither the Ozone Limiting Method or Ambient Ratio Method were applied to these results.
[b] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-tenth-high.

As mentioned above all of the SIAs (which would include Class I SIAs) are less than the 46-km distance between the facility and the closest Class I area, the Northern Cheyenne Indian Reservation (NCIR). Other nearby Class I areas include: Yellowstone National Park, North Absaroka Wilderness, and UL Bend Wilderness Area (all approximately 200 km from the proposed facility site). Therefore, the emissions from the facility are not likely to have a significant impact on the Northern Cheyenne Indian Reservation, or the other Class I areas nearby. PM_{10}, SO_2, and NO_x emissions were modeled using ISC-PRIME for the Class I (Northern Cheyenne Indian Reservation) and Class II Increment analyses. The following table shows the ISC-PRIME modeling results for the Class I and II increments analyses; none of the increments were exceeded.

Class I and II Modeling Results

Pollutant	Avg. Period	Class II Modeled Conc. ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)	% Class II Increment Consumed	Class I Modeled Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	% Class I Increment Consumed
PM_{10}	24-hr	10.1	30	33.7	0.0827	8	1.03
	Annual	2.07	17	12.1	0.00808	4	0.2
SO_2	3-hr	68.1	512	13.3	2.87	25	11.5
	24-hr	19.6	91	21.5	0.425	5	8.5
	Annual	2.98	20	14.9	0.0322	2	1.6
NO_x	Annual[a]	1.91	25	7.6	0.0206	2.5	0.8

Bison conducted an analysis of impacts on sensitive species and other Air Quality Related Values near the plant site. The results of these analyses did not trigger any concerns. Additionally, Bison conducted a special analysis for cumulative impacts on the Northern Cheyenne Indian Reservation (that included emissions from PPL Montana LLC's Colstrip Units 3&4) at those times when the RMP Project impacts were above significance levels. In this ISC-Prime analysis there were no predicted exceedances of the Class I increments when the RMP impacts were significant.

B. Cumulative Impacts for Class I Areas

Since the results of the ISC-PRIME analysis predicted 3-hour and 24-hour SO_2 impacts above the significance level (4%) of the Class I increments followed by the Department, RMP was required to submit a cumulative impact assessment for Class I SO_2 increments and visibility at the NCIR, Yellowstone National Park, UL Bend Wilderness Area, and the North Absaroka Wilderness. This analysis was conducted using CALPUFF and 1990, 1992 and 1996 meteorological data. The analysis included increment-consuming emissions from PPL Montana LLC's Colstrip Units 3 & 4 and the recently permitted Roundup Power Plant. Increment consumption of RMP in the CALPUFF analysis was never above significance levels and further cumulative increment analyses were not conducted.

Visibility impacts are separated into short-range (less than 50 kilometers) and long-range (greater than 50 kilometers) impacts. The NCIR is the only Class I area that falls into the category of short-range impacts. The other Class I areas fall into the category of long-range impacts. The visibility analysis for the NCIR was conducted using VISCREEN. A Level-1 screening analysis was performed to provide a conservative estimate of plume visual impacts (in this case, VISCREEN required only the NO_x emission rate from the main boiler stack as input into the model). The conservatism is achieved by the use of worst-case meteorological conditions: extremely stable atmospheric conditions, coupled with a very low wind speed persisting for 12 hours, and a wind direction that would transport the plume directly adjacent to the observer. As shown in the following table, Level-1 analysis results did not exceed the critical criteria inside the Class I area and, therefore, no further analysis of visibility degradation is warranted.

Short-range Visibility Impact Analysis, Class I (NCIR)

Background	Sun Angle (degrees)	Distance from Source (km)	Delta E		Contrast	
			Critical	Plume	Critical	Plume
Sky	10	46	2.00	1.791	0.05	0.008
Sky	140	46	2.00	0.975	0.05	-0.015
Terrain	10	46	2.00	1.689	0.05	0.017
Terrain	140	46	2.00	0.300	0.05	0.006

The following table lists the peak predicted visibility impacts from the facility emissions to surrounding mandatory federal Class I areas (the NCIR is included in the short-range impacts discussion above). The total number of days over the modeled three-year period in which an extinction change of more than 5% is predicted was 13 and the total number of days over the modeled three-year period in which an extinction change of more than 10% is predicted was 3. Extinction change is a measurement of visibility impairment. Based on the modeling analysis, the peak predicted visibility impacts would occur at the North Absaroka Wilderness Area on 12 days and at U.L. Bend Wilderness Area on 1 day.

Peak Predicted Class I Area Visibility Impacts

Modeled Year	Change in Extinction, 24-hr Average	Number of Days ΔB_{ext} 5.0%	Number of Days ΔB_{ext}.10.0%
1990	2.55%	0	
1992	7.93%	2	
1996	17.6%	11	3
Max/Total	17.6%	13	3

The following table shows the peak predicted SO_2 and NO_x deposition rates for all modeled years, which are below the guideline significance threshold of 0.005 kg/ha/yr suggested by the National Park Service.

Peak Annual Average Nitrogen and Sulfur Deposition Rates

Pollutant	Deposition Rate (kg/ha/yr)		
	1990	1992	1996
Nitrogen	0.000794	0.000653	0.000654
Sulfur	0.00256	0.00356	0.00290

The results of these analyses were shared with the Federal Land Managers. The modeling submitted in support of Permit Application #3185-02 (based on "worst case" emissions) shows compliance with all ambient standards and PSD increments.

VI. Taking or Damaging Implication Analysis

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

VII. 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, Inc.
Hardin Generator Project
P.O. Box 5650
Bismarck, ND 58506-5650

Air Quality Permit Number: #3185-02

Preliminary Determination Issued: November 8, 2004
Department Decision Issued: December 22, 2004
Permit Final: May 16, 2005

1. *Legal Description of Site*: RMP electrical power generating facility would be located approximately 1.2 miles northeast of Hardin, Montana. The legal description of the site is the Northwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. RMP owns and would use approximately 30 acres for the proposed facility.

2. *Description of Project*: RMP was granted an air quality preconstruction permit for the construction and operation of a nominal 113-MW coal-fired steam-electric generating station. The facility would consist of a pulverized coal-fired (PC-fired) boiler and a steam turbine, which would drive an electric generator. RMP would consume 8.5-MW of that power (in parasitic load). RMP requested a modification to their current Montana Air Quality Permit (#3185-01) to change the currently permitted control equipment on the PC-fired boiler for sulfur dioxide (SO_2) and particulate matter with an aerodynamic diameter less than 10 micrometers (PM_{10}) emissions and to make changes in the facility's material handling systems, cooling system, and plant layout. The currently permitted system for SO_2 and PM_{10} emissions includes a wet venturi scrubber operated in conjunction with a multiclone. RMP is proposing to replace that with a lime spray dry absorber (SDA) followed by a fabric filter baghouse. The changes in the cooling system and the consequential increase in potential PM_{10} emissions triggers review under Prevention of Significant Deterioration (PSD) of Air Quality. The increased PM_{10} 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 cannot be guaranteed in the current configuration. In addition, RMP requested to correct the current hydrofluoric acid (HF) limit that was established under Permit #3185-01.

3. *Benefits and Purposes (Objectives) of Project*: The purpose of the project would be for RMP to change their SO_2 and PM_{10} control equipment for the PC-fired boiler to a more effective combination with better H_2SO_4 control than is currently permitted in addition to changing the cooling tower system to more accurately reflect a workable system and to correct the previously overestimated cooling tower mist eliminator control efficiency. The plant layout and material handling operations also would be updated (along with the control equipment for material handling operations). The benefits of the project would be a more effective pollution control system on the Boiler than is currently permitted. Also, the change to the HF limit would correct a typographical error in the amendment request for Permit #3185-01.
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 Montana Air Quality Permit modification to RMP. Under the "no action" alternative, RMP: would not be able to install the proposed control equipment, therefore defaulting to the currently permitted control system for SO_2 and PM_{10} (which would be less effective than the proposed system); would have to go back to an inaccurate representation of the cooling tower configuration and emissions (which could cause noncompliance issues); would have to revert to the previous material handling and plant layout configuration; and would have to leave an error in the HF limit in the permit. Under the "no action" alternative, none of the impacts of the proposed permit modification, as described in this EA, would occur. RMP's proposed modification has demonstrated compliance with all applicable rules and standards as required for permit issuance.

5. *A Listing of Mitigation, Stipulations, and Other Controls*: A list of enforceable conditions would be included in Permit #3185-02.

6. *Regulatory Effects on Private Property*: The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and would 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.

Potential Physical and Biological Effects							
		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 Resources 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

The impacts from this project to terrestrial and aquatic life and habitats would be minor because the footprint of the constructed facility would only change slightly, with only a small portion of land being disturbed in addition to what was previously planned and permitted and because impacts to the surrounding area from the air emissions (considering the air dispersion characteristics) would be minor. Terrestrials (such as deer, antelope, rodents) would use the general area of the facility. The area around the facility would be fenced to limit access to the facility. The fencing likely would not restrict access by all animals that frequent the area, but it may discourage some animals from entering the facility property. The area to the south is currently used for industrial purposes and will 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 modifications to the facility because RMP would be increasing the withdrawal of water from the Bighorn River for its cooling tower (the rate of withdrawal and specifications of the cooling tower would change from the previous permitting action). However, this water withdrawal would have little impact on the overall river flow and habitat, as discussed in Section 7.B of this EA. Discharge from the cooling tower blow-down would amount to less than 30 gpm, and would be discharged to the makeup system for the lime slurry, to be injected into the SDA. If the discharged water could not be immediately used, it would be stored in a surge tank until it could be reused within the system. Non-industrial water (from the offices, for example) would be disposed of in the Hardin municipal wastewater treatment plant. The resulting air emissions to any water body from the facility would be minor.

The air quality modeling analysis (see section 7.F of this EA) was performed using all of the emissions from the RMP facility, not just the emissions associated with this permitting action (45.8 tons per year of potential PM_{10} emissions increase). The 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 (again, the facility as a whole) 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 modification and its small increase in PM_{10} emissions would be minor. The project (and the facility as a whole) would be in compliance with the National and Montana Ambient Air Quality Standards (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. In addition, limitations have been added in Permit #3185-02 to further regulate HAPs.

B. Water Quality, Quantity, and Distribution

The proposed modification to the facility 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 increased air emissions. The facility would use water from the Bighorn River to operate the cooling tower, and the facility would use the City of Hardin water and sewage facilities for other water demands and sewage discharge. Discharge from the cooling tower blow-down would amount to less than 30 gpm, and would be discharged to the makeup system for the lime slurry, to be injected into the SDA. If the discharged water could not be immediately used, it would be stored in a surge tank until it could be reused within the system. Therefore, the cooling tower discharge would not affect surface or groundwater. In addition, the proposed change of flue gas desulfurization (FGD) equipment on the boiler would decrease water usage by

approximately 20% (from a wet to a dry system).
As described in Section 7.F of this EA, the maximum, cumulative impacts from the air emissions from this facility would be moderate (again, from the facility as a whole, including the proposed modification). 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. With respect to concerns about acid rain, the proposed project would reduce originally permitted levels of SO_2 (a component of acid rain). In addition, the facility is subject to the U.S. Environmental Protection Agency's (EPA) Acid Rain Program.

The estimated water requirements for the facility (specifically the cooling tower) would be 1,400 gallons per minute (gpm), which would be obtained from existing water rights on the Bighorn River. The previous permit indicated 1,300 gpm would be obtained from the Bighorn River (so the water intake has increased by 100 gpm for this modification). There would be no direct discharge to the waters of the state of Montana from the operation of the cooling tower. Discharge from the cooling tower would be less than 30 gpm, and would either be disposed of in the Hardin wastewater municipal treatment plant or evaporated onsite. As mentioned above, the water drawn from the Bighorn River would be approximately 1,400 gpm, which translates to just over 3 cubic feet per second (cfs). The historic mean from January 1, 1980, through September 30, 2000, for the Bighorn River is 3623 cfs, with the minimum flow for that part of the Bighorn at 1020 cfs. The water requirements of RMP would be approximately 0.08% of the historic mean flow, and 0.3% of the minimum. Therefore the effect of the proposed water withdrawal and discharge/evaporation would be minor.

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 modification to the facility project would only change slightly the footprint of the facility as it was previously permitted. Any new footings (for new baghouses) would impact a small portion of land that has been previously used for industrial activity and the amount of resulting deposition of the air emissions would be small. Any changes to the facility footprint would be within the previously permitted facility site boundaries. Soil stability in the immediate vicinity of the proposed facility would likely be impacted by new footings required for the modification of the facility. The major construction for the three buildings (for the boiler, coal storage, and cooling tower) would not change for this modification. The facility would not be discharging 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 modification to the facility project would only change slightly the footprint of the facility as it was previously permitted. Any new footings (for new baghouses) would impact a small portion of land that has been previously used for industrial activity and the amount of resulting deposition of the air emissions would be small. Approximately 30 acres has been or would be disturbed for the entire facility construction and its perimeter.

As described in Section 7.F of this EA, the cumulative modeled air impacts from the air emissions from this facility would be moderate (again, from the facility as a whole, including the proposed modification). 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 modification and its small increase in PM_{10} emissions would be minor.

E. Aesthetics

The impacts to the aesthetics of the area from the proposed project at the RMP facility would be minor because very little would change aesthetically from the previously permitted plant. The overall appearance of the plant would not change, and noise and odors would remain near previously predicted levels regardless of the changes proposed in this action. Switching from a wet FGD system to a dry FGD system would change the plume from the Boiler stack to a dry plume, making it less visible. The facility would be barely visible from gathering places along the river (the dry plume on cold days may still be visible and would be large compared to other common sources in the area and would be visible from Hardin and Montana Highway 47).

F. Air Quality

The RMP facility (as a whole, including the proposed project) 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. Emissions of nitrogen oxides (NO_x), carbon monoxide (CO), particulate matter (PM), PM_{10}, volatile organic compounds (VOC), SO_2, and lead (Pb) would result from the proposed project, with NO_x, CO, PM_{10}, and SO_2 above the 100 ton per year PSD major source threshold for the facility as a whole.

For the proposed project, the air quality impacts would be minor (SO_2 emissions would decrease from the previous Permit #3185-01) and the overall increase in emissions is tied to 45.8 tons of potential emissions of PM_{10}. Air quality dispersion modeling (which factors in such parameters as wind speed, wind direction, atmospheric stability, stack temperature, stack emissions, etc.) was conducted for the RMP facility by Bison Engineering, Inc (Bison). The airborne concentrations of NO_x, SO_2, CO and PM_{10} were modeled to demonstrate compliance with the MAAQS and NAAQS and the 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 51, Guideline on Air Quality Models (revised), August 12, 1996. The air dispersion modeling analysis was independently reviewed by the Department.

As required by EPA modeling guidelines (used for this type of air quality permitting), the model must incorporate at least one year of on-site meteorological data or five years on nearby off-site data (data that has been through the appropriate quality assurance/quality control process). The ISC-PRIME model was used along with seven years of surface meteorological data (1984, 1986-1991) collected at the Billings International Airport National Weather Station, and local meteorological data collected on site (north of Hardin) during 2002-2003 and the corresponding upper air data collected at the Great Falls International Airport National Weather Station. The receptor grid was generated from digital elevation model (DEM) files using the six 7.5 minute United States Geological Survey (USGS) topographical maps. The receptor spacing placement was as follows: 100 meters along the fenceline and out to 2000 meters, 250-meter spacing from 2000 to 5000 meters, and 500-meter spacing from 5,000 to 16,000 meters from the fenceline.

Downwash was calculated using the EPA's Building Profile Input Program (BPIP).

As in the original application submittal of January 2002, modeling was conducted for PM_{10}, CO, SO_2, and NO_x emissions from RMP. All of the pollutants' modeled concentrations were below the monitoring de minimis concentrations except for PM_{10} and SO_2. RMP submitted one year's worth of on-site ambient monitoring data for PM_{10} and SO_2 to the Department. The modeling significance level was exceeded for all the pollutants in this analysis except CO thus a full impact analysis was required for PM_{10}, SO_2, and NO_2 to demonstrate compliance with the NAAQS, MAAQS, and PSD increments. The largest identified radius for determining the significant impact area (SIA) for this project was the 24-Hour SO_2 averaging period, which extended 16.3 kilometers. Significance levels are listed in 40 CFR 51, Appendix S. CO was below the modeling significance level so no additional modeling was conducted for CO emissions. The ambient analysis only included RMP because no major stationary sources exist within any of the significant impact areas (SIAs) or within 50 kilometers beyond the SIAs.

The NAAQS/MAAQS analysis demonstrated that the emissions from this facility would be below the ambient air quality standards. A comparison of the modeled impacts from RMP with the MAAQS is shown in the following table. The RMP impacts were compared with the MAAQS because the MAAQS are the same or more stringent than the NAAQS for the previously mentioned pollutants and averaging times. As displayed in the following table, the impacts from the RMP project on the air quality in comparison to the ambient air quality standards is minor. The ambient air quality standards are designed to protect public health with an adequate margin of safety (primary standard) and to promote public welfare (secondary standard).

Ambient Air Quality Analysis Modeling Results

Pollutant	Avg. Period	Modeled Conc. ($\mu g/m^3$)	Background Conc. ($\mu g/m^3$)	Ambient Conc. ($\mu g/m^3$)	NAAQS ($\mu g/m^3$)	% of NAAQS	MAAQS ($\mu g/m^3$)	% of MAAQS
PM_{10}	24-hr	10.1	54	64.1	150	42.7	150	42.7
	Annual	2.07	15	17.07	50	34.1	50	34.1
NO_2	1-hr	103	75	178	------	------	564	31.6
	Annual [a]	1.91	6	7.91	100	7.9	94	8.4
SO_2	1-hr[b]	142	35	177	------	------	1,300	13.6
	3-hr	68.1	26	94.1	1,300	7.24	------	-----
	24-hr	19.6	11	30.6	365	8.3	260	11.8
	Annual	2.98	3	5.98	80	7.5	52	11.5

[a] Neither the Ozone Limiting Method or Ambient Ratio Method were applied to these results.
[b] Concentrations are high-second high values except annual averages and SO_2 1-hr, which is high-tenth-high.

As mentioned above all of the SIAs (which would include Class I SIAs) are less than the 46-km distance between the facility and the closest Class I area, the Northern Cheyenne Indian Reservation (NCIR). Other nearby Class I areas include: Yellowstone National Park, North Absaroka Wilderness, and UL Bend Wilderness Area (all approximately 200 km from the proposed facility site). Therefore, the emissions from the facility are not likely to have a significant impact on the Northern Cheyenne Indian Reservation, or the other Class I areas nearby. PM_{10}, SO_2, and NO_x emissions were modeled using ISC-PRIME for the Class I (Northern Cheyenne Indian Reservation) and Class II Increment analyses. The following table shows the ISC-PRIME modeling results for the Class I and II increments analyses; none of the increments were exceeded.

Class I and II Modeling Results

Pollutant	Avg. Period	Class II Modeled Conc. ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)	% Class II Increment Consumed	Class I Modeled Conc. ($\mu g/m^3$)	Class I Increment ($\mu g/m^3$)	% Class I Increment Consumed
PM_{10}	24-hr	10.1	30	33.7	0.0827	8	1.03
	Annual	2.07	17	12.1	0.00808	4	0.2
SO_2	3-hr	68.1	512	13.3	2.87	25	11.5
	24-hr	19.6	91	21.5	0.425	5	8.5
	Annual	2.98	20	14.9	0.0322	2	1.6
NO_x	Annual[a]	1.91	25	7.6	0.0206	2.5	0.8

Bison conducted an analysis of impacts on sensitive species and other Air Quality Related Values near the plant site. The results of these analyses did not trigger any concerns. Additionally, Bison conducted a special analysis for cumulative impacts on the Northern Cheyenne Indian Reservation (that included emissions from PPL Montana LLC's Colstrip Units 3&4) at those times when the RMP Project impacts were above significance levels. In this ISC-Prime analysis there were no predicted exceedances of the Class I increments when the RMP impacts were significant.

Since the results of the ISC-PRIME analysis predicted 3-hour and 24-hour SO_2 impacts above the significance level (4%) of the Class I increments followed by the Department, RMP was required to submit a cumulative impact assessment for Class I SO_2 increments and visibility at the NCIR, Yellowstone National Park, UL Bend Wilderness Area, and the North Absaroka Wilderness. This analysis was conducted using CALPUFF and 1990, 1992 and 1996 meteorological data. The analysis included increment-consuming emissions from PPL Montana LLC's Colstrip Units 3 & 4 and the recently permitted Roundup Power Plant. Increment consumption of RMP in the CALPUFF analysis was never above significance levels and further cumulative increment analyses were not conducted.

Visibility impacts are separated into short-range (less than 50 kilometers) and long-range (greater than 50 kilometers) impacts. The NCIR is the only Class I area that falls into the category of short-range impacts. The other Class I areas fall into the category of long-range impacts. The visibility analysis for the NCIR was conducted using VISCREEN. A Level-1 screening analysis was performed to provide a conservative estimate of plume visual impacts (in this case, VISCREEN required only the NO_x emission rate from the main boiler stack as input into the model). The conservatism is achieved by the use of worst-case meteorological conditions: extremely stable atmospheric conditions, coupled with a very low wind speed persisting for 12 hours, and a wind direction that would transport the plume directly adjacent to the observer. As shown in the following table, Level-1 analysis results did not exceed the critical criteria inside the Class I area and, therefore, no further analysis of visibility degradation is warranted.

Short-range Visibility Impact Analysis, Class I (NCIR)

Background	Sun Angle (degrees)	Distance from Source (km)	Delta E		Contrast	
			Critical	Plume	Critical	Plume
Sky	10	46	2.00	1.791	0.05	0.008
Sky	140	46	2.00	0.975	0.05	-0.015
Terrain	10	46	2.00	1.689	0.05	0.017
Terrain	140	46	2.00	0.300	0.05	0.006

The following table lists the peak predicted visibility impacts from the facility emissions to surrounding mandatory federal Class I areas (the NCIR is included in the short-range impacts discussion above). The total number of days over the modeled three-year period in which an extinction change of more than 5% is predicted was 13 and the total number of days over the modeled three-year period in which an extinction change of more than 10% is predicted was 3. Extinction change is a measurement of visibility impairment. Based on the modeling analysis, the peak predicted visibility impacts would occur at the North Absaroka Wilderness Area on 12 days and at U.L. Bend Wilderness Area on 1 day.

Peak Predicted Class I Area Visibility Impacts

Modeled Year	Change in Extinction, 24-hr Average	Number of Days ΔB_{ext} 5.0%	Number of Days ΔB_{ext}.10.0%
1990	2.55%	0	
1992	7.93%	2	
1996	17.6%	11	3
Max/Total	17.6%	13	3

The following table shows the peak predicted SO_2 and NO_x deposition rates for all modeled years, which are below the guideline significance threshold of 0.005 kg/ha/yr suggested by the National Park Service.

Peak Annual Average Nitrogen and Sulfur Deposition Rates

Pollutant	Deposition Rate (kg/ha/yr)		
	1990	1992	1996
Nitrogen	0.000794	0.000653	0.000654
Sulfur	0.00256	0.00356	0.00290

The results of these analyses were shared with the Federal Land Managers. The modeling submitted in support of Permit Application #3185-02 (based on "worst case" emissions) shows compliance with all ambient standards and PSD increments.

In addition to the modeling analyses, a BACT analysis (see Section III of the permit analysis for Permit #3185-02) was performed as part of the permit action that resulted in specific permit conditions on applicable equipment. The results of that BACT analysis were factored into the modeling analysis (the SO_2 limit used in the model, as with the other pollutants, was the "worst-case" hourly limit, which could not be maintained without violating other conditions in the permit like the 30-day rolling average for SO_2). Another condition in the permit would limit the opacity (visible emissions) from the facility and general plant property.

The operation of the RMP facility would also result in emissions of HAPs. A major facility for HAPs is defined as a stationary source that has the potential to emit more than 10 tons per year of any individual HAP or 25 tons per year of all HAPs combined. The highest individual emission rate of a HAP from this project would be 6.75 tons per year (hydrochoric acid, HCl), and the combined emission rate of all HAPs from this project would be 13.73 tons per year. Not only is this source not considered a major source for HAPs, but any impact from HAPs would be minor because the emissions of the HAPs would be dispersed by the wind speed, wind direction, atmospheric stability or instability, stack temperature, and other dispersion parameters in the area. For example, the exposure to a person from the HAPs emissions from this facility would be less than the exposure level that occurs while fueling a vehicle. The public's acute exposure to HAPs while fueling a vehicle would be much higher than that from the emissions from this facility because the emissions from RMP would be emitted from a 250-foot tall stack at approximately 160°F. Due to the wind speed, wind direction, atmospheric stability or instability, stack temperature, and other parameters, the emissions from the RMP facility would greatly disperse (dilute) before creating impacts to the public. There are no ambient air quality standards for HAPs. In the BACT analysis of Permit #3185-02, control technologies were evaluated for HAPs associated with coal combustion, and control technology requirements and emission limits have been incorporated into that permit, as appropriate. The HAPs analyzed were Hg, acid gases, trace metals, and radionuclides.

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 project. 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 RMP 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 for 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 (for the facility as a whole, including the proposed modification), the facility would not violate any ambient standards. The RMP facility would be required to operate in compliance with 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 (by the facility as a whole), 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 slight increase in PM_{10} 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 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 be minor because the demands for water (from the Bighorn River) would be insignificant compared with historical flow and the resulting amount of wastewater would be small and would be reused within the process, not discharged. In addition, water use by the FGD system on the boiler would decrease by approximately 20% (going from a wet to a dry process for SO_2 control).

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 small amount of proposed increased emissions (above previously permitted levels) and the type of air pollutants emitted and the good dispersion characteristics of the stack and the area. Ambient air modeling for NO_x, CO, PM, PM_{10}, and SO_2 was conducted for the facility at "worst case" conditions and demonstrates that the cumulative emissions from the RMP facility (including the proposed modification) would not exceed any ambient air quality standard. In addition, Permit #3185-02 would contain conditions limiting the emissions from the facility.

The impacts to the energy resource from the proposed modification would be minor because the proposed FGD control equipment for the boiler uses approximately 40% less energy than the control equipment previously proposed (going from a wet to a dry process for SO_2 control). This reduction in energy use by the FGD system may reduce the 8.5 MW per year that the facility would have used of the power it generated.

I. Historical and Archaeological Sites

The impacts on historical and archaeological sites would be minor because the proposed modification would be located on the previously permitted site location and would disturb very little ground. Prior to any construction by RMP, the site contained no visible standing structures and is within an area that has 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 proposed location are a Cenex bulk storage facility and the buildings associated with Holly Sugar Corporation, which will both remain in place. 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 is 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 this modification on the physical and biological aspects of the human environment would be minor. Although the overall air impact from RMP by itself (including the proposed modification) 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 and would comply with the NAAQS/MAAQS. 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 modification.

The proposed modification, although it is associated with an increase in potential PM_{10} emissions of 45.8 tons per year, may actually slightly decrease the overall impact of the facility on the physical and biological impacts of the human environment. As a part of the SO_2 and PM_{10} control technology review for the boiler, the Department determined that emission limits for Hg and sulfuric acid mist were appropriate and analyzed the best available control technology for those pollutants as well as radionuclides and trace metals from coal combustion (for which the Department used the PM_{10} emissions limit as a surrogate limit). In addition, the Department determined that a slightly lower SO_2 limit was appropriate, decreasing allowable SO_2 emissions from the facility.

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

Potential Social and Economic Effects							
		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 SOCIAL AND ECONOMIC EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed modifications to the previously permitted RMP facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because proposed changes would occur within the RMP site and would not change the nature or use of that site. The proposed changes to the RMP facility 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 change 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 modification to the RMP facility would not cause a change in the cultural uniqueness and diversity of the area because any changes would occur on the permitted RMP 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. Therefore, changing control equipment on the boiler and updating the cooling tower specifications, plant layout, and material handling operations at the RMP facility in that area would not be “out of place.”

As described in Section 7.F of this EA, the RMP project (modeled as a whole, including the proposed modification) 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 modification of RMP would not create a situation in which any increments would be exceeded. Therefore, the proposed modification to the RMP facility would cause no change in the cultural uniqueness and diversity of the area.

C. Local and State Tax Base and Tax Revenue

The proposed modification of the proposed facility would have no effect the state tax base and tax revenue because it would not change the amount of taxes owed by the RMP facility.

D. Agricultural or Industrial Production

The impacts to agricultural and industrial production in the area from this proposed modification would be minor because the modifications to the RMP facility would occur on the previously permitted RMP site, would impact a minimal amount of land within that site (that was previously used for industrial purposes), and the resulting deposition from air quality emissions would be small.

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 (from the whole facility, including the proposed modification). 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 modification 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 (as a whole, including the proposed modification), taking into account other dispersion characteristics, are well below the MAAQS and the NAAQS. The air quality permit for this 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 air pollutants (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 modifications to the RMP facility 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 as a whole, including the proposed modification, (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 modification to the RMP facility above the numerous projected construction-related employment opportunities and approximately 45 full-time positions (including 10 positions associated with truck drivers for coal hauling operations) previously associated with the facility.

H. Distribution of Population

The proposed modification to the RMP facility would have no effect on the normal population distribution in the area above the 45 full-time positions and temporary construction-related positions previously associated with the facility.

I. Demands of Government Services

Demands on government services from the proposed modification to the RMP facility 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 appropriate permits by the facility for the proposed modification (including a state air quality permit), the permits for the associated activities of the project, and compliance verification with those permits would also require minor services from the government.

J. Industrial and Commercial Activity

The proposed modification to the RMP facility would represent no change in industrial activity in the area. The proposed modification would only change how the internal workings of the plant are performed (the proposed changes in control equipment for the boiler, the cooling tower updates, and the plant layout/material handling changes). The facility, as previously permitted, 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 changes and the RMP project 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 modification of the RMP facility.

L. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from this 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 modification would have only a minor impact on human health.

Recommendation: No 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 the modification of a currently permitted pulverized coal-fired electrical power generation facility. Requested modifications include a change in the currently permitted control equipment on the PC-fired boiler for SO_2 and PM_{10} emissions and changes in the facility's material handling systems, cooling system, and plant layout. Permit #3185-02 would include conditions and limitations to ensure the facility would operate in compliance with all applicable statutes and regulations. In addition, there would be no significant impacts associated with this proposal.

Other groups or agencies contacted or that 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

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