AIR QUALITY PERMIT

Issued To: Thompson River Co-Gen, L.L.C.
8 – 1st Street East, Suite 205
Kalispell, MT 59901

Permit: #3175-04
Application Complete: 6/09/06
Preliminary Determination Issued: 7/06/06
Department Decision Issued: 8/21/06
Permit Final: 9/06/06
AFS: #089-0009

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

SECTION I: Permitted Facilities

A. Plant Location

TRC operates a 16.5-megawatt (MW) capacity electricity and steam co-generation plant. A complete list of permitted equipment/emission sources is contained in Section I.A of the permit analysis. The TRC plant is located approximately 3.7 miles east-southeast of Thompson Falls, Montana. The legal description of the site is in the SW¼ of the NW¼ of the NE¼ of Section 13, Township 21 North, Range 29 West, in Sanders County, Montana. The approximate universal transverse mercator (UTM) coordinates are Zone 11, Easting 631.6 kilometers (km), and Northing 5270.6 km.

B. Current Permit Action

On June 9, 2006, the Department of Environmental Quality (Department) received a complete application for the modification of TRC's Montana air quality Permit #3175-02. Specifically, TRC requested the following changes to the permit terms/conditions relating to the Babcock and Wilcox Spreader-Stoker boiler (boiler):

- Removal of the requirement that the installed sulfur dioxide (SO_2) control equipment meet or exceed 90% SO_2 reduction;
- Modification of the language specifying the SO_2 control technology as a dry-lime scrubber to a generic flue gas desulfurization (FGD) system;
- Reevaluation of the Best Available Control Technology (BACT) determined SO_2 emission limit(s) of 0.220 pounds per million British thermal unit (lb/MMBtu) based on a 1-hour (hr) average and 42.42 pounds per hour (lb/hr) based on a 1-hr average. TRC proposed a new SO_2 BACT emission limit of 0.220 lb/MMBtu based on a rolling 30-day average or 85% SO_2 control efficiency, whichever is less stringent. TRC also proposed removal of the SO_2 BACT limit expressed in lb/hr;
- Reevaluation of the BACT-determined oxides of nitrogen (NO_x) emission limits of 0.178 lb/MMBtu based on a 1-hour average and 34.32 lb/hr based on a 1-hr average. TRC proposed the installation and operation of a selective non-catalytic reduction (SNCR) system and a new NO_x BACT emission limit expressed in lb/MMBtu, based on a 30-day rolling average, to be determined based on achievable NO_x emissions established through a statistical analysis of NO_x CEMS data from the first 275 days of SNCR operation. TRC also proposed removal of the NO_x BACT limit expressed in lb/hr;
- Removal of the hourly boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr;
- Removal of the boiler steam production limit of 130,000 lb/hr;

- Removal of the boiler baghouse fan flow capacity of 40,513 dry-standard cubic feet per minute (dscfm); and
- Inclusion of boiler startup and shutdown limits and operating conditions, including SO_2 and NO_x emission limits, which would apply during defined periods of startup and shutdown only.
- Cessation of PM_{10} ambient air quality monitoring requirements when TRC is not in operation.

After Department review of TRC's application for permit modification, the following modifications were made to TRC's permit:

- Removal of the requirement that the installed SO_2 control equipment meet or exceed 90% SO_2 reduction;
- Modification of the SO_2 control strategy language to require a generic FGD system;
- Modification of the existing SO_2 BACT emission limit of 0.220 lb/MMBtu based on a 1-hr average to 0.220 lb/MMBtu based on a rolling 30-day average;
- Removal of the BACT determined SO_2 emission limit of 42.42 lb/hr;
- Inclusion of a 1-hr maximum SO_2 emission rate of 72.3 lb/hr applicable at all times, except during periods of startup and shutdown;
- Inclusion of a requirement for an SO_2 continuous emissions monitoring system (CEMS);
- Inclusion of NO_x BACT requirement for a selective non-catalytic reduction (SNCR) system and FGR combustion control in addition to the existing over-fire air (OFA) combustion control requirement;
- Modification of the existing NO_x BACT determined emission rate of 0.178 lb/MMBtu based on a 1-hr average to 0.196 lb/MMBtu based on a rolling 30-day average;
- Inclusion of a 10-day boiler/SNCR mapping/testing period with an applicable emission limit of 0.28 lb/MMBtu to determine appropriate placement of SNCR injection nozzles to optimize SNCR NO_x control efficiency;
- Removal of the BACT determined NO_x emission limit of 34.32 lb/hr;
- Inclusion of a 1-hr maximum NO_x emission rate of 47.24 lb/hr applicable at all times except during periods of startup and shutdown;
- Modification of the hourly boiler heat input limit of 192.8 MMBtu/hr to 192.8 MMBtu/hr based on a 24-hour average and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr based on a rolling 12-month average;
- Removal of the steam production limit of 130,000 lb/hr;
- Removal of the boiler baghouse fan flow rate of 40,513 dscfm;
- Inclusion of enforceable boiler startup and shutdown operating conditions and SO_2 and NO_x emission limits applicable during periods of startup and shutdown only and inclusion of a boiler startup and shutdown plan (Attachment 3) describing the operational circumstances which constitute boiler startup and shutdown; and
- Interim cessation of PM_{10} ambient air quality monitoring requirements until initial startup of the boiler after issuance of Permit #3175-04 and continuation of ambient air quality monitoring operations thereafter.

A more detailed analysis of the Department's action is contained in Section I.D of the permit analysis to this permit.

SECTION II: Conditions and Limitations

A. General Plant Requirements

1. TRC shall not cause or authorize emissions to be discharged into the outdoor atmosphere from any sources installed after November 23, 1968, and not subject to 40 CFR Part 60, that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes (ARM 17.8.304).

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

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

4. TRC shall comply with all applicable standards and limitations, and the reporting, recordkeeping and notification requirements contained in 40 CFR 60, Subpart A, and 40 CFR Part 60, Subpart Db (ARM 17.8.340, 40 CFR 60, Subpart A, and Subpart Db).

5. TRC shall obtain a written coal analysis that is representative of each load of coal received from each coal supplier. The coal analysis shall contain, at a minimum, sulfur content, ash content, Btu value (Btu/lb), and chlorine concentration (ARM 17.8.749).

6. TRC shall install and operate a Continuous Opacity Monitoring System (COMS) to monitor compliance with the boiler opacity limits (ARM 17.8.340 and 40 CFR Part 60, Subpart Db).

7. TRC shall install and operate a NO_x Continuous Emission Monitoring System (CEMS) to monitor compliance with the boiler NO_x emission limits (ARM 17.8.340 and 40 CFR Part 60, Subpart Db).

8. TRC shall install and operate an SO_2 CEMS to monitor compliance with the boiler SO_2 emission limits. The applicable SO_2 CEMS shall be installed and certified within 180 days of initial boiler startup following issuance of Permit #3175-04 (ARM 17.8.749).

9. At all times, including periods of startup, shutdown, soot blowing, and malfunction, TRC shall, to the extent practicable, maintain and operate any affected equipment including associated air pollution control equipment in a manner consistent with air pollution control practices for minimizing emissions (ARM 17.8.749).

B. Boiler Startup and Shutdown Operations

1. The requirements contained in Section II.B shall apply during boiler startup and shutdown operations. Boiler startup and shutdown operations shall be conducted as described in the *Boiler Startup and Shutdown Procedures* included in Attachment 3 of Permit #3175-04 (ARM 17.8.749).

2. Boiler startup operations, as described in Attachment 3, shall not exceed 48 hours from initial fuel feed to the boiler pre-heater or boiler, whichever is applicable at initiation of the boiler startup event (ARM 17.8.749).

3. Boiler shutdown operations, as described in Attachment 3, shall not exceed 8 hours from initial backing down of solid fuel feed (coal and/or wood-waste) to the boiler (ARM 17.8.749).

4. During boiler startup and shutdown operations, the boiler may combust coal with a sulfur content less than or equal to 1% sulfur by weight, wood-waste/biomass, fuel oil with a sulfur content less than or equal to 0.05% sulfur by weight, or propane (ARM 17.8.752).

5. The boiler baghouse (DC5) shall be operational during startup and shutdown event(s) (ARM 17.8.749).

6. During startup and shutdown operations, oxides of nitrogen (NO_x) emissions from the boiler stack shall not exceed 74.0 lb/hr (ARM 17.8.749).

7. During startup and shutdown operations, sulfur dioxide (SO_2) emissions from the boiler stack shall not exceed 155.0 lb/hr (ARM 17.8.749).

C. Boiler Operations

1. Boiler heat input capacity shall be limited to 192.8 million British thermal units per hour (MMBtu/hr) based on a 24-hour daily average and 1,688,928 MMBtu during any rolling 12-month time period (ARM 17.8.749).

2. The boiler coal-fuel feed rate shall not exceed 105,558 tons of coal during any rolling 12-month time period (ARM 17.8.749).

3. The boiler main stack shall be a minimum of 100.5 feet tall and shall be 6 feet in diameter (ARM 17.8.749).

4. NO_x emissions from the boiler shall be controlled by over-fire air (OFA), flue gas recirculation (FGR), and SNCR. The OFA and FGR NO_x controls shall be installed prior to initial startup of the boiler combusting any fuel, following issuance of Permit #3175-04. Beginning the date of initial solid fuel (wood-waste and/or coal) feed to the boiler after issuance of Permit #3175-04, TRC shall be allowed a 10-day operational mapping/testing period prior to installation and operation of SNCR in which to model/test the boiler for appropriate location of the SNCR equipment within the boiler furnace. SNCR shall be installed prior to any additional boiler operations following completion of the 10-day SNCR testing period (ARM 17.8.752).

5. SO_2 emissions from the boiler shall be controlled by a FGD system when combusting coal. The FGD shall be installed prior to initial startup of the boiler following issuance of Permit #3175-04 (ARM 17.8.752).

6. Particulate matter/particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM/PM_{10}) emissions from the boiler shall be controlled by a fabric filter baghouse (DC5) (ARM 17.8.752).

7. Carbon monoxide (CO) and Volatile Organic Compound (VOC) emissions from the boiler shall be controlled by proper boiler design and operation and good combustion practices (ARM 17.8.752).

8. Hydrochloric acid (HCl) gas, sulfuric acid mist (H_2SO_4), and mercury (Hg) emissions from the boiler shall be controlled by a FGD unit in combination with a fabric filter baghouse (ARM 17.8.752).

9. The boiler may be fired with coal and/or wood-waste biomass only except for periods of boiler startup and shutdown, as specified in Section II.B (ARM 17.8.749).

10. Coal fired in the boiler shall have a minimum heating value of 8,000 Btu/lb (ARM 17.8.749).

11. The sulfur content of any coal fired at TRC shall not exceed 1% by weight (ARM 17.8. 752).

12. TRC shall not cause or authorize to be discharged into the atmosphere from the fabric filter baghouse controlling emissions from the boiler (boiler Baghouse – DC5) any visible emissions that exhibit an opacity of 20% or greater averaged over 6 consecutive minutes except for one 6-minute period per hour of not greater than 27% opacity (ARM 17.8.340 and 40 CFR Part 60.43b(f), Subpart Db).

13. Except during periods of boiler startup and shutdown, as specified in Section II.B, emissions from the boiler shall not exceed the following,:

    a. NO_x Emissions:

        i. 47.24 lb/hr, based on a 1-hr average (ARM 17.8.749).
        ii. 0.280 lb/MMBtu averaged over the initial 10-day SNCR mapping/testing period prior to installation and initial operation of SNCR, as specified in Section II.C.4. This emission limit shall expire upon installation of SNCR (ARM 17.8.749).
        iii. After installation of SNCR, NO_x emissions from the Boiler stack shall not exceed 0.196 lb/MMBtu based on a rolling 30-day average (ARM 17.8.749).

    b. CO Emissions:

        i. 0.259 lb/MMBtu, based on a 1-hr average (ARM 17.8.752); and
        ii. 49.92 lb/hr, based on a 1-hr average (ARM 17.8.752).

    c. SO_2 Emissions:

        i. 0.220 lb/MMBtu, based on a rolling 30-day average (ARM 17.8.752); and
        ii. 72.3 lb/hr, based on a 1-hr average (ARM 17.8.749).

    d. PM/PM_{10} Emissions:

        i. 5.90 lb/hr, based on a 1-hr average (ARM 17.8.752); and
        ii. 0.017 gr/dscf*, based on a 1-hr average (ARM 17.8.752).

        * The grain loading limit in Section II.C.13.d(ii) is the boiler Baghouse (DC5) limit.

    e. VOC Emissions:

        i. 0.0308 lb/MMBtu, based on a 1-hr average (ARM 17.8.752); and
        ii. 5.93 lb/hr, based on a 1-hr average (ARM 17.8.752).

f. HCl Emissions:

   i. 0.01125 lb/MMBtu, based on a 1-hr average (ARM 17.8.752);
   ii. 2.17 lb/hr, based on a 1-hr average (ARM 17.8.752); and
   iii. 9.50 ton/yr (ARM 17.8.749).

D. Boiler Pre-Heater Operations

1. The boiler pre-heater shall be limited to a maximum heat input capacity of 60 MMBtu/hr (ARM 17.8.749).

2. The boiler pre-heater shall be fired on propane or diesel fuel only (ARM 17.8.749).

3. The boiler pre-heater shall be limited to a maximum of 500 hours of operation during any rolling 12-month time period (ARM 17.8.749).

4. The boiler pre-heater shall be equipped with an automatic shut-off device, which is activated when the coal and/or wood-waste biomass fuel feeder becomes operational. Boiler pre-heater operations shall be limited to startup, shutdown, malfunction, and boiler commissioning operations. TRC shall not operate the boiler pre-heater when electricity is being generated through boiler operations or when the boiler fuel feed (wood-waste and/or coal) is operational (ARM 17.8.749).

E. Boiler Refractory Brick Curing Heaters

1. TRC may operate propane-fired boiler refractory brick pre-heaters only for the purpose of curing boiler refractory brick. The refractory brick curing heater(s) shall be limited to a combined maximum heat input capacity of 60 MMBtu/hr (ARM 17.8.749).

2. The refractory curing heater(s) shall be limited to a maximum of 500 hours of operation per heater during any rolling 12-month time period (ARM 17.8.749).

3. TRC shall not operate the refractory curing heater(s) when electricity is being generated through boiler operations or when the boiler fuel feed (wood-waste and/or coal) is operational (ARM 17.8.749).

F. Coal Fuel Handling and Storage Operations

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1. All railcar coal deliveries/transfers shall be unloaded via a bottom dump into an under-track hopper. PM/PM_{10} emissions from railcar transfers to the under-track hopper shall be enclosed and controlled by a fabric filter baghouse (Fuel Handling Baghouse – DC1) (ARM 17.8.752).

2. PM/PM_{10} emissions from the Fuel Handling Baghouse – DC1 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

3. Coal shall be delivered via conveyor (C1 and C2) to the day-bin coal silo (S1) prior to boiler feed. PM/PM_{10} emissions from C1 coal loading shall be controlled by a partially enclosed (3-sided) hopper and vented to DC1. S1 shall be enclosed and vented to a fabric filter bin vent (Fuel Handling Bin Vent – DC2) (ARM 17.8.752).

4. PM/PM_{10} emissions from the Fuel Handling Bin Vent – DC2 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

5. All material transfer conveyors for coal fuel storage and handling operations shall be limited to a maximum of 200 tons per hour capacity and shall be enclosed and vented to DC1 and/or DC2 (ARM 17.8.752).

6. TRC shall install and maintain wind fencing and an earthen berm to control fugitive dust emissions resulting from outdoor coal storage piles and operations. Further, TRC shall use reasonable precautions to control fugitive dust emissions from coal pile storage operations. Reasonable precautions shall include, but not be limited to, minimizing the number of coal pile disturbances, minimizing the area of coal pile disturbances, minimizing the fall distance of coal pile storage operations, and the use of wet dust suppression, as necessary, to control fugitive dust emissions from coal pile storage operations (ARM 17.8.752).

7. Outdoor coal storage shall be limited to a maximum of 6,000 tons at any given time (ARM 17.8.749).

G. Wood-Waste/Biomass Fuel Handling and Storage Operations

1. Wood-waste biomass fuel shall be delivered to the boiler via a pneumatic conveyor system. The pneumatic conveyor shall be enclosed and vented through the boiler and DC5 (ARM 17.8.752).

2. On-site wood-waste biomass storage shall be limited to a maximum of 3,000 tons at any given time (ARM 17.8.749).

H. Lime Handling and Storage Operations

1. All lime shall be stored in an enclosed silo. TRC shall install and operate a fabric filter bin vent (Lime Silo Bin Vent – DC3) to control PM/PM_{10} emissions from the lime silo supplying the dry-lime scrubber (ARM 17.8.752).

2. PM/PM_{10} emissions from the Lime Silo Bin Vent – DC3 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

I. Ash (Fly Ash and Bottom Ash) Handling and Storage Operations

1. All ash (fly and bottom ash) produced during boiler operations shall be stored in enclosed silos. TRC shall install and operate fabric filter bin vents (Fly Ash Silo Bin Vent – DC4 & Bottom Ash Silo Bin Vent – DC6) to control PM/PM_{10} emissions from the ash silos collecting boiler bottom ash/fly ash (ARM 17.8.752).

2. PM/PM_{10} emissions from the Fly Ash Silo Bin Vent – DC4 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

3. PM/PM_{10} emissions from the Bottom Ash Silo Bin Vent – DC6 shall not exceed 0.02 gr/dscf (ARM 17.8.752).

4. All fly ash transfers to trucks shall be gravity fed through a retractable load-out spout (ARM 17.8.749).

5. All bottom ash transfers to trucks shall utilize a partial (3-sided) enclosure to control fugitive dust emissions (ARM 17.8.749).

J. Testing Requirements

1. Compliance with the NO_x emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. TRC shall conduct performance source testing for NO_x and CO, concurrently. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing. TRC may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR Part 60, Subpart Db).

2. Compliance with the PM/PM_{10} emission limits for the boiler/boiler Baghouse – DC5 shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue annually or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR Part 60, Subpart Db).

3. Compliance with the opacity limit for the boiler/boiler Baghouse – DC5 shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, and ARM 17.8.749, and 40 CFR 60, Subpart Da).

   After the initial source test monitoring compliance with the boiler/boiler Baghouse – DC5 opacity limit, TRC shall use the data from the continuous opacity monitoring system (COMS) to monitor continued compliance with the applicable opacity limit (ARM 17.8.749).

4. Compliance with the CO emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. TRC shall conduct the performance source testing for CO and NO_x, concurrently. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, 40 CFR Part 60, Subpart A, and 40 CFR Part 60, Subpart Db).

5. Compliance with the SO_2 emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing

shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing. TRC may use testing in conjunction with the Relative Accuracy Test completed for certification of the CEMS, as a compliance test, if maximum achievable process rates are maintained (ARM 17.8.105 and ARM 17.8.749).

6. Compliance with the HCl emission limits for the boiler shall be monitored by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup of the boiler following installation of the SNCR system required under Permit #3175-04, or according to another testing/monitoring schedule as may be approved by the Department in writing. After the initial source test, testing shall continue on an every 4-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105).

7. TRC shall provide the Department with a record of the amount of coal being combusted and a coal analysis including sulfur content, chlorine content, ash content, and Btu value during all compliance source tests on the boiler (ARM 17.8.749 and ARM 17.8.106).

8. Compliance with the opacity limit for the Fuel Handling Baghouse – DC1 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

   Compliance with the PM/PM_{10} emission limits for the Fuel Handling Baghouse – DC1 shall be monitored by a performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

9. Compliance with the opacity limit for the Fuel Handling Bin Vent – DC2 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

   Compliance with the PM/PM_{10} emission limits for the Fuel Handling Bin Vent – DC2 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

10. Compliance with the opacity limit for the Lime Silo Bin Vent – DC3 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105,ARM 17.8.749, and ARM 17.8.752).

Compliance with the PM/PM_{10} emission limits for the Lime Silo Bin Vent – DC3 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

11. Compliance with the opacity limit for the Fly Ash Silo Bin Vent – DC4 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the PM/PM_{10} emission limits for the Fly Ash Silo Bin Vent – DC4 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

12. Compliance with the opacity limit for the Bottom Ash Silo Bin Vent – DC6 shall be monitored by an initial Method 9 performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department in writing (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

    Compliance with the PM/PM_{10} emission limits for the Bottom Ash Silo Bin Vent – DC6 shall be monitored by a performance source test conducted as required by the Department (ARM 17.8.105, ARM 17.8.749, and ARM 17.8.752).

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

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

K. Operational Reporting and Recordkeeping Requirements

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

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

2. TRC shall maintain on site records of all coal analyses conducted in accordance with the coal sampling requirement. TRC shall submit a summary of all coal analyses to the Department by February 15 of each year; the information may be submitted along with the annual emission inventory (ARM 17.8.505 and ARM 17.8.749).

3. TRC shall maintain on site records of all annual COMS/CEMS certifications. The records shall be maintained by TRC for at least 5 years following the date of the measurement, must be available at the facility site for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

4. TRC 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).

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

6. TRC shall document, by month, the boiler heat input value. By the 25th day of each month, TRC shall total the heat input in MMBtu for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory. TRC shall use the coal heating value established under the coal analysis requirement for the coal fired at that time and shall use a wood-waste heating value of 5,200 Btu/lb from AP-42, Fifth Edition, Volume I, Appendix A (ARM 17.8.749).

7. TRC shall document, by day, the boiler heat input value in MMBtu/hr on a 24-hr calendar-day average. TRC shall maintain a heat input monitoring system capable of demonstrating compliance with the 24-hr calendar-day heat input limit. TRC shall use the coal heating value established under the coal analysis requirement for the coal fired at that time and shall use a wood-waste heating value of 5,200 Btu/lb from AP-42, Fifth Edition, Volume I, Appendix A (ARM 17.8.749).

8. TRC shall document, by month, the coal feed rate to the boiler in tons/month. By the 25th day of each month, TRC shall total the total tons of coal feed to the boiler for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

9. TRC shall maintain records monitoring compliance with all applicable fuel use requirements (ARM 17.8.749).

10. TRC shall maintain records monitoring compliance with the coal type and heating value requirements (ARM 17.8.749).

11. TRC shall document, by month, the boiler pre-heater operating hours. By the 25th day of each month, TRC shall total the boiler pre-heater operating hours for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

12. TRC shall document, by month, the refractory curing heater(s) operating hours. By the 25th day of each month, TRC shall total each of the refractory curing heater(s) operating hours for the previous month. The monthly information will be used to verify compliance with the rolling 12-month limitation. The information for each of the previous months shall be submitted along with the annual emission inventory (ARM 17.8.749).

13. TRC shall maintain records monitoring compliance with the outdoor coal storage limit of 6,000 tons at any given time (ARM 17.8.749).

14. TRC shall maintain records monitoring compliance with the outdoor wood-waste storage limit of 3,000 tons at any given time (ARM 17.8.749).

15. TRC shall document each boiler startup and shutdown event. The boiler startup and shutdown event documentation shall include, at a minimum, the reason/basis for the startup or shutdown event, the duration of the startup or shutdown event (in hours), and the procedures used to conduct and complete the startup or shutdown event. The information shall be submitted to the Department upon request (ARM 17.8.749).

L. Monitoring Requirements

1. TRC shall install, operate, and maintain the applicable COMS and NO_x CEMS to monitor compliance with the applicable boiler emission limits. NO_x and opacity emissions monitoring shall be subject to 40 CFR 60, Subpart Db, Appendix B (Performance Specifications) and Appendix F (Quality Assurance/Quality Control) provisions. TRC shall conduct a Relative Accuracy Test Audit (RATA) for the NO_x CEMS and shall inspect and audit the COMS annually, using neutral density filters (EPA Technical Assistance Document: Performance Audit Procedures for Opacity Monitors; EPA-450/4-92-010, April 1992). The annual monitor RATA/audit may coincide with the required compliance source testing (ARM 17.8.749).

2. TRC shall install, operate, and maintain the applicable SO_2 CEMS to monitor compliance with the applicable boiler emission limits. TRC shall install the SO_2 CEMS prior to initial operation of the boiler following issuance of Permit #3175-04. TRC is not subject to the SO_2 monitoring requirements contained in 40 CFR 60, Subpart Db, Appendix B (Performance Specifications) and Appendix F (Quality Assurance/Quality Control); however, for the purpose of maintaining established and accepted monitoring protocol, TRC shall comply with the SO_2 CEMS monitoring requirements of these provisions. TRC shall conduct an annual RATA for the SO_2 CEMS. The annual monitor RATA may coincide with the required compliance source testing (ARM 17.8.749).

3. All stack testing shall be conducted according to 40 CFR Part 60, Appendix A, 40 CFR Part 60, Subpart Db, and ARM 17.8.105, Testing Requirements Provisions. Test methods and procedures, where there is more than one option for any given pollutant, shall be approved by the Department in writing prior to commencement of testing (ARM 17.8.106 and ARM 17.8.749).

4. Monitoring data shall be maintained for a minimum of 5 years at the TRC facility (ARM 17.8.749).

M. Ambient Air Monitoring

Following issuance of Permit #3175-04, TRC may cease operation of the ambient air quality monitoring station required under Permit #3175-02. However, beginning on the date of initial startup of the boiler after issuance of Permit #3175-04, TRC shall operate a PM_{10} ambient air quality-monitoring network at the project site. The monitoring requirements are fully described in the Monitoring Plan (Attachment 1). Exact monitoring locations must be approved by the Department prior to installation or relocation. TRC may not conduct initial start-up of the boiler after issuance of Permit #3175-04 until the ambient monitoring station has been located at a Department approved monitoring site (ARM 17.8.749 and ARM 17.8.204).

N. Notification

1. Within 15 days after actual startup of the boiler following issuance of Permit #3175-04, TRC shall notify the Department of the date of actual startup (ARM 17.8.749).

2. Within 30 days of commencement of installation of the SO_2 CEMS, TRC shall notify the Department of the date of commencement of installation (ARM 17.8.749)

3. Within 15 days after completed installation of the SO_2 CEMS, TRC shall notify the Department of the date of completed installation (ARM 17.8.749).

4. TRC shall notify the Department of the date of initial solid fuel feed (wood-waste/coal) to the boiler after issuance of Permit #3175-04 (ARM 17.8.749).

5. Within 30 days of commencement of installation of the SNCR unit, TRC shall notify the Department of the date of commencement of installation (ARM 17.8.749).

6. Within 15 days after completed installation of the SNCR unit, TRC shall notify the Department of the date of completed installation (ARM 17.8.749).

7. Within 30 days of commencement of installation of the FGD system, TRC shall notify the Department of the date of commencement of installation (ARM 17.8.749)

8. Within 15 days after completed installation of the FGD unit, TRC shall notify the Department of the date of completed installation (ARM 17.8.749).

SECTION III: General Conditions

A. Inspection – TRC 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 the terms, conditions, and matters stated herein shall be deemed accepted if TRC fails to appeal as indicated below.

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

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

E. Appeals – Any person or persons jointly or severally adversely affected by the Department's decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b). 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. Permit Fee – Pursuant to Section 75-2-220, MCA, failure by TRC to pay the annual operation fee may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.

H. Construction Commencement – Construction must begin within 3 years of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked. This permit will expire 3 years after the date of permit issuance unless construction commences within that time period (ARM 17.8.762).

ATTACHMENT 1
Permit #3175-04

Ambient Air Monitoring Plan
Thompson River Co-Gen, LLC

1. This ambient air monitoring plan is required by Montana Air Quality Permit (MAQP) #3175-04, which applies to Thompson River Co-Gen's (TRC) electrical and steam co-generation operations near Thompson Falls, in Sanders County, Montana. This monitoring plan may be changed by the Department of Environmental Quality (Department). All current requirements of this plan are considered conditions of MAQP #3175-04.

2. TRC shall install, operate, and maintain a single ambient air quality monitoring station in the vicinity of plant. The exact location of the monitoring site must be approved by the Department and meet all siting requirements contained in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; and Parts 50, 53, and 58 of the Code of Federal Regulation; or any other requirements specified by the Department.

3. TRC shall continue air monitoring for at least 5 years after implementation of the ambient air monitoring plan. At that time, the air monitoring data will be reviewed by the Department and the Department will determine if continued monitoring or additional monitoring is warranted. The Department may require continued air monitoring to track long-term impacts of emissions for the facility or require additional ambient air monitoring or analyses if any changes take place in regard to quality and/or quantity of emissions or the area of impact from the emissions.

4. TRC shall monitor the following parameters at the sites and frequencies described below:

Location	Site	Parameter	Frequency
Plant Area 30-089-0009	Thompson River Co-Gen HWY 200	PM_{10}[1] Local Conditions: 85101 Standard Conditions: 81102	Every 3rd day[2] according to EPA monitoring schedule

[1]PM_{10} = particulate matter less than 10 microns.
[2]Every 3rd day throughout the year (1/3 schedule)

5. Data recovery (DR) for all parameters shall be at least 80%, computed on a quarterly and annual basis. The Department may require continued monitoring if this condition is not met. The data recovery shall be calculated using the following equation(s), as applicable:

$$\text{Manual Methods \% DR} = \left[\frac{\text{total number of valid samples collected}}{\text{total number of samples scheduled}}\right] X\,100$$

or

$$\text{Automated Methods \% DR} = \left[\frac{\text{total number of hours possible} - \text{hours lost to QA/QC checks} - \text{hours lost to downtime}}{\text{total number of hours possible}}\right] X\,100$$

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

7. TRC shall utilize air monitoring and quality assurance procedures which are equal to or exceed the requirements described in the Montana Quality Assurance Manual, including revisions; the EPA Quality Assurance Manual, including revisions; 40 CFR Parts 53 and 58 of the Code of Federal Regulations; and any other requirements specified by the Department.

8. TRC shall submit quarterly data reports within 45 days after the end of the calendar quarter and an annual data report within 90 days after the end of the calendar year. The annual report may be substituted for the fourth quarterly report if all information in Item 9 below is included in the report.

9. The quarterly report shall consist of a narrative data summary and a data submittal of all data points in AIRS format. This data shall be submitted on a 3" diskette or a compact disc (CD). The narrative data summary shall include:

    a. A topographic map of appropriate scale showing the air monitoring site locations in relation to the plant, any nearby residences and/or businesses, and the town of Thompson Falls.

    b. A hard copy of the individual data points

    c. The quarterly and monthly means for PM_{10}

    d. The first and second highest 24-hour PM_{10} concentrations and dates

    e. A summary of the data collection efficiency

    f. A summary of the reasons for missing data

    g. A precision and accuracy (audit) summary

    h. A summary of any ambient air standard exceedances

    i. Calibration information

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

    a. A topographic map of appropriate scale showing the air monitoring site locations in relation to the plant, any nearby residences and/or businesses, and the town of Thompson Falls.

    b. A pollution trend analysis

    c. The annual means for PM_{10}

    d. The first and second highest 24-hour PM_{10} concentrations and dates

    e. An annual summary of data collection efficiency

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

    g. An annual summary of any ambient standard exceedance

    h. Recommendations for future monitoring

11. The Department may audit, or may require TRC to contract with an independent firm to audit the air-monitoring network, the laboratory performing associated analyses, and any data handling procedures at unspecified times. Based on the audits and subsequent reports, the Department may recommend or require changes in the air monitoring network and associated activities in order to improve precision, accuracy, and data completeness.

ATTACHMENT 2
Permit #3175-04

INSTRUCTIONS FOR COMPLETING EXCESS EMISSION REPORTS

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* / total hours of point source operation during reporting period)) x 100

* All time required for calibration and to perform preventative maintenance must be included in the opacity 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, energized for ESPs; 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

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. ______________________

____

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)

____

d. Date of Control Equipment Performance Test ______________________

e. Control Equipment Operating Parameter During Performance Test

____

____

____

____

PART 4 - Excess Emission (by Pollutant)

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

PART 5 - Continuous Monitoring System Operation Failures

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

PART 6 - Control Equipment Operation During Excess Emissions

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

Part 7 - Excess Emissions and CEMS performance Summary Report

Use Table IV: Complete one sheet for each monitor.

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

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

SIGNATURE ______________________________

NAME ______________________________

TITLE ______________________________

DATE ______________________________

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. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \text{ X } 100 = \right]$	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. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \text{ X } 100 = \right]$

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

ATTACHMENT 3
Boiler Startup and Shutdown Procedures
Permit #3175-04

Introduction

The requirements contained in Section II.B of Montana Air Quality Permit #3175-04 shall apply during Babcock and Wilcox spreader stoker boiler (boiler) startup and shutdown operational events. Boiler startup and shutdown operations shall be conducted as described in this attachment.

Startup of the boiler may take up to 48 hours to complete while shutdown of the boiler may take up to 8 hours to complete, depending on the boiler conditions at initiation of the startup or shutdown event. Although the steps for performing a boiler startup or shutdown event are generally the same, the amount of effort, inspection level, and duration of the event may vary significantly for each event. The most important factors governing the startup or shutdown procedures include, but are not limited to: boiler temperature, chemistry of the water in the boiler drum, condition of the coal bed, condition of the coal burning grates, condition of the steam-driven turbine, and condition of auxiliary systems, such as pumps and electrical gear. All of these factors can significantly influence the duration and exact actions taken during a startup or shutdown event. The following startup and shutdown procedures generally describe typical operational procedures used by TRC during a boiler startup or shutdown event.

Startup Procedures

A startup event takes the facility from a non-operational condition to a steady-state electrical load condition. During the startup process, the facility goes through a number of steps to go from a cold start or a warm re-start until the system is brought up to a steady-state load. During this process, oxides of nitrogen (NO_x) and sulfur dioxide (SO_2) emissions will vary until conditions for the safe and effective operation of the applicable NO_x and/or SO_2 air pollution control equipment are reached. Particulate emissions are captured by the baghouse at all times of operation, including periods of startup.

Cold-Start Conditions

A cold-start event occurs when there is no fuel feed to the boiler and the low temperature of the boiler requires the initial use of the propane/diesel-fired startup burner to bring the pressure of the boiler up to 50 PSIG.

Step 1. TRC personnel establish a uniform coal bed on the boiler grate. This protects the boiler grate from radiant heat damage from the startup burner and assures proper lighting and combustion of the coal pile. (Estimated time for Step 1 = 1 hour.)

Step 2. TRC personnel start the induced draft and forced draft fans, and balance the airflow, achieving approximately 30% of maximum airflow. (Estimated time for Step 2 = 1 hour.)

Step 3. TRC personnel light the propane/diesel startup burner. This action does not ignite the coal pile on the grate. The heat input on the startup burner is raised to anywhere from approximately 11 to 60 MMBtu/hr. The boiler is warmed until the drum pressure reaches 50 PSIG. The boiler may be held at 50 PSIG with the startup burner until the boiler drum water chemistry is balanced within specification before startup can proceed. (Estimated time for Step 3 = 2 - 12 hours.)

Step 4. The startup burner is turned off and secured against operation during periods of coal/wood fuel feed. TRC personnel ignite the coal with a hand-held propane torch. (Estimated time for Step 4 = 2 - 3 hours.)

Step 5. Once the coal fire is well established, the control room operator starts the coal feed in manual mode at a rate of 0.5 to 1.0 ton per hour. TRC personnel open the steam warm-up lines to the turbine, which heats the turbine main steam lines, lube oil system, and bearings. Cooling water is sent to the condenser and cooling tower. The boiler is heated in this condition until the drum pressure reaches 600 to 700 PSIG. (Estimated time for Step 5 = 4 - 8 hours.)

Step 6. TRC personnel open the throttle sending steam to the turbine and the turbine begins to roll. There is no electrical load at this time. As the turbine speeds up, it is held at different rotations per minute (rpm) set-points to control turbine vibration. There are up to 4 holding points as the turbine comes up to speed. Each hold takes 2 to 3 hours to complete. The final speed of the turbine is 3,600 rpm. (Estimated time for Step 6 = 2 - 12 hours.)

Step 7. When the turbine is holding steady at 3,600 rpm, the electrical breaker is closed, and the turbine output is synchronized with the grid at 60 Hz. The facility control system takes control of the system and automatically raises the turbine load to 3 megawatts instantly. The Over Fire Air (OFA) fans are started, the nozzles are balanced and put on automatic control. (Estimated time for Step 7 = 1 hour.)

Step 8. The control system automatically ramps up the fuel feed rate to maintain boiler pressure as the turbine load increases, up to full load of approximately 9.5 tons per hour. As the load increases, there may be more holding points on the load setting to control turbine vibration. Typically, there are 3 to 4 holding points at 2 to 3 hours each. As the boiler steam output reaches approximately 50 to 75% of capacity, the SO_2 flue-gas desulfurization (FGD) system comes online and becomes effective. Below 50 % steam load, there is no active SO_2 control. Also in this steam load range, the selective non-catalytic reduction (SNCR) NO_x control system comes online and becomes effective. The flue gas recirculation (FGR) system fans are also started making the FGR NO_x control system effective. Below this steam load range, there is either no NO_x control or only the OFA system is operating for NO_x control. With the increased fuel feed, the boiler comes up to full steam production and the startup event is complete. (Estimated time for Step 8 = 2 - 12 hours.)

Total elapsed time from cold start to full load typically varies between 12 and 48 hours.

Warm-Start Conditions

A warm-start event occurs when the boiler temperature is elevated and the boiler drum pressure is above 15 PSIG, but there is no fuel feed to or electrical output from the boiler. A warm-start uses the same procedures as described in the cold-start event procedures discussed above except procedures are initiated at step 5, depending on the condition of the boiler and turbine at time of re-start.

Shutdown Procedures

A shutdown event takes the boiler from a steady-state electrical load condition to a non-operational condition or from a mid startup condition to a non-operating condition. During this process, NO_x and SO_2 emissions are controlled by the applicable emission control systems until the boiler operating parameters can no longer support the operation of the respective controls, as discussed in the startup procedures. Particulate emissions are captured by the baghouse at all times of operation, including periods of shutdown.

Step 1. TRC personnel back the fuel feed rate and the electrical load down. As the rate of fuel feed is reduced, the steam production rate decreases. When the steam load drops below the 50% to 75% range, the SNCR NO_x control and FGR system are taken offline. In this range, the FGD SO_2 control is also taken offline. The electrical load is reduced to 3 megawatts, and the electrical breaker is opened. The turbine now has no electrical output. The OFA fans are shut down. (Estimated time for Step 1 = 2 - 4 hours.)

Step 2. The fuel feed rate is reduced to 0.0 tons per hour. The coal fire on the grate burns out. The boiler slowly cools down. The turbine slowly coasts down. After the fire on the boiler grate is out, the induced draft and forced draft fans are shut down, stopping all airflow through the boiler. All boiler emissions cease at this point. (Estimated time for Step 2 = 2 - 4 hours.)

Permit Analysis
Thompson River Co-Gen., L.L.C.
Permit #3175-04

I. Introduction/Process Description

A. Permitted Equipment

The following table indicates all permitted sources of emissions and emission controls utilized for each emitting unit at the Thompson River Co-Gen, L.L.C. (TRC) facility:

Emitting Unit/Process	Control Device/Practice
Boiler (192.8 million British thermal unit (MMBtu/hr)) Permit Limit of 192.8 MMBtu/hr on a daily average and 1,688,928 MMBtu/yr	PM/PM_{10} – Baghouse DC5 (40,513 dry standard cubic feet per minute (dscfm) capacity flow) SO_2 – Flue Gas Desulfurization (FGD) Unit Hg – FGD/Baghouse Acid Gases (HCl and H_2SO_4) – FGD/Baghouse NO_x – Over-Fire Air (OFA), Flue-Gas Recirculation (FGR), and Selective Non-Catalytic Reduction (SNCR) Unit.
Wet Cooling Tower	NA
Fuel Handling Operations (Coal)	Enclosures, Fuel Handling Baghouse – DC1 (2,200 cubic feet per minute (cfm)) and Fuel Handling Bin Vent – DC2 (1,000 cfm)
Fuel Handling Operations (Wood Waste Bio-Mass)	Enclosed Pneumatic Conveying System Vented to boiler Baghouse
Outdoor Coal Storage	(≤ 6,000 tons) Wind Fencing, Earthen Berm, Reasonable Precautions Including Water Spray, As Necessary
Outdoor Wood-Waste Biomass Storage	(≤ 3,000 tons) Wind Fencing, Earthen Berm, and Reasonable Precautions Including Water Spray, As Necessary
Lime Storage and Handling Operations	Enclosures, Lime Silo Bin Vent – DC3 (1,000 cfm)
Bottom Ash/Fly Ash Storage and Handling Operations	Enclosures, Fly Ash Bin Vent – DC4 and Bottom Ash Bin Vent – DC6 (1,000 cfm/unit), Fly-Ash Retractable Load-out Spout (Truck Transfer), Bottom-Ash Partial Enclosure (3-Sided) (Truck Transfer)
Truck Traffic/Haul Roads	Paved Roads, Water and/or Chemical Dust Suppressant
Boiler Startup Pre-Heater	Limited to 60 MMBtu/hr (total combined heat input); Diesel or Propane-Fired Only; Startup, Shutdown, Malfunction, and boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year
Refractory Curing Heater(s) (Propane-Fired)	Limited to 60 MMBtu/hr; Propane-Fired Only; Startup, Shutdown, Malfunction, and boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year Per Heater

B. Source Description

TRC operates a 16.5-megawatt (MW) capacity coal/wood-waste biomass-fired electricity and steam co-generation plant. The plant incorporates a 192.8 MMBtu/hr capacity boiler (boiler), which is capable of a reported 130,000 pounds of steam production per hour. Most of the steam is sent to a turbine generator for the production of electricity to be sent to the power grid with a small percentage (up to 10%) of the steam and energy produced sent directly to Thompson River Lumber Company (TRL), for use in the lumber dry kilns and general operations at the sawmill. TRC will have a parasitic load (use) of approximately 0.4 MW.

Because TRC and TRL are under separate ownership and control and are covered under separate Standard Industrial Classification (SIC) codes, the two sources are considered separate sources.

The boiler is supported by coal and wood-waste biomass fuel handling system(s), including outdoor fuel storage; a cooling tower; a lime handling system; an ash/fly ash handling system; and various support trucks/vehicles. The boiler and supporting facilities incorporate various emission control devices to limit potential pollutant emissions from each source.

The boiler is equipped with OFA, FGR, and an SNCR system to control oxides of nitrogen (NO_x) emissions, a combination of low sulfur coal (≤ 1% sulfur by weight) and a FGD in tandem with the boiler baghouse to control sulfur dioxide (SO_2) emissions, the same FGD and baghouse to control mercury (Hg), hydrochloric acid (HCl), and other acid gas emissions, combustion control to limit carbon monoxide (CO) emissions, a baghouse to control particulate matter/particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM/PM_{10}) emissions, and proper design and combustion to control Volatile Organic Compound (VOC) emissions. Boiler combustion gases first enter the FGD then pass through the boiler baghouse and eventually vent to the atmosphere through the boiler main stack.

The boiler fires low-sulfur coal and/or wood waste bio-mass only, except for periods of startup, shutdown, malfunction, and boiler commissioning where the 60 MMBtu/hr propane or diesel fired boiler pre-heater is in operation. The boiler pre-heater cannot be in operation while the boiler is producing energy or the boiler fuel feed system is operational and the unit is limited to a maximum of 500 hours of operation during any rolling 12-month time period.

Coal is delivered by railcar and unloaded to an under-track hopper. Air displaced from the under-track hopper is vented to DC1. Some coal is stored in the under track hopper while the majority of coal is transferred from the under-track hopper, via front-end loader, to an outside storage area incorporating wind fencing, an earthen berm, and water spray, as necessary, to control fugitive dust emissions from coal storage operations. From the under-track hopper and the outdoor coal storage area, coal is transferred, via a front-end loader, to a 3-sided feed hopper and on to a 200 tons per hour (ton/hr) capacity enclosed conveyor (C1) that will transfer coal to a second 200 ton/hr capacity enclosed conveyor (C2) that will unload to an enclosed day-bin silo (S1) on top of the boiler-house. Air displaced from the transfer between the front-end loader and the feed-hopper and the conveyor transfer points between the feed-hopper and C1 and C1 to C2 is vented to DC1 while air displaced from the transfer between C2 and S1 is vented to DC2.

Additionally, wood waste is delivered to the site for storage until use is needed. Wood-waste biomass is stored in an outside storage area incorporating wind fencing, an earthen berm, and water spray, as necessary, to control fugitive dust emissions from wood-waste storage operations. From the on-site storage area, wood-waste is transferred to the adjacent TRL, for processing into fuel grade wood-waste. After processing at the TRL site, the fuel grade wood-waste is pneumatically transferred through an enclosed pneumatic conveying system to the TRL boiler. After reaching the TRL boiler, the wood-waste enters a cyclone (CS1), and is then transferred directly into the boiler through the OFA ports. Air entering the boiler via the wood-waste biomass pneumatic feed is directly vented through the boiler baghouse (DC5). The transfer of fuel from S1 to the boiler is controlled by negative pressure from the boiler.

Lime for use in the FGD is delivered by trucks and pneumatically conveyed to a 1,000-ton capacity storage silo (S3). From S3 lime is pneumatically conveyed to the FGD. Air that is displaced from S3 is vented through DC3.

Combustion in the boiler produces bottom ash and fly ash. The ash is temporarily stored in silos on site including fly-ash silo (S4) and bottom-ash silo (S5). Bottom-ash from S5 is gravity-fed through a partial enclosure (3-sided enclosure) to a truck for removal from the site while fly ash from S4 is gravity fed through a retractable load out spout to a truck for removal from the site. Air displaced from the transfer between trucks and S4 and S5 is vented to DC4 and DC6.

A cooling tower is used to dissipate heat from the boiler by using the latent heat of water vaporization to exchange heat between the process and the air passing through the cooling tower. The cooling tower uses an induced counter flow draft incorporating 3 cells. The make up rate for the cooling tower is approximately 125 gallons per minute.

C. Permit History

On November 9, 2001, TRC was issued final Montana Air Quality Permit (MAQP) #3175-00 for the construction and operation of a 12.5-MW capacity electrical and steam co-generation plant. The plant was permitted for a 156 MMBtu/hr heat input capacity coal and wood-waste biomass-fired boiler and associated fuel handling, storage, and support facilities.

On September 7, 2004, the Montana Department of Environmental Quality (Department) received a complete application for proposed modifications to the permitted TRC operations. Based on the information contained in the complete permit application, the following modifications were proposed under MAQP #3175-01:

- Increase in the allowable boiler baghouse emission rate (lb/hour) for PM/PM_{10}. The previously permitted Best Available Control Technology (BACT) emission limit determination of 0.017 grains per dry standard cubic feet (gr/dscf) of air-flow through the boiler baghouse would remain applicable to the baghouse-controlled boiler operations. However, due to the increase in capacity air-flow through the baghouse the permit action resulted in an increased allowable PM and PM_{10} emission rate of 5.90 lb/hr;
- Incorporation of an enforceable boiler I.D. fan flow capacity of 70,000 acfm, calculated as 40,513 dry standard cubic feet per minute (dscfm);
- Increase in the facility electrical output capacity from 12.5 MW to 16.5 MW;
- Incorporation of an enforceable boiler heat input capacity limit of 192.8 MMBtu/hr and 1,688,928 MMBtu/yr. This limit would be monitored on a continuous basis using information obtained from the required coal analysis and published wood-waste fuel specifications. Based on the hourly limit, the source is below the listed New Source Review – Prevention of Significant Deterioration (NSR/PSD) heat input threshold value of 250 MMBtu/hr;
- Incorporation of an enforceable annual maximum boiler coal feed limit of 105,558 tons during any rolling 12-month time period. This limit is based on the maximum boiler heat input capacity feed rate of 192.8 MMBtu/hr and the worst case coal heating value of 8,000 Btu/lb;
- Incorporation of enforceable boiler main stack minimum requirements of 100.5 feet tall and 6 feet in diameter;

- Incorporation of an enforceable minimum coal heating value of 8,000 British thermal units per pound (Btu/lb) of coal;
- Incorporation of an enforceable maximum sulfur in coal value of 1.0% sulfur by weight;
- Incorporation of new NO_x, CO, VOC, SOx, and HCl BACT emission limits for boiler operations. The BACT analyses and determination(s) for modified boiler emissions were conducted due to the increased boiler heat input capacity. A BACT analysis and determination summary was provided in the permit analysis to MAQP #3175-01;
- Incorporation of an enforceable coal conveyor maximum capacity of 200 ton/hr for each coal handling conveyor at the TRC site;
- Incorporation of an enforceable partial (3-sided) enclosure requirement for coal conveyor loading en-route to the coal day bin S1;
- Addition of a 60 MMBtu/hr capacity diesel and/or propane-fired boiler pre-heater to the existing permitted equipment at the facility. The pre-heater would not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and would be limited to a maximum of 500 hours of operation per year;
- Addition of refractory curing heaters with a maximum combined heat input capacity of 60 MMBtu/hr to the existing permitted equipment at the facility. The refractory curing heaters would not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and each heater would be limited to a maximum of 500 hours of operation during any rolling 12-month time period;
- Modification of the permitted BACT requirement for primary coal storage within a baghouse controlled silo. Outdoor storage of coal utilizing wind fencing, earthen berm, and water spray, as necessary, to control fugitive coal storage PM/PM_{10} emissions would replace the initial BACT determination under MAQP #3175-00. A summary of the BACT analysis used to make the new outdoor fuel storage BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Addition of on-site wood-waste biomass storage operations utilizing wind fencing, earthen berm, and water spray, as necessary, as BACT control of fugitive wood-waste biomass storage PM/PM_{10} emissions. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Revisions to the previously permitted ash handling operations for the addition of a second ash handling bin vent under a new BACT determination. A summary of the BACT analysis used to make this BACT determination is contained in Section III of the permit analysis for MAQP #3175-01;
- Incorporation of an enforceable coal storage limit of 6,000 tons at any given time;
- Incorporation of an enforceable on-site wood-waste storage limit of 3,000 tons at any given time; and
- Incorporation of PM_{10} ambient air quality monitoring requirements into the permit.

Also, TRC requested that the Department modify the previously permitted BACT requirement that all fuel transfer conveyors be enclosed to require that all fuel transfer conveyors must be covered. TRC constructed coal fuel conveyors incorporating a cover, which extends past the conveyor, creating, in effect, an enclosed conveying system. Further, TRC proposed the construction of a fully enclosed pneumatic conveying system for wood-waste biomass fuel. The Department determined that these conveying systems constitute enclosed fuel transfer conveyors; therefore, the Department will not modify the permit to require covered versus enclosed conveyors.

Because many of the above cited permit modifications affected the concentration of and plume rise and dispersion characteristics of pollutants resulting from modified TRC operations, the Department determined that air dispersion modeling was required to demonstrate compliance with applicable National and Montana Ambient Air Quality Standards (NAAQS/MAAQS). A summary of air dispersion modeling results is contained in Section VI, Ambient Air Quality Impacts, of the permit analysis for MAQP #3175-01.

The preliminary determination was open for public comment from October 8, 2004, through October 25, 2004. Based on comments received during the public comment period, the Department modified the preliminary determination as follows:

- Incorporation of an enforceable requirement for coal fuel chlorine and ash content reporting during all source testing (Section II.C.5);
- Correction of the ambient air impact analysis summary to indicate the correct information analyzed (Section VI of the Permit Analysis and Section 7.F of the EA);
- The dry lime scrubber BACT control requirement was referenced as a FGD throughout the Department decision and permit analysis for consistency and clarification of terms;
- Modification of the language contained in Section II.A.26 of the preliminary determination from the "on-site" coal storage limit of 6,000 tons to the analyzed and intended "outside" coal storage limit of 6,000 tons;
- Incorporation of increased PM_{10} ambient air quality monitoring schedule. The Department maintains that a single ambient air quality monitor remains appropriate; however, the Department modified the ambient monitoring schedule to require sample analysis on an every 3rd day schedule year round; and
- Incorporation of an enforceable boiler steam production limit in place of the electrical megawatt production limit included in the preliminary determination (Section II.A.1).

MAQP**#3175-01** replaced MAQP #3175-00.

On February 24, 2005, the Department received from TRC a notice of an administrative error contained in TRCs MAQP #3175-01. Specifically, Section II.C, Testing Requirements, did not include a specific testing schedule for NO_x emissions from the boiler, while Section II.B clearly specified that boiler NO_x emission limits are subject to source testing. MAQP #3175-01 did include provisions enabling the Department to invoke boiler NO_x source testing; however, at the request of TRC and in the interest of providing clarification for boiler NO_x source testing requirements, the current permit action amended the permit to include the appropriate NO_x source testing schedule under the provisions of ARM 17.8.764(1)(c). The amended NO_x source-testing requirement was included in Section II.C.1 of MAQP #3175-02.

Further, on April 8, 2005, TRC submitted a request for an additional permit amendment under the provisions of ARM 17.8.764(1)(b) to change the existing Method 5 source-testing schedule for various permitted emitting units, maintain and specify the implied Method 9 source testing schedule, and accurately characterize certain emitting unit control technologies as fabric filter bin vents. In the initial application for MAQP #3175-00 and subsequent MAQP modification #3175-01, emitting units DC-2 (Fuel Handling Bin Vent), DC-3 (Lime Silo Bin Vent), DC-4 (Fly-Ash Silo Bin Vent), and DC-6 (Bottom-Ash Silo Bin Vent) were inconsistently characterized as varied types of fabric filter dust collecting systems (i.e. baghouses, bin vents, and/or dust collectors) and inaccurately characterized as having a continuous air-flow. These units are actually fabric filter bin vents, which control particulate emissions using natural draft or simple air displacement within the associated silo, or similar unit, to provide air flow through the filter. Given this information, the Department determined that the appropriate permit limit(s) for the affected units remained 20% opacity and a grain-loading limit of 0.02 gr/dscf. In accordance with Department fabric filter bin vent testing guidance the Department determined that the appropriate compliance demonstration for these units is an initial and periodic Method 9 source testing. Therefore, under the provisions of ARM 17.8.764(1)(b), the Department is amending the permit to remove the implied initial Method 5 source test requirement for the affected units and maintain initial and periodic Method 9 source testing. However, the

Department maintained the authority to require a Method 5 source test demonstration for the affected units. Further, the permit action re-characterized all affected units as bin vents throughout the permit to clarify the nature of the control device.

In addition, since TRC has accomplished various notification requirements contained in Section II.G of MAQP #3175-01, those affected notifications were removed from the permit. Permit **#3175-02** replaced Permit #3175-01.

On January 4, 2006, the Department received a complete application for the modification of TRC's Montana Air Quality permit #3175-02. The application was assigned Permit **#3175-03**. Specifically, TRC requested various changes to applicable permit terms/conditions relating to the Babcock and Wilcox Spreader-Stoker boiler. On February 10, 2006, the Department issued a Preliminary Determination (PD) on Air Quality Permit #3175-03 for the proposed modification of the TRC air quality permit. On March 13, 2006, and subsequently on May 3, 2006, the Department received official public comment and supporting information from TRC indicating to the Department that TRC could not comply with the existing air quality permit or limits proposed in the Department's PD, some of which constituted BACT. This information was not included in the TRC permit application for permit action #3175-03 and was not analyzed by the Department in the permit application review process and, therefore, not identified in the PD issued for public comment. Because the above-cited information indicated to the Department that TRC was unable to comply with all applicable requirements, the Department's decision was to deny TRC's application for permit modification #3175-03. In a letter dated May 19, 2006, the Department denied the application and indicated that if TRC wished to pursue changes to its existing air quality permit, a complete application, including all relevant information, must be submitted to the Department for review.

D. Current Permit Action

On June 9, 2006, the Department received a complete application for the modification of TRC's Montana air quality Permit #3175-02. Specifically, TRC requested the following changes to the permit terms/conditions related to the boiler:

- Removal of the requirement that the installed SO_2 control equipment meet or exceed 90% SO_2 reduction;
- Modification of the language specifying the SO_2 control technology as a dry-lime scrubber to a generic flue gas desulfurization (FGD) system;
- Reevaluation of the Best Available Control Technology (BACT) determined SO_2 emission limit(s) of 0.220 pounds per million British thermal unit (lb/MMBtu) based on a 1-hour (hr) average and 42.42 pounds per hour (lb/hr) based on a 1-hr average. TRC proposed a new SO_2 BACT emission limit of 0.220 lb/MMBtu based on a rolling 30-day average or 85% SO_2 control efficiency, whichever is less stringent. TRC also proposed removal of the SO_2 BACT limit expressed in lb/hr;
- Reevaluation of the BACT-determined oxides of nitrogen (NO_x) emission limits of 0.178 lb/MMBtu based on a 1-hour average and 34.32 lb/hr based on a 1-hr average. TRC proposed the installation and operation of a selective non-catalytic reduction (SNCR) system and a new NO_x BACT emission limit expressed in lb/MMBtu, based on a 30-day rolling average, to be determined based on achievable NO_x emissions established through a statistical analysis of NO_x CEMS data from the first 275 days of SNCR operation. TRC also proposed removal of the NO_x BACT limit expressed in lb/hr;
- Removal of the hourly boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr;
- Removal of the boiler steam production limit of 130,000 lb/hr;

- Removal of the boiler baghouse fan flow capacity of 40,513 dry-standard cubic feet per minute (dscfm); and
- Inclusion of boiler startup and shutdown limits and operating conditions, including SO_2 and NO_x emission limits, which would apply during defined periods of startup and shutdown only.
- Cessation of PM_{10} ambient air quality monitoring requirements when TRC is not in operation.

Based on Department review of TRC's application for permit modification, the following modifications were made to TRC's permit under the current permit action:

SO_2 Modifications:

- Removal of the requirement that the installed SO_2 control equipment meet or exceed 90% SO_2 reduction. Based on the equipment specific information contained in the application for permit modification, the Department determined that this efficiency is not achievable on a steady-state basis and promotes the combustion of coal fuel with a higher sulfur concentration in order to attain a higher percent reduction without additional environmental benefit;
- Modification of the SO_2 control strategy language to require a generic FGD system in place of the previously specified dry-lime scrubber SO_2 control requirement. This modification affords TRC flexibility in choosing and installing an SO_2 control strategy capable of achieving the permitted BACT emission limits;
- Modification of the existing SO_2 BACT emission limit of 0.220 lb/MMBtu based on a 1-hr average to 0.220 lb/MMBtu based on a 30-day rolling average. Because coal sulfur content and heating value is variable, the Department determined that the 30-day rolling SO_2 BACT emission rate averaging time is appropriate in this case as it will provide needed flexibility for the combustion of worst-case allowable coal on a short-term basis but provide greater assurance that the affected unit will operate through combustion of typical coals for longer term normal operations. A detailed discussion of the Department's SO_2 BACT determination is contained in Section III, BACT Determination, of this permit analysis. The SO_2 BACT limit of 0.220 lb/MMBtu proposed under the current permit action is the same as the existing SO_2 BACT limit under Permit #3175-02. However, this limit is different than the SO_2 BACT limit proposed under the Department's preliminary determination on Permit #3175-03, which was subsequently denied by the Department. For the reasons described in the BACT analysis contained in Section III of this permit analysis, the Department determined that the limit proposed under the current permit action constitutes BACT in this case.
- The Department determined that a secondary lb/hr BACT emission limit based on the permitted BACT emission rate in lb/MMBtu and the boiler heat input capacity is redundant; therefore, the current permit action removes the previously BACT determined emission limit of 42.42 lb/hr. Because the current permit action maintains an enforceable boiler heat input limit, the Department determined that the BACT determined emission limit in lb/MMBtu is protective of the permit analysis and constitutes BACT in this case.
- Inclusion of a boiler SO_2 emission limit of 155.0 lb SO_2/hr applicable during defined periods of startup and shutdown only (see Attachment 3). Under the current permit action TRC provided a boiler startup and shutdown plan (Attachment 3) describing the operational circumstances which constitute boiler startup and shutdown. As reported in the application for the current permit action, the required FGD SO_2 control equipment will be rendered ineffective until the boiler reaches an operational steam production level of approximately 70,000 pounds of steam per hour (information from Hamon Research Cottrell) or a heat input value of approximately 104 MMBtu/hr. The boiler steam load capacity is reported at 130,000 pounds of steam per hour at 192.8 MMBtu/hr. On June 7, 2006, the Department

sent TRC an application deficiency letter highlighting information lacking from the application for Permit #3175-04. In the deficiency letter, the Department asked TRC how the boiler would comply with an uncontrolled SO_2 emission limit of 155 lb/hr considering that worst-case permitted allowable coal (8000 Btu/lb and 1% sulfur) combusted at a heat input rate of 104 MMBtu/hr would result in emissions exceeding this limit. In response to the Department's letter, TRC indicated that the above-cited worst-case allowable coal is theoretical and that actual coals received from the contracted coal supplier would have higher Btu content and lower sulfur concentration than the worst-case allowable coal. TRC further indicated that more typical coal would be stockpiled on-site to ensure compliance with the start-up and shutdown uncontrolled emission limit of 155 lb/hr. Assuming combustion of TRC reported typical coal at approximately 10,200 Btu/lb and 0.7% sulfur and a boiler heat input rate of 104 MMBtu/hr (effective FGD control cut-off level), uncontrolled SO_2 emissions from the TRC stoker boiler would not exceed 155 lb/hr. The SO_2 startup and shutdown emission limit of 155.0 lb SO_2/hr was shown through modeling to be protective of the applicable ambient air quality standard(s).

- Inclusion of a worst-case 1-hour SO_2 emission limit of 72.3 lb/hr based on a 1-hr averaging period applicable at all times except during periods of startup and shutdown. Based on the information contained in the application for Permit #3175-04, the Department determined that this action is justified, as this rate represents an 85% SO_2 control efficiency (guaranteed LSD/FGD control efficiency) when combusting permitted allowable worst-case coals and assuming a boiler heat input of 192.8 MMBtu/hr.
- Inclusion of an SO_2 continuous emissions monitoring system (CEMS) requirement. The Department determined, based on TRC's past SO_2 reduction performance, that an SO_2 CEMS is justified, especially considering the longer-term SO_2 emission limit averaging time (rolling 30-day average) deemed BACT in this case.

NO_x Modifications:

- Inclusion of BACT-determined SNCR and FGR NO_x control requirements in combination with the existing BACT requirement for OFA NO_x control.
- Modification of the existing NO_x BACT-determined emission rate of 0.178 lb/MMBtu based on a 1-hr average to 0.196 lb/MMBtu based on a rolling 30-day average. As specified in the permit, an emission limit of 0.28 lb/MMBtu shall apply during the initial 10-day SNCR Mapping/testing period prior to installation and operation of SNCR. An emission limit of 0.28 lb/MMBtu represents the TRC reported achievable NO_x emission rate assuming the BACT-determined OFA and FGR NO_x combustion controls are installed and operational during the SNCR mapping/testing period, as required by permit. Further, since the proposed SNCR NO_x control strategy in combination with the existing NO_x combustion controls (OFA/FGR) constitutes BACT for NO_x emissions, the Department determined that an emission limit of 0.196 lb NO_x/MMBtu constitutes BACT, in this case. This emission limit/rate represents an additional 30% reduction (SNCR manufacturers guarantee) in NO_x emissions through incorporation of SNCR, assuming the reported combustion control emission rate of 0.28 lb/MMBtu and a boiler heat input rate of 192.8 MMBtu/hr. A more detailed discussion of the NO_x control and emission limit determination is contained in Section III.A.4, NO_x BACT Determination, of this permit analysis. The Department determined that a rolling 30-day average to demonstrate compliance with the BACT-determined limit is justified. The increased averaging time will provide necessary flexibility due to reported variability in boiler operating temperature and related SNCR and combustion control efficiency. The NO_x BACT limit of 0.196 lb/MMBtu proposed under the current permit action is different than the NO_x BACT limit proposed under the Department's preliminary determination on Permit #3175-03, which was subsequently denied by the Department. For the reasons described in the BACT

analysis contained in Section III of this permit analysis, the Department determined that the NO_x BACT limit proposed under the current permit action constitutes BACT in this case;

- Inclusion of a boiler NO_x emission limit of 74.0 lb NO_x/hr applicable during defined periods of startup and shutdown only (see Attachment 3). Under the current permit action TRC provided a boiler startup and shutdown plan (see Attachment 3) describing the operational circumstances which constitute boiler startup and shutdown. Based on information from Fuel Tech, Inc. (manufacturer of SNCR system), the SNCR unit would not be effective at a heat input rate of less than 134 MMBtu/hr. The function of the OFA and FGR is similarly reduced at lower operating loads on the boiler and is essentially shut down below approximately 90 MMbtu/hr based on the recommendations of the boilers combustion system manufacturer. Based on this information, a short term limit considering no control and maintaining compliance with the applicable ambient air quality standards is necessary in order for the TRC boiler to operate within the requirements of the permit. Assuming an uncontrolled NO_x emissions rate of 0.55 lb/MMBtu (AP-42, Section 1.1) and a boiler heat input rate of 134 MMBtu/hr (effective NO_x control cut-off level), uncontrolled NO_x emissions from the TRC stoker boiler firing subbituminous coal would be 74.0 lb/hr. Through the permit application process for this permit modification, TRC demonstrated compliance with the applicable ambient air quality standards through modeling an emissions rate of 195 lb NO_x/hr. Therefore, a NO_x emission rate of 74 lb/hr is appropriate in this case and has been shown to be protective of the health-based ambient air quality standards.
- Under the current permit action, the Department established a worst case 1-hour average NO_x emission limit of 47.24 lb/hr applicable at all times except during periods of startup and shutdown. Based on the information contained in the application for Permit #3175-04, the Department determined that this action is justified, as this rate represents a 30% reduction (guaranteed SNCR control efficiency) from the reported worst-case NO_x emissions rate of 0.35 lb/MMBtu, assuming a boiler heat input of 192.8 MMBtu/hr and required combustion controls (OFA and FGR).

Other Permit Modifications:

- Modification of the hourly boiler heat input limit of 192.8 MMBtu/hr to a limit of 192.8 MMBtu/hr based on a 24-hour average and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr. The annual heat input limit represents the reported and analyzed sustainable boiler heat input capacity of 192.8 MMBtu/hr (192.8 MMBtu/hr x 8760 hr/year). The application for Permit #3175-04 proposed removal of the existing short-term boiler heat input limit of 192.8 MMBtu/hr and maintenance of the annual heat input limit. TRC's application for permit modification states that because this heat input value (192.8 MMBtu/hr) was used in the calculation establishing the boiler BACT emission limits, the affected BACT limit takes into account heat input as part of the limit itself and the limit is therefore redundant. The Department disagrees with the conclusions of this argument because there is some uncertainty as to the boiler's heat input capacity and because this heat input value has been relied upon in the analysis establishing the boiler BACT limits. In the application for Permit #3175-04 (and supporting documentation under permit action #3175-03), TRC reported that the boiler may potentially accommodate a continuous maximum firing rate of approximately 215 MMBtu/hr. However, the analysis conducted by TRC for the current permit action maintains a sustainable boiler heat input capacity of 192.8 MMBtu/hr and not 215 MMBtu/hr. Therefore, the Department determined that inclusion of a short-term enforceable heat input limit is necessary to protect the analysis conducted for the proposed boiler. Further, because the boiler's heat input is directly related to BACT emissions limits, incorporation of a short-term heat input limit provides additional and practical assurance of compliance with permit limits. Finally, because the Department's analysis relied on a boiler heat input rate of 192.8 MMBtu/hr as the sustainable steady-state boiler heat input capacity the Department determined that a 24-hour (calendar-day), rather than a 1-hour, averaging period is appropriate to demonstrate compliance with the limit in this case. To provide basis for the Department's determination on the appropriate averaging period for a sustainable boiler heat input rate, the Department used indirect guidance from USEPA related specifically to federal New Source Performance Standards applicability under 40 CFR, Part 60, Subpart D. This guidance (Applicability Determination Index Control Number 0300104) states, "the heat input rate of the steam generating unit should be based on a 24-hour full load demonstration measuring peak Btu/hr heat input after achieving steady-state conditions.";

- Removal of the steam production limit of 130,000 lb/hr. This limit was included in the previous permit(s) to protect the analyses conducted for boiler operation and control. However, in concurrence with the current permit application, the Department believes that other existing and new permit limits and conditions serve this purpose and that the steam production limit is unnecessary and actually penalizes TRC for potential increased efficiency;
- Removal of the boiler baghouse fan flow rate of 40,513 dscfm. This limit was included in the previous permit(s) to protect the analyses conducted for boiler operation and control. However, in concurrence with the current permit application, the Department believes that other existing and new permit limits and conditions serve this purpose.
- Inclusion of boiler startup and shutdown limits and operating conditions applicable during periods of startup and shutdown only and a boiler startup and shutdown plan (see Attachment 3) describing operational circumstances which constitute boiler startup and shutdown events. The Department believes that any startup and shutdown emissions must consider the startup and shutdown process, fuels, and controls, if applicable.
- Interim cessation of PM_{10} ambient air quality monitoring requirements until initial startup of the boiler after issuance of Permit #3175-04, and continued operations thereafter.

The preliminary determination was subject to public comment from July 6, 2006, through August 7, 2006. Based on comments received during the public comment period, the Department modified the preliminary determination as follows:

- Removal of the boiler start-up and shutdown event notification requirement contained in Section II.N.9 of the Department's preliminary determination #3175-04. The recordkeeping requirements contained in Section II.K.15 provide adequate compliance assurance related to start-up and shutdown event recordkeeping and notification.

The Department decision incorporates the above-cited change. Permit **#3175-04** replaces Permit #3175-02.

E. Additional Information

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

II. Applicable Rules and Regulations

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

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

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

   TRC shall conduct initial source testing for NO_x, CO, SO_2, PM/PM_{10}, and HCl within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test monitoring compliance with the applicable boiler emission limits, TRC shall conduct additional source testing as indicated below, or according to another Department approved testing/monitoring schedule:

   - NO_x, CO, and SO_2 on an every 2-yr basis and/or CEMS, as applicable;
   - Opacity and PM/PM_{10} on an annual basis, and/or COMS; and
   - HCl on an every 4-yr basis.

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).

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

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

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

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

1. ARM 17.8.204 Ambient Air Monitoring.
2. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide.
3. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide.
4. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide.
5. ARM 17.8.213 Ambient Air Quality Standard for Ozone.
6. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter.
7. ARM 17.8.221 Ambient Air Quality Standard for Visibility.
8. ARM 17.8.223 Ambient Air Quality Standard for PM_{10}.

TRC shall maintain compliance with all applicable ambient air quality standards.

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

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

2. ARM 17.8.308 Particulate Matter, Airborne. (1) This rule requires an opacity limitation of 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate matter. (2) Under this rule, TRC 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 section.

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

5. ARM 17.8.322 Sulfur Oxide Emissions--Sulfur in Fuel. This rule requires that no person shall burn liquid, solid or gaseous fuel in excess of the amount set forth in this section. TRC has proposed a limit less than that required in this section. Permit #3175-03 contains a federally enforceable permit limit for coal sulfur content.

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

   40 CFR 60, Subpart A, General Provisions. This subpart applies to the boiler because the boiler is an affected unit under 40 CFR 60, Subpart Db.

   40 CFR 60, Subpart Db, Standard of Performance for Industrial-Commercial-Institutional Steam Generating Units. This subpart applies to the boiler because the boiler meets the definition of an affected source under this Subpart.

7. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. The source, as defined and applied in 40 CFR 63, shall comply with the requirements of 40 CFR 63, as applicable. TRC is not a major source of Hazardous Air Pollutants (HAPs); therefore, TRC is not currently subject to any Maximum Achievable Control Technology (MACT) standards under this rule.

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. TRC must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). The proposed height of the new or altered stack for TRC is below the allowable 65-meter GEP stack height.

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

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

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

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

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. TRC has a PTE greater than 25 tons per year of PM, PM_{10}, NO_x, CO, SO_2, and VOCs; therefore, an air quality permit is required.

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

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

5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration, or use of a source. TRC submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. TRC submitted an affidavit of publication of public notice for the May 25, 2006, issue of the *Sanders County Ledger*, a newspaper of general circulation in the Town of Thompson Falls in Sanders 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 the permit analysis to this permit.

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 TRC 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 not a major stationary source since this facility is not a listed source and the facility's potential to emit is below 250 tons per year of any pollutant (excluding fugitive emissions).

Because the project has a symbiotic relationship with TRL the Department reviewed whether or not the two sources should be considered a single source under the requirements of NSR. If TRC and TRL were considered a single source, the source would be subject to the requirements of the NSR/PSD program. In order for two separate facilities to be considered a single source the following three criteria must be met:

- The facilities must be under common control and ownership;
- The facilities must be located on contiguous and adjacent properties; and
- The facilities must share the same SIC code.

While TRC and TRL are located on contiguous and adjacent properties, the companies are owned by separate entities, do not have common control, and have separate SIC codes. Therefore, TRC and TRL are considered separate sources under the requirements of NSR/PSD.

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

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

   a. Potential to emit (PTE) > 100 ton/year of any pollutant; or

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

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

2. ARM 17.8.1204 Air Quality Operating Permit Program. (1) Title V of the FCAA amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Montana Air Quality Permit #3175-03 for TRC, the following conclusions were made:

   a. The facility's PTE is greater than 100 ton/year for NO_x, CO, and SO_2.

   b. The facility's permitted allowable PTE is less than 10 ton/year for any individual HAP and less than 25 ton/year of all HAPs.

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

   d. This facility is subject to 40 CFR Part 60, Subpart Db.

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

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

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

Based on these facts, the Department determined that TRC is a major source of emissions as defined under Title V. Operating Permit #OP3175-00 was issued final and effective on August 20, 2002. Changes made under MAQP #3175-01 and MAQP #3175-04 constitute a significant modification of Operating Permit #OP3175-00. Therefore, in accordance with the provisions of ARM 17.8.1227, TRC submitted a permit application for a significant modification to Title V Operating Permit #OP3175-00, concurrent with the submittal of the permit application for MAQP #3175-04.

III. BACT Determination

A BACT determination is required for each new or altered source. TRC shall install on the new or altered source the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized.

A BACT analysis was submitted by TRC in Permit Application #3175-03. The BACT analysis for Permit #3175-03 addresses some available methods of controlling NO_x, SO_2, HCl, H_2SO_4, and Hg emissions from the boiler. The Department reviewed these methods, as well as previous BACT determinations for similar permitted sources. The following text provides the BACT analysis submitted by TRC in the application for permit modification and the Department's BACT determination(s) based on the information provided.

<u>Pollutant-Specific BACT Review and Determination for the boiler</u>

Based on source testing and consultation with industry experts, TRC determined that the affected boiler operating with existing NO_x and SO_2 control strategies is incapable of achieving the applicable BACT emission limits (see background information contained in the application for Permit #3175-03). Therefore, under the current permit action, TRC proposed the modification of the applicable BACT determinations for these pollutants. In accordance with EPA guidance/policy regarding the modification of existing BACT emission limits, the proposed changes are subject to a current-day BACT analysis and determination process. In addition, because the previously BACT determined control strategy for SO_2 emissions was deemed BACT for the control of HCl, H_2SO_4, and Hg from the boiler, these pollutants have also been analyzed under the current day BACT analysis and determination process summarized below. The complete BACT analysis is contained in the application for Permit #3175-03.

A. Boiler NO_x Emissions

NO_X emissions can be controlled through combustion controls and/or flue gas scrubbing. As an introduction to the detailed discussion of NO_X control technologies, it is useful first to review the mechanisms by which NO_X is formed in the exhaust from a coal/wood waste-fired boiler. NO_X, refers to the cumulative emissions of nitric oxide (NO), nitrogen dioxide (NO_2), and trace quantities of other species. NO_X emissions from combustion processes are typically more than 95 percent NO with the remainder being primarily NO_2. Once the flue gas leaves the stack, however, most of the NO is oxidized in the atmosphere to create NO_2 in a process that can take several hours to complete. The extent to which the NO is oxidized to NO_2 is a function of a number of meteorological variables, including ambient ozone levels.

The two primary mechanisms for formation of NO_X are thermal NO_X and fuel NO_X. Thermal NO_X refers to the NO_X formed through high-temperature oxidation of the nitrogen found in the combustion air. The primary factors contributing to an increased thermal NO_X formation rate are the same factors contributing to complete combustion of fuel: combustion temperature, residence time, and mixing or turbulence. Regardless of the fuel being combusted, thermal NO_X generally becomes a significant factor at combustion temperatures of approximately 2,200ºF, with exponential increases in formation rate at higher temperatures. For fuels with relatively low nitrogen content, such as natural gas, thermal NO_X is the primary NO_X formation mechanism.

Fuel NO_X refers to the NO_X formed by the conversion of fuel-bound nitrogen to NO_X during combustion. Fuel NO_X accounts for a major portion of the total NO_X emissions from the combustion of nitrogen containing fuels, such as coal and wood waste. A variety of factors, including the combustion temperature, fuel-air stoichiometric ratio, and coal/wood waste characteristics (moisture, volatile matter, and nitrogen) are believed to contribute to the fuel NO_X formation mechanism.

1. Identification and Technical Feasibility Analysis of NOx Control Technologies

Stoker type boilers are the most common type of coal/wood waste firing system in the United States. The reduction of NOx emissions from stoker boilers can be accomplished with combustion modification and flue gas treatment techniques or a combination of these. The application of a specific technique will depend on the type of boiler, the characteristic of its primary fuel, and method of firing. Some controls have seen limited application, whereas certain boilers have little or no flexibility for modification of combustion conditions because of method of firing, size, physical configuration, or operating practices.

The US EPA RACT/BACT/LAER Clearinghouse Database (RBLC) and California's BACT database (CARB) were reviewed to identify the types of NO_x controls permitted for coal/wood-fired boilers. Table 3-1 contained in the application for Permit #3175-03 (referenced under permit application #3175-04) provides the results of this review for coal/wood-fired boilers permitted since 1994. The review of the CARB BACT database identified only those using fluidized bed type boilers, most of which were permitted using ammonia injection for NO_x control. There are three types of NO_x controls that have been permitted for coal/wood-fired boilers: combustion controls (CC), selective non-catalytic reduction (SNCR), and selective catalytic reduction (SCR). Each of these control methods is discussed below.

Combustion Controls (CC)

Thermal NO_X can be reduced by minimizing the amount of excess oxygen, delaying the mixing of fuel and air, and through good combustion design. The first technique is often referred to as low excess air (LEA) and can be attained by optimizing the operation for minimum excess air without excessive increase in combustible emissions (i.e., CO and VOC). The effect of lower oxygen concentration on NO_X is partially offset by some increase in thermal NO_X because of higher peak temperatures with lower gas volume. Another technique, called air staging, reduces flame temperature and oxygen availability by minimizing the amount of combustion air that is introduced in the primary burning zone, and introduces the final amount of combustion air above the primary combustion zone. Staged combustion air can be accomplished by several means, but stoker boilers include staged air combustion as an inherent part of the design. For stoker boilers, air staging begins by introducing the coal/wood waste on a grate, having air blown from below the grate up through the burning coal/wood, and by introduction of over-fire air (OFA) above the grate for final burnout of combustibles. By limiting the amount of air introduced below the grate, the conversion of nitrogen to NO_X can be minimized due to the resulting lowered flame temperatures. Final burnout air is introduced through OFA ports above the grate. A third technique involves having a larger furnace area to lower the peak heat release temperature in the furnace and to allow sufficient residence time for final burnout of combustibles.

Fuel NO_X can be reduced by suppressing the amount of air required for complete combustion in the primary combustion zone (on the grate for stoker boilers), and by using low nitrogen fuels. The overfeed stoker inherently operates with lower oxygen levels at the grate and higher oxygen levels in the furnace. For overfeed, coal/wood-fired, stoker boilers, the combustion control techniques discussed above are collectively referred to as good combustion practice, good combustion design and operation, or combustion controls. In this document these types of controls are referred to as combustion controls (CC).

Selective Non-Catalytic Reduction (SNCR)

SNCR is a post-combustion process for NO_x control that can reduce NO_x emissions by 30 to 70 percent. Current SNCR technologies consist of a reagent injection system, which uses NH_3 or urea. The overall reactions reduce NO_x to nitrogen and water vapor and are similar to the SCR reactions described below. However, in contrast with SCR (discussed below), SNCR involves the injection of NH_3 into high-temperature regions of the boiler to reduce NO_x without the use of a catalyst. A catalyst is not necessary to support the reaction of NH_3 and NO at flue gas temperatures in the range of 1,400°F to 2,000°F. Above 2,000°F to 2,200°F, NH_3 is oxidized to NO, and below 1,400°F, the NO_x reduction reaction stops. NO_x reduction performance is maximized in the narrow temperature window of 1,600°F to 1,900°F.

The most critical operating and design factors associated with SNCR include the following:

- Temperature;
- Mixing;
- Reagent to NO_x Ratio;
- Ammonium Sulfate Formation; and
- Hazardous material concerns.

Each of these factors is discussed in more detail below.

Temperature Effects**.** The performance of SNCR is sensitive to flue gas temperature because optimal NO_x reduction occurs in a limited temperature window. In addition, adequate residence time at this temperature is necessary to complete the reactions. Flue gas temperatures in the stoker boiler furnace section, located between the grate and the flue gas passage into the convective section of the boiler, change when there are changes in boiler load, fuel characteristics, and combustion air temperature or flow. Because of this variability, the flue gas at the reagent injection point will not always be at the optimum temperature for NO_x reduction.

At temperatures below the optimum SNCR operating temperature range, the NH_3/NO_x reaction will not occur at the highest efficiencies, and un-reacted NH_3 will either be emitted as NH_3 slip, or it will react with SO_3 to form ammonium salts, or will be incorporated in the ash. Above the optimum temperature, the amount of NH_3 that oxidizes to NO_x increases and the NO_x reduction performance deteriorates rapidly. Both laboratory work and field data show NH_3 slip to be a strong function of temperature. At temperatures above 1,900°F, un-reacted NH_3 emissions decrease due to NH_3 oxidation to NO_x. At temperatures below 1,600°F, un-reacted NH_3 emissions increase. Laboratory data show that maximum NO_x removal and lowest NH_3 slip can be achieved by injecting NH_3 in the narrow temperature window of 1,600°F to 1,900°F.

The furnace section of the TRC coal/wood-fired, stoker boiler typically operates with temperatures in the range of 1,000°F to 2,000°F. As such, the furnace volume may, at times, be at temperatures below optimal for high NO_X reductions and low NH_3 slip using SNCR. As a result, at times, the boiler will not be able to achieve the higher end of potential NO_X reductions (levels of up to 70 percent reduction) using SNCR technology. In addition, during startup periods and lower operating loads, SNCR cannot be used due to the low furnace temperatures.

Mixing Effects. Complete mixing of the reagent (NH_3) with the flue gas can be difficult because of the relatively small volume of the furnace that is at the correct temperature for SNCR reagent injection. Failure to mix the SNCR reagents adequately with the flue gas will result in increased NH_3 slip and decreased NO_x reduction. For the TRC stoker boiler, computational fluid dynamic modeling and an extensive testing program will be required to optimize NO_X reduction and minimize ammonia slip from application of SNCR.

Reagent to NO_X Ratio. In SNCR processes, the total amount of reagent (NH_3 or urea) injected into the flue gas is typically expressed as the molar ratio of NH_3 to inlet NO_X. A molar ratio higher than 1.0 indicates that excess reagent has been injected. By injecting excess reagent, the chemical reactions are "shifted" to favor the reduction of NO_X to N_2 and water. The SNCR process may require two to six times the amount of reagent theoretically required to achieve high NO_X reduction. This is because, even at optimum operating temperatures, some of the NH_3 injected oxidizes to NO_X, and some of the injected NH_3 will remain un-reacted. Therefore, as the amount of excess reagent increases, the amount of NH_3 oxidizing to NO_x increases or the amount of un-reacted NH_3 emissions (or ammonia slip) increase, or both.

The NO_X reduction achievable and the amount of NH_3 slip also depend upon the inlet and outlet NO_X concentrations in the reaction zone. Lower inlet NO_X concentrations require lower total NH_3 injection but a higher NH_3-to-NO_X ratio in order to obtain the same percentage reduction. Therefore, as NO_X inlet concentrations decrease, relatively more reagent is required to achieve the same percent reduction and NH_3 slip increases.

Ammonium Sulfate Formation. An important operating concern with SNCR is the reaction of SO_3 and un-reacted NH_3 in the flue gases to form ammonium sulfate ($(NH_4)_2SO_4$), ammonium bisulfate (NH_4HSO_4), and ammonia chloride (NH_4Cl). During combustion, a percentage of SO_2 will be oxidized to SO_3. The SO_3 reacts with free NH_3 and water to form ammonium sulfate salts:

$$2\,NH_3 + SO_3 + H_2O \rightarrow (NH_4)_2SO_4$$

$$NH_3 + SO_3 + H_2O \rightarrow NH_4HSO_4$$

Ammonium sulfates can condense on heat exchange surfaces, downstream particulate controls, and flue gas handling equipment causing fouling and corrosion. These deposits will cause an increase in pressure drop across these systems. Unfortunately, air soot blowing is often ineffective at removing the ammonium salt deposits. As a result, water washing may be necessary to remove the sticky, water-soluble material. Therefore, the boiler's flue gas handling systems must be constructed of materials that can tolerate corrosion, and be designed to accommodate water washing. Ammonium salt deposits can cause unplanned outages.

Additionally, ammonium salts form as very small particles, and these fine particles ($PM_{2.5}$) increase exhaust plume opacity. For example, at a pulverized coal-fired boiler in California, the opacity of the exhaust plume visibly increased during the testing of NO_xOUT technology (urea injection). The plume was attached to the exhaust stack outlet and persisted for more than an hour after urea injection was discontinued. It was assumed that the plume was caused by NH_3 slip combining with trace amounts of chloride from the coal and/or sulfate in the flue gas. The plume was minimized as NH_3 slip was reduced, but at the expense of NO_x reduction. The formation of ammonium chloride salts takes place after the flue gas has been exhausted from the stack causing a detached plume effect. Although minimizing ammonia slip levels reduces the achievable NO_X reduction, operating experience has shown that ammonia slip levels of less than 10 ppm are necessary to:

- Minimize ammonium salt formation and deposition and the resulting equipment fouling and corrosion problems;
- Minimize increases in opacity;
- Balance the emissions of NH_3 relative to NO_x from a health effects standpoint; and
- Optimize reagent consumption (costs) relative to NO_x removal.

Current Applications/Achievable NO_x Reductions. Application of SNCR is combustor/fuel-specific because the performance of SNCR is extremely temperature and mixing dependent. NO_X and NH_3 emission levels achievable on one boiler will not necessarily translate into the same NO_x and NH_3 emission levels achievable on a different type of boiler using different fuels. The location at various loads of the desired SNCR temperature window for the TRC stoker boiler is unknown at this time. Individual boilers will exhibit unique performance characteristics. These performance characteristics directly affect the ability of an SNCR system to meet a required NO_X limit cost effectively, and without unduly restricting boiler operation due to increased maintenance outages. Applicable NO_X limits for boilers using SNCR to control NO_X emissions must consider these factors.

Selective Catalytic Reduction (SCR)

SCR is a flue gas treatment technique for controlling NO_x that can reduce emissions by 50 to 90 percent on those sources where its application is technically feasible. SCR uses an ammonia (NH_3) injection system and a catalytic reactor. Conventional SCR catalysts used to treat coal combustion flue gases operate in the temperature window of 500°F to 1000°F. An SCR system utilizes an injection grid, which disperses NH_3 in the flue gas upstream of the catalyst. NH_3 reacts with NO_X in the presence of the catalyst to form nitrogen (gas) and water according to the following general equations:

$$NH_3 + NO + 1/2\ O_2 \rightarrow N_2 + 3/2\ H_2O$$

$$NH_3 + 1/2\ NO_2 + 1/4\ O_2 \rightarrow 3/2\ N_2 + 3/2\ H_2O$$

For the TRC stoker boiler, the SCR system would have to be located before the economizer where the temperature window is approximately 500°F. SCR also affects the overall plant operation, because NH_3 and SO_3 in the flue gas react to form ammonium sulfate and bisulfate upstream of the particulate control and flue gas handling equipment. Ammonium salt deposition could damage these controls and equipment. Because the SCR system is located upstream of the economizer where the flue gas temperatures are on the low end of the acceptable operating range, any changes in boiler operations, such as decreased load operation, will alter flue gas temperatures at the catalyst bed and can significantly affect SCR performance. Important operating and design factors associated with SCR include catalyst deactivation, problems with un-reacted SO_3 and NH_3, and process control limitations.

Catalyst deactivation is the loss of active catalyst sites necessary to promote the NH_3/NO_x reaction. Catalyst deactivation primarily occurs via four mechanisms -- poisoning, fouling, thermal degradation, and mechanical losses (i.e., erosion). Because the SCR system is located upstream of the particulate control, mechanical losses and fouling have the potential to be significant problems with catalyst life due to the high dust/particulate load in the flue gas. Permanent catalyst poisoning results from metals and trace elements (e.g., Na, K, and As) in coal/wood. These elements will react irreversibly with the active acid sites on the SCR catalyst surface, thus poisoning the catalyst. Testing of a vanadium-titanium SCR catalyst, which is the predominant catalyst type, showed that alkali metals (i.e., Li, Na, K, Rb, and Cs) are strong catalyst poisons. The poisoning effect increases with metal basicity (i.e., K is a stronger poison than Na). Western coals and wood ash have high alkali metal contents. The alkali content of the ash from the TRC coal contains approximately 10 percent alkali, most of which would be potassium oxides. The high alkali metal content and the small size of stoker boilers are the major reasons that SCR emission control technology has not been previously applied to stoker boilers.

Recently, one proposed wood-fired boiler facility has been issued a permit limit based on the application of SCR. This facility, South Point Power, has seven existing coal-fired stoker boilers that will be converted to fire up to 318 MMBtu/hr of wood per boiler making the facility's total permitted heat input over 2,200 MMBtu/hr. The flue gases from all seven units are to be handled in a single pollution control train, which includes a hot ESP before the SCR catalyst. The startup date of this facility is unknown. As such, SCR is not demonstrated in the U.S. for wood firing, and this technology is considered technically infeasible for the TRC stoker boiler. However, the economic impacts of the technology demonstrate that SCR technology is not economically viable for the TRC coal/wood-fired boiler even if the technical obstacles to its application could be overcome.

2. Ranking of Available and Technically Feasible NO_x Control Technologies

NOx Control Technology	Control Efficiency	NOx Emission Rate (lb/MMBtu)
SNCR	30-70%	0.196 lb/MMBtu (36% control efficiency[a])
TRC Baseline Combustion Control	---	0.28 lb/MMBtu[b]

[a] This emission rate represents a conservatively low SNCR NOx control efficiency achieving compliance with the BACT determined emission limit under Permit #3175-04, assuming TRC-baseline steady-state achievable NOx emissions rate with existing combustion controls.
[b] This emission rate represents the TRC-baseline steady-state achievable NO_x emission rate using existing combustion controls (OFA and FGR) reported in the application for Permit #3175-04.

3. Energy, Environmental, and Economic Impacts of Available NO_X Control Technologies

A complete analysis of the potential energy, environmental, and economic impact of the TRC-specific application of SCR, SNCR, and combustion controls (existing control) to the proposed project is detailed in the application for Permit #3175-04 and supporting materials (i.e., referenced permit application #3175-03). Based on the information contained in the application, the Department determined that SNCR and combustion controls (OFA and FGR) constitute feasible control strategies for the TRC project. Based on the information provided in the application for permit modification, the Department determined that SCR is technically and economically infeasible for application to the TRC-specific coal/wood-fired boiler.

4. NO_x BACT Determination

Under the current permit action, TRC proposed and the Department concurred that SNCR in combination with the existing OFA and FGR combustion controls constitutes BACT for the control of NO_x emissions from the boiler. Using the TRC reported baseline combustion control NO_x emission rate of 0.28 lbs/MMBtu, the SNCR manufacturer consulted for the TRC project (Fuel Tech, Inc.) guarantees a 30% NO_x reduction rate once the actual temperature, flow, and other operating parameters of the TRC boiler are within the manufacturer's prescribed SNCR operating ranges. This operating range is defined by the manufacturer as between 70% and 100% load, and is the basis for a manufacturers' guarantee of 30% NO_x reduction. A NO_x reduction of 30% from the reported combustion control baseline emissions rate results in an emission rate of 0.196 lb NO_x/MMBtu. Further, the Department determined that the appropriate averaging time to demonstrate compliance with the applicable NO_x BACT emission limit of 0.196 lb/MMBtu is a rolling 30-day average. The Department determined that the 30-day rolling average is appropriate because this averaging period will provide necessary operational flexibility and is consistent with the requirements contained in 40 CFR 60, Subpart Db; recent similar source permits for boilers with SNCR NO_x emission control requirements (see EPA RACT/BACT/LAER Clearinghouse); and NO_x limit compliance demonstration periods contained in other recent Department permits for electric utility steam generating units.

Because the effectiveness of SNCR is highly dependent on specific boiler and control equipment operating parameters, computational fluid dynamic modeling and an extensive testing program will be required to determine the appropriate location for the SNCR urea/ammonia injection system(s) within the boiler furnace to optimize NO_X reduction and minimize ammonia slip from application of SNCR to the boiler. In light of this, TRC proposed a 10-day period prior to installation and operation of SNCR during which an enforceable emission limit of 0.28 lb/MMBtu would apply to allow for modeling and testing of the boiler to optimize application of SNCR. At the end of the initial 10-day boiler mapping/testing period, SNCR would be required and the BACT-determined NO_x emission limit of 0.196 lb NO_x/MMBtu would be applicable. The Department determined that this operating scenario is necessary to accommodate proper installation and operation of the BACT-determined SNCR control technology. Further, based on the analysis contained in TRC's application for permit modification, the Department determined that an emission limit of 0.28 lb NO_x/MMBtu is the appropriate limit considering the existing BACT-determined OFA and FGR combustion controls without the BACT-determined SNCR system in operation.

In summary, after evaluation of the previously discussed information, the Department determined that the operation of OFA and FGR combustion controls and SNCR to achieve an emission limit of 0.196 lb/MMBtu based on a rolling 30-day average constitutes BACT, in this case. The Department determined that the applicable NO_x BACT controls, initial 10-day boiler mapping/testing period, and the 30-day rolling compliance demonstration period provide TRC with an appropriate level of operational flexibility to meet the BACT-determined NO_x emission limit of 0.196 lb/MMBtu. The periodic NO_x source testing requirements and the NO_x CEMS requirement will adequately monitor compliance with the permitted NO_x BACT emission limit.

B. Boiler SO_2 Emissions

Sulfur oxide (SO_x) emissions from fossil fuel combustion consist primarily of SO_2. Additional compounds of SO_x also form at a much lower quantity and consist of sulfur trioxide (SO_3) and gaseous sulfates. These compounds form as the sulfur in the fossil fuel is oxidized during the combustion process.

1. Identification of and Technical Feasibility Analysis of SO_2 Control Technologies

SO_2 emissions can be controlled through limitations on fuel sulfur content and/or flue gas scrubbing. TRC uses low sulfur coal (western bituminous or subbituminous coals). Additional control of SO_2 is based on the use of flue gas scrubbing technologies.

As provided in the table below, the current permit limits coal to no more than 1.0% sulfur by weight and no less than 8,000 Btu per pound heat content. Typical coal burned at TRC has a sulfur content that varies from 0.4% to 1.0% by weight on an as-received basis. TRC estimates the average sulfur content of coal burned is approximately 0.7%. The typical heat content of coal burned at TRC varies from approximately 10,000 to 10,500 Btu per pound on an as-received basis. TRC estimates that the typical coal received is approximately 10,200 Btu per pound. These estimates are used as the basis for the typical coal scenario of the BACT analysis. The following BACT analysis addresses the application of flue gas scrubbing technologies.

COAL PARAMETER	PERMIT LIMITS	TYPICAL COAL
Weight % Sulfur	≤ 1.0	0.7
Btu/lb	≥ 8,000	10,200
Lbs SO_2/MMBtu	2.50	1.373

The US EPA RACT/BACT/LAER Clearinghouse Database (RBLC) and California Air Resources Board (CARB) BACT database were reviewed to identity the types of SO_2 controls permitted for coal/wood-fired boilers. Table 2-5 in the application for Permit #3175-03 (referenced for permit application #3175-04) summarizes the results of this review for coal/wood-fired boilers permitted since 1994. The review of the CARB BACT database identified only boilers using circulating fluidized bed (CFB) type boilers most of which were permitted using limestone injection for SO_2 control. The RBLC identified varied flue gas desulfurization (FGD) unit systems for the control of SO_2. These FGD technologies are discussed in greater detail below.

FGD systems are typically divided into regenerable (or byproduct recovery) and non-regenerable systems. Although regenerable systems minimize waste generation, these systems have very high capital and operating costs and are not used to any significant extent in the U.S. These systems are used where very large amounts of SO_2 are being removed and where waste disposal is not economically feasible. Likewise, non-regenerable FGD systems are typically divided into systems having low capital costs and high capital costs. The high capital cost systems are economical where very high SO_2 removal rates are desired and large amounts of SO_2 must be removed. Low capital cost systems are economical where moderate to high SO_2 removal rates are desired and small amounts of SO_2 must be removed. Low capital cost systems are also more economical for retrofit applications because of the increased capital costs associated with retrofitting large amounts of equipment at compact plant sites. The following table summarizes the characteristics of the different types of FGD systems and the rationale for consideration in this BACT analysis.

FGD System	% Reduction	Advantage	Disadvantage	Rationale
Regenerable or Byproduct Recovery (Dual Alkali, Magnesium Oxide, Wellman-Lord)	95+	Minimizes waste disposal High SO_2 removal capability	Very high capital and operating costs. Not economical unless large amount of SO_2 to be removed and waste disposal costs are high. System has large footprint.	Excluded from analysis because the small amount of SO_2 to be removed makes technology economically infeasible.

Non-regenerable – High Capital Cost (lime/lime-stone wet and dry FGD and wet sodium FGD)	70-95	Lower capital and operating costs than regenerable systems when waste disposal costs are moderate to low	High capital and operating costs. Generates large volumes of waste. Not economical unless moderate to large amount of SO_2 to be removed. System has large footprint.	Wet lime/ limestone FGD not analyzed because of the small amount of SO_2 to be removed. Lime spray drying analyzed because typically used for small systems (e.g., municipal waste combustors). Wet sodium FGD analyzed because onsite treatment of liquid, sodium-containing waste assumed to be available.
Non-regenerable – Low Capital Cost (dry and wet sorbent injection using calcium and sodium compounds)	40-90	Low capital and operating costs. System has small footprint.	High chemical consumption and high operating costs where moderate to large amounts of SO_2 to be removed. Generates large volumes of waste.	Dry and wet lime injection selected due to small amount of SO_2 to be removed and limited footprint at plant.

Wet limestone scrubber systems (WSS) and lime spray dryer (LSD) absorbers are FGD technologies screened for SO_2 removal. Typically in the United States these FGD systems are favored because of their simplicity of operation and equivalent removal capabilities compared to relatively complex byproduct recovery FGD systems. WSS and LSD FGD systems have the advantage of using low-cost widely available calcium-based additives. WSS sodium-based systems are economical where the liquid waste can be economically treated before discharge to a water source and the amount of SO_2 to be removed is small (cost of soda ash/sodium hydroxide is prohibitive relative to lime or limestone for moderate to high amounts of SO_2 removed). Because the TRC application constitutes a relatively small amount of SO_2 to remove and sodium sulfate salts can be disposed of, WSS has been evaluated further. WSS can achieve 95 percent removal.

WSS FGD comprises relatively large capital equipment and operating costs compared to the LSD FGD system. Therefore, WSS FGD are typically used for large coal-fired power plant applications where tens of thousands of tons per year of SO_2 are being removed. As previously indicated the WSS FGD application can achieve 90 to 95 percent removal. However, considering WSS FGD for a 192.8 MMBtu/hr application using low sulfur coals would incur extremely high capital and operating costs for the removal of a small amount of SO_2 relative to large, utility coal-fired boilers.

LSD FGD has moderate capital equipment and operating costs compared to a WSS FGD system. Because the TRC boiler already has a BACT determined fabric filter baghouse for PM/PM_{10} control, the cost of the LSD FGD system is further reduced. A LSD FGD system with a fabric filter can achieve 85 to 90 percent removal. Therefore, on an economic basis, the retrofit of a LSD FGD system is evaluated further in the BACT analysis.

Because of the higher capital costs and space requirements for LSD FGD technologies, dry sorbent injection (DSI) technology using hydrated lime and/or sodium carbonates is expected to be more cost-effective where small amounts of SO_2 need to be removed. Therefore, the use of a hydrated lime/sodium bicarbonate DSI on the stoker boiler to control annual average SO_2 emissions by 50 to 90 percent is also evaluated.

Wet Sodium Scrubbing System (WSS)**.** The wet sodium scrubbing system is a two-stage process that removes SO_2 from the flue gas through the use of a gas to liquid contact absorber following particulate control. The absorber module serves as the contact zone where alkaline additive (sodium hydroxide) and SO_2 in the flue gas react to form sodium sulfate reaction products. A liquid blowdown from the circulating liquid loop is used to remove the accumulated sodium sulfate salts. A liquid waste is generated by this process, and this process uses the largest quantity of water of the FGD processes. For purposes of this BACT, a 95% SO_2 removal efficiency is assumed.

For WSS FGD, lime slurry scrubbing is not feasible in this small a plant with Montana winters. The labor costs will be very high, dewatering is essential since ponds will freeze, and this plant is near a river. Dewatering in winter is very difficult. Wet sodium alkali scrubbing (WSS FGD) produces a 10% weight soluble sodium sulfite/sodium sulfate waste liquid. The only method for disposal is to evaporate the water and produce a dry salt for landfill. This is a soluble salt, so a lined landfill is necessary to protect groundwater. The sodium alkali is 4-5 times as expensive as equivalent lime in the LSD FGD lime systems. Although 90% SO_2 removal is a certainty with WSS FGD, the operating costs are the highest of any of the FGD methods. There is adequate waste heat available at the inlet to the baghouse to evaporate the water from the wet scrubber blowdown, but this requires a spray dryer at least as expensive as for the LSD FGD process. Thus, the wet process has much higher capital cost and clearly much higher operating costs.

Lime Spray Dryer Absorber System (LSD). The lime spray dryer absorber system is a two-stage process that removes SO_2 from the flue gas through the use of a spray dryer/absorber followed by a fabric filter baghouse. The absorber module serves as the initial contact zone where alkaline additive (calcium hydroxide) and SO_2 in the flue gas react to form dry reaction products. The majority of reaction products formed in the spray dryer flow out of the absorber module and into the fabric filter for removal with the fly ash.

The absorber module is sized on the basis of gas flow rate and residence time. Residence times of approximately 10 seconds have proved sufficient to ensure adequate reaction product drying. The atomizers, which disperse the additive slurry, are sized on the basis of additive and tempering water feed necessary to achieve the required SO_2 removal level and outlet gas temperature.

Flue gas temperatures at the fabric filter inlet must be sufficiently high to avoid corrosion in the fabric filter and in other downstream equipment. Low flue gas temperatures can also cause condensation of cementitious fly ash materials on the filter bags, severely degrading bag life and fabric filter operation. Adjustment of the spray dryer module approach temperature (number of degrees that the spray dryer operates above the saturation temperature) determines the spray dryer module outlet gas temperature. The amount of water added to the slurry is adjusted to control the spray dryer module outlet gas temperature. For the same SO_2 removal efficiency, a higher approach temperature results in greater lime consumption. Lime consumption increases as a result of a reduction in the SO_2 removal reaction efficiency at the higher approach temperature. An "approach temperature" (i.e., approach to saturation temperature) of 38°F results in a fabric filter inlet gas temperature of approximately 165°F. An inlet gas temperature of 165°F is sufficiently high to protect the fabric filter and other downstream equipment.

The preparation of lime for use as an additive in a spray dryer is accomplished by the additive storage and preparation system. With this system, pebble lime is stored in silos to protect it from moisture. Lime from storage silos is hydrated in a slaker/classifier system for feed to the slurry storage tanks (24-hour capacity). Additive from the slurry storage tank is pumped to the additive feed tank. Since a significant portion of the lime feed does not initially react with the SO_2 in the flue gas stream, a portion of the solids collected in the fabric filter is returned and mixed with fresh lime slurry so that unreacted lime or alkalinity contained in the fly ash can be utilized. The lime and recycled solids are blended in a recycle slurry mix tank and pumped to the additive feed tanks. The solids collected in the fabric filter, which are not recycled to the additive preparation system, are collected in the solids storage silo and subsequently transported by trucks to a landfill. This process uses about a third less water than do the WSS FGD processes. For purposes of this BACT, an 85-90% SO_2 removal efficiency is assumed.

For LSD FGD, guaranteed 85% SO_2 removal can be obtained from control equipment manufacturers and there are several reference facilities in operation at 80% plus efficiency when combusting low sulfur coal, at conditions very close to TRC's conditions. The technology is not new, and this is not a "pioneering" application for 80-85% removal on 0.5% sulfur coal at reasonable calcium to sulfur stoichiometries. Recycle of baghouse fly ash, unused lime and reaction products is not necessary at 80-85% removal efficiencies, eliminating the accelerated erosion of ducts and bags which accompany high baghouse ash recycle rates, and which increase maintenance and operating costs, plus the chance of unplanned outages. 90% removal can be achieved at much higher stoichiometries, but the only guarantees which can be given at 90% require recycle of baghouse ash and high recycle rates, resulting in accelerated erosion of ducts and bags, increased atomizer maintenance and operating costs, and increased chance of unplanned outages. A number of suppliers have experience with multiple installations of the absorption equipment and the auxiliary equipment, which has to be included. For reference only, to go from 85% removal at about 200% stoichiometry (conservative, but achievable even without perfect tuning) to 90% removal will require an increase in stoichiometry to 220% meaning 120% unused lime instead of 100% unused lime to the landfill (about 1,400 pounds per day) plus the additional reaction products. This means more than 550,000 pounds per year more landfill (and materials handling) to get a routine 90% instead of 85% removal (93,160 pounds per year more SO_2 removed). LSD FGD is expensive for achieving 90% sulfur control on low sulfur Western coals as currently burned by TRC.

<u>Dry Sorbent Injection Scrubbing System (DSI)</u>. The DSI system is a two-stage process that removes both SO_2 and particulate from the flue gas through the use of flue gas ductwork residence time followed by a fabric filter. The alkali sorbent is injected into the existing ductwork, the initial contact zone, where alkaline additive (lime, sodium carbonates, etc.) and SO_2 in the flue gas react to form dry reaction products. The reaction products formed in the ductwork flow into the fabric filter for removal with the fly ash.

A sodium alkali DSI system has the advantage over calcium-based alkali DSI systems for two reasons. First, the amount of sorbent necessary for injection is less because sodium sorbents are more reactive than calcium-based sorbents. And, secondly, the utilization of the sorbent is higher because of the higher reactivity. This double effect significantly reduces the increased particulate loading to the fabric filter and significantly reduces the amount of wasted/unreacted sorbent. The disadvantage of the sodium alkali injection system is the much higher cost of the sodium alkali relative to a calcium-based alkali. Additionally, sodium sulfate salts are much more water-soluble than calcium sulfate salts. This process uses very little water.

A DSI system can achieve up to 90 percent removal. However, a DSI system operates more efficiently at high sulfur inlet loading. Using low sulfur coals does not allow the DSI system to reach maximum design removal efficiency. For purposes of this BACT, an 80% SO_2 removal efficiency is assumed.

TRC received vendor quotations and information from two DSI suppliers, which claimed that 80 to 90 percent SO_2 control was achievable on a 30-day rolling average. However, upon detailed review of the vendor supplied information and guarantees, TRC concluded that neither proposal is attractive for many reasons. Despite some significant differences, the proposals use almost identical SO_2/hydrated lime absorption methods. They rely on the "new" lime being wetted (thus semi-dry) and then mixing the wetted new sorbent with huge quantities of dried, recycled lime, reaction products and flyash. This would create an enormous surface area available for absorption. Both vendors claim SO_2 removal results, which are better than what other prevailing suppliers guarantee with semi-dry methods on Western low sulfur coal. They are both what can be described as alternative technologies to the norm, not well proven, and neither has been demonstrated, even on small scale, on low sulfur Western coal, which is a serious potential problem for TRC.

One vendor's guarantee is based on TRC heating the flue gas up to a minimum of 300°F requiring 2 MMBtu/hr of natural gas or an energy loss of 2 MMBtu/hr from flue gas heat recovery. Both the operating and capital costs are much higher than expected for this system. The lime stoichiometry is not guaranteed and thus, the remedy for non-performance will be more lime. The other vendor did not provide any guarantees.

2. Ranking of Available and Technically Feasible SO_2 Control Technologies

FGD Control	Permit Limit Coals			Typical Coals		
	% Reduction	Lb/MMBtu	ton/yr	% Reduction	Lb/MMBtu	ton/yr
Baseline	0	2.500	2,113	0	1.373	1,160
DSI	80-90	0.500	423	80-90	0.275	232
LSD	85-90	0.250	211	85-90	0.138	116
WSS	90-95	0.125	106	90-95	0.069	58

3. Energy, Environmental, and Economic Impacts of Available SO_2 Control Technologies

A complete analysis of the potential energy, environmental, and economic impact of the TRC-specific application of WSS, LSD, and DSI FGD to the proposed project is detailed in the application for Permit #3175-04 and referenced documentation (i.e., application for Permit #3175-03). Based on the information contained in the application, the Department determined that WSS, LSD, and DSI constitute feasible control strategies for the TRC project.

4. SO_2 BACT Determination

Under the current permit action, TRC proposed the installation and operation of a generic FGD system to meet an emission limit of 0.220 lb SO_2/MMBtu or 85% control efficiency, whichever is less stringent. As described in the above summary, for the purpose of providing flexibility in the type of FGD employed to achieve the BACT determined SO_2 emission limit, TRC proposed the use of a generic FGD system in place of the previously specified DSI system BACT determined control strategy to control SO_2 emissions from the boiler. The SO_2 BACT analysis under the current permit action indicated a preferred strategy of a LSD FGD unit with a guaranteed control efficiency of 85% SO_2 removal and a typical SO_2 control efficiency ranging from 85% to 90%. The Department determined that a generic FGD capable of a minimum 85% SO_2 control efficiency constitutes BACT, in this case.

Further, the Department determined that the appropriate averaging time to demonstrate compliance with the applicable SO_2 BACT emission limit is a rolling 30-day average. The BACT-determined rolling 30-day averaging period constitutes a change in the previously BACT-determined 1-hr averaging time; however, the Department determined that the increased averaging period is justified, in this case, because coal sulfur content and heating value is variable. The increased averaging period will provide necessary flexibility for the combustion of worst-case permitted allowable coal on a short-term basis but provide greater assurance that the affected unit will operate through combustion of more typical coals for longer-term normal operations and/or that the generic FGD achieve the higher end of reported control efficiency when combusting worst-case coals.

Because the Department determined that a generic FGD system constitutes BACT in this case, the Department determined that the TRC proposed and existing BACT emission limit of 0.220 lb/MMBtu based on a rolling 30-day average is the appropriate BACT emission limit, in this case. An emission limit of 0.220 lb/MMBtu represents an approximate 84% reduction in SO_2 emissions when combusting reported typical coals (10,200 Btu/lb and 0.7% sulfur), which is a less than the reported and guaranteed control efficiency for the proposed and BACT determined FGD SO_2 control strategy. Further, while TRC is allowed by permit to combust coal with a heating value of 8000 Btu/lb and 1% sulfur, this coal represents a theoretical worst-case coal with a heating value less than, and sulfur content greater than, any coals actually received and combusted by TRC to date. Information provided by TRC during the current permit application process indicates that TRC's actual worst-case coal would have a minimum heating value of 10,000 Btu/lb and a maximum sulfur content of 1% sulfur by weight. Using these values, an emission limit of 0.220 lb/MMBtu represents an approximate 89% SO_2 control efficiency when combusting worst-case coal, which is within the reported control efficiency range for the proposed and BACT determined FGD. Further, the theoretical permitted allowable coal (8000 Btu/lb and 1% sulfur by weight), would require an approximate 91% SO_2 control efficiency to achieve BACT limit of 0.220 lb/MMBtu, which the Department determined would not significantly impact TRC's ability to comply with the BACT-determined emission limit considering a 30-day rolling average compliance demonstration period and the theoretical nature of this worst-case allowable coal. Also, TRC has the permitted ability to combust lower sulfur coal and/or wood-waste, which has a lower sulfur concentration than coal, thereby providing additional operational flexibility to meet the BACT-determined emission limit of 0.220 lb SO_2/MMBtu based on a rolling 30-day average. Because the BACT analysis indicates that the BACT-determined generic FGD system with an 85% to 90% SO_2 control efficiency range can achieve an emission limit of 0.220 lb/MMBtu based on a rolling 30-day average when combusting typical and worst case coals, the Department determined that TRC's proposed alternative SO_2 limitation of 85% SO_2 reduction (if less stringent than 0.220 lb/MMBtu) is unjustified and does not constitute BACT in this case.

The Department determined that installation and operation of a generic FGD system and modification of the compliance demonstration period for the existing SO_2 BACT determined emission rate of 0.220 lb/MMBtu from a 1-hr average to a rolling 30-day average constitutes BACT, in this case. The periodic SO_2 source testing requirements and the SO_2 CEMS requirement will adequately monitor compliance with the permitted SO_2 BACT limit.

C. Boiler HCl Emissions

A priority HAP emitted from coal-fired spreader stoker boilers, HCl, is characterized as an acid gas. HCl represents the large majority of potential HAPs from TRC. Based on emission calculations using published HAPs emission factors (AP-42), HCl would constitute approximately 97% of all HAPs emitted from the boiler. The amount of HCl generated by combustion of coal in the boiler would be dependent on the chlorine and ash content of the coal.

1. Identification of and Technical Feasibility Analysis of HCl Control Technologies

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

- FGD and baghouse with 14% bypass were estimated to remove approximately 82% of the HCl;
- Wet FGD units with 15% bypass was estimated to remove approximately 80% of the HCl;
- Fabric filters (baghouses) removed approximately 44% of the HCl;
- ESP removed less than 6% of the acid gases.

HCl is water-soluble, and based on the finding in EPA's Utility RTC, HCl, along with most other acid gasses, would be effectively controlled in the baghouse/FGD system that TRC would be required to use to control SO_2 and PM_{10} emissions from the boiler. TRC's Permit #3175-03 would not allow flue gas to be bypassed around the baghouse/FGD system; therefore, the system should reduce emissions of HCl by greater than the 82% removal efficiency described above.

Based on published literature, the Department determined that the use of a baghouse/FGD system constitutes BACT for HCl. In addition, the Department determined that a BACT emission limit of 2.17 lb/hr or 0.01125 lb/MMBtu for HCl is the appropriate BACT limit. Using the published AP-42, Section 1.1, Table 1.1-15, HCl emission factor of 1.2 lb/ton of coal fired, a nominal coal heating value of 8,000 Btu/lb, and the boiler heat input capacity of 192.8 MMBtu/hr, this limit represents approximately 85% co-benefit HCl control efficiency using permitted SO_2 and PM/PM_{10} BACT determinations.

Acid gases generally react with lime (the reagent for the FGD) to form solids, which are removed in the baghouse downstream of the FGD. Since the lime FGD and baghouse would be operated to control SO_2 and PM_{10} emissions, respectively, the criteria pollutant controls would result in a co-benefit control of acid gas emissions. The proposed emission limits for HCl are consistent with published FGD specifications reporting an achievable HCl removal efficiency as high as 98% (www.spcdmg.com). Further, the BACT determined HCl limit for TRC boiler operations is within the range of other acid gas emission limits that have recently been established and that were identified by the Department during this BACT analysis.

Using the SO_2 and PM_{10} emission limits as surrogate emission limits for HCl will provide a more frequent indication of TRC's compliance with the HCl emission limit. In order for TRC to meet the HCl, SO_2, and PM_{10} emission limits, the FGD/baghouse controls will have to be operated optimally. The emission controls and corresponding emission limits are consistent with recent similar source permit determinations. The limit established by the Department for TRC is based on the permit application and would be a 1-hour average (the averaging time that corresponds to the relevant test method).

FGD/Baghouse Control Strategy. 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. In order to maintain compliance with the SO_2, PM_{10}, and HCl emission limits for the boiler, TRC will need to closely monitor the control equipment and maintain the equipment.

Similar source control strategy analyses (Maximum Achievable Control Technology (MACT) Analysis: Montana Roundup Power Project Permit #3182-00) indicate that the installation and operation of the FGD/baghouse for the soul purpose of controlling HCl emissions would result in unreasonable cost effectiveness. Because FGD/baghouse 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 FGD/baghouse 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 FGD/baghouse system would not be economically reasonable for controlling acid gas emissions.

Wet FGD/Wet ESP. Wet FGD/Wet ESP was a potential control strategy identified for controlling acid gases. Similar to the FGD/baghouse control strategy, operation of the Wet FGD/Wet ESP for the soul purpose of controlling HCl emissions would result in unreasonable cost effectiveness. However, since HCl would be effectively controlled by using the same control strategy employed for the reduction of SO_2 and PM/PM_{10} emissions from boiler operations, this control strategy becomes economically reasonable as a co-benefit acid gas control.

However, since TRC is an existing permitted source with the FGD/baghouse BACT control strategy already required and constructed at the facility under the initial permit action, the construction and operation of the Wet FGD/Wet ESP system would result in additional equipment costs. These resulting equipment costs would make this control strategy economically unreasonable.

Because the Department determined that the FGD/baghouse system would result in the highest control of HCl emissions and it was determined that the Wet FGD/Wet ESP strategy would be economically unreasonable in this case, the Department determined that Wet FGD/Wet ESP does not constitute BACT in this case.

Baghouse Alone. Baghouse control was a potential strategy identified for controlling acid gases. Similar to the previously described control strategies, operation of the baghouse alone for the sole purpose of controlling HCl emissions would result in unreasonable cost effectiveness. However, since HCl would be effectively controlled by using the same control strategy employed for the reduction of PM/PM_{10} emissions from boiler operations, this control strategy becomes economically reasonable as a co-benefit acid gas control.

However, since TRC is an existing permitted source with the FGD/baghouse BACT control strategy already required and constructed at the facility under the initial permit action, the removal of the requirement for the FGD system would result in additional SO_2 emissions therefore resulting in increased environmental impact. Further, this strategy would not comply with the SO_2 BACT requirements.

Because the Department determined that the FGD/baghouse system would result in the highest control of HCl emissions and would result in a co-benefit SO_2 control, and it was determined that the baghouse strategy alone would be economically unreasonable, the Department determined that baghouse control alone does not constitute BACT, in this case.

ESP Alone. ESP was a potential control strategy identified for controlling acid gases. Similar to the previously described control strategies, operation of the ESP alone for the sole purpose of controlling HCl emissions would result in unreasonable cost effectiveness. However, since HCl would be effectively controlled by using the same control strategy employed for the reduction of PM/PM_{10} emissions from boiler operations, this control strategy becomes economically reasonable as a co-benefit acid gas control.

However, since TRC is an existing permitted source with the FGD/baghouse BACT control strategy already required and constructed at the facility under the initial permit action, the construction and operation of the ESP system would result in additional equipment costs. These resulting equipment costs would make this control strategy economically unreasonable. Also, this system would not result in the co-benefit control of SO_2 emissions therefore resulting in increased environmental impact.

Because the Department determined that the FGD/baghouse system would result in the highest control of HCl emissions and would result in a co-benefit SO_2 control, and it was determined that the ESP strategy alone would be economically unreasonable, the Department determined that ESP control alone does not constitute BACT, in this case.

2. Ranking of Available and Technically Feasible HCl Control Technologies

HCl Control Technology	HCl Control Efficiency
FGD and Baghouse with 14% bypass	82%
Wet FGD units with 15% bypass	80%
Fabric filters (baghouses)	44%
ESP	6%

3. Energy, Environmental, and Economic Impacts of available HCl Control Technologies

A complete analysis of the potential energy, environmental, and economic impact of the TRC-specific application of HCl control technologies to the proposed project is detailed in the application for Permit #3175-01 and Permit #3175-03. Based on the information contained in these applications, the Department determined that all above cited technologies constitute feasible control strategies for the TRC project.

4. HCl BACT Determination

In summary, the Department analyzed the use of a FGD/baghouse system, a Wet FGD/Wet ESP system, a baghouse alone, and ESP alone as possible HCl control strategies for the boiler. All of the previously mentioned control strategies are capable of HCl emission reductions. However, since the permitted FGD/baghouse system SO_2 and PM/PM_{10} BACT determinations also result in the highest co-benefit control of HCl emissions, the Department determined, taking into consideration technical, environmental, economic, and other factors determined that the FGD/baghouse control strategy constitutes BACT for the control of HCl emissions in this case. The Department believes that the boiler, operated with the BACT determined FGD/baghouse system, is capable of meeting the established HCl BACT emission limit of 2.17 lb/hr and 0.01125 lb/MMBtu. The periodic HCl source testing requirements and the surrogate compliance monitoring afforded by the PM/PM_{10} and the SO_2 periodic source testing and the SO_2 CAM requirements will adequately monitor compliance with the permitted HCl BACT limit.

D. Boiler Mercury Emissions

Mercury is a trace metal emission resulting from the combustion of fuel containing mercury. Although baghouses effectively control most trace metals, mercury requires additional consideration because it can be emitted as a mixture of solid and gaseous forms. Mercury 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 mercury in the flue gas is termed mercury speciation. Each form of mercury has different physical and chemical characteristics, and conventional pollution control devices have varying control efficiencies for each of the forms. Mercury speciation for a coal-fired boiler would depend upon the combustion characteristics of the boiler as well as the characteristics of the feed coal.

Mercury emissions from a power plant are a function of several factors including fuel mercury content, fuel chlorine content, boiler type and operation, flue gas composition, and the type of emission controls used for criteria pollutants. The mercury 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 mercury concentration of U.S. coal is reported in the Utility RTC to be approximately 7.7 lb/TBtu. Based on available analyses of Bull Mountain coal (TRC contracted coal supplier), the mercury concentration of the fuel used for TRC operations is expected to be approximately 4.2 lb/TBtu. Wood-waste biomass has a lower concentration of Hg; therefore, the following analysis focuses on Hg emissions resulting from coal combustion.

1. Identification of and Technical Feasibility Analysis of Hg Control Technologies

During coal combustion, mercury readily volatilizes from the fuel and is found predominantly in the vapor phase, as either elemental mercury or ionic mercury. Mercury speciation testing indicates that the distribution of ionic mercury (most likely mercury (II) chloride ($HgCl_2$)) and elemental mercury 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 mercury in the flue gas. Specifically, test results indicate that flue gas from subbituminous coals will contain significantly more elemental mercury than flue gas from bituminous coals, while higher concentrations of ionic mercury may be associated with bituminous coals, especially those with high chlorine concentrations. The EPA's Information Collection Request (ICR) testing results for coal-fired power plants including the Mecklenburg, Logan, and SEI plants (for bituminous coal with average chlorine content of 1,100 parts per million (ppm) have indicated that mercury collection efficiency upwards of 97% is possible. Similar mercury testing for emissions from Craig, Rawhide, and NSP Sherburne (for subbituminous coal with an average chlorine content of 170 ppm) have indicated that a mercury collection efficiency of only about 36% is possible (average removal is 24.2%). According to the analyses conducted by Roundup Power, the Bull Mountain coal that would be used at TRC has a maximum chlorine content of about 200 ppm. The typical chlorine content of the Bull Mountains coal will likely be less than 100 ppm. Chlorine content of coal appears to be an indicator of the amount of oxidized mercury that will be present in flue gas (i.e. the higher the chlorine content, the higher chance that the mercury will tend toward oxidized mercury and the lower the chlorine content, the higher the chance that the mercury will tend toward elemental mercury). National testing and research efforts have indicated that elemental mercury appears to be the most difficult form of mercury to control.

Several studies are underway to identify control technologies that may effectively reduce mercury emissions. Most, if not all, of the technologies are in the research/development stage and are not currently commercially available. The particulate form mercury will be controlled as a trace metal or particulate making baghouse control a highly effective control strategy for this form of mercury. Some of the more promising mercury control technologies for elemental mercury and ionic mercury 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.

<u>Sorbent Injection (including Activated Carbon Injection)</u>. Activated carbon injection (ACI) is considered a potential control technology to enhance mercury removal from boiler flue gas. This technology involves the injection of activated carbon into the flue gas duct upstream of a particulate control device. Mercury is adsorbed to the surface of the activated carbon 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 activated carbon injection, including: (1) the temperature of the flue gas; (2) the speciation of mercury in the flue gas; and (3) the flue gas composition.

Pilot-scale studies of activated carbon injection upstream of a baghouse suggest that mercury removal efficiencies and the required amount of activated carbon are apparently temperature dependent. These tests suggest that more mercury 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 activated carbon injection may enhance removal of elemental mercury in a FGD/baghouse system. Removal may be further enhanced with the injection of iodide-impregnated or sulfur-impregnated activated carbon ahead of the system.

Large-scale field tests of ACI on coal-fired electric generating units have demonstrated removal rates of 90 percent and higher. Although no ACI unit has been installed commercially on an electric-generating unit yet, 90-percent and higher mercury capture with ACI is feasible. The technology involves very little capital equipment: a silo to hold the sorbent, and hose, nozzles and pumps to inject it into the flue gas ducts. Tests on such ACI systems continue to show improvement. The removal rates may be further improved when the technology is used along with such additional controls as a fabric filter used for PM control. Some vendors are currently offering ACI to electric generating plant customers and two sales have so far been reported.

The efficiency of ACI in removing mercury from lower ranks of coal, such as subbituminous and lignite, has clearly caught up with ACI's success rate in removing mercury from bituminous coal. In a leading approach, the injection of halogenated sorbents into the gas stream of units burning lower ranks of coal can enable ACI to attain results comparable to those with bituminous coals. Carbon sorbents impregnated with bromine or iodine compounds enhance capture of mercury on subbituminous western coals, which contain lower chlorine levels and are therefore more challenging to clean. Research findings clearly indicate lignite and subbituminous coals behave similarly to each other in terms of mercury speciation and control. For this reason, halogenated sorbents offer much promise for improving mercury capture in these lower ranks of coal. Moreover, the technology can be readily adopted on existing coal-fired boilers.

Although ACI and other sorbent injection technology is becoming more and more technically and economically feasible and the Department has required the installation of ACI (or equivalent) on two coal-fired electric-generating units within the state of Montana, ACI at this time would be economically infeasible for a unit the size of TRC's. In addition, EPA has excluded units with an electrical generation capacity smaller than 25 MW (TRC capacity is 16.5 MW) from the Clean Air Mercury Rule, the regulation that would be encouraging the installation of mercury-specific control on coal-fired units. Therefore, Department determined that activated carbon injection does not constitute BACT, in this case.

FGD Systems. Ionic mercury is water-soluble, and therefore FGD systems may effectively remove ionic mercury from boiler flue gas. EPA's preliminary results from tests of Wet and FGD systems indicate that up to 90% or more of the ionic mercury was captured by these systems. Elemental mercury 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 mercury and ionic mercury. For example, the case-by-case MACT tool predicted that a bituminous PC boiler with SDA, baghouse, and SCR controls would remove 97% of the flue gas mercury, while a subbituminous PC boiler with SDA, baghouse, and SCR controls would remove 23% of the flue gas mercury. The wide range in results suggests that the mercury speciation in the flue gas streams tested varied significantly and/or that other, poorly understood factors affect mercury removal mechanisms.

A study for the recent Montana Roundup Power Project indicates that Bull Mountain coal (TRC's contracted coal supplier) speciation of mercury in the flue gas may tend toward ionic mercury. The permitted BACT determination for FGD system that would be used to control SO_2 emissions should provide effective control of the ionic mercury in the flue gas. More research is required before the level of elemental mercury oxidation can be estimated.

A FGD system is required as BACT for SO_2. Research shows that this control is effective as a co-benefit control for mercury emissions from the boiler. However, because the use of a FGD in combination with a baghouse increases the effectiveness of mercury control and a baghouse is currently required as BACT for PM/PM_{10} emissions from the boiler, the Department determined that a FGD system alone does not constitute BACT for the boiler, in this case.

Enhanced FGD Systems. Another category of mercury control involves the enhancement of existing FGD systems to improve the mercury removal rate. As discussed above, existing FGD systems should effectively remove oxidized (ionic) mercury from flue gas; therefore, methods to improve the capture of elemental mercury are being investigated by EPA and the scientific community. The primary options under investigation involve converting the elemental mercury 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 mercury to more soluble ionic mercury. The primary process to oxidize elemental mercury involves passing the flue gas across a catalyst upstream of the FGD system. Conventional SCR systems may provide some oxidation of elemental mercury, 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.

To the best of the Department's knowledge, Enhanced FGD mercury control technologies are still in the demonstration phase. Therefore, the Department determined that Enhanced FGD is not currently an available control strategy and thus is not a suitable candidate for a full-scale mercury BACT control system at this time. Therefore, the Department determined that Enhanced FGD does not constitute BACT, in this case.

Combination of Conventional Pollutant Control Systems. TRC proposed the use of FGD, baghouses, OFA, and Good Combustion Practices to control the emission of criteria pollutants. The effectiveness of this combination of conventional control systems to reduce mercury emissions will depend on the speciation of mercury in the flue gas. Since TRC has a contract with Bull Mountain Coal, the boilers would burn coal that tends to speciate toward the ionic form, which is water soluble and effectively controlled in a FGD/baghouse system.

A FGD system in combination with baghouse control is required as BACT for SO_2 and PM/PM_{10}, respectively. Because research shows that this control is effective as a co-benefit control for mercury emissions from the boiler and because this control strategy has been used by similar and recently permitted sources in the industry as a means of mercury control, the Department determined that a FGD system in tandem with baghouse control constitutes BACT for the boiler, in this case.

2. Ranking of Available and Technically Feasible Mercury Control Technologies

Mercury Control Strategy	**Mercury Control Efficiency**
Sorbent Injection (Including Activated Carbon Injection)	Variable (see discussion in Section D.1 above)
FGD Systems	Variable (see discussion in Section D.1 above)
Enhanced FGD Systems	Variable (see discussion in Section D.1 above)
Combination of Conventional Pollutant Control Systems	Variable (see discussion in Section D.1 above)

3. Energy, Environmental, and Economic Impacts of available Hg Control Technologies

A complete analysis of the potential energy, environmental, and economic impact of the TRC-specific application of mercury control technologies to the proposed project is detailed in the application for Permit #3175-01 and Permit #3175-03. Based on the information contained in these applications, the Department determined that all above cited technologies constitute technically feasible control strategies for the TRC project.

4. Mercury BACT Determination

The Department determined that the criteria pollutant controls, specifically the FGD and baghouse control, in tandem, required through the BACT analysis for Permit #3175-03 and Permit #3175-01, respectively, constitute BACT control for mercury emissions from the TRC facility, in this case. The Department believes that the emission control monitoring provided by the SO_2 and PM/PM_{10} monitoring requirements will provide surrogate assurance that TRC emission controls are effectively controlling mercury emissions. The Department has also determined that a specific mercury emission limit would be difficult and costly to measure for a coal-fired boiler of this relatively small size and with low mercury emissions. Therefore, in accordance with the definition of BACT contained in ARM 17.8.740, the Department determined that a specific mercury emission limit is not warranted, rather, the Department will require that TRC employ FGD and baghouse control for mercury emissions as the BACT determination, in this case.

E. Boiler H_2SO_4 Emissions

H_2SO_4 is a regulated pollutant of concern resulting from the combustion of coal. H_2SO_4 is typically generated when sulfuric trioxide (SO_3) in the flue gas reacts with water to form H_2SO_4.

1. Identification of and Technical Feasibility Analysis of H_2SO_4 Control Technologies

Four options were analyzed for the H_2SO_4 control technology review. These four options include the following:

- FGD/ Baghouse;
- Wet FGD;
- Wet FGD with WESP; and
- No Additional Controls

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

FGD/Baghouse Control Strategy. Using a FGD system, SO_3 would react with sprayed lime to form calcium sulfate. Because SO_3 is very reactive, approximately 90% of the SO_3 would be removed from the flue gas in the dry-lime scrubber and subsequent reactions in the fabric filter baghouse. The remaining 10% (5 ppm) of the SO_3 would be emitted to the atmosphere, react with water in the atmosphere, and precipitate out of the atmosphere as H_2SO_4.

A FGD system and baghouse control is required under the BACT determination for SO_2 and PM/PM_{10}, respectively. As discussed above, this control results in a highly effective co-benefit control of H_2SO_4 emissions from the boiler. Therefore, because the use of a FGD and baghouse control results in highly effective control of H_2SO_4 emissions and is required as a BACT determination for SO_2 emissions from the boiler, thereby making this strategy feasible for the project, the Department determined that a FGD system and baghouse control constitutes BACT for the boiler, in this case.

Wet FGD with Wet ESP (WESP). While using Wet FGD, H_2SO_4 can be further reduced by using a WESP downstream from the Wet FGD. The H_2SO_4 would be removed from the flue gas stream as a condensable particulate in the WESP. Using WESP in conjunction with wet FGD would reduce the H_2SO_4 emissions by approximately 90%. The remaining 10% (5 ppm) would be emitted to atmosphere.

A FGD system and baghouse control is required as the BACT determination for SO_2 and PM/PM_{10} emissions, respectively. As previously discussed, this control results in a highly effective co-benefit control of H_2SO_4 emissions from the boiler. Therefore, because the use of a FGD and baghouse control results in equally effective control of H_2SO_4 emissions and this strategy is required as a BACT for SO_2 emissions from the boiler, the Department determined that the Wet FGD system with a WESP does not constitute BACT for the boiler, in this case.

Wet FGD. Using a wet FGD system, SO_3 would enter the wet scrubbers and react with the water to form micron sized H_2SO_4 droplets. Because micron sized droplets can pass through the spray levels and the mist eliminator, the droplets can be emitted as H_2SO_4. Although some of the droplets would react with limestone in the wet scrubber, the size of the droplets would prevent the majority of the droplets from contacting the limestone. Approximately 25% of the H_2SO_4 droplets would be captured by this system and approximately 75% (37.5 ppm) of the H_2SO_4 droplets would be released to the atmosphere from this system.

A FGD system and baghouse control is required as the BACT determination for SO_2 and PM/PM_{10} emissions, respectively. As previously discussed, this control results in a highly effective co-benefit control of H_2SO_4 emissions from the boiler. Therefore, because the use of a FGD and baghouse control results in equally effective control of H_2SO_4 emissions and this strategy is required as a BACT for SO_2 emissions from the boiler, the Department determined that a the lesser effective Wet FGD system does not constitute BACT for the boiler, in this case.

No Additional Controls. The base case would result in no additional control of H_2SO_4 from boiler operations. A FGD system and baghouse control is required as the BACT determination for SO_2 and PM/PM_{10}, respectively. As previously discussed, this control results in a highly effective co-benefit control of H_2SO_4 emissions from the boiler. Therefore, because the use of a FGD and baghouse results in highly effective control of H_2SO_4 emissions and is required under the BACT determination for SO_2 emissions from the boiler, thereby making these strategies feasible for the project, the Department determined that no additional control does not constitute BACT for the boiler, in this case.

2. Ranking of Available and Technically Feasible H_2SO_4 Control Technologies

H_2SO_4 Control Strategy	**H_2SO_4 Control Efficiency**
FGD/ Baghouse	90%
Wet FGD	90%
Wet FGD with WESP	25%
No Additional Controls	---

3. Energy, Environmental, and Economic Impacts of available H_2SO_4 Control Technologies

A complete analysis of the potential energy, environmental, and economic impact of the TRC-specific application of H_2SO_4 control technologies to the proposed project is detailed in the application for Permit #3175-01 and Permit #3175-03. Based on the information contained in these applications, the Department determined that all above cited technologies constitute feasible control strategies for the TRC project.

4. H_2SO_4 BACT Determination

The Department determined, based on recent similar source H_2SO_4 BACT determinations, that the use of a FGD/ baghouse control strategy constitutes BACT for H_2SO_4 emissions. For TRC boiler operations, the use of a FGD System and baghouse control was determined to be technologically and economically feasible since this control strategy has been shown to be feasible for the control of SO_2 emissions. H_2SO_4 emissions will be controlled as a co-benefit of the SO_2 BACT requirement for a FGD. The Department has also determined that a specific H_2SO_4 emission limit would be difficult and costly to measure for a coal-fired boiler of this relatively small size and with low H_2SO_4 emissions. Therefore, in accordance with the definition of BACT contained in ARM 17.8.740, the Department determined that a specific H_2SO_4 emission limit is not warranted, rather, the Department will require that TRC employ FGD and baghouse control for H_2SO_4 emissions as the BACT determination, in this case.

Boiler BACT Control Summary and Emission Limits

The boiler BACT analyses summarized above result in the following pollutant specific BACT control technology/strategy and emission limit determinations:

Pollutant	BACT Control Strategy/Technology	BACT Emission Limit
NO_x	OFA/FGR (Combustion Controls)/SNCR	0.196 lb/MMBtu
SO_x	FGD w/Baghouse	0.220 lb/MMBtu
HCl	FGD w/Baghouse	0.01125 lb/MMBtu
Hg	FGD w/Baghouse	Control Requirement Only
H_2SO_4	FGD w/Baghouse	Control Requirement Only

IV. Emission Inventory

Source	PM	PM_{10}	NO_x	CO	SO_x	VOC	Pb	HCl
Babcock & Wilcox boiler (192.8 MMBtu/hr)	0.00	0.00	165.52	218.72	185.78	26.18	0.04	9.50
Boiler Baghouse DC5 (70,000 acfm)	25.86	25.86	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Handling Baghouse DC1 (2,200 acfm)	1.65	1.65	0.00	0.00	0.00	0.00	0.00	0.00
Fuel Handling Baghouse DC2 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Lime Silo Baghouse DC3 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Fly Ash Silo Baghouse DC4 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Bottom Ash Silo Baghouse DC6 (1000 acfm)	0.75	0.75	0.00	0.00	0.00	0.00	0.00	0.00
Vehicle Traffic	5.35	2.41	0.00	0.00	0.00	0.00	0.00	0.00
Cooling Tower	3.01	3.01	0.00	0.00	0.00	0.00	0.00	0.00
Outdoor Coal Storage Operations	0.96	0.83	0.00	0.00	0.00	0.00	0.00	0.00
Outdoor Wood-Waste Storage Operations	0.48	0.48	0.00	0.00	0.00	0.00	0.00	0.00
Disturbed Areas (Berm)	0.22	0.22	0.00	0.00	0.00	0.00	0.00	0.00
Total Emissions	40.54	37.47	165.52	218.72	185.78	26.18	0.04	9.50

Boiler

Heat Input Capacity: 192.8 MMBtu/hr (Permit Limit: 3-hr average)
Operating Hours: 8760 hr/yr

NO_x Emission Calculations

Emission Factor: 0.196 lb/MMBtu (BACT Limit)
Calculations: 0.196 lb/MMBtu * 192.8 MMBtu/hr = 37.78 lb/hr
37.78 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 165.52 ton/yr

CO Emission Calculations

Emission Factor: 0.259 lb/MMBtu (BACT Limit)
Calculations: 0.259 lb/MMBtu * 192.8 MMBtu/hr = 49.92
49.92 * 8760 hr/yr * 0.0005 ton/lb = 218.65 ton/yr

SO_x Emission Calculations

Emission Factor: 0.220 lb/MMBtu (BACT Limit)
Calculations: 0.220 lb/MMBtu * 192.8 MMBtu/hr = 42.42
42.42 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 185.78 ton/yr

VOC Emission Calculations

Emission Factor: 0.0308 lb/MMBtu (BACT Limit)
Calculations: 0.0308 lb/MMBtu * 192.8 MMBtu/hr = 5.93 lb/hr
5.93 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 25.96 ton/yr

Pb Emission Calculations

Emission Factor: 4.9E-05 lb/MMBtu (AP-42, Table 1.6-5, 2/99)
Calculations: 4.9E-05 lb/MMBtu * 156 MMBtu/hr * 8760 hr/yr * 0.0005 ton/lb = 0.03 ton/yr

HCl Emissions

Emission Factor: 0.01125 lb/MMBtu (BACT Limit)
Calculations: 0.01125 lb/MMBtu * 192.8 MMBtu/hr = 2.17 lb/hr
2.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 9.50 ton/yr

Boiler Baghouse – DC5

Air-Flow Capacity: 40,513 dscfm (70,000 acfm)

PM Emission Calculations

Emission Factor: 0.017 gr/dscf (BACT Limit)
Calculations: 0.017 gr/dscf * 40,513 dscfm * 1 lb/7000 gr * 60 min/hr = 5.90 lb/hr
5.90 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 25.86 ton/yr

PM_{10} Emission Calculations

Emission Factor: 0.017 gr/dscf (BACT Limit)
Calculations: 0.017 gr/dscf * 40,513 dscfm * 1 lb/7000 gr * 60 min/hr = 5.90 lb/hr
5.90 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 25.86 ton/yr

Fuel Handling Baghouse – DC1

Air-Flow Capacity: 2,200 cfm

PM Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 2,200 cfm * 1 lb/7000 gr * 60 min/hr = 0.38 lb/hr
0.38 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.65 ton/yr

PM_{10} Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 2,200 cfm * 1 lb/7000 gr * 60 min/hr = 0.38 lb/hr
0.38 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 1.65 ton/yr

Fuel Handling Bin Vent – DC2

Air-Flow Capacity: 1,000 cfm

PM Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

PM_{10} Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Lime Silo Bin Vent – DC3

Air-Flow Capacity: 1,000 cfm

PM Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

PM_{10} Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Fly Ash Silo Bin Vent – DC4

Air-Flow Capacity: 1,000 cfm

PM Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

PM_{10} Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Bottom Ash Silo Bin Vent – DC6

Air-Flow Capacity: 1,000 cfm

PM Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

PM_{10} Emission Calculations

Emission Factor: 0.02 gr/dscf (BACT Limit)
Calculations: 0.02 gr/dscf * 1,000 cfm * 1 lb/7000 gr * 60 min/hr = 0.17 lb/hr
0.17 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.74 ton/yr

Vehicle Traffic

Miles/Round Trip (miles/hr): 0.2036

PM Emission Calculations

Emission Factor: 6 lb/vehicle mile traveled (VMT) (MT-DEQ Guidance Statement)
Calculations: 6 lb/VMT * 0.2036 VMT/hr * 8760 hr/yr * 0.0005 ton/lb = 5.35 ton/yr

PM_{10} Emission Calculations

Emission Factor: 2.70 lb/VMT
Calculations: 2.70 lb/VMT * 0.2036 VMT/hr * 8760 hr/yr * 0.0005 ton/lb = 2.41 ton/yr

Cooling Tower

Operating Capacity: 125 gallon/min
Total Dissolved Solids (TDS) Value: 55,000 ppm (lb TDS/MM lb H_2O)
Drift Factor: 0.02 lb/100 lb H_2O

PM Emission Calculations

0.02 lb drift/100 lb H_2O * 125 gal H_2O/min * 60 min/hr * 8.34 lb/gal * 55,000 ppm = 0.69 lb/hr
0.69 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 3.01 ton/yr

PM_{10} Calculations

0.02 lb drift/100 lb H_2O * 125 gal H_2O/min * 60 min/hr * 8.34 lb/gal * 55,000 ppm = 0.69 lb/hr
0.69 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 3.01 ton/yr

Outdoor Coal Storage

Pile Area: 0.482 acres
Mean Wind Speed: 6.3 mph
PM10 Fraction: 0.848
Control Efficiency: 90% (Earthen Berm, Wind Fence, BMP)

PM Emissions

Emission Factor: 0.22 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.22 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.96 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

PM_{10} Emissions

Emission Factor: 0.19 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.19 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.83 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

Outdoor Wood-Waste Storage

Pile Area: 0.241 acres
Mean Wind Speed: 6.3 mph
Control Efficiency: 90% (Earthen Berm, Wind Fence, BMP)

PM Emissions

Emission Factor: 0.11 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.11 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.48 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

PM_{10} Emissions

Emission Factor: 0.11 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.11 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.48 ton/yr
* Equation derived emission factor considers all relevant factors and assumes 90% control

Disturbed Areas (Earthen Berm)

Pile Area: 0.578 acres
Mean Wind Speed: 6.3 mph
Control Efficiency: 0%

PM Emissions

Emission Factor: 0.05 lb/hr (Equation Derived Factor, AP-42, Table 11.19-4, 07/98)
Calculations: 0.05 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.22 ton/yr
* Equation derived emission factor considers all relevant factors and assumes no control

PM_{10} Emissions

Emission Factor: 0.05 lb/hr (Equation Derived Factor, AP-42, Table 11.19-1, 07/98)
Calculations: 0.05 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 0.22 ton/yr
* Equation derived emission factor considers all relevant factors and assumes no control

V. Existing Air Quality

The air quality classification for the immediate area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for all pollutants. The closest nonattainment area is the Thompson Falls PM_{10} nonattainment area. The boundary is approximately 3.7 miles (6 kilometers (km)) from the proposed facility. Previous ISC3 computer modeling conducted for the permitted project demonstrates that operation of the facility will not adversely impact the Thompson Falls PM_{10} nonattainment area. The current permit action does not result in any increase to allowable or actual PM_{10} emissions from the source; therefore, the current permit action will not result in further impacts to the affected non-attainemnt area. The current permit action results in an increase in allowable short-term (lb/hr based on 1-hr average) emission rates for NO_x and SO_2. However, as part of the complete application for Permit #3175-04, TRC demonstrated compliance with the applicable ambient air quality standards; therefore, the Department determined that the proposed modifications will not result in any significant impacts to existing air quality.

VI. Ambient Air Impact Analysis

TRC's modeled emissions of regulated pollutants are: 237 tpy of NOx, 248 tpy of SO_2, 37.3 tpy of PM_{10}, 26 tpy of VOCs, 219 tpy of CO, and 0.041 tpy of Pb. The modeled NOx and SO_2 emissions rates do not match the allowable NOx and SO_2 emissions rates under Permit #3175-04. However, since the modeled emissions rates for NOx and SO_2 are higher than TRC's permitted allowable NOx and SO_2 emission rates, the model provides a conservative (more protective) analysis of estimated impacts from the proposed project.

The air quality classification for the TRC project area is "Unclassifiable or Better than National Standards" (40 CFR 81.327) for the criteria pollutants. The closest nonattainment area is the Thompson Falls PM_{10} nonattainment area located approximately 3.7 miles west/northwest of the site. The closest Class I areas are the Flathead Indian Reservation, located 37 km east of the site and the Cabinet Mountain Wilderness Area, located 49 km northwest of the site. Bison Engineering, Inc. (Bison) submitted modeling on behalf of TRC.

MODELING PARAMETERS

Emissions of NO_X, SO_2, CO, PM_{10} and Pb were modeled to demonstrate compliance with the MAAQS and NAAQS. The modeling was performed in accordance 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), April 15, 2003.

The modeling used EPA's Industrial Source Complex model with the BPIP-PRIME downwash algorithm (ISC3-PRIME). The Department ran the ISC-PRIME modeling files provided electronically by Bison Engineering Inc. (Bison), to verify the modeling results. TRC's modeling used ten years of surface meteorological data from two sites. The National Weather Service surface data sets for Missoula (1986-1987, and 1989-1991) and Kalispell (1987-1991) were used. Surface met data was processed with corresponding upper air data from the Spokane, Washington NWS station. The processed met data files were provided with the modeling submittal.

Bison modeled emissions from sources at TRC and the adjacent TRL facility. The modeling included point sources, area sources and volume sources; the source parameters are consistent with accepted modeling practice. TRC's ambient air quality boundary is their lease property boundary. Because TRL's PM_{10} emissions dominate the PM_{10} model, however, the ambient air quality boundary for the PM_{10} model is the TRL property boundary. Receptor elevations were generated from digital elevation model (DEM) files using the using 7.5-minute United States Geological Survey (USGS) topographical maps. The ISC-PRIME modeling used a Cartesian grid and boundary receptor system with the following intervals and orientation:

- 50 meter (m) spacing along the TRC lease boundary for CO, SO_2 and NOx modeling;
- 50 meter (m) spacing along the TRL property boundary for PM_{10} modeling;
- 100 m spacing from the proposed fenceline out to 1 kilometer (km);
- 250 m spacing from 1 km to 3 km;
- 500 meter spacing from 3 km to 10 km;
- 100 m spacing beyond 10 km;
- 100 m spacing around the boundary of the Thompson Falls PM_{10} non-attainment area;
- 100 m rectangular grid covering the entire Thompson Falls PM_{10} non-attainment area;
- One receptor at the closest Flathead Indian Reservation boundary; and
- One receptor at the closest Cabinet Mountain Wilderness boundary.

TRC has submitted a series of modeling analyses throughout the permitting history for this facility. The following is a list of modeling submittals used to define the final results of each modeling phase.

- PM_{10} and CO significant impact results are from TRC's Revision 4 modeling, submitted April 23, 2004. This is the last PM_{10} and CO modeling submitted using the TRC lease boundary as the ambient impact boundary. This modeling used the ISC3 model (rather than ISC-PRIME), and used an 8-foot stack diameter (instead of 6-foot), but the results are considered representative for the purpose used.
- PM_{10} MAAQS/NAAQS compliance modeling, including TRC and TRL sources, was final in modeling Revision 7, submitted July 30, 2004. Revision 7 used the TRL property boundary as the ambient air quality boundary as is appropriate for PM_{10} modeling.
- The Department estimated SO_2 and NO_x significant impact modeling results based on the Revision 15 modeling results and a ratio between the permitted emission rates and the modeled emission rates. Revision 15 modeling, submitted January 4, 2006, used a proposed maximum 1-hour emission rate for all NO_x and SO_2 averaging periods and the results were considered a conservative estimate of TRC's impacts.
- SO_2 and NOx impacts for the MAAQS/NAAQS compliance demonstration were calculated as described above.
- The radius of impact (ROI) distances for SO_2 and NO_x are listed as reported in the Revision 15 modeling because it was not possible to recalculate ROI.

SIGNIFICANT IMPACT MODELING

Significant impact modeling is used to establish the need for cumulative impact modeling. TRC's model results from the current application and past submittals are compared to the applicable Class II significant impact levels (SILs) in Table 1. TRC's impacts exceed the SILs for PM_{10}, NO_x and SO_2. The radius of impact (ROI) for each model is included in Table 1. The area within the ROI is referred to as the significant impact area (SIA).

Table 1: TRC Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. ($\mu g/m^3$)	Class II SIL[a] ($\mu g/m^3$)	Significant (Y/N)	Radius of Impact (km)
PM_{10}	24-hr	50 [b]	5	Y	1.3 [b]
	Annual	13.4 [b]	1	Y	1.1 [b]
NO_x	Annual	4.6 [c]	1	Y	10.3
CO	1-hr	1,437 [b]	2,000	N	------
	8-hr	301 [b]	500	N	------
SO_2	3-hr	180 [c]	25	Y	11.5 [d]
	24-hr	73 [c]	5	Y	14.7 [d]
	Annual	5.1 [c]	1	Y	10.3 [d]
O_3	Net Increase of VOC: 26 tpy. Less than 100 tpy, source is exempt from O_3 analysis.				

[a] All concentrations are 1st-high for comparison to SIL's.
[b] PM_{10} and CO impacts are from TRC's April 2004 submittal (Rev. 4).
[c] SO_2 and NOx impacts are estimated based on TRC's Rev. 15 modeling, submitted on January 4, 2006, and the permitted emission rates.
[d] SO_2 and NOx ROI's are based on the Rev. 15 submitted modeling, without adjustment.

TRC's modeling showed significant impacts for PM_{10}, NO_x and SO_2. Cumulative impact modeling was included to demonstrate compliance with the MAAQS and NAAQS for these pollutants. CO impacts from TRC were below the modeling significance so no additional modeling was conducted for CO emissions. Because the TRL mill lies within the SIA for the TRC facility, TRL's sources were included in the MAAQS/NAAQS compliance modeling.

NAAQS/MAAQS COMPLIANCE DEMONSTRATION

NAAQS/MAAQS modeling was conducted for PM_{10}, SO_2, and NO_x emissions from TRC. The ambient analysis included TRL as an existing source for the full impact analysis. No other major stationary sources exist within TRL's SIA or within 50 kilometers beyond the SIA.

Modeling results are compared to the applicable MAAQS and NAAQS in Table 2. Modeled concentrations show the impacts from TRC and TRL sources and include the background values. The Department provided background pollutant values used for this analysis. As shown in Table 2, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 2: NAAQS/MAAQS Compliance Demonstration

Pollutant	Avg. Period	Modeled Conc.[a] ($\mu g/m^3$)	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	106[b]	30	136	150	91	150	91
	Annual	31.3[b]	8	39.3	50	79	50	79
NO_2	1-hr	214[c]	75	289	------	------	564	51
	Annual	3.4[d]	6	9.4	100	9.4	94	10
SO_2	1-hr	433	35	468	------	------	1,300	36
	3-hr	180	26	206	1,300	16	------	-----
	24-hr	73	11	84	365	23	262	32
	Annual	5.1	3	8.1	80	10	52	16

[a] Concentrations are high-second high values except annual averages.
[b] Includes TRC and TRL impacts (from Rev. 7, July 30, 2004).
[c] The ozone limiting method has been applied to this result.
[d] The ambient ratio method has been applied to this result.

THOMPSON FALLS PM_{10} NON-ATTAINMENT AREA MODELING

TRC modeled to determine impacts of their project on the Thompson Falls PM_{10} non-attainment area. A source is not expected to cause or contribute to a violation of the NAAQS in the non-attainment area if the 24-hour modeled impact is less than 5 $\mu g/m^3$ or the annual modeled impact is less than 1 $\mu g/m^3$ (40CFR51, Appendix S). As shown in Table 3, TRC's modeled impacts at the Thompson Falls receptors were below the non-attainment area significant impact levels.

Table 3: PM_{10} Non-Attainment Area Impacts

Pollu-tant	Avg. Period	Concentration ($\mu g/m^3$)		Date and Met Data for H1H Result	Sig. Impact on Non-attainment Area?	Further Modeling Required?
		Modeled High-1st-High	Significance Level			
PM_{10}	24-hr	3.36[a]	5	10-6-87, Missoula	No	No
	Annual	0.29[a]	1	1987, Missoula	No	No

[a] Based on Rev. 7, submitted July 30, 2004.

CLASS I AREA MODELING

TRC modeled SO_2 and NO_x impacts at receptors located at the Flathead Indian Reservation and Cabinet Mountain Wilderness areas. TRC's modeled impacts are compared to Montana's proposed SIL's for Class I areas. Each Class I SIL is equal to 4% of the associated Class I increment. The Class I modeling results are shown in Table 4.

Table 4: TRC Class I Modeling Results (ISC-PRIME)

Pollutant	Avg. Period	Class I Modeled Conc. ($\mu g/m^3$)	Montana Class I SIL[a] ($\mu g/m^3$)	Is TRC Significant? (Y/N)	Met Data Set
Cabinet Mountain Wilderness					
SO_2	3-hr	0.69	1.0	N	1988 Kalispell
	24-hr	0.16	0.2	N	1989 Kalispell
	Annual	0.01	0.1	N	1989 Kalispell
NOx	Annual[a]	0.03	0.1	N	1989 Kalispell
Flathead Indian Reservation					
SO_2	3-hr	0.83	1.0	N	1986 Missoula
	24-hr	0.14[b]	0.2	N	1990 Kalispell
	Annual	0.023	0.1	N	1986 Missoula
NOx	Annual[a]	0.011	0.1	N	1987 Missoula

[a] Class I SIL's found in Montana's Modeling Guideline
[b] SO_2 24-hour impact based on BACT emission limit rather than peak 1-hour emission rate.

CONCLUSIONS

The preceding analysis represents a summary of predicted ambient air quality impacts resulting from the proposed TRC project. A comprehensive and complete dispersion modeling analysis demonstrating compliance with all applicable standards is on file with the Department. Based on this analysis, the Department determined that the proposed project operating in compliance with the applicable requirements contained in Permit #3175-04 is expected to maintain compliance with all applicable standards as required for permit issuance. Modeling has also shown that the project is not expected to adversely impact the Thompson Falls PM_{10} non-attainment area.

VII. Taking or Damaging Implication Analysis

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

VIII. Environmental Assessment

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

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

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued For: Thompson River Co-Gen, L.L.C.
285 – 2nd Avenue West North
Kalispell, MT 59901

Air Quality Permit Number: 3175-04

Preliminary Determination Issued: July 6, 2006
Department's Decision Issued: August 21, 2006
Permit Final: September 6, 2006

1. *Legal Description of Site*: The TRC facility is located in Section 13, Township 21 North, Range 29 West, Sanders County, Montana.

2. *Description of Project*: In accordance with the requirements of the Montana Environmental Policy Act (MEPA) the Department must conduct a systematic interdisciplinary analysis of state actions that have or may have an impact on the human environment affected by a state action. In this case, the state action would be the modification of existing permitted TRC operations. In line with the requirements of MEPA, the Department conducted the following EA for the state action described in this section. The current permit action would allow for modification of the previously permitted TRC operations. Based on Department analysis of the information contained in the complete permit application submitted to the Department on June 9, 2006, the following modifications would be made to Permit #3175-02 under the current permit action:

- Removal of the requirement that the installed sulfur dioxide (SO_2) control equipment meet or exceed 90% SO_2 reduction;
- Modification of the SO_2 control strategy language to specify a general flue gas desulfurization (FGD) unit;
- Modification of the existing SO_2 BACT emission limit of 0.220 pounds per million British thermal unit (lb/MMBtu) based on a 1-hr average to 0.220 lb/MMBtu based on a 30-day rolling average;
- Removal of the BACT determined SO_2 emission limit of 42.42 pounds per hour (lb/hr);
- Inclusion of a worst-case 1-hr maximum SO_2 emission rate of 72.3 lb/hr, except during periods of startup and shutdown;
- Inclusion of a SO_x continuous emissions monitoring system (CEMS);
- Modification of the existing oxides of nitrogen (NO_x) BACT determined emission rate of 0.178 lb/MMBtu based on a 1-hr average to 0.196 lb/MMBtu based on a rolling 30-day average;
- Removal of the BACT determined NO_x emission limit of 34.32 lb/hr;
- Inclusion of a worst-case 1-hr NO_x maximum emission rate of 47.24 lb/hr, except during periods of startup and shutdown;
- Inclusion of NO_x BACT requirement for SNCR and FGR combustion control in addition to the existing OFA combustion control requirement;

- Inclusion of a startup and shutdown plan (Attachment 3) describing the operational conditions which constitute startup and shutdown operations and incorporation of startup and shutdown operational and emission limits including a NO_x emission limit of 74.0 lb/hr and an SO_2 emission limit of 155.0 lb/hr;
- Modification of the hourly boiler heat input limit of 192.8 MMBtu/hr to 192.8 MMBtu/hr based on a 24-hour average and maintenance of the annual boiler heat input limit of 1,688,928 MMBtu/yr based on a rolling 12-month average;
- Removal of the steam production limit of 130,000 lb/hr; and
- Removal of the boiler baghouse fan flow rate of 40,513 dry-standard cubic feet per minute (dscfm).
- Interim cessation of PM_{10} ambient air quality monitoring requirements until initial startup of the boiler after issuance of Permit #3175-04 and continued operations thereafter.

A more detailed analysis of the Department's action would be contained in Section I.D of the permit analysis to this permit.

3. *Objectives of Project*: The purpose of the current permit action would be to allow for proposed changes in required control equipment, applicable emission limits, and facility operations, as appropriate, to bring the constructed facility into compliance with the Clean Air Act of Montana through appropriate permitting of constructed facilities.

4. *Description of Alternatives*: The Department could deny issuance of the modified air quality permit and require that TRC comply with their existing permit. The only other alternative considered was for the Department to take no action. The "no-action" alternative and denial of the permit action were dismissed because TRC demonstrated, to the Department's satisfaction, compliance with all applicable rules and standards as required for modified permit issuance. Furthermore, TRC submitted modeling demonstrating that the project, as proposed, would not cause or contribute to an exceedance of any ambient air quality standard.

5. *A Listing of Mitigation, Stipulations and Other Controls*: A list of enforceable conditions and a BACT analysis would be contained in Permit #3175-04.

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 are reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and do not unduly restrict private property rights.

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

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

Any impacts resulting from the proposed project to terrestrial and aquatic life and habitats would be minor because all proposed activities would take place within the defined TRC property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

Terrestrials (such as deer, antelope, rodents, and insects) would use the general area of the facility. The area around the facility would be fenced to limit access to the facility. The fencing would likely not restrict access from all animals that frequent the area, but it may discourage some animals from entering the facility property. Further, because other industrial sources, including the Thompson River Lumber Company (TRL) and a solid waste disposal facility are located directly adjacent to the proposed TRC property boundary, terrestrials that routinely inhabit the area are accustomed to the industrial character of the site. Therefore, any impacts to terrestrial and aquatic life and habits due to the proposed modified construction and operation of the TRC facility would have minor and typical impacts.

Further, potential increased emissions of NO_x and SO_2 from the proposed permit modification would result in minor impacts to existing terrestrial and aquatic life and habits in the immediate area (see Section VI of the permit analysis and Section 7.F of this EA). The ambient air quality impact analysis of the air emissions from this facility indicates that worst-case impacts from the TRC emissions on land or on surface water would be minor. However, the Department determined, based on TRC's past SO_2 reduction performance, that an SO_2 CEMS would be justified for the proposed project, especially considering the longer-term SO_2 emission limit averaging times deemed BACT under the current permit action. The Department believes that the relatively small amount of air impact would correspond to an equally small amount of deposition in the surrounding area; therefore, any impacts to terrestrial and aquatic life and habits from deposition of air pollutants would be minor.

Overall, any impacts to terrestrial and aquatic life and habits from TRCs proposed permit modifications including construction activities, normal operations resulting in air emissions and deposition of air emissions, and waste-water storage and water use, would be minor.

B. Water Quality, Quantity, and Distribution

Any impacts resulting from the proposed project to water quality, quantity, and distribution would be minor because all proposed activities would take place within the defined TRC property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

Minor impacts to water quality would result from the proposed TRC modification because the modification would result in increased allowable air emissions of NO_x and SO_2. Increased emissions from the proposed permit modification would result in minor impacts to existing water resources in the immediate area (see Section VI of the permit analysis and Section 7.F of this EA). The ambient air quality impact analysis of the air emissions from this facility indicates that worst-case impacts from the TRC emissions on surface water would be minor and the Department believes that the relatively small amount of air impact would correspond to an equally small amount of deposition in the surrounding water resources; therefore, any impacts to water resources from deposition of air pollutants would be minor.

Further, the nature of TRC operations potentially allows for harmful industrial spills to occur at the TRC site. Any accidental spills or leaks from equipment would be subject to the appropriate environmental regulations; therefore, the Department determined that any accidental spills would result in only minor impacts to water quality, quantity, and distribution in the area.

Overall, any impacts to water quality, quantity, and distribution from TRCs proposed permit modifications, including construction activities, normal operations resulting in air emissions and deposition of air emissions, and waste-water storage and water use, would be minor.

C. Geology and Soil Quality, Stability, and Moisture

Any impacts resulting from the proposed project to geology and soil quality, stability, and moisture would be minor because all proposed activities would take place within the defined TRC property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

The impacts from the proposed TRC permit modification to the geology and soil quality, stability, and moisture of the project area would be minor because the facility is a constructed, but non-operational facility. Therefore, since the majority of the facility has already been constructed, little additional ground disturbance and construction activities would be required to accommodate the proposed permit modification. Under the proposed permit modification, TRC did propose some changes to control equipment, which may result in modified construction activities and some disturbance to various areas within the TRC site. However, TRC constructed the facility on leased property previously used for industrial purposes, specifically for lumber manufacturing operations, and, as previously described, the overall nature of the area is industrial. Therefore, the Department determined that the relatively small portion of land that may be disturbed under the permit modification would result in only minor and typical industrial impacts to the existing geology and soil quality, stability and moisture of the project area.

Further, increased allowable air emissions of NO_x and SO_2 from the proposed permit modification would result in minor impacts to existing geology and soil quality, stability and moisture in the immediate area (see Section VI of the permit analysis and Section 7.F Of this EA). Because TRC operations would maintain compliance with the applicable ambient air quality standards, the Department believes that the relatively small amount of air impact would correspond to an equally small amount of deposition in the surrounding area; therefore, any impacts to the geology and soil quality, stability, and moisture of the project area from deposition of air pollutants would be minor.

Overall, any impacts to the geology and soil quality, stability and moisture of the project area from TRCs proposed permit modifications, including construction activities and normal operations resulting in air emissions and deposition of air emissions would be minor.

D. Vegetation Cover, Quantity, and Quality

Any impacts resulting from the proposed project to vegetation cover, quantity, and quality would be minor because all proposed activities would take place within the defined TRC property boundary, an existing industrial site. Further, minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis) would be realized due to dispersion of pollutants.

Minor impacts to vegetation cover, quantity, and quality would result from the proposed TRC modification because the modification would result in changed facility equipment operations and increased short-term (lb/hr based on a 1-hr average) allowable air emissions of NO_x and SO_2 resulting in increased deposition of those pollutants on existing vegetation. The impacts from the proposed TRC permit modification to the vegetation cover, quantity, and quality of the project area would be minor because the facility is a constructed, but non-operational facility. Therefore, since the majority of the facility has already been constructed, little additional existing vegetation disturbance would be required to accommodate the proposed permit modification. Under the proposed permit modification, TRC did propose some changes to control equipment, which may result in modified construction activities and some disturbance to various areas within the TRC site. However, TRC constructed the facility on leased property previously used for industrial purposes, specifically for lumber manufacturing operations. The area in question was previously used as a log storage yard that routinely underwent industrial surface disturbance; therefore, existing on-site vegetation currently consists of transient vegetation that would not be affected by the proposed construction modifications. Therefore, the Department determined that the relatively small portion of land that may be disturbed under the permit modification would result in only minor and typical industrial impacts to the existing vegetation cover, quantity, and quality of the project area.

Further, increased NO_x and SO_2 emissions from the proposed permit modification would result in minor impacts to existing vegetation cover, quantity, and quality of the project area (see Section VI of the permit analysis and Section 7.F of this EA). The ambient air quality impact analysis of the air emissions from this facility indicates that worst-case impacts from the TRC emissions on vegetation would be minor. Because TRC operations would maintain compliance with the applicable ambient air quality standards, the Department believes that the relatively small amount of air impact would correspond to an equally small amount of deposition in the surrounding area; therefore, any impacts to vegetation cover, quantity, and quality of the project area from deposition of air pollutants would be minor.

Overall, any impacts to the vegetation cover, quantity, and quality of the project area from TRCs proposed permit modifications, including construction activities and normal operations resulting in air emissions and deposition of air emissions would be minor.

E. Aesthetics

Minor impacts to the aesthetic nature of the area would result from the proposed TRC modification because the modification would result in changed facility control equipment and increased allowable air emissions of NO_x and SO_2. The changed emission control equipment would be visible from locations around the TRC site. However, because the proposed area of construction is located in a previously disturbed industrial location with a solid waste transfer station and lumber sawmill in relatively close proximity, any aesthetic impacts would be minor and consistent with current industrial land use of the area.

The facility would be visible from MT Highway 200 (approximately ¼ mile to the north), a small residential subdivision (approximately ¾ mile west/southwest), an individual residence (approximately ½ mile west), and may be visible from the Clark Fork River (approximately ¼ mile south and located in the river valley below the proposed site). However, as previously cited, the proposed permit modification would potentially result in only a minor amount of new construction with the majority of TRC structures already built thereby resulting in only a minor impact to the aesthetic nature of the area.

Overall, any impacts to the aesthetic nature of the project area from TRCs proposed permit modifications, including construction activities and normal operations resulting in air emissions and deposition of air emissions would be minor.

F. Air Quality

The air quality impacts from the construction and operation of the proposed modified facility would be minor because Permit #3175-04 would include conditions limiting emissions of air pollution from the source. Specifically, the current permit action would include conditions limiting NO_x, SO_2, and hydrochloric acid gas (HCl) emissions through the application of emission limits and control strategies established under the BACT determination process conducted for the proposed permit modification. In addition, the permit analyzed and established a BACT control strategy for sulfuric acid mist (H_2SO_4) and mercury (Hg) emissions. Lead emissions were evaluated as part of the application process for the initial air quality Permit #3175-00; however, because potential uncontrolled lead emissions from the boiler were shown to be negligible, the permit did not limit these emissions. Under the proposed permit modification, the Department determined that lead emissions would not appreciably increase and would remain negligible; therefore, no further analysis was conducted for potential lead emissions from the proposed permit modification. A summary of the BACT analysis and determination conducted for the proposed permit modification is contained in Section III of the permit analysis to Permit #3175-04. Further, the operations would be limited by Permit #3175-04 to criteria pollutant emissions of less than 250 tons per pollutant during any rolling 12-month time period from non-fugitive sources at the plant.

In addition, the Department determined, based on the ambient air quality dispersion modeling analysis conducted for the proposed permit modification, that the impact from the proposed permit modification would be minor (see Section VI of permit analysis to this permit). The Department believes that facility changes considered under the proposed permit modification would not cause or contribute to a violation of any ambient air quality standard. The Clean Air Act, which was last amended in 1990, requires the U.S. Environmental Protection Agency (EPA) to set NAAQS for pollutants considered harmful to public health and the environment (Criteria Pollutants: carbon monoxide (CO), NO_x, Ozone (O_3), Lead (Pb), particulate matter with an aerodynamic diameter less than or equal to 10 microns (PM_{10}), and SO_2). In addition, Montana has established equally protective or, in some cases, more stringent standards for these pollutants termed Montana Ambient Air Quality Standards (MAAQS). The Clean Air Act established two types of NAAQS, Primary and Secondary. Primary Standards set limits to protect public health, including, but not limited to, the health of "sensitive" populations such as asthmatics, children, and the elderly. Secondary Standards set limits to protect public welfare, including, but not limited to, protection against decreased visibility, damage to animals, crops, vegetation, and buildings. Primary and Secondary Standards are identical with the exception of SO_2 which has a less stringent Secondary Standard. The air quality classification for the immediate area of proposed TRC operation is considered "Unclassifiable or Better than National Standards" (40 CFR 81.327) for all pollutants. The closest nonattainment area is the Thompson Falls PM_{10} nonattainment area located approximately 3.7 miles west/northwest of the TRC site location.

Overall, any impacts to the air quality of the project area from TRCs proposed permit modifications, including construction activities, normal operations resulting in air emissions, and deposition of air emissions would be minor and in compliance with all applicable MAAQS and NAAQS.

G. Unique Endangered, Fragile, or Limited Environmental Resources

Under the initial TRC Permit Action #3175-00, the Department contacted the Montana Natural Heritage Program (MNHP) in an effort to identify any species of special concern associated with the proposed site location. Search results concluded there are 5 such environmental resources in the area. Area in this case is defined by the township and range of the proposed site, with an additional one-mile buffer. The species of special concern identified by MNHP include the *oncorhynchus clarki lewisi* (Westslope Cutthroat Trout), *salvelinus confluentus* (Bull Trout), *felis lynx* (Lynx), *ursus arctos horribilis* (Grizzly Bear), and *clarkia rhomboidia* (Common Clarkia). While the previously cited species of special concern have been identified within the defined area, the MNHP search did not indicate any species of special concern located directly on the proposed site.

The proposed site of construction/operation has historically been used for industrial purposes. Proposed permit modification construction and operational activities would take place within a 6-acre plot of land, leased by TRC and located within the existing 165-acre TRL mill property boundary. Because industrial operations have been ongoing within the existing TRL property boundary for an extended period of time (exceeding 50 years) and potential permitted emissions from the proposed facility show compliance with all applicable air quality standards, it is unlikely that any of these species of special concern would be affected by the proposed project.

Overall, any impacts to any unique endangered, fragile, or limited environmental resources locating in or near the project area from TRC's proposed permit modifications, including construction activities, normal operations resulting in air emissions and deposition of air emissions would be minor.

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

Demands on environmental resources of water, air, and energy would be minor. As previously discussed, the proposed permit modification would increase allowable air emissions of NO_x and SO_2; however, air dispersion modeling demonstrated compliance with the MAAQS/NAAQS. Therefore, any impacts to air resources in the area would be minor and would be in compliance with applicable standards. Any impacts to the local air resource would be minor as demonstrated through the ambient air quality impact analysis conducted for the proposed permit modification.

Regarding impacts to the environmental resource of water, the proposed permit action does not include any increase in the demand for water. Therefore, any impacts to the demand for water resources in the affected area associated with TRC operations has already been analyzed under previous permit actions and determined to be minor.

Further, under the current permit action, additional energy associated with the construction and operation of new emission control strategies may be used at the facility; therefore, minor impacts to energy would occur. TRC would produce approximately 16.5 MW of power with a majority being sold and sent directly to the power grid and the remaining power purchased and used by TRL and TRC facility operations.

Overall, any impacts to the demands on the environmental resources of water, air, and energy from TRCs proposed permit modifications would be minor.

I. Historical and Archaeological Sites

Under the initial Permit Action #3175-00, conducted in 2001, in an effort to identify any historical and archaeological sites near the proposed project area, the Department contacted the Montana Historical Society, State Historic Preservation Office (SHPO). According to SHPO, the absence of recorded cultural/historical properties in the search locale may be due to a lack of previous inventory. Due to the potential for minor additional ground disturbance from the proposed project and the low topography of the area, the potential for the presence of historical/cultural sites that could be impacted by the project does exist. Therefore, SHPO recommended that a cultural resource inventory be conducted prior to project initiation. However, neither the Department nor SHPO has the authority to require TRC to conduct a cultural resource inventory. The Department determined that due to the previous industrial disturbance in the area (the area is an active industrial site with multiple occasions for industrial disturbance) and the small amount of land disturbance that may be required for the proposed permit modification, it is unlikely that any undisturbed existing historical or cultural resource exists in the area and if these resources did exist, any impacts would be minor due to previous industrial disturbance in the area.

J. Cumulative and Secondary Impacts

Overall, any cumulative and secondary impacts from the proposed permit modification on the physical and biological resources of the human environment in the immediate area would be minor due to the fact that the predominant use of the surrounding area would not change as a result of the proposed project. The Department believes that this facility could be expected to operate in compliance with all applicable rules and regulations as would be outlined in Permit #3175-04.

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

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

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

A. Social Structures and Mores
B. Cultural Uniqueness and Diversity

The proposed permit modification would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) or impact the cultural uniqueness and diversity of the area because the proposed modification would not change the current industrial nature of proposed TRC operation or the overall industrial nature of the area of operation. The predominant use of the surrounding area would not change as a result of the proposed project. The proposed modification of the TRC facility would be consistent with the current industrial use of the previously permitted TRC facility. In addition, the overall industrial nature of the surrounding area, as a whole, would not be altered by the proposed TRC permit modification, as the area currently facilitates other industrial sources including the TRL operation and a solid waste transfer station both of which are located directly adjacent to the TRC site, as well as an existing gravel pit in the greater surrounding area.

C. Local and State Tax Base and Tax Revenue

The proposed permit modification would result in minor impact to the local state tax base or tax revenue because the plant would be able to begin normal operations again thereby providing for jobs, which were previously discontinued due to TRC's inability to comply with the existing air quality permit. However, any impacts would be minor because, regardless of the modified equipment and operational practices, TRC would still be responsible for all appropriate state and county taxes imposed upon the business operation. In addition, TRC employees, and any temporary construction/contract workers employed by TRC for the purpose of constructing the modified facility, would continue to add to the overall income base of the area.

D. Agricultural or Industrial Production

The proposed permit changes would not displace or otherwise affect any agricultural land or practices. The proposed site of construction and operation was previously used as a log storage yard by TRL and has since accommodated the construction of the TRC facility. In addition, the proposed modifications would result in only a minor and beneficial impact on local industrial production because TRC would be allowed to resume operations as a result of the proposed permit modification. TRC would provide power and steam for normal operations at TRL.

E. Human Health

There would be minor potential effects on human health due to the increased allowable air emissions of NO_x and SO_2 requested under the proposed permit modification. However, Permit #3175-04 would include 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.

As detailed in Section 7.F of this EA, the Clean Air Act established two types of NAAQS, Primary and Secondary. Primary Standards set limits to protect public health, including, but not limited to, the health of "sensitive" populations such as asthmatics, children, and the elderly. Under the proposed permit modification, TRC conducted an ambient air quality impact analysis demonstrating that TRC operations, as proposed under the permit modification, would comply with all applicable ambient air quality standards thereby protecting human health. Overall, the Department determined, based on the ambient air impact analysis for the proposed permit modification, that any impact to public health would be minor.

F. Access to and Quality of Recreational and Wilderness Activities

The proposed permit modifications and overall TRC operations would not affect access to any recreational or wilderness activities in the area. After permit modification, the TRC operation would continue to be located within the 165-acre plot that was previously used for TRL's lumber mill operations. The area is comprised of private property with no public access and would continue in this state after modification of the permit.

The proposed operations may have a minor effect on the quality of recreational or wilderness activities in the area by its physical and visible presence and by creating additional noise and/or odors in the area. However, as previously stated, the area in question is currently utilized for industrial purposes and would not change from the current industrial status as a result of the proposed project.

G. Quantity and Distribution of Employment
H. Distribution of Population

The proposed permit modification would result in minor impacts to the quantity and distribution of employment in the area and/or the distribution of population in the area because the project would allow TRC to continue previously discontinued employment opportunities for approximately 15 full-time positions, upon completion of the modified facility. Construction employment may realize a small increase, as the proposed permit modification may require the construction of changed air emissions control equipment. Any increased construction employment would be temporary thereby minimizing any impact to the quantity and distribution of employment and the distribution of population in the area. Overall, any impact to the quantity and distribution of employment and distribution of population in the area would be minor as a result of the proposed permit modification.

I. Demands on Government Services

Demands on government services from the proposed permit modification would be minor because TRC would be required to procure the appropriate permits (including local building permits and a state air quality permit) and any permits for the associated activities of the project. Further, compliance verification with those permits would also require minor services from the government.

In addition, minor increases may be seen in traffic on existing roads in the area during the construction phase of the proposed permit modifications. As the proposed site is within an existing industrial location, employee water and sewage disposal facilities would continue to be connected to existing water and sewer sources. Further, all process water needs for the facility operations would remain unchanged as a result of the proposed permit modification. All spent water (waste-water) would continue to be discharged to an evaporation pond to be located on site and would therefore not require the use of any county or state services, including permitting. Overall, any demands on government services resulting from the proposed permit modification would be minor.

J. Industrial and Commercial Activity

The proposed permit modification would change various aspects of the previously permitted TRC operations but would not result in an overall change in facility purpose; therefore, the proposed permit modification would not impact any industrial or commercial activity in the area beyond those impacts already realized through the initial Permit Action #3175-00.

K. Locally Adopted Environmental Plans and Goals

The City of Thompson Falls is a PM_{10} nonattainment area. The PM_{10} nonattainment area boundary is located approximately 3.7 miles west/northwest of the proposed modified facility. However, the proposed permit modification does not propose any change in allowable PM_{10} emissions. Therefore, the proposed permit modification would not contribute to the nonattainment status of the area. Because the proposed permit modification would not allow any additional PM_{10} emissions, the Department determined that the proposed permit modification would not adversely impact the local Thompson Falls PM_{10} nonattainment area.

The Department is unaware of any other locally adopted Environmental plans or goals. The state air quality standards would protect air quality at the proposed site and the environment surrounding the site.

L. Cumulative and Secondary Impacts

Overall, cumulative and secondary impacts from the proposed permit modification on the economic and social resources of the human environment in the immediate area would be minor due to the fact that the predominant use of the surrounding area would not change as a result of the proposed project. The Department believes that this facility could be expected to operate in compliance with all applicable rules and regulations as would be outlined in Permit #3175-04.

Recommendation: An EIS is not required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The current permit action is for the modification of an existing and permitted electrical-steam co-generation plant. Permit #3175-04 includes conditions and limitations to ensure the facility will operate in compliance with all applicable rules and regulations. In addition, there are no significant impacts associated with this proposal.

Other groups or agencies contacted or which may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program, Montana Department of Natural Resources and Conservation, Montana Department of Environmental Quality – Water Protection Bureau.

Individuals or groups contributing to this EA: Department of Environmental Quality – Air Resources Management Bureau, Montana Historical Society – State Historic Preservation Office, Natural Resource Information System – Montana Natural Heritage Program, Montana Department of Natural Resources and Conservation, Montana Department of Environmental Quality – Water Protection Bureau.

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