THOMPSON RIVER CO-GEN, LLC a Colorado Company Complainant vs. AVISTA CORPORATION, dba Avista Utilities a Washington Corporation Respondent	))))))))))	Case No. AVU-E-05-07

EXHIBIT No. 6

to

Direct Testimony of
L.Underwood, Thompson River Co-Gen, LLC

Mike Underwood

From: Mike Underwood [lmuco@msn.com]
Sent: Tuesday, April 26, 2005 12:58 PM
To: Barry *Bates; Fred Busch; H. Benson Lewis; Kelly Flint; Kim Christensen; Todd L Savage
Subject: Fw: TRC QF Negotiations.
Attachments: TRC-Project Description.doc; TRC Presentation-AVA.ppt; TRC-NWE-Delivery Agreement.DOC; TRC-Plot.pdf; TRC-Air Permit.pdf; Savage O&M Agt..pdf

----- Original Message -----
From: Thompson, Mark
To: dave.milller@avistacorp.com
Cc: lmuco@msn.com
Sent: Tuesday, April 26, 2005 9:46 AM
Subject: TRC QF Negotiations.

Dave:
We appreciate your response and communication to date regarding the TRC Project and possible QF agreement. Thompson River Co-gen has requested that I initiate the follow-up to your March 11th letter. Attached you will find information, which should be sufficient to beginning contract negotiations under the "Avista Utilities (Idaho Territory) Avoided Cost Rates for Fueled Projects Smaller than Ten Megawatts". The team from TRC will be Mike Underwood, Benson Lewis, and myself. Mike has requested a meeting in early May to begin discussions. TRC has reviewed the draft contract that you provided and would like to have an electronic (word) version if possible. Mike Underwood's email address is lmuco@msn.com <mailto:lmuco@msn.com>.

As we have discussed, NorthWestern has agreed provide QF energy firming, shaping and firm transmission from TRC to Burke for 10 MW flat. In anticipation of such, NWE and TRC have drafted a Delivery Agreement (attached), which is nearly identical to the Delivery Agreement with Tiber Montana for the Tiber / IPC QF Agreement, which has been approved by the IPUC and is currently in effect.

Therefore, in effect, NWE is assuming the performance risk of the TRC Project. TRC will provide AVA any material requested to demonstrate that they are maintaining QF status (Co-Generation status - Coal-based topping cycle cogeneration facility)

I realize that you and your team may have additional questions, which we can easily discuss. TRC would like to proceed in developing and filing a contract with the IPUC by mid-June, with commencement of energy in October, or as mutually agreed amongst the parties. Please feel free to contact myself or Mike

Underwood (303-534-1119) with any questions. Thank you.

Mark Thompson

<<TRC-Project Description.doc>> <<TRC Presentation-AVA.ppt>> <<TRC-NWE-Delivery Agreement.DOC>> <<TRC-Plot.pdf>> <<TRC-Air Permit.pdf>> <<Savage O&M Agt..pdf>>

Thompson River CoGen, LLC

Project Location:

Thompson River CoGen, LLC

249 Airport Road

Thompson Falls, MT 59873

Contact Information:

Thompson River Co-Gen, LLC *

Attn: Mike Underwood

1610 Wynkoop St, Suite 100

Denver, CO 80202

Phone: 303-534-1119

** Thompson River Co-Gen, LLC is a Colorado LLC.*

TRC Project Description:

Thompson River Co-Gen ("TRC") is a coal and biomass cogeneration facility located approximately four miles outside of Thompson Falls, Montana (on Highway 200). Project commissioned in December 2004.

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- FERC compliant.
- Air Quality Permit in effect issued by the MT Department of Environmental Quality.
- Water Permit
- Waster Water Permit

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- **Electricity.**
  - Proposed twenty-year PURPA electric energy sales agreement to Avista (Idaho service territory) for 87,600 MWHs per year. (10 MW per Hour, firm)
    - Via firming, shaping and transmission agreement with NorthWestern.
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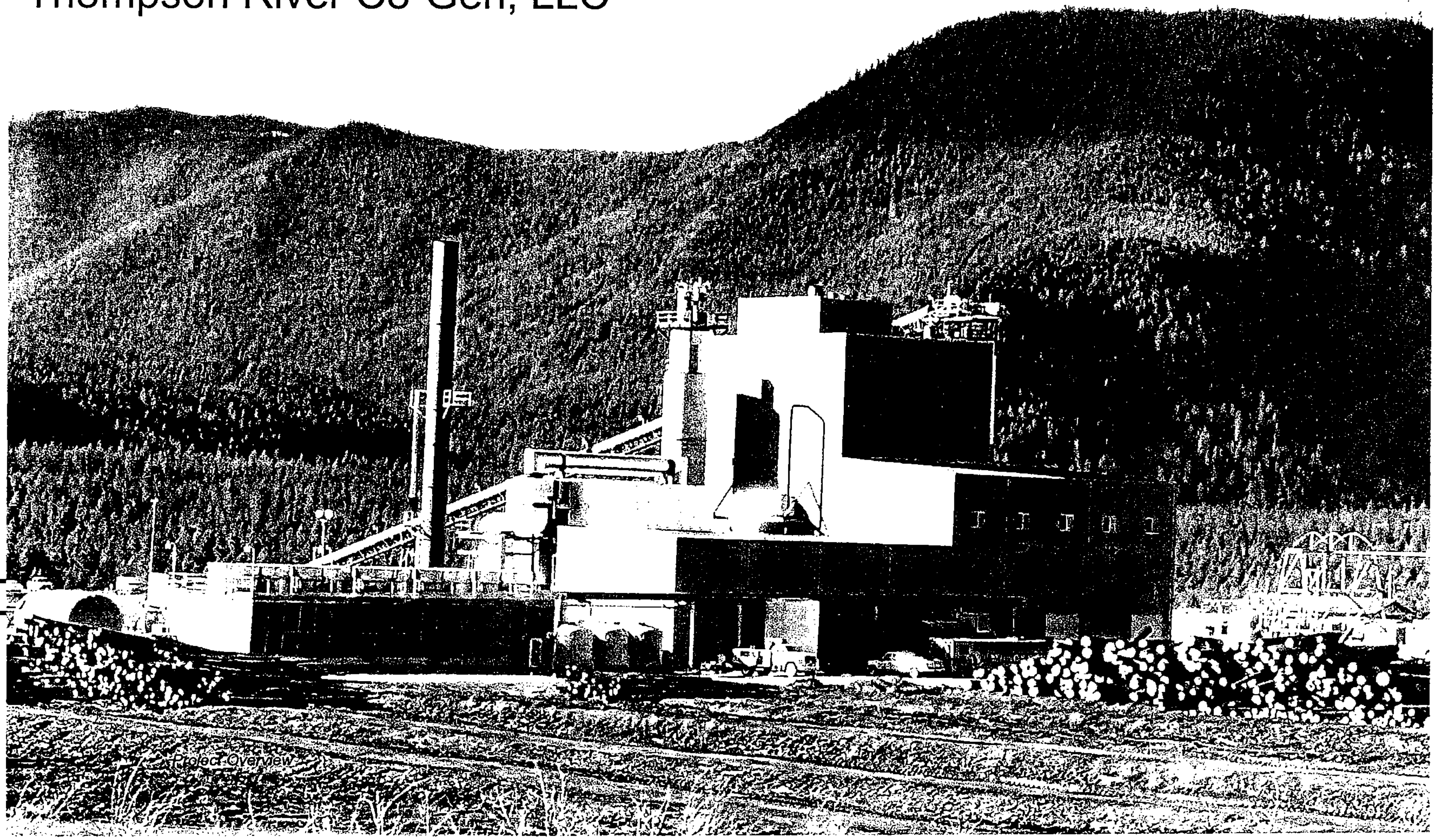
  - Electric energy sale to Thompson River Lumber under 35-year PPA.
- **Steam Sales**
  - Extraction steam sale agreement (66MM lbs) to Thompson River Lumber.
- **Fuel Supply**
  - Long-term, fixed price coal agreement with Roundup Trading International from the Bull Mountain Mine, located in Eastern Montana, which meet all permit and unit specifications.
  - Long-term coal transportation agreement with Montana Rail Link, including dedicated lease cars from Savage Companies, Inc.
  - Various waste wood supply agreements with Thompson River Lumber and other suppliers in the area.

Thompson River Co-Gen, LLC



Thompson River Cogeneration LLC Partners

- **Savage Companies, Inc. (41% owner) – Providing Operations & Management Services**
  - Privately Owned Diversified Business Operations since 1946
  - Over 50 Operations in 26 States, Canada, and Africa. Headquartered in Salt Lake City.
  - National Leader in Providing Materials Management and Transportation Systems and Facilities To A Wide Range of Industries
  - Extensive Experience Dealing With Utilities and Independent Power Production
  - Savage Services, Inc. has Contracted with TRC to provide cost-based O&M services.

- **Barry Bates, age 50 (25% owner)**
  - Business Owner/Developer
  - Owner - Professional Recovery Systems – Denver, CO
  - 18 Years Investment Banking Experience – Denver, CO
  - Active investor

- **Michael Underwood, age 52 (34% owner) – Managing Partner**
  - Business Owner in Denver
  - Owner - Professional Recovery Systems – Denver, CO,
  - LMU & Company – Denver, CO
  - 20+ Years Investment Banking, Mergers and Acquisition Experience - Denver, CO

Key Team Members

- **TIMEC Constructors and Factory Sales & Engineering, Inc**
  - Provide Equipment, Procurement & Construction (EPC) services.

- **RDI Consulting**
  - Various RDI Consultants assisting on project feasibility, financial modeling, fuel procurement strategy, electric market analysis, purchase power contracting strategy and implementation, and other strategic issues.

- **NTL Engineering & Geoscience, Inc.**
  - Provided geotechnical survey and analysis.

- **Bison Engineering (Environmental Engineers to TRC)**
  - Harold W. Robbins
    - Mr. Robbins is President of Bison Engineering and has more than 25 years of experience in air quality work. He has a B.A. degree in physics and an M.S. degree in environmental studies.
    - Mr. Robbins has been the project manager for many PSD and NSR permit applications for power generation stations, the lime manufacturing industry, petroleum refineries, a coal-liquefaction facility, compressor stations, wood products facilities, and many other industries. As a project manager, he has worked on numerous emission inventories, Best Available Control Technology analyses, ambient monitoring networks, and source tests. Hal is also an expert on air quality dispersion modeling.
    - Mr. Robbins was formerly Chief of the Montana Air Quality Bureau

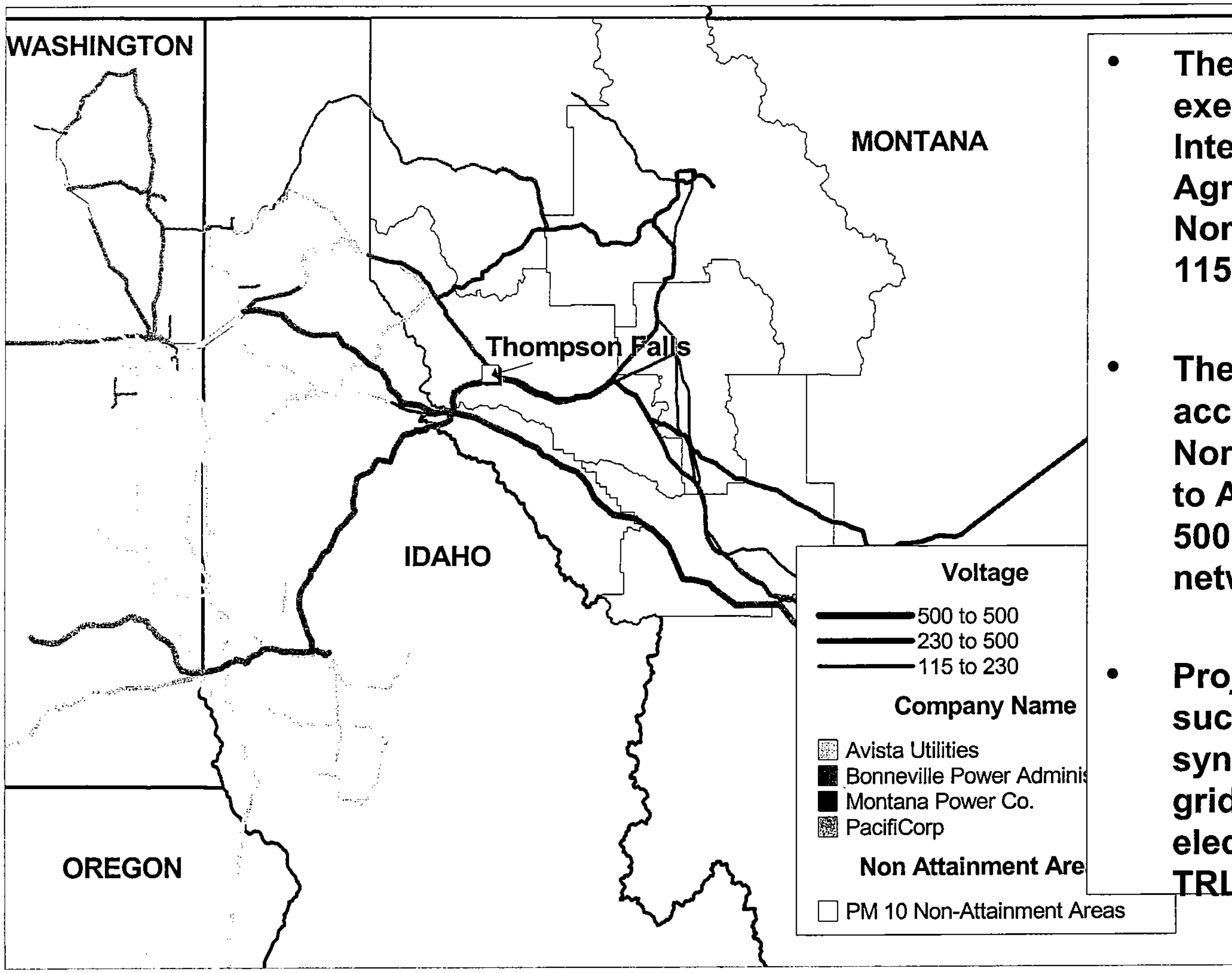
Independent Engineer Review

- Stone & Webster has reviewed the Project and provided a fatal flaw analysis.
- NorthWestern engineering review and oversight of Project substation and Electric Interconnection
- Department of Environmental Quality has performed review of emissions specifications.
- RTI provides continued ASTM laboratory analysis on coal quality and performance specifications for the Project.

Project Highlights & Specifications

- **Site – Adjacent to Thompson River Lumber**
  - 9-Acre site, located in Sanders County on Montana State Highway 200 adjacent to the Clark Fork River.
- **Equipment**
  - Project Equipment was independently evaluated and inspected by industry professionals.
  - Babcock & Wilcox 130,000 lbs/hr @850 PSIG, 900° boiler, with a reconditioned 16.5 megawatt ("MW") Elliot condensing steam turbine (13,500 heat rate).
  - Detroit Stoker 4-feeder moving grate system, incl. control and equipment updates.
  - Allen Bradley controls and plc packaged by CPL Systems, Inc.
  - Marley Sigma, five-cell cooling tower.
  - Andersen 2000 scrubber and six cell bag house, six cells of approximately 1,100 bags.
  - Water treatment facilities include pre-filter, softener and reverse osmosis de-mineralizer for boiler make up.
  - Fuel yard for 6,000+ ton coal pile, and a 3,000 ton wood-waste pile, supplied by Montana Rail rink spur and 500 ton coal offloading facility.
- **Transmission Interconnection**
  - Schweitzer Engineering Laboratories switchgear and GE 13.2 to 115 kV step up transformers with dual switch breakers provide substation interconnection with NorthWestern.
- **Fuel Supply – Plant engineered & permitted to burn coal and / or wood waste without restrictions**
  - TRC has a 10-year, fixed price coal contract, with a TRC optional 10-year extension, providing 100% of the Project's coal requirements.
  - Project permitted and sited to operate on fuel blends from 100% coal to 100% wood-waste.

Area Transmission Infrastructure



- The Project has executed a Generation Interconnection Agreement with NorthWestern on the 115 kV system (in red)
- The Project maintains access from NorthWestern's system to Avista and BPA's 500 kV transmission network (in green)
- Project currently has successfully synchronized to the grid and is providing electricity and steam to TRL and NorthWestern.

Energy Output Products

- **TRC proposes wholesale electricity contracts with Avista Corp and NorthWestern**
  - 20-year PURPA (Qualifying Facility) contract with **Avista Corp.** **(76% of TRC Output.)**
    - 10 MW firm, base-load contract, delivered by NorthWestern, as scheduling agent.
  - 20-year PPA with **NorthWestern** for Surplus Energy **(18% of TRC Output.)**
    - NorthWestern is the Scheduling Agent and Transmission Provider.
    - NorthWestern firms, shapes and delivers energy to Avista Corp.
    - NorthWestern purchases excess energy.
- **Thermal & Electric Sales to Thompson River Lumber**
  - TRC has a 45-year agreement with Thompson River Lumber (TRL) to provide the mills electric requirements. Average busbar netback of $40.00 per MWH. **(6% of TRC Output)**.
  - TRC also provides approximately 60+ MM pounds of steam annually to TRL under a 45-year agreement, displacing less efficient boilers. (Steam sales represent approximately 15% of the total thermal energy output of TRC.)

Fuel Supply Overview

Coal Supply:

- **Bull Mountain Mine**, Northern Powder River Basin, Roundup Trading International, LLC
- Up to a 20 Year, fixed price contract with minimal escalation secured for 100% of the fuel requirements.

Specifications:

10,450 Btu/Lb	.5 Lbs SO_2/MMBtu
18% Moisture By Weight	<1% Sodium By Weight
<8% Ash	

Pricing:

Fixed Price /Ton, loaded in the car, first ten years, escalating at 1.5% for the following ten years.

Transportation:

- **Montana Rail Link** (Lockwood (mine staging/loading site) to Woodlin (the Project site).
- Fixed Price / Ton with 1.5% per year escalation (includes rail and dedicated equipment) during the ten-year agreement.

Wood Waste:

- **Thompson River Lumber** wood-waste supply supply for up to 40% of total fuel requirements.
- Negotiated agreements with other lumber mills and the US Forest Service.

Permitting Overview

- **Air Quality Permit #3175-01**
  - Final, non-contestable Air Permit issued in November 2004, which allows the Project to operate as designed. The project is designed with a sophisticated EMS to monitor and insure compliance with emission controls for SOx and NOx, CO, and HCl
  - The project can operate with fuel blend, with up to 100% coal as the exclusive fuel input.

- **The Project is FERC compliant and meets the standards for a coal-based topping-cycle cogeneration qualifying facility.**

- **Water Permit**
  - Thompson River Lumber (land owner) required to supply plant water requirements.
  - 250 GPM, 403 Acre-Feet, Interim ground water permit issued. Interim ground water sufficient to maintain complete plant operations.
  - Existing TRL surface water rights sufficient to satisfy Mill requirements, with potential to submit "change of use" permit request.

- **Water Discharge Permit**
  - Existing, lined retaining pond sufficient to maintain plant operations.
  - Water discharge permit, pending, which will enhance Project economics.

DELIVERY AGREEMENT
BETWEEN
THOMPSON RIVER CO-GEN, L.L.C.
AND
NORTHWESTERN ENERGY

This Agreement, entered into this _____ day of May, 2005, is by and between Thompson River Co-Gen, L.L.C., a Colorado Limited Liability Company, ("TRC"), and NorthWestern Corporation d/b/a NorthWestern Energy, a Delaware Corporation ("NWE"). TRC and NWE are sometimes referred to in this Agreement collectively as "Parties" and individually as "Party."

RECITALS

I. WHEREAS, TRC maintains the rights to all QF energy from an electric coal / wood-waste generation project located near Thompson Falls, Montana with a nameplate capacity of 14.0 MW ("Facility"); and

II. WHEREAS, Avista Corp ("QF Buyer") desires to purchase from TRC, and TRC desires to sell to QF Buyer, a quantity of firm QF energy produced from the Facility, and energy provided by NWE so that the energy deliveries to Avista Corp will be in compliance with item 2 listed below and as identified in Attachment A of this Delivery Agreement ("Attachment A") or as modified by mutual agreement of the Parties, during each calendar year beginning in October 2005 and continuing for a period of twenty (20) years; and

III. WHEREAS, NWE will facilitate such deliveries to QF Buyer, as long as the agreement between the QF Buyer and TRC is in effect in accordance with the general terms and conditions set forth herein.

Therefore, the Parties agree to the following basic terms and conditions:

1. NWE will accept the TRC QF energy generated by the Facility into its energy portfolio.

2. NWE will provide a hourly flat, firm QF energy schedule from its system to the Point of Delivery ("POD") with the QF Buyer on behalf of TRC, as identified in Attachment A, beginning on the Contract Date and subsequently each period for each year for the duration of 20 years.

3. NWE has obtained and agrees to maintain firm transmission capacity reservations (or like reservations) from the NWE system and any other required transmission entity in order to deliver the energy as specified in the Firm Energy Sales Agreement between Avista Corp and Thompson River Co-Gen L.L.C. to the QF Buyer's POD in the amount equal to the quantity each month, as designated in Attachment A, and consistent with the general terms and conditions of the NWE Open Access Tariff.

4. NWE, as the exclusive scheduling agent for TRC, will provide a pre-schedule of the QF energy deliveries to the QF Buyer in accordance with the scheduling, remedial action and checkout protocols of the Western Energy Coordinating Council (WECC) and North American Reliability Council (NERC). TRC will maintain timely access to the final checkout of the energy schedules each month.

5. The hourly firm energy schedule facilitated by the firm transmission reservation shall be equal to the quantity set forth in Attachment A and shall remained unchanged for the duration of the month, unless such deliveries are interrupted by an event of force majeure, or are curtailed by the QF Buyer or by the transmitting entity consistent with its Open Access Tariff and Prudent Electric Practices on firm transmission.

6. NWE will provide all necessary ancillary services, such as reserves, to provide the product described in Paragraph 2, above.

7. TRC shall compensate NWE for the firm transmission, energy losses, shaping and scheduling services.

8. The Parties agree that the QF Buyer is a third party beneficiary of this Agreement.

9. Nothing in this Agreement shall supersede anything in the Firm Energy Sales Agreement between Avista Corp and Thompson River Co-Gen L.L.C.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names by their authorized officers.

NorthWestern Corporation, d/b/a
NorthWestern Energy

____
By:
Title:

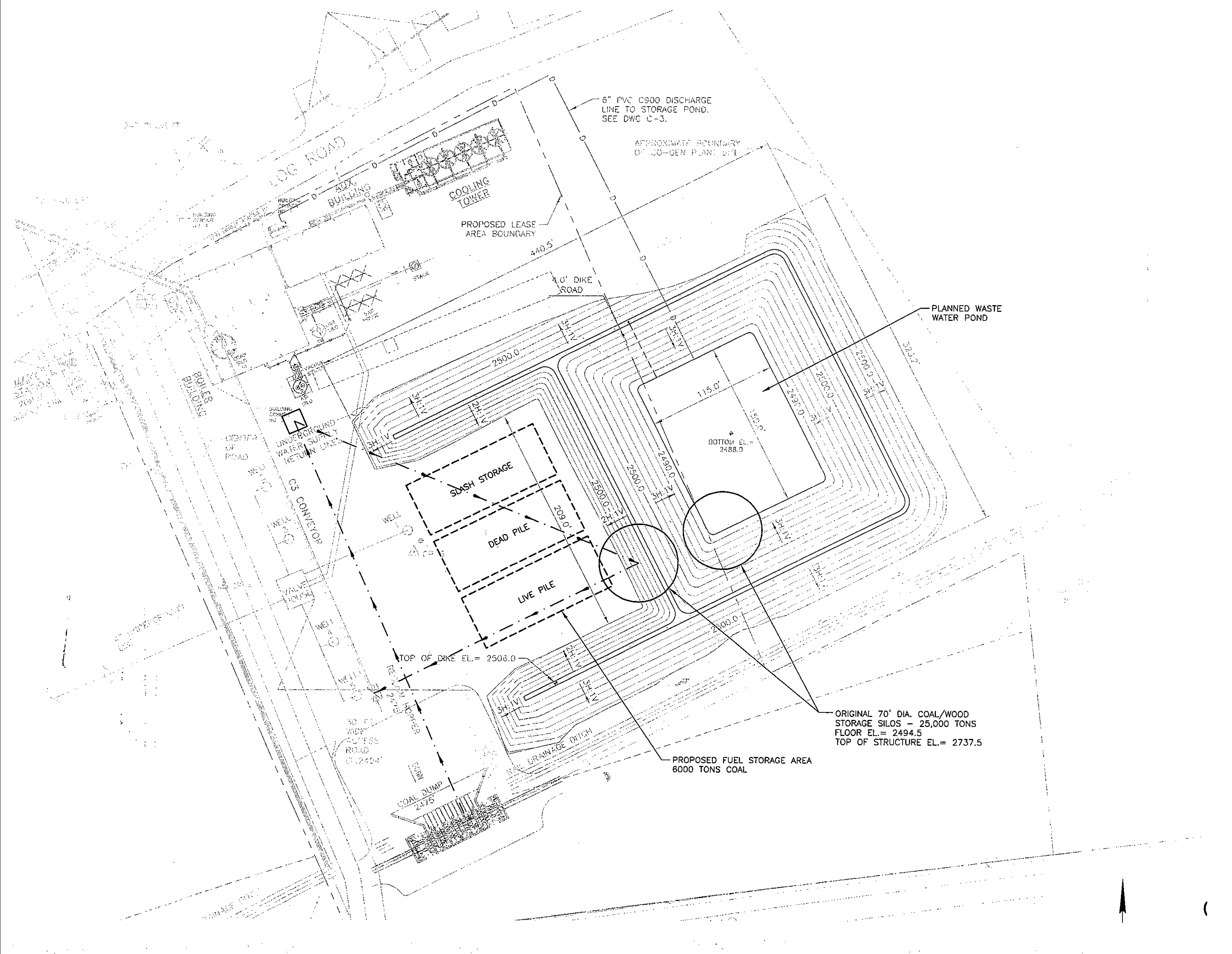
Thompson River Co-Gen, L.L.C.

____
By: Michael Underwood
Title: Managing Partner

Attachment A

Month	Hourly Exchange Energy	Monthly Exchange Energy	POD
January	10	7,440	Burke
February	10	6,720	Burke
March	10	7,440	Burke
April	10	7,200	Burke
May	10	7,440	Burke
June	10	7,200	Burke
July	10	7,440	Burke
August	10	7,440	Burke
September	10	7,200	Burke
October	10	7,440	Burke
November	10	7,200	Burke
December	10	7,440	Burke

- Daylight Savings and Leap year schedules will reflect the hourly nomination stated above.
- Monthly Exchange Energy is defined for easy calculation purposes only.
- POD may be modified as mutually agreed by QF Buyer , TRC & NWE.



6" PVC C900 DISCHARGE LINE TO STORAGE POND. SEE DWG C-3.
APPROXIMATE BOUNDARY OF CO-GEN PLANT SITE
LOG ROAD
AUX. BUILDING
COOLING TOWER
PROPOSED LEASE AREA BOUNDARY
440.5'
STACK
4.0' DIKE ROAD
BOILER BUILDING
UNDERGROUND WATER SUPPLY RETURN LINES
CENTER OF ROAD
C3 CONVEYOR
WELL
VALVE HOUSE
SLASH STORAGE
DEAD PILE
LIVE PILE
209.0'
2500.0
2490.0
115.0'
150.0'
BOTTOM EL.= 2488.0
3H:1V
2H:1V
323.0'
PLANNED WASTE WATER POND
TOP OF DIKE EL.= 2506.0
RECLAIM HOPPER
30 FT. WIDE ACCESS ROAD
COAL DUMP 2475
DRAINAGE DITCH
ORIGINAL 70' DIA. COAL/WOOD STORAGE SILOS – 25,000 TONS FLOOR EL.= 2494.5 TOP OF STRUCTURE EL.= 2737.5
PROPOSED FUEL STORAGE AREA 6000 TONS COAL

Thompson River CoGen, LLC

Project Location:

Thompson River CoGen, LLC
249 Airport Road
Thompson Falls, MT 59873

Contact Information:

Thompson River Co-Gen, LLC *
Attn: Mike Underwood
1610 Wynkoop St, Suite 100
Denver, CO 80202
Phone: 303-534-1119

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AIR QUALITY PERMIT

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

Permit: #3175-01
Application Complete: 09/07/04
Preliminary Determination Issued: 10/08/04
Department's Decision Issued: 11/05/04
Final Permit Issued: 11/23/04
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 proposes to operate 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 will be located approximately 3.7 miles east-southeast of Thompson Falls, MT. 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 September 7, 2004, the Montana Department of Environmental Quality (Department) received a complete application for proposed changes to the permitted TRC operations. Based on the information contained in the complete permit application, various permit changes have been proposed under the current permit action. A detailed description of the proposed permit modification is contained in Section I.D of the permit analysis for this permit.

Further, because many of the proposed permit changes 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.A, Ambient Air Quality Impacts, of the permit analysis for this permit.

SECTION II: Conditions and Limitations

A. Operational Conditions

1. Boiler steam production shall be limited to a maximum of 130,000 pounds per hour (lb/hr) (ARM 17.8.749).

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

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

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

5. Oxides of nitrogen (NO_x) emissions from the Boiler shall be controlled by the use of over-fire air (OFA) (ARM 17.8.752).

6. Sulfur dioxide (SO_2) emissions from the Boiler shall be controlled by a dry-lime scrubber when combusting coal (ARM 17.8.752).

7. The control efficiency of the SO_2 emission control equipment shall be maintained at a minimum of 90% based on a rolling 30-day average. The SO_2 control efficiency shall be established as detailed in 40 CFR 60.45(b) (ARM 17.8.340, ARM 17.8.752, and 40 CFR 60, Subpart Db).

8. 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).

9. 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).

10. Hydrochloric acid (HCl) gas, sulfuric acid mist (H_2SO_4), and mercury (Hg) emissions from the Boiler shall be controlled by a dry-lime scrubber in combination with a fabric filter baghouse (ARM 17.8.752).

11. The Boiler may be fired with coal and/or wood-waste biomass only except for periods of Boiler start-up when diesel or propane fuel may be used (ARM 17.8.749).

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

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

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

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

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

17. 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).

18. The boiler pre-heater shall be equipped with an automatic shut-off device, which is activated when the coal feeder becomes operational. Boiler pre-heater operations shall be limited to start-up, 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).

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

20. 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).

21. 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).

22. 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).

23. 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 baghouse (Fuel Handling Baghouse – DC2) (ARM 17.8.752).

24. 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 a Fuel Handling Baghouse – DC1 and/or DC2 (ARM 17.8.752).

25. 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).

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

27. 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).

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

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

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

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

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

33. TRC shall install and operate a Continuous Opacity Monitoring System (COMS) to monitor opacity from the Boiler (ARM 17.8.340 and 40 CFR Part 60, Subpart Db).

34. 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).

35. 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).

36. 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 in Section II.A.35 (ARM 17.8.749).

37. 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 40 CFR Part 60, Subpart Db).

B. Emission Limitations

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 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).

3. All boiler emission limits shall be calculated on a 1-hour averaging time. Emissions from the Boiler shall not exceed the following (ARM 17.8.752):

   a. NO_x Emissions:

      i. 0.178 lb/MMBtu; and
      ii. 34.32 lb/hr

   b. CO Emissions:

      i. 0.259 lb/MMBtu; and
      ii. 49.92 lb/hr

c. SO_2 Emissions:

i. 0.220 lb/MMBtu; and
ii. 42.42 lb/hr.

d. PM/PM_{10} Emissions:

i. 5.90 lb/hr; and
ii. 0.017 gr/dscf.*
iii. The Boiler I.D. fan shall be limited to a maximum flow rate of 40,513 dscfm (ARM 17.8.749).

* The grain loading limit in Section II.B.3.d(ii) is the Boiler Baghouse (DC5) limit.

e. VOC Emissions:

i. 0.0308 lb/MMBtu; and
ii. 5.93 lb/hr.

f. HCl Emissions (ARM 17.8.749 and ARM 17.8.752):

i. 0.01125 lb/MMBtu; and
ii. 2.17 lb/hr and 9.50 ton/yr

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

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

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

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

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

C. Testing Requirements

1. Compliance with the PM/PM_{10} emission limits for the Boiler/Boiler Baghouse – DC5 shall be determined 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. After the initial source test, testing shall continue annually or according to another testing /monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60.8, and 40 CFR Part 60, Subpart Db).

2. Compliance with the CO limits for the Boiler shall be determined 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. The testing shall continue on an every 2-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, 40 CFR Part 60, Subpart A, and 40 CFR Part 60, Subpart Db).

3. Compliance with the SO_2 emission limits for the Boiler shall be determined 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. After the initial source test, testing shall continue annually or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105).

4. Compliance with the HCl emission limits for the Boiler shall be determined 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. 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 (ARM 17.8.105).

5. 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).

6. Compliance with the PM/PM_{10} limits for the Fuel Handling Baghouse – DC1 shall be determined 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. 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 (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).

7. Compliance with the PM/PM_{10} limits for the Fuel Handling Baghouse – DC2 shall be determined 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. 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 (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).

8. Compliance with the PM/PM_{10} limits for the Lime Silo Bin Vent – DC3 shall be determined 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. 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 (ARM 17.8.105,ARM 17.8.749, ARM 17.8.752).

9. Compliance with the PM/PM_{10} limits for the Fly Ash Silo Bin Vent – DC4 shall be determined 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. 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 (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).

10. Compliance with the PM/PM_{10} limits for the Bottom Ash Silo Bin Vent – DC6 shall be determined 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. 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 (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).

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

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

D. 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. TRC shall submit the required information annually to the Department by February 15 (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 as required in Section II.E.1. 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 hour, the Boiler steam production in pounds per hour. TRC shall maintain a steam production monitoring system capable of demonstrating compliance with the hourly steam production limit contained in Section II.A.1 (ARM 17.8.749).

7. 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/month during each of the previous 12 months for use in verifying compliance with the limitation in Section II.A.2. The information for each of the previous 12 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).

8. TRC shall document, by hour, the boiler heat input value in MMBtu/hr. TRC shall maintain a heat input monitoring system capable of demonstrating compliance with the hourly heat input limit contained in Section II.A.2. 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).

9. TRC shall document, by month, the coal feed rate to the boiler. By the 25th day of each month, TRC shall total the coal feed to the boiler during each of the previous 12 months for use in verifying compliance with the limitation in Section II.A.3. The information for each of the previous 12 months shall be submitted along with the annual emission inventory (ARM 17.8.749).

10. TRC shall document compliance with the SO_2 percent reduction requirement contained in Section II.A.7. Documentation shall be in accordance with the applicable provisions contained in 40 CFR 60, Subpart Db (ARM 17.8.749 and 40 CFR 60, Subpart Db).

11. TRC shall maintain records monitoring compliance with the fuel use requirements specified in Section II.A.11 (ARM 17.8.749).

12. TRC shall maintain records monitoring compliance with the coal type and heating value requirements specified in Section II.A.12 (ARM 17.8.749).

13. 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 during each of the previous 12 months for use in verifying compliance with the limitation in Section II.A.17. The information for each of the previous 12 months shall be submitted along with the annual emission inventory (ARM 17.8.749).

14. 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 during each of the previous 12 months for use in verifying compliance with the limitation in Section II.A.20. The information for each of the previous 12 months shall be submitted along with the annual emission inventory (ARM 17.8.749).

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

16. 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).

E. Monitoring Requirements

1. TRC shall install, operate, and maintain the applicable COMS/CEMS listed in Section II.A. Emission 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 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.

2. All stack testing that is required (in Section II.C) 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 prior to commencement of testing (ARM 17.8.106 and ARM 17.8.749).

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

F. Ambient Air Monitoring

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 (ARM 17.8.749 and ARM 17.8.204).

G. Notification

1. Within 15 days after actual startup of the Boiler, TRC shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

2. Within 15 days after actual startup of the fabric filter baghouse for the under truck hopper used for fuel unloading and handling, TRC shall notify the Department of the date of actual startup (ARM 17.8.749).

3. Within 15 days after actual startup of the fabric filter baghouse for the fuel storage and handling system, TRC shall notify the Department of the date of actual startup (ARM 17.8.749).

4. Within 15 days of actual startup of the bin vent dust collector for the lime silo, TRC shall notify the Department of the date of actual startup (40 CFR Part 60.7 and ARM 17.8.749).

5. Within 30 days after commencement of construction of the Bottom Ash Dust Collector – DC6 for the bottom ash silo, TRC shall notify the Department of the date of commencement of construction (ARM 17.8.749).

6. Within 15 days after actual startup of the Bottom Ash Dust Collector – DC6 for the bottom ash silo, TRC shall notify the Department of the date of actual startup (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) 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

Ambient Air Monitoring Plan
Thompson River Co-Gen, LLC

1. This ambient air monitoring plan is required by Montana Air Quality Permit (MAQP) #3175-01, 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 #3175-01.

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 30-089-0008	Thompson River Co-gen	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:

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

or

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

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

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 all 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	Time 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	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 duration of excess emissions	2. Total CEMS downtime
3. $\left[\frac{\text{Total duration of excess emissions}}{\text{Total time CEM operated}} \times 100 = \right]$	3. $\left[\frac{\text{Total CEMS downtime}}{\text{Total time source emitted}} \times 100 = \right]$

1 For opacity, record all times in minutes. For gases, record all times in hours. Fractions are acceptable (e.g., 4.06 hours)

2 CEMS downtime shall be regarded as any time CEMS is not measuring emissions.

Permit Analysis
Thompson River Co-Gen., L.L.C.
Permit #3175-01

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 and 1,688,928 MMBtu/yr	PM/PM_{10} – Baghouse (40,513 dry standard cubic feet per minute (dscfm) capacity flow SO_2 – Dry Flue Gas Desulfurization Unit (Dry FGD) or Dry Lime Scrubber Hg – Dry FGD/Baghouse Acid Gases (HCl and H_2SO_4) – Dry FGD/Baghouse NO_x – Over-Fire Air (OFA)
Wet Cooling Tower	NA
Fuel Handling Operations (Coal)	Enclosures, Fuel Handling Baghouse – DC1 (2,200 acfm) and DC2 (1,000 acfm)
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 Dust Collector – DC3 (1,000 dscfm)
Bottom Ash/Fly Ash Storage and Handling Operations	Enclosures, Fly Ash Dust Collector – DC4 and Bottom Ash Dust Collector – DC6 (1,000 dscfm/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 Start-Up Pre-Heater	Limited to 60 MMBtu/hr (total combined heat input); Diesel or Propane-Fired Only; Start-Up, 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; Start-Up, Shutdown, Malfunction, and Boiler Commissioning Operations Only; and Maximum of 500 Hours of Operation Per Year Per Heater

B. Source Description

TRC will operate 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 limited to a maximum of 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.

The relationship between TRC and TRL is symbiotic, however, because the two sources 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 will incorporate various emission control devices to limit potential pollutant emissions from each source.

The Boiler will use OFA to control oxides of nitrogen (NO_x) emissions, a combination of low sulfur coal ($\leq$ 1% sulfur by weight) and a Dry FGD in tandem with the boiler baghouse to control sulfur dioxide (SO_2) emissions, the same Dry 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 will first enter the dry-lime scrubber then pass through the Boiler baghouse and eventually vent to the atmosphere through the Boiler main stack.

The Boiler will fire low-sulfur coal and/or wood waste bio-mass only, except for periods of start-up, shutdown, malfunction, and Boiler commissioning where the 60 MMBtu/hr propane or diesel fired boiler pre-heater will be 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 will be delivered by railcar and unloaded to an under-track hopper. Air displaced from the under-track hopper will be vented to DC1. Some coal will be stored in the under track hopper while the majority of coal will be 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 will be transferred, via a front-end loader, to a 3-sided feed hopper and on to a 200 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 will be vented to DC1 while air displaced from the transfer between C2 and S1 will vent to DC2. Additionally, wood waste will be delivered to the site for storage until use is needed. Wood-waste biomass will be 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 will be transferred to the adjacent TRL, for processing into fuel grade wood-waste. After processing at the TRL site, the fuel grade wood-waste will be pneumatically transferred through an enclosed pneumatic conveying system to the TRL boiler. After reaching the TRL Boiler, the wood-waste will enter a cyclone (CS1), and then be transferred directly into the boiler through the OFA ports. Air entering the boiler via the wood-waste biomass pneumatic feed will be directly vented through the boiler baghouse (DC5). The transfer of fuel from S1 to the Boiler will be controlled by negative pressure from the boiler.

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

Combustion in the Boiler will produce bottom ash and fly ash. The ash will be temporarily stored in silos on site including fly-ash silo (S4) and bottom-ash silo (S5). Bottom-ash from S5 will be gravity-fed through a partial enclosure (3-sided enclosure) to a truck for removal from the site while fly ash from S4 will be 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 will be vented to DC4 and DC6.

A cooling tower will be 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 125 gallons per minute. Water for the cooling tower will come from the Clark Fork River. TRC will use a portion of the water rights granted to TRL to acquire the water for operations. Cooling tower water will be discharged to an on-site evaporation pond.

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.

D. Current Permit Action

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 have been proposed for Permit #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 current permit action would result 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 is provided in the permit analysis to this permit;
- 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 Permit #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 to this permit;
- 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 to this permit;
- Revisions to the previously permitted ash handling operations for the addition of a second ash handling baghouse 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 to this permit;
- 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, under the current permit action, 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 has 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 to this permit.

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 Dry 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).

The Department decision incorporates the above-cited changes. Permit **#3175-01** replaces Permit #3175-00.

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. <u>ARM 17.8.105 Testing Requirements</u>. 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.

3. <u>ARM 17.8.106 Source Testing Protocol</u>. 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 section 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 section 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 section 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 #3175-01 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 section 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.

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 section 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 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_x, 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 October 16, 2003, 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 this permit analysis.

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

9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving 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 proposed 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 do sit 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. PTE > 100 ton/year of any pollutant; or

   b. PTE > 10 ton/year of any one Hazardous Air Pollutant (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 Air Quality Permit #3175-01 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 being made under the current permit action 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 this permit action.

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 #3175-00 and expanded upon through the current permit application for Permit #3175-01. The BACT analysis for Permit #3175-01 addresses some available methods of controlling NO_x, CO, PM/PM_{10}, SO_x, VOC, HCl, mercury

(Hg), and sulfuric acid mist (H_2SO_4) emissions from the Boiler, PM/PM_{10} emissions from fuel (coal and wood-waste biomass) material handling and storage operations, and Boiler pre-heater and Boiler refractory curing heater operations at the TRC site.

The Department reviewed these methods, as well as previous BACT determinations for similar permitted sources. As described below, various control options were reviewed by the Department for the purpose of making the following pollutant specific BACT determinations. The Environmental Protection Agency's (EPA) Draft New Source Review Workshop Manual (October 1990) (NSR Manual) states that "historically, EPA has not considered the BACT requirement as a means to re-define the design of the source when considering available control technologies." However, the NSR Manual goes on to indicate "...this is an aspect of the New Source Review – Prevention of Significant Deterioration permitting process in which states have the discretion to engage in a broader analysis if they so desire." In this case, since part of the proposed project is the modification of an existing and previously permitted coal and wood-waste fired Boiler, the Department determined that the analysis of potentially inherently lower polluting processes including, but not limited to, integrated gasification combined cycle (IGCC) and circulating fluidized bed (CFB) coal combustion technologies, is not appropriate.

A. Pollutant-Specific BACT Review and Determination for the Boiler

Under the BACT

Under the current permit action, TRC proposed the construction and operation of a 192.8 MMBtu/hr heat input capacity coal and wood-waste fired Babcock and Wilcox spreader stoker boiler (Boiler). This Boiler has been constructed at the TRC site and is approximately 20% larger than the 156 MMBtu/hr-capacity boiler analyzed through the BACT process and permitted under Permit #3175-00. Because of the increased Boiler heat input capacity, the Department determined that the constructed Boiler constitutes a modified emitting unit and is subject to BACT review under the current permit action. The PM, PM_{10}, NO_x, CO, VOC, and SO_x BACT analyses submitted and reviewed for TRC's initially proposed 156 MMBtu/hr boiler are adequate for the Boiler under the proposed permit modification because it is the same boiler technology with the same available options for controlling emissions. The previous BACT analyses result in the same BACT control technology/strategy determinations in either case, as demonstrated in the following pollutant specific BACT analyses for the Boiler.

1. Boiler NO_x Emissions

The most recent RACT/BACT/LAER Clearinghouse (RBLC) Ranking Report for NO_x emissions from boilers was used as reference in the following NO_x BACT Analysis. Uncontrolled NO_x emissions from sub-bituminous (Bull Mountain coal) coal-fired utility boilers generally range from 0.5 to 1.5 lb/MMBtu on a heat input basis, with spreader-stoker boilers, similar to the proposed Boiler, averaging 0.5 lb/MMBtu (AP-42, Section 1.1, Table 1.1-3). Most of the NO_x emissions from Boiler operations will be fuel NO_x derived from fuel bound nitrogen. In addition, thermal NO_x can result when the intense heat of combustion causes atmospheric nitrogen to combine with atmospheric oxygen.

The Department determined that the new NO_x BACT emission limit for the Boiler is 0.178 lb/MMBtu calculated on a 1-hour average and 34.32 lb/hr. These limits are within the appropriate range for established BACT determinations/limits for other recently permitted similar sources contained in the RBLC.

Applicable NO_x control strategies for the Boiler can be divided into two main categories: combustion controls, which limit NO_x production, and post-combustion controls, which destroy NO_x after formation. The following NO_x control strategies/technologies, listed from the top or most effective control strategy down to the lowest control strategy, were identified as being technologically feasible control options and were reviewed for the current permit action. The most recent RBLC ranking report for NO_x from boilers of this type was used as reference. The following control strategies were determined to be "available" control strategies for the Boiler:

a. Selective Catalytic Reduction (SCR) – Achieve 75-85% NO_x Reduction;
b. Selective Non-Catalytic Reduction (SNCR) – Achieve 30-60% NO_x Reduction;
c. OFA – Achieve 20-30% NO_x Reduction;
d. Low Excess Air (LEA) – Achieve 10-20% NO_x Reduction; and
e. Flue Gas Re-circulation (FGR) – Minimal NO_x Control Efficiency.

NO_x Emission Control Options

The following analysis explains and summarizes the available NO_x control options/ strategies for the proposed project. A complete analysis is contained in the permit application for Permit #3175-00 and #3175-01:

a. SCR NO_x Emission Control

SCR is a post combustion gas treatment technique that uses a catalyst to reduce nitrogen oxide (NO) and nitrogen dioxide (NO_2) to molecular Nitrogen, water, and oxygen. Ammonia (NH_3) is commonly used as the reducing agent. Ammonia vaporized and injected into the flue gas upstream of the catalyst bed combines with NO_x at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water.

The catalyst lowers the temperature required for the chemical reaction between NO_x and NH_3. Catalysts used for the NO_x reduction include base metals, precious metals, and zeolites. Commonly, the catalyst of choice for the reaction is a mixture of titanium and vanadium oxides. An attribute common to all catalysts is the narrow "window" of acceptable system temperatures. In this case, the temperature window is approximately 575°F to 800°F. At temperatures below 575°F, the NO_x reduction reaction will not proceed, while operation at temperatures exceeding 800°F will shorten catalyst life and can lead to the oxidation of NH_3 to either nitrogen oxides (thereby increasing NO_x emissions) or possibly generating explosive levels of ammonium nitrate in the exhaust gas stream. The stack temperature for the Boiler is approximately 300°F making the use of SCR technically difficult.

Other factors impacting the effectiveness of SCR include catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of NH_3 injection system, and the potential for catalyst poisoning.

As previously described, the use of SCR invokes various technical problems including the narrow "window" of acceptable system temperatures, short catalyst life, a possible increase in NO_x production due to high operating temperatures, and the possible production of explosive levels of ammonium nitrate. In addition, various physical problems exist including limited placement locations for the catalyst and limited physical spacing for an in-line duct burner to raise temperatures. Also, the burning of various combinations of coal and wood waste bio-mass leads to varying contaminant/particulate loading to the SCR unit increasing the potential to foul and ultimately deactivate the catalysts. If the SCR is placed downstream of the baghouse, additional fuel costs will be incurred. Finally, the annual operating/maintenance costs of SCR have been shown to be $14,678/ton of NO_x reduction making the cost effectiveness of SCR control economically unreasonable compared to other recently permitted similar sources. Therefore, based on the previously discussed technical and economic feasibility concerns, the Department determined that SCR does not constitute BACT, in this case.

b. SNCR NO_x Emission Control

SNCR involves the non-catalytic decomposition of NO_x to nitrogen and water. A nitrogenous reducing agent, typically ammonia or urea, is injected into the upper reaches of the furnace. Because a catalyst is not used to drive the reaction, temperatures of 1,600°F to 2,100°F are required.

NO_x removal efficiency varies considerably for this technology, depending on inlet NO_x concentrations, fluctuating flue gas temperatures, residence time, amount and type of nitrogenous reducing agent, mixing effectiveness, and the presence of interfering chemical substances in the gas stream.

However, similar to SCR described above, technical difficulties exist for SNCR application. Since SNCR requires a flue gas temperature of 1,600°F to 2,100°F, additional burners would be required to raise the flue gas temperature. Additional burners would produce additional emissions and consume additional energy resources. In addition, physical considerations limit the placement of reagent injection nozzles and an in-line duct burner to raise temperatures. Finally, annual operating/maintenance costs of SNCR have been shown to be approximately $107,091/ton of NO_x reduction making the cost effectiveness of SNCR control economically unreasonable compared to other recently permitted similar sources. Therefore, the Department determined that SNCR does not constitute BACT, in this case.

c. OFA NO_x Emission Control

OFA allows for staged combustion by supplying less than the stoichiometric amount of air theoretically required for complete combustion through the burners, with the remaining air injected into the furnace through over-fire air ports. Having an oxygen-deficient primary combustion zone in the furnace lowers the formation of NO_x. In the previously described atmosphere, most of the fuel nitrogen compounds are driven into the gas phase. Having combustion occur over a larger portion of the furnace lowers peak flame temperatures, thus, limiting thermal NO_x formation.

Poorly controlled OFA may result in increased CO and hydrocarbon emissions, as well as unburned carbon in the resultant fly ash. These products of incomplete combustion would be accompanied by a decrease in boiler efficiency. OFA may also lead to reducing conditions in the lower furnace that in turn may lead to corrosion. When using OFA with stoker boilers, too much OFA can result in too little under-fire air caused by a diversion of combustion air to OFA ports. Further, OFA may lead to overheating and slagging of the grate.

Because OFA is intrinsic to the design of the boiler as combustion control and is capable of achieving significant NO_x reductions within the range of other recently permitted similar sources identified in the RBLC, the Department considers the use of OFA to be BACT for control of NO_x emissions from the Boiler. Further, the established BACT emission limit of 0.178 lb/MMBtu is within the emission limit range of other similar and recently permitted sources. The Department is confident that NO_x monitoring will ensure compliance, as TRC is required to demonstrate compliance with this limit through the utilization of a continuous NO_x emission monitoring system (CEMS).

d. LEA NO_x Emission Control

LEA operation involves lowering the amount of combustion air to the minimum level compatible with efficient and complete combustion. Limiting the amount of air fed to the furnace reduces the availability of oxygen for the formation of fuel NO_x and lowers the peak flame temperature inhibiting thermal NO_x formation.

Emission reductions achieved by LEA are limited by the need to have sufficient oxygen present for flame stability and to ensure complete combustion. As excess air levels decrease, emissions of CO, hydrocarbons, and unburned carbon increase, resulting in lower boiler efficiency. Other technical problems with LEA operation include the possibility of increased corrosion and slagging (formation of large agglomerates of solidified ash) in the upper boiler as a result of the reducing atmosphere created at low oxygen levels. Further, because stoker boilers use primary combustion air to cool the grate, overheating of the grate may occur with LEA operation.

As previously described, the use of LEA invokes various technical problems including decreased boiler efficiency, increased corrosion and slagging, and possible over-heating of the grate. Therefore, the Department determined that LEA does not constitute BACT, in this case.

e. FGR NO_x Emission Control

FGR systems control NO_x by recycling a portion of the cooled flue gas back into the primary combustion zone. The recycled air lowers NO_x emissions by two separate mechanisms. First the recycled gas is made up of combustion products that act as inerts during combustion, thereby lowering combustion temperatures. Second, the oxygen content in the primary flame zone is lowered. The amount of re-circulation is limited by flame instability, increased CO concentrations, and reduced boiler efficiency. Typically, 15-20% of the total flue gas is recycled. Lower temperatures and altered temperature profiles attributable to FGR may result in reduced boiler efficiency.

Because FGR reduces thermal NO_x formation and has only a minor effect on fuel NO_x levels, its principal application is for oil and gas fired boilers. However, FGR is also applicable to coal fired stoker boilers; by replacing the combustion air flowing through the grate, it allows operation at reduced excess air levels without grate over-heating. Retrofitting FGR onto existing boilers requires installation of ductwork, re-circulation fans, air foils for re-circulated flue gas, and combustion air and controls for variable load operation. Because the proposed boiler would require retro-fitting to facilitate FGR, retro-fitting was factored into the incremental cost of installation, under the BACT analysis.

As previously described, the use of FGR invokes various technical problems including the need to retro-fit the existing Boiler with ductwork, re-circulation fans, air foils for re-circulated flue gas, and combustion air and controls for variable load operation. Therefore, due to the technical difficulties associated FGR the Department determined that FGR does not constitute BACT, in this case.

NO_x BACT Control Summary

In summary, the Department analyzed the use of SCR, SNCR, OFA, LEA, and FGR as technically feasible and available NO_x control strategies for the Boiler. Taking into consideration technical, environmental, economic, and other factors, as previously discussed, the Department determined that OFA constitutes BACT for the control of NO_x emissions from the Boiler, in this case. The Boiler, operated with the BACT-determined OFA system, is capable of meeting the established NO_x BACT emission limit of 0.178 lb/MMBtu. Further the required NO_x CEMS and periodic source testing requirements will adequately monitor compliance with the permitted BACT limit.

2. Boiler CO Emissions

The CO BACT analysis was conducted using information from the *Office of Air Quality Planning and Standards Control Cost Manual,* 5th Edition, February 1996 (OAQPS Manual). The most recent RBLC ranking report for CO from boilers was also used as reference.

The Department determined that the new CO BACT emission limit for the Boiler is 0.259 lb/MMBtu calculated on a 1-hour average and 49.92 lb/hr. These limits are within the appropriate range for established BACT determinations/limits for other recently permitted similar sources contained in the RBLC.

The following control strategies were determined to be available control strategies for the Boiler.

a. Post-Combustion Oxidation;
b. Proper Design and Combustion

CO Emission Control Options

The following analysis explains and summarizes the available CO control options. A complete analysis is contained in the applications for Permits #3175-00 and #3175-01.

a. Post-Combustion Oxidation

Although various specialized technologies exist, fundamentally, oxidizers, or incinerators, use heat to destroy CO in the gas stream. Incineration is an oxidation process that ideally breaks down the molecular structure of an organic compound into carbon dioxide and water vapor.

Temperature, residence time, and turbulence of the system affect CO control efficiency. A thermal incinerator generally operates at temperatures between 1,450°F and 1,600°F. Catalytic incineration is similar to thermal incineration; however, catalytic incineration allows for oxidation at temperatures ranging from 600 to 1,000°F. The catalyst systems that are used are typically metal oxides such as nickel oxide, copper oxide, manganese dioxide, or chromium oxide. Noble metals such as platinum and palladium may also be used. Due to the high temperatures required for complete destruction, fuel costs can be expensive and fuel consumption can be excessive with oxidation units. To lower fuel usage, regenerative thermal oxidizers (RTOs) or regenerative catalytic oxidizers (RCOs) can be used to preheat exhaust gases.

As previously described, oxidation of post-combustion gases invokes various technical problems including the need for high combustion temperatures and subsequent increased fuel use. The use of RTO's and/or RCO's can decrease those fuel use needs. However, the cost effectiveness of using RTO or RCO was determined to be $402,677/ton of CO reduction and $416,154/ton of CO reduction, respectively, making oxidation of post-combustion gases economically unreasonable compared to other recently permitted similar sources. Therefore, the Department determined that oxidation of post-combustion gases does not constitute BACT, in this case.

b. Proper Design and Combustion

In an ideal combustion process, all of the carbon and hydrogen contained within the fuel are oxidized to carbon dioxide (CO_2) and water. The emission of CO in a combustion process is the result of incomplete organic fuel combustion.

Reduction of CO can be accomplished by controlling the combustion temperature, residence time, and available oxygen. Normal combustion practice at the TRC facility will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel usage. This efficiency of fuel combustion will also minimize CO formation.

Because proper design and combustion control has been proposed by TRC to control CO emissions from the Boiler and this methodology is capable of achieving significant CO reductions and has been utilized by similar and recently permitted sources identified in the RBLC as a means of CO control, the Department determined that proper design and combustion control constitute BACT for the Boiler, in this case. Further, the established BACT emission limit of 0.259 lb/MMBtu is within the emission limit range of other similar and recently permitted sources identified in the RBLC.

CO BACT Summary:

In summary, the Department analyzed the use of proper design and combustion and oxidation of post combustion gases as possible CO control strategies for the Boiler. Taking into consideration technical, environmental, economic, and other factors, as previously discussed, the Department determined that proper design and combustion practices constitutes BACT for the control of CO emissions from the Boiler, in this case. The Department believes that the Boiler, operated under the BACT determined proper design and good combustion practices, is capable of meeting the established CO BACT emission limit of 0.259 lb/MMBtu. This limit is within the range of other recently permitted similar sources identified in the RBLC. Further, the Department is confident that the periodic CO source testing will adequately monitor compliance with the permitted BACT limit.

3. SO_2 Emissions

Based on the BACT analysis submitted by TRC in it's application for Permit #3175-00, Permit #3175-01, and other recent BACT determinations for similar source permitting identified in the RBLC, the Department believes that an SO_2 BACT emission limit of 0.220 lb/MMBtu constitutes BACT for the TRC boiler utilizing the previously permitted BACT-determined controls. Under the current permit action, TRC proposed the use of low sulfur fuel (≤ 1% Sulfur by weight) in combination with the BACT determined dry-lime scrubber, commonly referred to as a Dry Flue Gas Desulfurization Unit (Dry FGD), to achieve an SO_2 emission limit of 0.24 lb/MMBtu (approximately 89% SO_2 control based on published uncontrolled emission factors). This TRC proposed limit represents the previous permit limit (Permit #3175-00) reduced accordingly to account for the increased boiler heat input capacity.

As provided in the BACT analysis for Permit #3175-00, at the time of initial permitting TRC was uncertain of the availability of low-sulfur coal and therefore proposed, and was granted, a higher emission limit than would normally be approved through the BACT process absent the extenuating circumstances. However, since TRC has proposed a maximum sulfur in coal content of 1% by weight (considered low-sulfur coal), and because TRC incorporates highly effective Dry FGD BACT control for SO_2, the Department determined that a 1-hour SO_2 emission limit of 0.22 lb/MMBtu (approximately 90% SO_2 control based on published emission factors) is the appropriate BACT determination, in this case. This determination is based on the highly effective permitted BACT controls utilized for Boiler SO_2 control, where other similar sources identified in the RBLC utilizing the same or similar controls are achieving in excess of 90% control efficiency.

Sulfur dioxide (SO_2) emissions from boilers like the one proposed for TRC result from the oxidation of sulfur contained in the fuels. There are two general means for reducing the amount of SO_2 emissions from the generation of electric power:

a. Combination Control – Low Sulfur Fuel and SO_2 Add-On Control Strategies;
b. SO_2 Add-On Control Strategies; and
c. Low Sulfur Fuels.

$\underline{SO_2\text{ Emission Control Options}}$

The following analysis explains and summarizes the available SO_2 control options. A complete analysis is contained in the applications for Permits #3175-00 and #3175-01:

a. Combination Control – Low-Sulfur Fuel and SO_2 Add-On Control Strategy

TRC proposed a combination of low sulfur fuels and a Dry FGD add-on control as BACT for the proposed project modification. TRC proposed to use this combination of controls to achieve a maximum SO_2 emission rate of 0.24 lb/MMBtu (approximately 89% control based on published emission factors). As discussed in the SO_2 BACT introduction, the Department determined, based on other recent similar source BACT emission limit determinations for sources utilizing the same or similar controls, that a BACT emission limit of 0.22 lb/MMBtu (approximately 90% control based on published emission factors) is the appropriate BACT emission limit, in this case.

Of the two fuels currently proposed for this project (coal and wood-waste biomass), coal is the predominant source of sulfur. Under the current permit action, TRC proposed a maximum sulfur-in-fuel content of 1% by weight. Wood-waste, by comparison, contains relatively little sulfur with the sulfur content of wood waste being approximately 0.02 % by weight.

In order to meet a 0.22 lb/MMBtu BACT emission limitation, TRC proposed the use of the previously permitted (Permit #3175-00) and BACT-determined Dry FGD and low sulfur coal and/or wood-waste fuel to control SO_2 emissions from the boiler down to the applicable BACT emission limit. The Dry FGD system is a "dry" scrubber system that converts SO_2 in the flue gas to $CaSO_3/CaSO_4$, that will be collected by the scrubbing system and/or the downstream fabric filter baghouse particulate BACT control required under Permit #3175-01.

The Dry FGD or scrubbing system uses quicklime and water to create a lime slurry. The slurry is blended to obtain the maximum control efficiency while creating the minimum amount of waste. Additionally, the Dry FGD provides for the re-circulation of a portion of the fly ash (a combination of coal ash and entrained lime) to maximize the SO_2 removal efficiency while minimizing the amount of waste generated.

TRC will control emissions of SO_2 primarily by limiting the amount of sulfur introduced into the boiler with the fuel. When firing extremely low sulfur coals and or wood-waste biomass in a high concentration, SO_2 emission rates may be lower than 0.220 lb/MMBtu BACT emission limit. Additionally, as wood waste supplies allow, TRC will fire a coal/wood waste blended fuel designed to minimize the amount of sulfur introduced into the boiler.

b. SO_2 Add-On Control Strategies

Many methods have been successfully used to control SO_2 emissions from fossil-fuel fired boilers. The vast majority of those techniques rely upon the reaction of SO_2 in the flue gas with an alkaline reagent to form a particulate. Those systems that rely upon the SO_2/alkali reaction, commonly referred to as flue gas desulfurization units (FGD units), differ mainly in the type of reagent used and the method employed to bring the SO_2 in the flue gas in contact with the alkali reagent.

Reagents successfully employed in SO_2 FGD units include limestone (comprised mainly of calcium carbonate, $CaCO_3$), quicklime (calcium oxide, CaO), magnesium oxide (MgO), sodium hydroxide (NaOH), ammonium hydroxide (NH_4OH) and various combinations of those reagents. The reaction with SO_2 yields compounds such as $CaSO_3$, $CaSO_4$, $NaSO_4$, NH_4SO_3, which are solids at ambient conditions and are easily collected by particulate matter control methods.

Contacting techniques for FGD systems vary somewhat but fall into two main categories: wet systems and dry systems. Wet systems use a reagent-slurry that is typically brought into contact with the flue gas in a scrubber "tower." The tower typically has trays, baffles or other similar features to divert the gas stream, create a contacting surface, and/or create turbulence in order to achieve maximum interaction between the SO_2 gas and the alkaline reagent. Dry systems typically spray or atomize the reagent into the flue gas stream to achieve the required contact. Many "dry" systems actually use a wet reagent slurry, that is injected into a spray chamber where it contacts the flue gas stream. The hot flue gas vaporizes the water leaving a dry particulate that either settles out in the spray chamber or is entrained in the flue gas stream and captured by the downstream particulate control device.

Under the right conditions, nearly all of these systems are capable of removing up to 95% of the SO_2 in boiler flue gas and, under certain conditions, even greater removal is achievable. The removal efficiency achieved by these systems mainly depends upon the amount of reagent used, the effectiveness of the contacting technique and the amount of SO_2 in the flue gas. Generally, the more reagent used the better the removal efficiency, the more effective the contacting technique the better the removal efficiency, and the more SO_2 in the flue gas the better the removal efficiency.

The amount of reagent used and the type of contacting technique are generally controllable and can be adjusted as conditions change. However, as SO_2 concentrations decrease, high removal efficiencies are more difficult to achieve even with highly effective contacting techniques and copious amounts of reagent.

Under the current permit action, TRC proposed the use of a Dry FGD (dry-lime scrubber in this case) and low sulfur fuels to control SO_2 emissions from the boiler. The Department does not believe that TRC operations would comply with the applicable BACT emission limit of 0.220 lb/MMBtu with the Dry FGD system in operation without the requirement for combustion of low sulfur coals only. Therefore, the Department does not consider the use of a Dry FGD, alone, to be BACT for the control of SO_2 emissions from the Boiler, in this case.

c. Sulfur in Fuels (Low-Sulfur Fuel)

Fossil fuels typically used to fire boilers for electricity generation include natural gas, fuel-oil and coal. Petroleum coke, bagasse, and wood waste are also used in some generating facilities. The sulfur content and associated SO_2 emissions vary widely among these fuels. Pipeline quality natural gas generally contains very little sulfur while petroleum coke may contain as much as 6% sulfur by weight. Ordinarily, where sulfur in fuel is very low (e.g., pipeline quality natural gas), no add-on SO_2 controls are considered necessary. Instead, the use of low sulfur fuel is considered BACT. Where higher sulfur fuels are used (e.g., petroleum coke or coal), add-on controls are generally required in order to reduce SO_2 emissions to the atmosphere.

Under the current permit action, TRC proposed a maximum sulfur-in-fuel content of 1% by weight (considered low-sulfur coal). The Department does not believe that TRC operations would comply with the applicable BACT emission limit of 0.22 lb/MMBtu with only low sulfur coal fired as a BACT requirement. Therefore, the Department does not consider the use of low sulfur fuels, alone, to be BACT for the Boiler, in this case.

SO_2 BACT Summary:

In summary, TRC proposed the use of a Dry FGD in conjunction with low sulfur fuels (≤ 1% sulfur by weight) to maintain compliance with the SO_2 BACT emission limit of 0.24 lb/MMBtu (1-hr avg.). The Department determined that a limit of 0.220 lb/MMBtu is the appropriate BACT limit, in this case. The established BACT emission limit of 0.220 lb/MMBtu is based on a 90% reduction from 2.17 lb/MMBtu value calculated using uncontrolled AP-42 Emission factors for spreader stoker boilers firing sub-bituminous coal. Dry FGD literature indicates that 50-95% control is appropriate. Further, recent similar source permitting demonstrates that this 90% SO_2 reduction is achievable. Through research and taking into consideration technical, environmental, economic, and other factors, the Department determined that this control strategy is consistent with other recent similar source permitting BACT requirements. Further, the permitted BACT emission limit represents approximately 90% SO_2 control and is within the emission limit and control efficiency range of other similar recently permitted sources. The Department believes that the Boiler, operated under the BACT determined control and fuel limits, is capable of meeting the established SO_2 BACT emission limit of 0.220 lb/MMBtu. The Department is confident that the periodic SO_2 source testing, applicable Compliance Assurance Monitoring (CAM) requirements under ARM 17.8, Subchapter 15, and the sulfur in fuel monitoring and recordkeeping requirements will adequately monitor compliance with the permitted SO_2 BACT limits.

4. VOC Emissions

The VOC BACT analysis was conducted using information from the EPA - OAQPS Manual and the most recent RBLC ranking report for VOC from boilers. This analysis demonstrates a BACT emission limit range of 0.0030 to 0.130 lb\MMBtu for coal combustion in boilers and a range of 0.0160 to 0.100 lb/MMBtu for wood-waste biomass combustion in boilers.

The Department determined that the new VOC BACT emission limit for the Boiler is 0.0308 lb/MMBtu calculated on a 1-hour average and 5.93 lb/hr. These limits are within the appropriate range for established BACT determinations/limits for other recently permitted similar sources contained in the RBLC.

High volume emission streams with low gaseous pollutant concentrations pose challenges in identifying acceptable VOC control strategies. Most add-on control technologies are less effective and/or less cost-effective for gas streams with these characteristics. The following control strategies were determined to be available control strategies for VOC emission from the Boiler.

a. Thermal Incineration and Catalytic Thermal Incineration;
b. Adsorption Processes; and
c. Proper Design and Combustion.

<u>VOC Emission Control Options</u>

The following analysis explains and summarizes the available VOC control options. A complete analysis is contained in the application for Permit #3175-00 and #3175-01.

a. Thermal Incineration and Catalytic Thermal Incineration

Although various specialized technologies exist, fundamentally, oxidizers or incinerators use heat to destroy gases in the exhaust stream. Incineration is an oxidation process that ideally breaks down the molecular structure of an organic compound into CO_2 and water vapor. For complete VOC destruction, a thermal incinerator would generally operate at a temperature of approximately 1,800°F. Catalytic incineration generally uses a metal oxide or noble metal catalyst to allow for oxidation to occur at temperatures ranging from 600°F to 1,000°F. Due to the high temperatures required for complete destruction through thermal oxidation, increased fuel costs can be excessive with oxidation units and increased environmental impact (increased NO_x, CO, SO_x, etc.) can result from increased fuel combustion. To lower fuel usage, RTOs or RCOs can be used to pre-heat exhaust gases, as described in Section III.A.2 above (CO BACT analysis).

As described in Section III.A.2 (CO BACT Analysis) above, the thermal incineration or oxidation of post-combustion gases invokes various technical problems including the need for high combustion temperatures and subsequent increased fuel use. The use of RTO's and/or RCO's can decrease fuel use needs. However, as provided in the application for Permit #3175-00, the cost effectiveness of using RTO or RCO was determined to be $17,272/ton of VOC reduction and $16,686/ton of VOC reduction, respectively, making thermal oxidation of post-combustion gases economically unreasonable compared to other recently permitted similar sources. Therefore, the Department determined that thermal incineration/oxidation of post-combustion gases with or without the use of RTO or RCO does not constitute BACT, in this case.

b. Adsorption Processes

Adsorption is not a pollutant destruction method, rather, a concentration technology used to remove gaseous pollutants from low to medium concentration gas streams. Adsorption systems collect gaseous pollutants onto an adsorbent media with large internal surface area. Widely used VOC adsorbents include activated carbon, silica gel, activated alumina, synthetic zeolites, fuller's earth, and other clays. Adsorptive capacity of the solid for the gas tends to increase with the gas phase concentration, molecular weight, diffusivity, polarity, and boiling point. The adsorbed pollutants are concentrated using thermal desorption and then oxidized either on-site or off-site by a separate contractor.

Further, the use of adsorption technology involves potential adverse environmental impacts. Employing adsorption techniques will produce a concentrated volume of pollutants. Although the quantity of concentrated pollutants will be relatively small, transportation, storage, and/or handling of the pollutant(s) could result in environmental impacts.

Finally, assuming a published VOC control efficiency of 95% for adsorption technologies, the cost effectiveness of using adsorption was determined to be $9721/ton of VOC reduction making adsorption control technology economically unreasonable compared to other recently permitted similar sources. Therefore, as described above, due to various environmental and economic impacts associated with the use of adsorption technology to control VOC emissions from boiler operations, the Department determined that adsorption does not constitute BACT, in this case.

c. Proper Design and Combustion

Reduction of VOCs can be accomplished by controlling the "Three Ts" of combustion: time, temperature, and turbulence. VOCs are generally the product of incomplete combustion or inefficient fuel use. Under the current permit action, TRC is proposing that normal combustion practices at TRC will involve maximizing the heating efficiency of the fuel in an effort to minimize fuel use and fuel costs.

Because proper design and combustion control has been proposed by TRC to control VOC emissions from the Boiler and this methodology is capable of achieving significant VOC reductions and has been utilized by similar sources identified in the RBLC as a means of VOC control, the Department considers proper design and combustion control to be BACT for the Boiler, in this case. Further, the established BACT emission limit of 0.0308 lb/MMBtu is within the emission limit range of other similar and recently permitted sources identified in the RBLC and the Department is confident that the periodic source testing requirements will adequately monitor compliance with this BACT limit.

<u>VOC BACT Summary and Determination</u>:

In summary, the Department analyzed the use of proper design and combustion, thermal oxidation, and catalytic oxidation of post combustion gases as possible VOC control strategies for the Boiler. Taking into consideration technical, environmental, economic, and other factors, as previously discussed, the Department determined that proper design and combustion practices will constitute BACT for the control of VOC emissions from the Boiler, in this case. The Department believes that the Boiler, operated under the BACT determined proper design and good combustion practices, is capable of meeting the established VOC BACT emission limit of 0.0308 lb/MMBtu. This limit is within the range of other recently permitted similar sources.

5. PM/PM_{10} Emissions

As proposed by TRC under the current permit modification, the Department agrees that the grain loading PM/PM_{10} emission limit of 0.017 gr/dscf applicable to the 156 MMBtu/hr boiler under Permit #3175-00 is applicable to the 192.8 MMBtu/hr boiler because this limit is within the appropriate range for established BACT determinations/limits for other recently permitted similar sources identified in the RBLC. However, since, under the current permit action, the capacity air-flow of the Boiler baghouse (DC5) would increase from the previously analyzed and permitted 53,620 acfm (31,685 dscfm) to 70,000 acfm (40,513 dscfm), the lb/hr emission limit would increase accordingly from 4.62 to 5.90 lb/hr.

The most recent RBLC ranking report for PM/PM_{10} emissions from boilers of this type was used as reference. The available control devices used to reduce PM/PM_{10} emissions from spreader stoker boilers similar to that proposed are:

a. Fabric filters (baghouses) (> 90% Reduction);
b. Electrostatic precipitators (ESPs) (> 90% Reduction);
c. Wet scrubbers (> 85% Reduction); and
d. Mechanical collectors (multitube cyclones or multiclones) (25-65% Reduction).

PM/PM_{10} control Options

The following summaries discuss available PM/PM_{10} control options for boilers similar to that proposed by TRC.

a. Fabric Filters/Baghouses

Fabric filter baghouses have had limited applications to spreader stoker boilers, particularly those boilers fired exclusively on wood or wood-waste biomass. The principal drawback to this strategy, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly-ash. Steps can be taken to reduce this hazard, including the installation of a mechanical collector upstream of the baghouse to remove larger burning particles of fly-ash (i.e. sparklers). Despite complications, baghouses are generally preferred for particulate control. In this case, a majority of the fuel combusted will be low sulfur coal for which the baghouse control strategy is best suited. Collection efficiencies are typically 90% or even as high as 99% for this control strategy.

Because fabric filter baghouse control has been proposed by TRC to control particulate emissions from the Boiler and this methodology is capable of achieving significant (90% +) reductions and has been utilized by similar and recently permitted sources identified in the RBLC as a means of particulate control, the Department determined that fabric filter baghouse control constitutes BACT for the Boiler, in this case. Further, the established BACT emission limit of 0.017 gr/dscf constitutes ≥ 96% PM/PM_{10} control efficiency based on published uncontrolled emission factors and is within the emission limit range (> 90%) of other similar and recently permitted sources identified in the RBLC.

b. ESPs

ESPs are employed when collection efficiencies of greater than 90% are required. When applied to spreader stoker boilers, ESPs are often used downstream of mechanical collector pre-cleaners that remove the larger size particulate matter. Collection efficiencies of 90% to 99% for PM/PM_{10} have been observed for ESPs. A variation of the ESP is the electrostatic gravel bed filter. In this device, PM/PM_{10} in flue gases is removed by impaction with gravel media inside a packed bed and collection is augmented by an electrically charged grid within the bed. PM/PM_{10} collection efficiencies are typically over 80% for this strategy.

Because TRC proposed the use of a fabric filter baghouse to reduce PM/PM_{10} emissions from the proposed boiler operations and because the proposed strategy is capable of significant PM/PM_{10} reduction similar or greater than ESPs, the use of an ESP does not constitute BACT, in this case.

c. Wet Scrubbers

The most widely used wet scrubbers for spreader stoker type boilers are venturi scrubbers. With gas-side pressure drops exceeding 15 inches of water, particulate collection efficiencies of 85% or greater have been reported.

Because TRC has proposed the use of a fabric filter baghouse to reduce PM/PM_{10} emissions from the proposed boiler operations and because the proposed strategy is capable of PM/PM_{10} reductions greater than venturi or wet scrubbers, the use of a wet scrubber technology does not constitute BACT, in this case.

d. Multiclones

The use of multiclones (mechanical collectors) provides particulate control for other similar type spreader stoker boilers. Often, two multiclones are used in series, allowing the first collector to remove the bulk of the dust and the second to remove the smaller particles. The efficiency of this arrangement ranges from 25% to 65% reduction.

Because TRC has proposed the use of a fabric filter baghouse to reduce PM/PM_{10} emissions from the proposed boiler operations and because the proposed strategy is capable of PM/PM_{10} reductions greater than a multiclone, the use of a multiclone does not constitute BACT, in this case.

Boiler PM/PM_{10} BACT Control Summary

In summary, the Department analyzed the use of fabric filter baghouses, ESPs, wet scrubbers, and multiclones as possible PM/PM_{10} control strategies for the Boiler. All of the previously mentioned control strategies are capable of significant PM/PM_{10} emission reductions, however, TRC proposed the use of a baghouse to reduce PM/PM_{10} emissions from the proposed Boiler. Because this control strategy is capable of significant reduction of PM/PM_{10} equal to or greater than other methods and this strategy is commonly used for sources of this type, the Department, taking into consideration technical, environmental, economic, and other factors determined that the use of a fabric filter baghouse constitutes BACT, in this case. The Department believes that the Boiler, operated with the BACT determined fabric filter baghouse, is capable of meeting the established PM/PM_{10} BACT emission limit of 0.017 gr/dscf. Further the Department is confident that the required continuous opacity monitoring system (COMS) and periodic source testing will adequately monitor compliance with the permitted BACT limit.

6. 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.

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:

a. Dry FGD and baghouse with 14% bypass were estimated to remove approximately 82% of the HCl;
b. Wet FGD units with 15% bypass was estimated to remove approximately 80% of the HCl;
c. Fabric filters (baghouses) removed approximately 44% of the HCl;
d. 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/Dry FGD system that TRC would be required to use to control SO_2 and PM_{10} emissions from the Boiler. TRC's Permit #3175-01 would not allow flue gas to be bypassed around the baghouse/Dry 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/Dry 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 Dry FGD) to form solids, which are removed in the baghouse downstream of the Dry FGD. Since the lime Dry 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 Dry 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 Dry 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).

a. Dry 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 Dry FGD/baghouse for the soul purpose of controlling HCl emissions would result in unreasonable cost effectiveness. Because Dry 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 Dry 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 Dry FGD/baghouse system would not be economically reasonable for controlling acid gas emissions.

b. Wet FGD/Wet ESP

Wet FGD/Wet ESP was a potential control strategy identified for controlling acid gases. Similar to the Dry 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 Dry 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 Dry 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.

c. 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 Dry FGD/baghouse BACT control strategy already required and constructed at the facility under the initial permit action, the removal of the requirement for the Dry 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 Dry 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.

d. 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 Dry 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 Dry 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.

HCl BACT Control Summary

In summary, the Department analyzed the use of a Dry 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 Dry 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 Dry 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 Dry 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.

7. Hg 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. According to a recent Hg control analysis conducted for the Montana Roundup Power Project (Permit #3182-00), 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.

During 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.

a. Activated Carbon Injection;
b. Sorbent Injection;
c. FGD Systems;
d. Enhanced FGD Systems; and
e. Combination of Conventional Pollutant Control Systems.

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

a. Activated Carbon Injection

Activated carbon injection 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 Dry FGD/baghouse system. Removal may be further enhanced with the injection of iodide-impregnated or sulfur-impregnated activated carbon ahead of the system.

Recent studies (Montana Roundup Power Project - MACT Application) have concluded that while activated carbon injection appears promising as a mercury control technology, more data and research into mercury speciation, flue gas composition, and the interaction of flue gas and mercury species at various conditions are needed to understand the factors that affect mercury removal. The Department's research into the use of activated carbon injection, in this case, has yielded the same conclusion--additional testing and research is necessary to determine the effects that mercury speciation, flue gas composition, and the interaction of flue gas and mercury species at various conditions will have on mercury collection efficiency. Also, activated carbon injection is not required under EPA's recently proposed utility MACT, providing further justification for not requiring this control strategy as BACT, in this case. For these reasons, the Department eliminated activated carbon injection as a BACT candidate for mercury control at the TRC facility, at this time.

From a practical standpoint, the activated carbon injection strategy still requires more data and research into mercury speciation to establish the effectiveness of this strategy; therefore, Department determined that activated carbon injection does not constitute BACT, in this case.

b. Sorbent Injection

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

That same document goes on to state "One technology has been identified as a potential beyond-the-floor control for mercury. That technology is sorbent injection…The applicant has agreed to install a sorbent injection system to remove the mercury from the exhaust of this unit."
In addition, the MidAmerican technical support document identifies the sorbent injection technology as a potential beyond-the-floor control. Such language in the technical support document indicates that the technology is not proven. Therefore, the Department believes that the use of sorbent technology does not constitute an available control strategy for mercury and is therefore eliminated from further consideration in this mercury BACT analysis. Therefore, the Department determined that sorbent injection does not constitute BACT, in this case.

c. 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 Dry 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 Dry 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 Dry 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 Dry 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 Dry FGD system alone does not constitute BACT for the Boiler, in this case.

d. 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.

e. Combination of Conventional Pollutant Control Systems

TRC proposed the use of Dry 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 Dry FGD/baghouse system.

A Dry 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 Dry FGD system in tandem with baghouse control constitutes BACT for the Boiler, in this case.

Mercury BACT Summary and Determination

The Department determined that the criteria pollutant controls, specifically the Dry FGD and baghouse control, in tandem, required through the BACT analysis for Permit #3175-01 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 Dry FGD and baghouse control for mercury emissions as the BACT determination, in this case.

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

a. Dry FGD/ Baghouse;
b. Wet FGD;
c. Wet FGD with WESP; and
d. No Additional Controls

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

a. Dry FGD/ Baghouse Control Strategy

Using a Dry 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 Dry 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 Dry 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 Dry FGD system and baghouse control constitutes BACT for the Boiler, in this case.

b. 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 Dry 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 Dry 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.

c. 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 Dry 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 Dry 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.

d. No Additional Controls

The base case would result in no additional control of H_2SO_4 from boiler operations. A Dry 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 Dry 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.

H_2SO_4 BACT Control Summary

The Department determined, based on recent similar source H_2SO_4 BACT determinations, that the use of a Dry FGD/ baghouse control strategy constitutes BACT for H_2SO_4 emissions. For TRC boiler operations, the use of a Dry 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 Dry 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 Dry 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 detailed 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	0.178 lb/MMBtu
CO	Good Combustion Practices/ No Additional Controls	0.259 lb/MMBtu
SO_x	Dry-FGD w/Baghouse	0.220 lb/MMBtu
VOC	Good Combustion Practices/ No Additional Controls	0.031 lb/MMBtu
PM/PM_{10}	Baghouse	0.017 gr/dscf
HCl	Dry-FGD w/Baghouse	0.01125 lb/MMBtu
Hg	Dry-FGD w/Baghouse	Control Requirement Only
H_2SO_4	Dry-FGD w/Baghouse	Control Requirement Only

B. BACT Review and Determination for Fuel Handling (Coal/Wood Waste Bio-Mass) and Ash/Fly Ash Handling and Storage

Typically, fuel (coal and wood-waste biomass) and fly-ash handling operations can result in high potential emissions of particulate matter. Because the proposed project is located in relatively close proximity to the Thompson Falls PM_{10} nonattainment area, emissions of particulate matter are of major concern.

TRC is required to enclose all coal transfers and operate a fuel handling fabric filter baghouse (DC1 and DC2) for all coal handling operations at the facility. Particulate emissions from the fuel handling dust collectors shall be limited to 0.02 gr/dscf. Further, TRC shall fully enclose all wood waste bio-mass transfers through a pneumatic transfer system and shall vent all wood-waste biomass handling operations to the boiler and ultimately the boiler baghouse which is limited to 0.017 gr/dscf. The Department determined, based on the high control efficiency associated with fabric filters, that TRC coal and wood waste biomass handling operations would show compliance with the permitted BACT emission limits for these activities. Further, based on review of other recently permitted similar sources, the Department determined that fabric filter control of these emission points constitutes BACT, in this case.

TRC shall enclose all bottom-ash/fly ash transfers and vent all bottom-ash/fly ash handling operations to a fabric filter baghouses (DC4 and DC6). Particulate emissions from these ash handling units shall be limited to 0.02 gr/dscf. The Department determined, based on the high control efficiency associated with fabric filters, that TRC ash handling and storage operations would show compliance with the permitted BACT emission limits for these activities. Further, based on review of other recently permitted similar sources, the Department determined that fabric filter control of these emission points constitutes BACT, in this case.

Because TRC proposed the previous control technologies for particulate emissions from the various fuel and ash handling operations and because fabric-filter baghouse control technology represents the top control option for these emission source types, the Department determined that the use of enclosures and operation of the various fabric filter dust collectors for material handling operations constitutes BACT for these sources and no further analysis is necessary.

C. BACT Review and Determination for Coal and/or Wood-Waste Biomass Storage

There are a number of available and technically feasible control strategies for the control of PM/PM10 emissions from coal and or wood-waste Biomass storage operations. These strategies include the following;

1. Complete Enclosure (Silo) with Fabric Filter Control (99%+ Control Efficiency);
2. Complete Enclosure (Coal Barn) (99% Control Efficiency);
3. Earthen Berm, Wind Fence, and Best Management Practices (BMP) including Wet Suppression (98% Control Efficiency);
4. Three-Sided Enclosure (90% Control Efficiency);
5. Wet Dust Suppression (50% Control Efficiency); and
6. No Add-On Control (Base Case)

Under Permit #3175-00, TRC proposed the installation and operation of a fully enclosed fuel (blended coal and wood-waste biomass) storage silo (25,000 ton capacity) that would be vented to a fabric filter baghouse, for the control of particulate matter emissions. Under the current permit action, due to several site and project specific factors governing the storage of fuel materials, TRC proposed outside storage of coal and wood waste biomass (separately) using an earthen berm, wind fencing, and BMP including water spray, as necessary, to control particulate emissions from fuel storage operations.

Since issuance of Permit #3175-00, the following changes have occurred to TRC operations and the TRC site resulting in the need for a new BACT analysis for the control of particulate matter emissions from fuel storage operations.

- TRC obtained a long-term contract for Montana-mined low-sulfur coal, negating the need to store 25,000 tons as a buffer for supply difficulties. As a result, TRC is proposing a maximum coal storage limit of 6,000 tons at any given time and 3,000 tons of wood-waste biomass at any given time.

- Availability of wood-waste from the neighboring Thompson River Lumber Company (TRL) has been reduced from previous estimates. The TRL wood-waste would be in sawdust form. TRC searched for new supplies of wood-waste outside of TRL in the form of slash. The procurement of slash wood-waste in place of sawdust fuel invalidated TRC's previously permitted blended fuel storage strategy in the single enclosed storage silo configuration because it is not technically feasible to store slash in this manner nor can the constructed fuel feeder accommodate this type of fuel because it is typically too large for the feed system.
- Due to the close proximity of the TRC facility to the Thompson Falls Airport (TFA), the Federal Aviation Administration (FAA) imposed a permanent structure height restriction of 108 feet at the TRC facility.
- Addition of a waste-water storage pond to the relatively small TRC property lease further limiting the available space to construct a suitable storage silo configuration (further discussion below).

1. <u>Complete Enclosure (Silo) with Fabric Filter Control</u>

As previously stated, under the fuel storage BACT analysis conducted for TRC's existing air quality Permit #3175-00, TRC proposed, and the Department concurred, that fully enclosed and fabric filter controlled fuel storage operations constitute BACT for TRC's fuel storage operations. Therefore, under the current permit action, TRC analyzed potentially feasible enclosed and fabric filter controlled fuel storage operations, taking into consideration the newly determined and above-cited operational and site restrictions.

Through research of enclosed coal storage strategies, TRC established that various physical criteria must be met for proper function. These criteria include the following:

- Proper storage pile or silo design must allow for coal to flow during all temperature and weather conditions. Design elements must include: a reclaim cone formed with a minimum of a 60° angle from horizontal for the emptying of hoppers or silos; a cone formed with a 37.5° angle of repose or natural pile form for the filling of a hopper or silo; and an approximate 3:1 height to width ratio of the silo.
- A maximum angle of 15° from horizontal for all conveyors lifting fuel vertically.

Under the current BACT analysis, TRC evaluated fuel storage silos with various standard silo diameters. This analysis showed that a single 6,000-ton silo would exceed the established FAA height restriction of 108 feet. Given this conclusion, TRC established that multiple silos would be required to meet the above criteria while allowing for 6,000 tons of fuel storage. To establish viable silo configurations TRC contacted various silo and dust control system manufacturers to evaluate feasible options. Through analysis, it was determined that the only feasible option would include 4 silos at 93-feet tall and a 45-foot diameter resulting in a capacity of 1,524 tons per silo (total capacity = 6,096 tons).

Next, TRC evaluated independent industry representative recommended dust control strategies that would be feasible for the control of dust from the 4-silo configuration discussed above. This analysis showed that 4 fabric filter baghouses would be required to effectively control the various emission points of the proposed storage system. The following table shows the recommended dust control system, locations, and volumes.

Emission Point	Baghouse #	Baghouse Duty	Estimated Air-Flow (ACFM)
Belt Conveyor Transfer	1	3 Pick-Up Points	3,700
Top of Silos	2	9 Pick-Up Points (includes 2 conveyor hood pick-ups, 3 belt plow pick-ups, and 4 silo vent pick-ups)	10,700
Silo Discharge	3	4 Pick-Up Points	6,000
Belt Conveyor Transfer	4	3 Pick-Up Points	3,700
Totals	4	19 Pick-Up Points	24,100

Assuming all emissions are enclosed and routed to these baghouses, the emissions are calculated at 18.1 tons per year using the currently permitted fuel handling and storage baghouse BACT emission limit of 0.02 grains per standard cubic foot of air-flow. As shown in the table below, the emissions from the available and technically feasible 4-silo fuel storage silo strategy would be significantly higher than the proposed controlled outdoor fuel storage strategy.

Controlled Particulate Emission Source	Estimated Control Efficiency	Controlled Particulate Emissions
Open Pile Storage (including transfers)	Below Grade Pile = 98%, Below Grade Enclosed Transfers = 90%, and Above-Grade Enclosed Transfers = 50%	3.0 ton/yr – Includes emissions from coal pile wind erosion (0.83 ton/yr), coal transfers (1.32 ton/yr), front end loader travel fugitive emissions (0.60 ton/yr, and enclosure berm wind erosion (0.22 ton/yr)
Four Silo Scenario (4 baghouses)	99%	18.1 ton/yr

This analysis shows that the installation and operation a technically feasible enclosed silo and fabric filter baghouse controlled fuel storage scenario would potentially result in approximately 6 times greater particulate emissions than the proposed controlled outdoor fuel storage strategy. Therefore, due to environmental impact from increased particulate emissions, the Department determined that this fuel storage strategy does not constitute BACT for fuel storage, in this case.

2. Complete Enclosure (Coal Barn or Domed Structure)

In addition to the above-analyzed enclosed storage scenario, TRC evaluated the feasibility of other enclosed fuel storage scenarios including a steel building or "coal barn" and a domed enclosure. Complete enclosure of the coal and wood-waste storage piles would represent a technically feasible control option and would result in 99% control efficiency. However, the cost analysis conducted for the coal barn enclosure strategy under the current permit action results in a cost effectiveness of \$24,655 per ton of PM/PM_{10} removed. This cost effectiveness is much greater than industry norms thereby making the use of a coal barn economically unreasonable for the proposed project.

The use of a domed structure was also examined as a method of enclosing a ground based coal and/or wood-waste pile. The dome structure presented its own unique set of problems for the proposed TRC project. Dome structures, much like silos, require access at the top of the pile for addition of coal to the pile via conveyors with the same angle of incline required for the conveyor and angle of repose required for pile forming dictated by the type and size of coal. The resulting structure designed and analyzed by engineers is a large structure that is incompatible with the design and layout of the waste-water holding pond on the limited site space remaining. Therefore, due to lack of available space, the use of an enclosed domed structure was deemed technically and practically infeasible for the proposed project and does not constitute BACT, in this case.

3. Earthen Berm, Wind Fence, Wet Suppression, and Best Management Practices (BMP)

   Under the current permit action TRC proposed the use of an earthen berm with wind fencing and reasonable precautions, including wet dust suppression, as necessary, for the control of particulate matter emissions from coal and wood waste storage operations at the TRC site. This control strategy, collectively, will result in highly effective particulate control and is consistent with other recently permitted and similar sources. The berms will provide a physical and visual barrier while the wind fence will significantly reduce the wind and magnitude of wind velocity contacting the pile(s), thus minimizing wind entrained particulate emissions. In addition, TRC will use reasonable precautions to control fugitive emissions from the pile(s). Reasonable precautions will include minimizing the number of pile disturbances, minimizing the area of the pile disturbance by effectively using 50% of the pile as an active pile and retaining 50% of the pile as inactive storage, minimizing material fall distance, and using wet dust suppression, as necessary, to control fugitive emissions.

   Due to the extenuating site/project-specific circumstances discussed previously, the Department determined that an earthen berm, wind fencing, and reasonable precautions, including wet dust suppression, as necessary, for the control of particulate matter emissions from coal and wood-waste storage operations constitutes BACT, in this case.

4. Three-Sided Enclosure

   In addition to the above-analyzed fully-enclosed storage scenarios, TRC evaluated the feasibility of partially enclosed fuel storage scenarios including a three-sided enclosure. Partial enclosure of the coal and wood-waste storage piles would represent a technically feasible control option and would result in 90% control efficiency. However, the cost analysis conducted for the coal barn enclosure strategy under the current permit action results in a cost effectiveness of \$16,602 per ton of PM/PM_{10} removed. This cost effectiveness is much greater than industry norms thereby making the use of a partial or three-sided enclosure economically unreasonable for the proposed project.

   In addition, the Department determined that a three-sided enclosure would result in a lesser degree of control than the proposed earthen berm, wind fencing, and BMP control strategy resulting in greater environmental impact. Therefore, due to environmental impact and economically unreasonable cost effectiveness, the Department determined that three-sided enclosure does not constitute BACT for the control of particulate emissions from fuel storage operations, in this case.

5. Wet Dust Suppression

Wet dust suppression is not always a technically feasible control alternative. Occasionally, moisture may interfere with further processing and/or too much agglomeration of the product (coal in this case). Also, application of additional moisture can result in increased fuel costs and/or cause upset combustion conditions. Addition of water to the coal may actually increase emissions by fracturing larger pieces of coal into smaller particles thereby enhancing wind entrainment. In addition, water sprays could cause or contribute to spontaneous combustion of the coal stored in the pile. Finally, in some cases, water may not be readily available.

As highlighted above, due to the various potential problems that may be associated with the use of wet dust suppression alone, the Department determined that this strategy is not a practical and effective control strategy. Further, wet dust suppression alone would result in a lesser degree of control than the proposed earthen berm, wind fencing, and BMP control strategy thereby resulting in greater environmental impact. Therefore, due to potentially increased environmental impact, issues of technical infeasibility, and the sometimes impractical aspect of wet dust suppression for these purposes, the Department determined that wet dust suppression alone, does not constitute BACT for the control of particulate emissions from fuel storage operations, in this case.

6. No Add-On Control (Base Case)

No add-on control would result in uncontrolled emissions from proposed fuel storage operations. Since TRC proposed the use of an earthen berm, wind fencing, and BMP, and the Department determined that this strategy will result in highly effective control of particulate emissions from this emission source, the Department determined that no add-on control does not constitute BACT, in this case.

Fuel Storage PM/PM_{10} BACT Control Summary

In summary, the Department analyzed the use of complete enclosures with fabric filter baghouse control; complete enclosure alone; earthen berm, wind fence, and reasonable precautions; three-sided enclosure; wet dust suppression alone; and no add-on control as possible PM/PM_{10} control strategies for fule storage operations at the TRC site. All of the previously mentioned control strategies are capable of significant PM/PM_{10} emission reductions, however, TRC proposed the use of an earthen berm, wind fence, and BMP to reduce PM/PM_{10} emissions from the proposed fuel storage operations. Because this control strategy is capable of significant reduction of PM/PM_{10} and this strategy is commonly used for sources of this type, the Department, taking into consideration technical, environmental, economic, and other factors determined that this control strategy constitutes BACT, in this case. Taking into consideration the previously discussed site/project-specific extenuating circumstances, the Department believes that the BACT analysis and determination for Permit #3175-01 constitutes BACT for these emission sources, in this case.

D. BACT Review and Determination for Propane/Diesel-Fired Boiler Pre-Heater and Propane-Fired Refractory Curing Heater

The current permit action incorporates enforceable operational limits for the proposed propane/diesel fired boiler pre-heater and the propane-fired refractory curing heaters. Because these operational limits restrict the allowable operating time and thus the potential emissions (all regulated emissions) from these units, the Department determined that any add-on control equipment would be cost prohibitive. Therefore, the Department determined that normal operation within the permit limits will constitute BACT for these units, in this case.

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

IV. Emission Inventory

Source	PM	PM_{10}	NO_x	CO	SO_x	VOC	Pb	HCl
Babcock & Wilcox Boiler (192.8 MMBtu/hr)	0.00	0.00	150.32	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	150.32	218.72	185.78	26.18	0.04	9.50

Boiler

Heat Input Capacity: 192.8 MMBtu/hr
Operating Hours: 8760 hr/yr

NO_x Emission Calculations

Emission Factor: 0.178 lb/MMBtu (BACT Limit)
Calculations: 0.178 lb/MMBtu * 192.8 MMBtu/hr = 34.32 lb/hr
34.32 lb/hr * 8760 hr/yr * 0.0005 ton/lb = 150.32 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: 0.031 lb/MMBtu (BACT Limit)
Calculations: 0.031 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 Baghouse – 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 Baghouse – 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 Baghouse – 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 Baghouse – 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 1.6 miles (2.7 kilometers) from the proposed facility. ISC3 computer modeling conducted for the proposed project demonstrates that operation of the proposed facility will not adversely impact the Thompson Falls PM$_{10}$ nonattainment area.

VI. Ambient Air Impact Analysis

A. Ambient Air Modeling Analysis

The Department determined, based on ambient air modeling, that the impact from this permitting action will be minor. The Department believes it will not cause or contribute to a violation of any ambient air quality standard.

On July 30, 2004, Bison Engineering Inc. (Bison) submitted air dispersion modeling on behalf of TRC. The airborne concentrations of CO, SO_2, NO_x, and PM$_{10}$ were modeled to demonstrate compliance with the Montana and National Ambient Air Quality Standards (MAAQS and NAAQS). The ISC3 model was used along with 10 years of meteorological data. The National Weather Service surface data sets for Missoula (1986-1987, and 1989-1991) and Kalispell (1987-1991) were used along with the corresponding years of upper air data from Spokane, Washington.

The receptor grid was generated, using the linear interpolation method, from digital elevation model (DEM) files of 7.5-minute United States Geological Survey (USGS) topographical maps for Eddy Mountain and Thompson Falls. The receptor spacing was 100 meters along the fence-line and out to a distance of 1,000 meters. Beyond 1,000 meters, additional receptors were spaced at 250-meter intervals out to a distance of 3,000 meters and at 500-meter intervals from 3,000 meters to 10,000 meters from the fence-line. Building dimension information was used with EPA Building Profile Input Program (BPIP) to calculate downwash parameters for input into ISC3.

TRC is requesting allowance of annual emissions as follows: 37.11 ton/yr of PM_{10}, 202.8 ton/yr of SO_2, 150.32 ton/yr of NOx, 218.63 ton/yr of CO, and 26.01 ton/yr of VOC. The permitted allowable SO_2 emissions are less than the emissions analyzed under the modeling analysis therby resulting in a more conservative SO_2 impact analysis.

The modeled impacts from TRC did not exceed the modeling thresholds for CO; therefore, a full analysis was not conducted for this pollutant. PM_{10} impacts to the nearby PM_{10} nonattainment area in Thompson Falls were calculated using only TRC emissions. Only TRC emissions were evaluated because emissions from the only other significant industrial pollution source in the area, the adjacent TRL, were already accounted for in the Thompson Falls SIP control strategy. Modeled PM_{10} impacts to the Thompson Falls nonattainment area were below modeling thresholds and thus no further analysis was needed for the SIP.

A full impact analysis for compliance with the MAAQS and NAAQS was conducted for SO_2, NO_x and PM_{10}. The full impact analysis for NO_X and PM_{10} included sources and impacts from the nearby TRL facility operations.

SO_2, NO_x, and PM_{10} MAAQS/NAAQS Modeling Results for the TRC Facility

Pollutant	Period	Concentration ($\mu g/m^3$)				
		Modeled Value	Background Value	Post-Processed	MAAQS/NAAQS Standard[a]	% of Standard
SO_2	1-hr H19H	364[b]	35	399	1300	30.7
	3-hr H2H	212	26	238	1300	18.3
	24-hr H2H	71.5	11	82.5	262	31.5
	Annual	6	3	9	52	17.3
NO_x	1-hr H2H	300/228[c]	75	303	564	53.7
	Annual	8.5	6	14.5	94	15.4
PM_{10}	24-hr H2H	106	30	136	150	90.1
	Annual	31.3	8	39.3	50	78.6

[a] Only the most restrictive standard is shown in the table.
[b] The 1-hr modeled SO_2 concentration is actually the high-tenth high as opposed to the high-nineteenth high.
[c] The post-processes NO_x concentrations are conservative over-estimates of NO_2 concentrations as ratio methods were not used.

As shown in the above table, all of the modeled concentrations for SO_2, NO_x, and PM_{10} are below the MAAQS/NAAQS. The modeled PM_{10} impacts, including impacts from the nearby TRL facility operations, represent a significant percentage of the available standard. Therefore, in accordance with Department ambient air quality monitoring policy, TRC will be required to conduct ambient air monitoring for PM_{10}. The ambient air quality monitoring requirements are detailed in Attachment 1.

In addition to the above detailed modeling, Bison, on behalf of TRC, conducted modeling to address TRC emissions during start-up and malfunction operations utilizing the boiler pre-heater and from the boiler refractory curing heaters. TRC, by permit, is not allowed to operate the boiler pre-heater or refractory curing heater(s) while the boiler is in operation and overall operation of these units is limited to 500 hours annually, per unit. Emissions from the 60 MMBtu/hr propane/diesel fired boiler pre-heater represent only a fraction of the boiler emission rates. These emissions were modeled out of the main stack in place of the boiler emissions and at reduced flow and temperature rates. All other plant emissions were held constant for the modeling demonstration. Although the plume rise for the boiler pre-heater scenario is less than

the main boiler scenario, the emission rate reduction associated with the boiler pre-heater scenario resulted in uniformly lower predicted impacts from this operating scenario when compared to boiler operations.
Bison prepared a similar modeling analysis for the operation of the refractory brick curing heaters. Again, the boiler emissions were turned off and the refractory heaters emissions were modeled out of the main stack in place of the boiler emissions. The refractory heater emissions result in even lower impacts than the boiler preheater emission impacts and the predicted impacts are again uniformly lower for this operating scenario when compared to boiler emission impacts.

In addition, during the public comment period for the Department's preliminary determination, the Department received public comment indicating that the adjacent waste transfer station located on the TRL site constitutes ambient air and that the full ambient air impact analysis conducted for TRC operations had not included receptors at this site. Based on this comment, the Department required that TRC conduct an ambient air impact analysis including receptors at the adjacent transfer station. On November 3, 2004, the Department received the updated ambient air impact analysis from Bison, on behalf of TRC. The model inputs used for this analysis were exactly the same as those used for the latest and previously described model accepted by the Department. The updated analysis demonstrates that ambient air impacts at the transfer station from proposed TRC operations would maintain compliance with the applicable NAAQS/MAAQS. Model results for the transfer station were generated for CO, NO_x, PM_{10}, and SO_2. All of the predicted maximum impacts from the transfer station modeling demonstration are below the highs predicted for the full impact analysis discussed previously. Therefore, none of the overall predicted high concentrations, locations, or times of occurrence have changed from the previously summarized full ambient air impact analysis conducted for the proposed TRC project. A complete analysis and summary of the transfer station modeling analysis is included in TRC's complete application for the proposed permit modification.

Therefore, it may be concluded that the modeled impacts from proposed TRC operations would not cause or contribute to a violation of the NAAQS/MAAQS or adversely impact the nearby Thompson Falls PM_{10} nonattainment area.

B. Ambient Air Quality Monitoring

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 (ARM 17.8.749 and ARM 17.8.204).

The proposed permit modification would result in an increase in potential and allowable PM_{10} emissions from those PM_{10} emissions analyzed and permitted under MAQP #3175-00. Further, through the proposed permit modification process, TRC established that actual PM_{10} ambient concentrations would increase substantially as a result of the current permit action. Therefore, due to Department concern with protection of the NAAQS/MAAQS for PM_{10}, the Department required a complete PM_{10} ambient air quality impact analysis under the current permit action. This analysis included the allowable PM_{10} emissions from the adjacent TRL facility. The analysis resulted in the following predicted impacts, included in the table below:

Averaging Period	**PM_{10} Concentration ($\mu g/m^3$)**				
	Modeled Value	**Background Value**	**Post-Processed Value**	**NAAQS/ MAAQS Standard***	**Percentage of Standard Consumed**
24-hr	106	30	136	150	90.1%
Annual	31.3	8	39.3	50	78.6%

* Only the most restrictive standard is shown in the table

As indicated in the table above, when PM_{10} emissions from TRL are modeled in conjunction with TRC emissions, 90.1% of the 24-hour and 78.6% of the annual PM_{10} standard(s) are consumed. Department "Monitoring Requirements" guidance, dated October 9, 1998 (Guidance), indicates that the Department must evaluate its degree of confidence in TRC's ability to comply with its permit conditions, whether or not a violation of a condition could be readily detected, and the degree of risk that a permit exceedance might result in an exceedance of the NAAQS/MAAQS. In accordance with the Guidance, regardless of permit content, because TRC is located only 1.6 miles (2.7 kilometers) east/southeast of the existing Thompson Falls PM_{10} non-attainment area, the Department determined that the degree of the risk of exceeding the PM_{10} NAAQS/MAAQS is great in this case and subsequently the Department's degree of confidence in TRC maintaining compliance with the standard is low to medium. Therefore, in accordance with the Ambient Monitoring Decision Matrix contained in the Guidance, a facility meeting the criteria for low to medium confidence and demonstrating that 80 to 95% of the standard will be consumed under permitted operations, requires ambient monitoring. The current permit action incorporates PM_{10} ambient air quality monitoring requirements into the permit under Attachment 1.

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
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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: 3175-01

Preliminary Determination Issued: October 8, 2004
Department's Decision Issued: November 5, 2004
Permit Final: November 23, 2004

1. *Legal Description of Site*: The Thompson River Co-Gen, L.L.C. (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 the information contained in the complete permit application submitted to the Department on September 7, 2004, the following modifications would be made to Permit #3175-00 under the current permit action:

   - Increase in the allowable boiler baghouse emission rate (lb/hour) for particulate matter (PM) and particulate matter with an aerodynamic diameter less than or equal to 10 micrometers (μm) (PM_{10}). The previously permitted BACT emission limit determination of 0.017 grains per dry standard cubic feet (gr/dscf) of air-flow through the boiler baghouse remains applicable to the baghouse-controlled boiler operations. The increase in capacity flow through the baghouse results 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 actual cubic feet per minute (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 million British thermal units per hour (MMBtu/hr) and 1,688,928 MMBtu/rolling 12-month time period (MMBtu/yr). This limit will 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 oxides of nitrogen (NO_x), carbon monoxide (CO), Volatile Organic Compounds (VOC), oxides of sulfur (SO_x), and hydrochloric acid (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 is provided in the permit analysis to this permit;
- 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 will not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and is 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 will not be allowed to operate while the boiler is producing energy or the boiler fuel feed is in operation and each heater is 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 replaces the initial BACT determination under Permit #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 to this permit;
- 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 to this permit;
- Revisions to the previously permitted ash handling operations for the addition of a second ash handling baghouse 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 to this permit;
- 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 permit.

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 Dry 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).

The Department decision would incorporate the above-cited changes. Permit #3175-01 would allow for the above-cited changes to TRC operations at the existing and previously permitted facility.

3. *Objectives of Project*: TRC constructed a facility that does not comply with all of the requirements of the existing air quality Permit #3175-00. The purpose of the current permit action would be to allow for proposed changes in equipment and facility operations, as appropriate, and 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 TRC could re-construct the facility to comply with existing air quality Permit #3175-00. 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 #3175-01.

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

Minor impacts to terrestrial and aquatic life and habitats would result from the proposed TRC modification because the modification would result in changed facility equipment operations and equipment locations and increased air emissions resulting in increased deposition of those pollutants on the land and water habitats used by terrestrial and aquatic life in the proposed project area. 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.

In addition, the impacts from the proposed TRC permit modification to terrestrial and aquatic life and habitats in the area would be minor because the facility is a constructed, but non-operational facility. Therefore, since the major aspects of the facility have been previously 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 equipment location and fuel handling and storage operations at the site, which would 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 would be disturbed under the permit modification would result in only minor and typical industrial impacts to any existing terrestrial and aquatic life and habits in the area.

Further, increased emissions 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, when TRC included emissions from the adjacent TRL operations in the ambient air quality impact analysis, worst-case PM_{10} emissions were shown to be in compliance with the standards, but consumed approximately 90% of the standard (see Section VI of the permit analysis and Section 7.F of this EA). Based on this analysis, and Department policy regarding ambient air quality impacts, TRC would be required to operate an ambient PM_{10} monitoring network at the facility to ensure that PM_{10} emissions do not exceed any applicable PM_{10} ambient air quality standard. 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 terrestrial and aquatic life and habits from deposition of air pollutants would be minor.

TRC operations would require approximately 125 gallons per minute of water for normal operations. As described in greater detail in Section 7.C of this EA, TRC is currently in the process of acquiring the appropriate water rights through the Montana Department of Natural Resources and Conservation (DNRC). Also, according to the Department's waste-water regulators, TRC does not initially intend to discharge any water to existing state surface or groundwater resources, rather, waste-water would be discharged to a completely lined evaporation pond. However, according to recent TRC correspondence with the Department's waste-water regulators, TRC may pursue a groundwater discharge permit in the future. Therefore, due to the relatively small amount of water used for normal operations and the current lack of industrial waste-water discharge associated with TRC operations, the Department determined that aquatic life and habitats would realize little or no impact from the proposed facility and proposed facility air permit modifications.

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

Minor impacts to water quality, quantity, and distribution would result from the proposed TRC modification because the modification would result in increased air emissions and subsequent water deposition of those emissions, the creation of a new water discharge evaporation pond, a potentially new groundwater appropriation/right, and a potentially modified surface water use appropriation/right.

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. However, when TRC included emissions from the adjacent TRL operations in the ambient air quality impact analysis, worst-case PM_{10} emissions were shown to be in compliance with the standards, but consumed approximately 90% of the standard (see Section VI of the permit analysis and Section 7.F of this EA). Based on this analysis, and Department policy regarding ambient air quality impacts, TRC would be required to operate an ambient PM_{10} monitoring network at the facility to ensure that PM_{10} emissions do not exceed any applicable PM_{10} ambient air quality standard. 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 water resources; therefore, any impacts to water resources from deposition of air pollutants would be minor.

Further, according to correspondence between TRC and the Department's waste-water discharge regulators, TRC does not initially intend to discharge any water to state surface or groundwater resources, rather, TRC intends to construct and operate a lined waste-water holding/evaporation pond at the site. However, recent TRC correspondence does indicate that TRC may seek a groundwater discharge permit in the future. Because TRC is not currently proposing to directly discharge any material to surface or ground water resources in the area, other than a newly constructed industrial waste-water evaporation pond, the Department does not require a wastewater discharge permit and any existing water resources in the area would not be impacted by proposed facility operations.

Also, the amount of water needed for normal operations at the TRC plant is small by industrial standards at approximately 125 gallons per minute. To accommodate the needed water, TRC applied for two water rights since the project started. One would be a surface water right from the nearby Clark Fork River and the other a groundwater right accessed through development of subsurface well. The Clark Fork River water right has gone through the public notice process required by the DNRC and was objected to by several local interested parties and the Avista Corporation (owner/operator of Noxon Rapids dam). The DNRC is currently working with the affected parties to see if the objections can be resolved outside of a formal process. However, the

DNRC believes, barring any changes in local opinion of the project, the Clark Fork River surface water right application will be scheduled for a contested case hearing to be held in approximately one year from this time. Regardless of the outcome of the surface water right issues, the Department determined that any impact to water resources would be minor given that the requested water right represents a very small fraction of the available surface water in the Clark Fork River drainage in the Thompson Falls area.

Regarding the use of groundwater and the groundwater appropriation/right, TRC drilled a well in June of 2004 and found a suitable water source at 680-feet below ground. The well would be able to produce the required flow rate for the plant. Because there are no other wells in the area developed at this depth, the proposed TRC well would not impact other existing or historical local water users. TRC submitted the new water right appropriation application for the well water to the DNRC. TRC also requested that the DNRC grant an interim permit for the well to allow TRC to determine the long term viability of the groundwater source and to determine if the chemistry of the water is feasible for plant use. According to TRC, the surface water is easier to treat because there are less dissolved solids in the water. The DNRC granted the interim permit on July 1, 2004, and the term of the interim permit is one year, expiring June 30, 2005. The interim permit allows TRC to use the ground-water right for its intended use. The groundwater right application has gone through public notice, which closed in September of 2004. Given that the TRC water right would be the only nearby use of this water resource and that the amount of water represents a relatively small amount of water for industrial purposes, the Department determined that any impact to water resources from development and use of the groundwater resource would be minor. TRC intends to continue to pursue both water rights and anticipates having to use both sources at different times of the year depending on surface water availability. The Department determined that any impacts to water resources from water use and discharge practices at TRC 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

Minor impacts to the geology and soil quality, stability and moisture of the project area would result from the proposed TRC modification because the modification would result in changed facility equipment operations and equipment locations and increased air emissions resulting in increased deposition of those pollutants on the land. 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 equipment location and fuel handling and storage operations at the site, which would 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 would 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 emissions 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). 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 surface water would be minor. However, when TRC included emissions from the adjacent TRL operations in the ambient air quality impact analysis, worst-case PM_{10} emissions were shown to be in compliance with the standards, but consumed approximately 90% of the standard (see Section VI of the permit analysis and Section 7.F of this EA). Based on this analysis, and Department policy regarding ambient air quality impacts, TRC would be required to operate an ambient PM_{10} monitoring network at the facility to ensure that PM_{10} emissions do not exceed any applicable PM_{10} ambient air quality standard. 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, normal operations resulting in air emissions and deposition of air emissions, and waste-water storage and water use, would be minor.

D. Vegetation Cover, Quantity, and Quality

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 equipment locations and increased air emissions 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 equipment location and fuel handling and storage operations at the site, which would 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 would 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 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. However, when TRC included emissions from the adjacent TRL operations in the ambient air quality impact analysis, worst-case PM_{10} emissions were shown to be in compliance with the standards, but consumed approximately 90% of the standard (see Section VI of the permit analysis and Section 7.F of this EA). Based on this analysis, and Department policy regarding ambient air quality impacts, TRC would be required to operate an ambient PM_{10} monitoring network at the facility to ensure that PM_{10} emissions do not exceed any applicable PM_{10} ambient air quality standard. 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, normal operations resulting in air emissions and deposition of air emissions, and waste-water storage and water use 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 equipment operations and equipment locations and increased air emissions. The proposed permit modification would include the installation and operation of outdoor coal/wood-waste storage operations utilizing an earthen berm and wind fencing for the control of fugitive dust emissions from these sources. These sources 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. Further, the area already incorporates earthen berm structures at various locations around the old log yard that now serves as the TRC construction site; therefore, the proposed earthen berm control measure for these sources would be a typical area structure and would result in only minor visual aesthetic impacts.

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 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.

Further, the proposed modifications would result in additional noise in the area. The noise impacts from this facility on the surrounding area would be minor because most noise increases associated with the proposed modification would be short-lived construction impacts at an existing industrial site where these types of noises are commonplace. The majority of noise from the facility would occur from rail movements on the newly constructed and existing rail spur that would support the facility. The proposed modification would likely increase the number of railcars delivering coal to the facility by reducing the amount of coal to be stored on site from the previously permitted 25,000 tons to a maximum allowable coal storage of 6,000 tons, but the proposed noise associated with rail movements would be common to the area with the existing rail line. Most rail activity associated with the facility would occur during the day. The other major noise source would be the fuel transfer mechanisms and the existing boiler. The boiler and much of the material handling operations would be located inside the property boundary. Potential noise impacts would be minimized by the distance between the facility and the nearest residence.

Finally, operation of the proposed TRC facility may result in increased industrial odors in the area. However, operation of the proposed facility would take the place of similar operations at TRL that result in the same odors. Therefore, any odors created by facility operations would be minor and typical for the area of operations.

Overall, any impacts to the aesthetic nature of the project area 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.

F. Air Quality

The air quality impacts from the construction and operation of the proposed modified facility would be minor because Permit #3175-01 would include conditions limiting emissions of air pollution from the source. Specifically, Permit #3175-01 would include conditions limiting NO_x, CO, SO_2, VOCs, PM, PM_{10}, and HCl emissions through the application of emission limits and control strategies established under the BACT and 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 #3175-01. Further, the operations would be limited by Permit #3175-01 to criteria pollutant emissions of 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. 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 national ambient air quality standards (NAAQS) for pollutants considered harmful to public health and the environment (Criteria Pollutants: CO, NO_x, Ozone, Lead, PM_{10}, 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 1.6 miles (2.7 kilometers) west/northwest of the TRC site location.

On July 30, 2004, Bison Engineering Inc. (Bison), on behalf of TRC, submitted a complete air dispersion modeling demonstration of compliance with applicable standards. The airborne concentrations of CO, SO_2, NO_x, and PM_{10} were modeled to demonstrate compliance with the MAAQS and NAAQS. The ISC3 model was used along with 10 years of meteorological data. The National Weather Service surface data sets for Missoula (1986-1987, and 1989-1991) and Kalispell (1987-1991) were used along with the corresponding years of upper air data from Spokane, Washington.

The receptor grid was generated, using the linear interpolation method, from digital elevation model (DEM) files of 7.5-minute United States Geological Survey (USGS) topographical maps for Eddy Mountain and Thompson Falls. The receptor spacing was 100 meters along the fence-line and out to a distance of 1,000 meters. Beyond 1,000 meters, additional receptors were spaced at 250-meter intervals out to a distance of 3,000 meters and at 500-meter intervals from 3,000 meters to 10,000 meters from the fence-line. Building dimension information was used with EPA Building Profile Input Program (BPIP) to calculate downwash parameters for input into ISC3.

TRC is requesting allowance of annual emissions as follows: 37.11 ton/yr of PM_{10}, 202.8 ton/yr of SO_2, 150.32 ton/yr of NO_x, 218.63 ton/yr of CO, and 26.01 ton/yr of VOC. The permitted allowable SO_2 emissions are less than the emissions analyzed under the modeling analysis thereby resulting in a more conservative SO_2 impact analysis.

The modeled impacts from TRC did not exceed the modeling threshold for CO; therefore, a full analysis was not conducted for this pollutant. PM_{10} impacts to the nearby PM_{10} nonattainment area in Thompson Falls were calculated using only TRC emissions. Only TRC emissions were evaluated because emissions from the only other significant industrial pollution source in the area, the adjacent TRL, were already accounted for in the Thompson Falls State Implementation Plan (SIP) control strategy. Modeled PM_{10} impacts to the Thompson Falls nonattainment area were below modeling significance levels and thus no further analysis was needed for the SIP.

A full impact analysis for compliance with the MAAQS and NAAQS was conducted for SO_2, NO_x and PM_{10}. The full impact analysis for NO_X and PM_{10} included sources and impacts from the nearby TRL facility operations.

SO_2, NO_x, and PM_{10} MAAQS/NAAQS Modeling Results for the TRC Facility

Pollutant	Period	Concentration ($\mu g/m^3$)				
		Modeled Value	Background Value	Post-Processed	MAAQS/NAAQS Standard[a]	% of Standard
SO_2	1-hr H19H	364[b]	35	399	1300	30.7
	3-hr H2H	212	26	238	1300	18.3
	24-hr H2H	71.5	11	82.5	262	31.5
	Annual	6	3	9	52	17.3
NO_x	1-hr H2H	300/228[c]	75	303	564	53.7
	Annual	8.5	6	14.5	94	15.4
PM_{10}	24-hr H2H	106	30	136	150	90.1
	Annual	31.3	8	39.3	50	78.6

[a] Only the most restrictive standard is shown in the table.
[b] The 1-hr modeled SO_2 concentration is actually the high-tenth high as opposed to the high-nineteenth high.
[c] The post-processes NO_x concentrations are conservative over-estimates of NO_2 concentrations as ratio methods were not used.

As shown in the above table, all of the modeled concentrations for SO_2, NO_x, and PM_{10} are below the MAAQS/NAAQS. The modeled PM_{10} impacts, including impacts from the nearby TRL facility operations, represent a significant percentage of the available standard. Therefore, in accordance with Department ambient air quality monitoring policy, TRC will be required to conduct ambient air monitoring for PM_{10}. The ambient air quality monitoring requirements are detailed in Attachment 1.

In addition to the above detailed modeling, Bison, on behalf of TRC, conducted modeling to address TRC emissions during start-up and malfunction operations utilizing the boiler pre-heater and from the boiler refractory curing heaters. TRC, by permit, is not allowed to operate the boiler pre-heater or refractory curing heater(s) while the boiler is in operation and overall operation of these units is limited to 500 hours annually, per unit. Emissions from the 60 MMBtu/hr propane/diesel fired boiler pre-heater represent only a fraction of the boiler emission rates. These emissions were modeled out of the main stack in place of the boiler emissions and at reduced flow and temperature rates. All other plant emissions were held constant for the modeling demonstration. Although the plume rise for the boiler pre-heater scenario is less than the main boiler scenario, the emission rate reduction associated with the boiler pre-heater scenario resulted in uniformly lower predicted impacts from this operating scenario when compared to boiler operations.

Bison prepared a similar modeling analysis for the operation of the refractory brick curing heaters. Again, the boiler emissions were turned off and the refractory heaters emissions were modeled out of the main stack in place of the boiler emissions. The refractory heater emissions result in even lower impacts than the boiler preheater emission impacts and the predicted impacts are again uniformly lower for this operating scenario when compared to boiler emission impacts.

Therefore, the Department concluded that the modeled impacts from the proposed TRC facility would not contribute to a violation of the MAAQS/NAAQS or adversely affect the Thompson Falls PM_{10} non-attainment area. In general, the modeling demonstrated that the dispersion characteristics, for the modeled pollutants, are such that any potential impacts would be minimized.

In addition, during the public comment period for the Department's preliminary determination, the Department received public comment indicating that the adjacent waste transfer station located on the TRL site constitutes ambient air and that the full ambient air impact analysis conducted for TRC operations had not included receptors at this site. Based on this comment, the Department required that TRC conduct an ambient air impact analysis including receptors at the adjacent transfer station. On November 3, 2004, the Department received the updated ambient air impact analysis from Bison, on behalf of TRC. The model inputs used for this analysis were exactly the same as those used for the latest and previously described model accepted by the Department. The updated analysis demonstrates that ambient air impacts at the transfer station from proposed TRC operations would maintain compliance with the applicable NAAQS/MAAQS. Model results for the transfer station were generated for CO, NO_x, PM_{10}, and SO_2. All of the predicted maximum impacts from the transfer station modeling demonstration are below the highs predicted for the full impact analysis discussed previously. Therefore, none of the overall predicted high concentrations, locations, or times of occurrence have changed from the previously summarized full ambient air impact analysis conducted for the proposed TRC project. A complete analysis and summary of the transfer station modeling analysis is included in TRC's complete application for the proposed permit modification.

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 detailed in Section 7.B of this EA, cooling tower operations at the plant would require a maximum of 125 gallons per hour for proper operation. The water would come directly from the Clark Fork River using shared water rights from TRL under a proposed historical water use change or from a new groundwater appropriation/right which is currently under review by the DNRC. Further, initially, TRC would not discharge any used process water back into any navigable waters, rather all water discharged from the cooling tower would be sent to a lined on-site evaporation pond. Recent correspondence with Department waste-water regulators indicates that TRC may pursue a groundwater discharge permit in the future. Any impacts to the local resources of water would be minor because of the relatively little amount of water required for normal operations.

As previously discussed, the proposed permit modification would increase allowable air pollutants in the area; 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. In addition, although modeled levels of PM_{10} emissions do not exceed any standards, Department policy dictates that the level of permitted emissions warrants the requirement for an ambient monitoring network for this pollutant to ensure the source does not exceed any set standard. Any impacts to local the air resource would be minor as demonstrated through the ambient air quality impact analysis conducted for the proposed permit modification.

Finally, under the current permit action, additional energy would be used and produced 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. Under the proposed permit modification, TRC also permitted a proposed 60 MMBtu/hr heat input capacity propane/diesel-fired boiler pre-heater and propane-fired boiler refractory brick curing heaters with a maximum capacity of 60 MMBtu/hr. Since these units would be limited to specific operating scenarios and ultimately a maximum of 500 hours of operation per unit per year, any demands for energy resources would be limited and minor.

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 ground disturbing nature of 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 would 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 #3175-01.

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 not impact the local state tax base or tax revenue 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 the numerous temporary construction/contract workers employed by TRC for the purpose of constructing the 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 due to slightly increased allowable energy production. 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 increase in emissions of pollutants requested under the proposed permit modification. However, Permit #3175-01 would incorporate conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

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 it's 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 not impact the quantity and distribution of employment in the area or the distribution of population in the area because the project would continue to provide employment opportunities for approximately 15 full-time positions, upon completion of the facility. Construction employment may realize a small increase, as the proposed permit modification would require the construction of outdoor coal and wood-waste storage operations including the construction of earthen berm structures, wind fencing, and water spray systems for the control of fugitive dust from these sources. 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 (including water rights appropriations and any necessary water discharge permits). 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. All process water for the facility operations would be obtained as discussed in Section 7.B through a new groundwater right appropriation and/or the currently contested change in water use from TRL operations. All spent water (waste-water) would 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 1.6 miles (2.7 kilometers) west/northwest of the proposed modified facility. The proposed modification would be outside of the nonattainment area and, as demonstrated through an ambient air quality impact analysis (See Section VI of the permit analysis and Section 7.F of this EA), would not significantly contribute to the nonattainment status of the area. In addition, the modeling inputs were based on the "worst case" PM_{10} emissions from the facility operating under the proposed changes. Not only would the facility seldom operate at "worst case" conditions, but the prevailing wind pattern in the area would generally carry the emissions from the facility to the east of the plant, away from the nonattainment area. Based on the previously discussed ambient air quality impact analysis conducted for the proposed permit modification, accounting for worst-case capacity plant operations, 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 #3175-01.

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 #3175-01 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.

EA prepared by: M. Eric Merchant, MPH
Date: September 30, 2004

POWER PLANT
OPERATING AND MAINTENANCE AGREEMENT

This Power Plan Operating and Maintenance Agreement (the "Agreement") is made and entered into as of the 9th day of July 2003, by and between THOMPSON RIVER CO-GEN LLC, a limited liability company organized and existing under the laws of the State of Colorado ("TRC"), and SAVAGE SERVICES CORPORATION, a Utah corporation ("Savage").

Background

A. TRC is constructing a power plant adjacent to the Thompson River Lumber Company Facility in Thompson Falls, Montana.

B. TRC desires to engage Savage to operate and maintain the power plant on a turnkey basis consistent with "Prudent Electric Practices," and Savage desires to accept such engagement, upon the terms and subject to the conditions set forth in this Agreement.

Agreement

The Parties, intending to be legally bound, agree as follows:

1. Background, Exhibits and Schedules. The foregoing recitals and all Exhibits and Schedules referenced in this Agreement are expressly made a part of this Agreement.

2. Definitions. For purposes of this Agreement, the following terms or words, which have their first letter capitalized, shall have the meanings set forth or referenced below. Terms and words that have their first letter capitalized but that are not defined herein shall the meaning set forth in the NorthWestern Agreement.

2.1 "Actual Cost" means a direct, out of pocket cost actually incurred by a Party, without markup or allocation of overhead.

2.2 "Annual Budget" means the annual expense budget to be submitted by Savage to TRC pursuant to Section 3.3(v).

2.3 "Annual Operating Plan" means the annual written plan for operating and maintaining the Plant in accordance with the corresponding Annual Budget, to be submitted by Savage to TRC pursuant to Section 3.3(v).

"Base Monthly O&M Fee" shall have the meaning set forth in Section 7.2(b).

2.5 "Budget Variance Report" means a written report submitted at the end of each Month documenting Savage's performance compared to the approved Annual Budget.

"Capital Improvements" shall have the meaning set forth in Section 6.1

2.7 "Commissioning" means the running of the Power Plant after Initial Start-Up where equipment is inspected, tuned and adjusted until Operational, as provided in the FSE Contract.

2.8 "Commissioning Phase" means the period of time from Initial Start-Up, as provided in the FSE Contract, through the Contract Operation Date.

2.9 "Construction Contractor" means TIMEC Constructors, and its subcontractors and agents.

2.10 "Dispute" shall have the meaning set forth in Section 14.2.

2.11 "FSE Contract" means that certain contract, dated October 15, 2001, between TRC and Factory Sales and Engineering.

2.12 "Initial Start-Up" shall have the meaning set forth the FSE Contact.

2.13 "Initial Plant Start-Up Date" means the date on which the Construction Contractor begins Initial Start-Up of the Plant.

2.14 "IPD" shall have the meaning set forth in Section 7.2(c).

2.15 "Month" means a calendar month during the Term, commencing at 12:01 a.m. current local time on the first day thereof and concluding at 12:01 a.m. current local time on the first day of the following calendar month.

2.16 "Non-Routine O&M" means operations activity, maintenance or repair required to maintain safe, continuous operation of the Plant that was not included in the Annual Budget or the Annual Operation Plan, to the extent not caused by Savage's negligence or intentional misconduct.

2.17 "NorthWestern Agreement" means that certain Co-Generation Power Sales Agreement, dated September 12, 2002, between TRC and NorthWestern Energy, LLC, a copy which is attached as Exhibit 2.17.

2.18 "O&M" means the aggregate of all services to be provided by Savage under this Agreement.

2.19 "Operational Phase" means the period of time from the Contract Operation Date through the balance of the Term.

2.20 "Party" – Savage and TRC are each called a "Party" and, collectively, are called the "Parties".

2.21 "Plant Manager" means the Savage employee assigned overall on-site operational and managerial responsibility for the O&M services.

2.22 "Power Plant" or "Plant" means the cogeneration power plant that TRC plans to install at Thompson Falls, Montana, including, but not limited to, the furnace, boiler, steam turbine, generator and equipment used to generate steam and electrical power at such plant, and including the substation, transmission, and interconnection equipment.

2.23 "Pre-Commissioning Phase" means the period of time beginning ninety (90) days prior to the estimated Initial Plant Start-Up Date and continuing through the Initial Plant Start-Up Date.

2.24 "Prudent Electric Practice" means those practices, methods and acts which:

(a) when engaged in are commonly used by independent power producers in prudent operations to operate electric equipment and associated mechanical and civil facilities lawfully and with safety, reliability, efficiency and expedition; or

(b) in the exercise of reasonable judgment considering the facts known when engaged in, could have been expected to achieve the desired result consistent with applicable law, safety, reliability, efficiency and expedition.

Prudent Electric Practice is not limited to the optimum practiced method or act, but rather is a spectrum of possible practices, methods or acts.

2.25 "Root Cause Analysis" means a written analysis of the nature, cause and impact of equipment or component failures, including cost impacts and recommended actions.

2.26 "Routine O&M" means any operating activity, maintenance or repair that is included in the Annual Budget and Annual Operating Plan, including all operating activities, maintenance and repairs that are performed during the normal operation of the Plant or as part of a Scheduled Maintenance Outage.

2.27 "Savage" means Savage Services Corporation, a Utah corporation.

2.28 "Term" means the term of this Agreement as set forth in Section 10.1 of this Agreement, unless otherwise earlier terminated as provided herein.

2.29 "TRC" means Thompson River Co-Gen, LLC, a Colorado limited liability company.

2.30 "TRL" means Thompson River Lumber Company of Montana, Inc.

2.31 "Uncontrollable Force" means any cause beyond the control of the Party affected, including but not restricted to failure of or threat of failure of facilities, flood, earthquake, tornado, storm, fire, lightening, epidemic, war, riot, terrorism, civil disturbance or disobedience, labor dispute, labor or material shortage, sabotage, restraint by court order or public authority, and action or nonaction by or failure to obtain the necessary authorizations or approvals from any governmental agency or authority, which by exercise of due diligence such Party could not reasonably have been expected to avoid and which by exercise of due diligence it shall be unable to overcome. Nothing contained herein shall be construed so as to require a Party to settle any strike or labor dispute in which it may be involved.

3. Savage's Obligations.

3.1 Pre-Commissioning Phase. In return for the fee described in Section 7.1, and subject to reimbursement for expenses as described in Section 7.3, Savage shall, during the Pre-Commissioning Phase, begin preparation to operate and maintain the Plant. In connection therewith, Savage shall:

(a) Select and assign a Plant Manager reasonably acceptable to TRC, who will represent Savage and TRC in all matters regarding the Operations and Maintenance Services Agreement.

(b) Establish a temporary O&M office on site to provide space for the Plant's O&M staff until the permanent offices and employee work areas are completed and ready to occupy.

(c) Prepare an Annual Budget and Annual Operating Plan for the period beginning on the Contract Operation Date and continuing through December 31 2004, initially, and annually for each calendar year of the Term thereafter, based on the preliminary outline attached as Schedule 3.1, for TRC's review and approval.

(d) Prepare a staffing plan and schedule for TRC's review and approval, which approval shall not be unreasonably delayed or withheld.

(e) Implement such staffing plan, upon receipt of TRC's approval thereof, by hiring the appropriate personnel in accordance with the approved schedule.

(f) Provide such personnel with appropriate policy manuals, site specific work rules, safety training and job-specific training.

(g) Develop appropriate lists and specifications for the procurement of the tools, office equipment, maintenance equipment and rolling stock consistent with the first Annual Budget and Operating Plan.

(h) Organize the Plant office, shop and control room upon completion of their construction.

(i) Procure the general supplies for the O&M activities in compliance with the first Annual Budget and first Annual Operating Plan.

(j) Develop an O&M procedures manual for the Plant.

(k) Develop a safety plan and program for the Plant, to be managed by the Plant Manager.

(l) Respond to requests from TRC for operating information and reasonable assistance in completing the Plant and preparing it for Commissioning, including by (i) providing experienced and knowledgeable personnel to review construction drawings and operating procedures provided by the Construction Contractor and suggesting changes where appropriate, and (ii) operating the Plant's equipment during check out, start-up and testing of subsystems by the Construction Contractor.

(m) Assist TRC to ensure that fuel for the Plant is properly purchased, shipped, documented and inventoried, and coordinate with TRL in the development of procedures for efficiently utilizing TRL's equipment and personnel to handle, stockpile, reclaim and feed fuel to the Plant on an as-needed basis.

(n) Contract for the services of Precision Energy Services, or an equivalent consulting engineer, to provide technical support during the Pre-Commissioning Phase, the Commissioning Phase and the first six months of the Operational Phase.

3.2 Commissioning Phase. The Parties acknowledge that, during the Commissioning Phase, the Construction Contractor (and not Savage) shall have primary responsibility for directing the operation and Commissioning of the Plant. In return for the fee described in Section 7.1, and subject to reimbursement for expenses as described in Section 7.3, Savage, shall during the Commissioning Phase:

(a) Assist the Construction Contractor to start-up and Commission the Plant and to conduct performance and emissions tests, including the project tests required under the NorthWestern Agreement.

(b) Start-up, operate and maintain the Plant as directed by the Construction Contractor or it representative.

(c) Supply the qualified personnel necessary to operate, maintain and monitor operations at the Plant, in accordance with the staffing plan described in Section 3.1(d).

(d) Manage the fuel, water treatment chemicals and spare parts inventories.

(e) Purchase supplies and consumables as required for on-going operation

(f) Monitor emissions instruments and report results to TRC as reasonably agreed by the Parties.

(g) Prepare a punch list of items to be repaired or completed by the Construction Contractor.

(h) Finalize the first Annual Budget described in Section 3.1(c), incorporating any results of performance tests that affect the costs of Routine O&M of the Plant.

3.3 Operational Phase – Routine O&M. In return for the fee described in Section 7.2, and subject to reimbursement for expenses as described in Section 7.3, Savage shall, during the Operational Phase, use best commercially reasonable efforts to operate and maintain the Plant in a safe, clean and efficient manner, in compliance with applicable laws, rules and regulations, and at a generation capacity level at which the Plant can reliably operate consistent with Prudent Electric Practices, the approved Annual Budgets and the approved Annual Operating Plans. In connection therewith, Savage shall:

(a) Supply the qualified personnel necessary to operate, maintain and monitor operations at the Plant, in accordance with the staffing plan described in Section 3.1(d), as amended from time to time with TRC's consent.

(b) Maintain an effective and safe work force through continued training, administration and compensation.

(c) Procure the necessary materials, supplies and consumables for the Routine O&M of the Plant.

(d) Implement and maintain an appropriate inventory and accessories tracking program.

(e) Implement and update regularly a preventive maintenance program meeting the available Plant equipment's manufacturer specifications; provided that contracts for major repairs and rebuilds shall be open to competitive bidding and approved by TRC, which approval shall not be unreasonably delayed or withheld.

(f) Perform and document periodic operational checks and tests of the Plant's equipment in accordance with the available equipment manufacturer's specification and applicable laws.

(g) Maintain such operating logs, records and reports as are appropriate for proper operation of the Plant, and for such technical evaluation as may be required, and provide such information to TRC or others as requested by TRC from time to time.

(h) Maintain current revisions to the Plant drawings, instruction books and operating and maintenance manuals.

(i) Maintain the Plant's maintenance shop, tool room equipment and instruments, and provide small (hand) tools required by Savage personnel for normal operations.

(j) Contract for the rental of such equipment as may reasonably be required for Routine O&M.

(k) Provide or contract for the maintenance of the Plant's fire protection equipment, including appropriate routine inspection.

(l) Maintain accurate cost documentation and accounting records regarding the services provided in accordance with generally accepted accounting principles.

(m) Provide TRC with monthly summary reports of the performance of the Plant, including actual versus budgeted costs.

(n) Develop and maintain a mutually-acceptable reporting system to provide storage and ready retrieval of operating data, costs and expenditures in excess of the fees listed in Section 7, and analyses and verification of same. Coordinate with TRC and NorthWestern to schedule any maintenance involving or resulting in a Scheduled Maintenance Outage.

(o) Provide or contract for appropriate security for the Plant.

(p) Provide or contract for the services of a yard maintenance company to maintain the Plant's grounds in a clean and kept manner as appropriate.

(q) Perform, operate and maintain for TRC the monitoring and reporting requirements specified in the air quality permit by the State of Montana with respect to this Plant.

(r) Coordinate the delivery of the fuel to Plant in accordance with TRC's contracts with fuel suppliers, and provide a monthly fuel inventory report.

(s) Operate the Power Plant consistent with the types and proportions of fuel listed in Schedule 3.3.

(t) On a monthly basis review existing and potential fuel sources to optimize the fuel blend in order to achieve optimum Plant efficiency and output. Savage may rely on fuel analysis provided by fuel suppliers.

(u) Load fly ash, grate ash and miscellaneous solid waste materials for removal from the Plant, and provide or contract for the disposal of such waste, and divert waste water to an evaporation pond provided by TRC.

(v) Prepare and, no later than November 1 of each calendar year during the Term, submit to TRC for its review and approval an Annual Operating Plan and an Annual Budget for the next calendar year. The Annual Budget shall include Savage's projections of all costs for operating the Power Plant including, but not limited to, management, administrative and operating labor, and all materials, fuel, lime, water treatment chemicals, spare parts and other consumables required to operate and maintain the Plant for the upcoming calendar year, and including (a) fees payable to Savage under Section 7, and (b) projected expenses reimbursable under Section 7.3.

(w) Provide assistance and information as necessary for TRC to obtain and maintain asset insurance.

(x) Review and comply with all applicable laws and initiate and maintain such precautions, procedures, and operating plans relating to the operation of the Power Plant as are necessary to comply therewith, or to assist TRC in complying therewith, as the case maybe.

(y) Maintain all of the necessary permits and licenses with respect to pollution controls and emissions and other governmental regulations and standards which are or may be required for the operation of the Power Plant.

(z) Notify TRC immediately of any event that results in a Forced Outage, loss or damage that will result in a loss of generating capability, or in Non-Routine O&M costs to TRC in excess of a pre-agreed upon amount, and prepare a Root Cause Analysis and submit such Analysis to TRC within five (5) days of the completion thereof.

(aa) Prepare and, no later than November 1 of each calendar year during the Term, submit to TRC a projection of the Plant's annual lime requirements and water treatment chemical requirements for the next calendar year.

3.4 Non-Routine O&M. The parties acknowledge that the Plant may, from time to time, require Non-Routine O&M. Subject to reimbursement for expenses as described in Section 7.3, Savage shall provide Non-Routine O&M as necessary and appropriate to ensure the efficient operation of the Plant, including those listed below.

(a) Recommend to TRC any modifications that Savage may identify at the Plant and, upon receipt of TRC's approval, implement the modification, with TRC to pay the actual cost thereof.

(b) Provide Non-Routine O&M including Forced Outage management, technical supervision, labor, inspection reports, and recommendations. Schedule 3.4 lists examples of Non-Routine O&M items that could arise and result in costs outside of the Annual Budget. Coordinate with TRC and NorthWestern to schedule any maintenance involving or resulting in a Scheduled Maintenance Outage.

(c) In the event of an emergency, Savage shall take all such action as it reasonably determines to be reasonable and necessary to prevent, avoid, or mitigate injury, damage, or loss.

3.5 Spare Parts. Savage shall determine an appropriate spare parts inventory reasonably required for satisfactory operation of the Power Plant, taking into account the inventory of existing spare parts provided by TRC and the recommendations of the various equipment suppliers, and present the same to TRC for approval. An initial generic list of spare parts and the estimated cost of these parts is attached as Schedule 3.5. Upon receipt of TRC's approval, which shall not be unreasonably delayed or withheld, Savage shall purchase and store such spare parts. Savage shall purchase replacements for spare parts used to repair the Power Plant and invoice TRC for the Actual Cost incurred. Savage shall keep lists of spare parts in inventory and their value as well as a history of parts used. The spare parts list attached as Schedule 3.5 may be amended from time-to-time by Savage, as appropriate, with the approval of TRC.

3.6 Exclusions. Savage shall not be responsible for construction or equipment required by the air quality permit prior to mobilization on the site.

3.7 Independent Contractor. Savage shall, in providing the O&M Services and at all times during the Term, be considered an independent contractor with respect to TRC. Neither Savage nor any employee of Savage or of any subcontractor shall be considered an employee, representative or agent of TRC for any purpose. Savage shall be solely responsible for payment of compensation to Savage's employees. Savage shall pay and report, for all its employees assigned to perform the services under this Agreement, federal and state income tax withholding, social security taxes, workers compensation and unemployment insurance applicable to such employees. Savage shall bear sole responsibility for any health or disability insurance, retirement benefits, or other welfare or pension benefits, if any, to which such employees may be entitled.

4. TRC's Obligations. TRC shall:

4.1 Construct or cause to be constructed, a complete and operable Power Plant that will pass the Successful Project Test required by the NorthWestern Agreement.

4.2 Provide all desks, cabinets, chairs, computers, fax machines, copiers, telephones and other furniture and equipment required to furnish completely a production office at the Plant; provided that TRC may request Savage to procure such items at TRC's expense.

4.3 Furnish all capital equipment required to equip an electrical shop, a mechanical shop and a vehicle maintenance area at the Plant, including but not limited to welders, acetylene torches, electrical test instruments, tools specifically designed for a designated use, hoists, electrical power tools and water test lab equipment; provided that TRC may request Savage to procure such items at TRC's expense.

Furnish such vehicles as upon which TRC and Savage may agree.

4.5 Provide Savage with not less than one-hundred twenty (120) days advance written notice of the projected Initial Plant Start-Up Date, in order to enable Savage to hire the necessary personnel and perform its Pre-Commissioning Phase obligations as outlined in Section 3.1.

4.6 Reconfirm the Initial Plant Start-Up Date in writing thirty (30) days in advance thereof, in order to enable Savage to hire the necessary personnel to perform its Commissioning Phase and Operational Phase obligations as outlined in Sections 3.3 and 3.4.

4.7 Deliver or cause others to deliver to Savage at least one set of all operating manuals, maintenance manuals and other manuals, flow diagrams, P & ID diagrams, equipment manufacturers' specifications (as available), control philosophy documents, PLC programming documents, design and engineering drawings and as-built drawings for the Power Plant, together with any other drawings, data and information reasonably requested by Savage, at least two months prior to start up of any equipment.

4.8 Pay all taxes, including real property taxes, personal property taxes, sales taxes, excise taxes, business taxes and other taxes, assessed on TRC or the Plant, including on fuel, spare parts inventories, water treatment chemical inventories, and supplies.

4.9 Pay the fees and reimburse the expenses as provided by Section 7 hereof.

4.10 Contract and pay for delivery of the utilities necessary for Power Plant operations, including, without limitation, telephone, power and water.

4.11 Deliver, or cause to be delivered to the Power Plant, fuels from the sources listed in Schedule 2, at no cost to Savage and in quantities and qualities sufficient to enable Savage to (a) operate the Plant in compliance with this Agreement and the North Western Agreement, and (b) achieve the approximate fuel blends listed on Schedule 3.3.

4.12 Notify Savage in writing not less than three (3) months prior to any material change in the properties of fuels or lime scheduled to be delivered to the Plant so that the resulting impact on the Annual Budget can be assessed.

4.13 Purchase, commission and annually test substation, transmission, interconnection, metering and telemetry equipment.

4.14 Pay all fees required for transmission of power to purchasers.

4.15 Pay the annual air quality operation fee and all other fees required by State or Federal regulations.

4.16 Be responsible for and pay for any and all costs incurred in connection with the Power Plant, or any such replacement equipment, which are considered to be capital improvements and are required to be capitalized pursuant to generally accepted accounting principles consistently applied.

4.17 Contract and pay for the delivery of sufficient quantities of lime and water treatment chemicals in quantities sufficient to enable Savage to operate the Plant in compliance with this Agreement, applicable laws, rules, regulations and permits, and the terms of the North Western Agreement.

4.18 Be responsible and pay any amounts due to TRL under that certain Power and Steam Supply Agreement, dated October 3, 2002, between TRC and TRL.

5. Ultimate Control. The parties acknowledge that TRC, as the owner, shall retain ultimate control over how operation and maintenance of the Power Plant will be conducted.

6. Capital Expenditures.

6.1 Savage shall from time to time identify and recommend to TRC areas of capital expenditures that will result in improved Power Plant operation and reliability or may be required by governing agencies ("Capital Improvements").

Savage shall plan and execute Capital Improvements upon approval by TRC.

6.3 TRC shall pay all reasonable costs incurred by Savage to implement approved projects, including the Actual Cost of outside contractor services.

6.4 TRC may elect to contract with others to implement these projects, but shall reimburse the Actual Cost, if any, incurred by Savage in supporting such contractors.

7 Fees and Expenses.

7.1 Pre-Commissioning Phase and Commissioning Phase Fees.

(a) TRC shall reimburse Savage monthly for costs actually incurred during the Pre-Commissioning Phase, which are estimated to be seventy-seven thousand two hundred and fifty dollars ($77,250.00).

(b) Savage shall credit to TRC any costs incurred during the Pre-Commission Phase that are reimbursed by or through economic development programs.

(c) TRC shall reimburse Savage monthly for fees paid to Precision Energy Services, or an equivalent consulting engineer, for engineering and operational support services provided during the period beginning thirty (30) days from the date of this Agreement and continuing through the Contract Operation Date, up to a maximum of forty-eight thousand dollars ($48,000.00).

Operational Phase Fees.

(a) TRC shall reimburse Savage monthly for fees paid Precision Energy Services, or an equivalent consulting engineer, for engineering and operational support services during the six-month period following the Contract Operation Date, up to a maximum of twenty-two thousand dollars ($22,000.00).

(b) TRC shall pay to Savage a fee (the "Base Monthly O&M Fee") of eight thousand three hundred thirty-three dollars ($8,333.00) beginning with the first month following the first anniversary of the Contract Operation Date, payable on or before the tenth day of each month of the remainder of the Term.

(c) The Base Monthly O&M Fee shall be subject to adjustment each year on the anniversary date of this Agreement, based on the change in the value of the Implicit Price Deflator for Gross Domestic Product (the "IPD"), as published by the Department of Commerce, Bureau of Economic Analysis. The base value of the IPD shall be the value first reported as a preliminary value for the IV Quarter of 2002, as published in March, 2003: 111.25.

7.3 Reimbursable O&M Costs. TRC shall reimburse Savage monthly for (i) ongoing Routine O&M expenses actually incurred by Savage, (ii) Non-Routine O&M expenses actually incurred during an emergency, as contemplated by Section 3.4(c), (iii) Non-Routine O&M expenses actually incurred, (iv) the Actual Cost of acquiring spare parts, as contemplated by Section 3.5, (v) the Actual Cost of approved Capital Improvements, as contemplated by Section 6, (vi) all costs described as reimbursable in this Agreement, and (vii) and all costs incurred on behalf of TRC, in each case as actually incurred.

7.4 Terms of Payment. Savage shall invoice TRC once monthly on the fifth (5th) business day of the month for all expenses actually incurred and properly reimbursable under this Section 7, plus the Base Monthly O&M Fee for the forthcoming month (when applicable). Terms of payment shall be ten (10) days after TRC's receipt of an invoice at the address or fax number set forth in Section 15.1 herein. Payment shall be considered made when funds are electronically deposited with Savage's financial agent.

8. Insurance.

8. Savage.

(a) Savage shall maintain its standard ISO Commercial General Liability and Business Automobile Liability Insurance as described below. The cost for any insurance required by TRC in excess of these amounts shall be reimbursed by TRC.

$2,000,000 General Aggregate Limit

$1,000,000 Personal Injury

$1,000,000 Each Occurrence Limit

$ 100,000 Fire Damage Limit (any one fire)

$ 5,000 Medical Expense (any one person

$1,000,000 Employee Benefits Liability

$1,000,000 hired and non-owned vehicle liability insurance

(b) Savage shall waive, with respect to TRC, Savage's rights of subrogation related to any workman's compensation claim for an employee related injury or disease. Upon written request by TRC, Savage shall furnish evidence of the above insurance.

(c) Savage shall provide TRC with certificates evidencing the required insurance policies and showing TRC and NorthWestern Energy, LLC as additional insureds to the commercial general liability and business and auto policies. Savage shall notify TRC of any proposed change of carriers or policies. Regardless of any provision of this Agreement and in the insurance policies to the contrary, such insurance shall not cover the negligent acts or omissions of TRC.

(d) All sums required to pay any deductible or retention of liability under any insurance policy beyond those required by Section 8.1(a) that are maintained by Savage at the request of TRC shall be a reimbursable cost for purposes of Section 7.3.

(e) Savage shall use commercially reasonable efforts to obtain a quote from its underwriters for the insurance required to be maintained by TRC under the NorthWestern Agreement, as further described in Section 8.2, below. TRC shall not be obligated to purchase such insurance through Savage's underwriters. However, if TRC elects to purchase such insurance through Savage's underwriter's, TRC shall pay all costs thereof, including any deductible or retention of liability thereunder.

8.2 TRC. TRC shall maintain property insurance covering the Power Plant in the amount required by the NorthWestern Agreement. Such insurance shall provide for a waiver of subrogation by TRC and its carrier against Savage with respect to or loss of the Power Plant. TRC shall provide appropriate liability insurance for its employees when they are on the Power Plant property.

8.3 Application of Insurance Proceeds. In the event of casualty loss or damage to the Power Plant, TRC shall apply the proceeds first to the cost of any repair, rebuilding, or restoration necessary to enable the Power Plant to resume or continue operation under this Agreement, subject to the requirements of (a) the NorthWestern Agreement, (b) TRC's agreements with its lenders, (c) the Power and Steam Supply Agreement between TRC and Thompson River Lumber Company of Montana, Inc., (d) the lease agreement between TRC and Thompson River Lumber Company of Montana, Inc., and (e) future financing agreements, power and energy sales agreements and leases with third parties.

9. Liability and Indemnity.

9.1 TRC. TRC shall indemnify and hold harmless Savage, its affiliates, directors, officers, employees, and agents from and against any suits, claims, losses, demands, liabilities, damages, costs, and expenses (including costs, reasonable attorney's fees, and reasonable investigative costs) in connection with any suit, demand, or action by any third party arising out of or resulting from (a) any breach of its representations, warranties, or obligations set forth in this Agreement; (b) TRC's exercise of control over the services under this Agreement. to the extent that TRC's instructions or directions violate applicable law or regulation; or (c) any negligence or willful misconduct by TRC, provided, however, that TRC's obligations hereunder shall be proportionately reduced to the extent the negligence or intentional misconduct of Savage or its affiliates, directors, officers or employees is the cause.

9.2 Savage. Savage shall indemnify and hold harmless TRC, its affiliates, directors, officers, employees, and agents from and against all suits, claims, losses, demands, liabilities, damages, costs, and expenses (including costs, reasonable attorney's fees, and reasonable investigative costs) in connection with any suit, demand, or action by any third party arising out of or resulting from (a) any breach of its representations, warranties, or obligations set forth in this Agreement; (b) Savage's exercise of control over the services under this Agreement, to the extent that Savage's instructions or directions violate applicable law or regulation; or (c) any negligence or willful misconduct by Savage, provided, however, that Savage's obligations hereunder shall be proportionately reduced to the extent the negligence or intentional misconduct of TRC or its affiliates, directors, officers or employees is the cause.

9.3 Limitation of Savage's Liability.

(a) Provided that Savage operates and maintains the Plant in a manner that is consistent with Prudent Electric Practices, Savage shall not be liable for damages, lost profits, costs or penalties, of any kind, incurred or suffered by TRC as a result of any Penalty Hours that may accrue under the NorthWestern Agreement. Such limitation shall apply even if Savage is in material breach of any of its other obligations to TRC, provided that the material breach does not directly or indirectly result in the accumulation of Penalty Hours.

(b) Savage shall not be considered to be in default in the performance of any of its obligations under this Agreement when a failure of performance shall be due to an Uncontrollable Force; provided Savage gives prompt notice of such fact to TRC and exercises due diligence to remove such inability with all reasonable dispatch.

9.4 Procedure for Indemnification for Third Party Claims. All indemnification obligations in this Agreement are conditioned upon the party seeking indemnification promptly notifying the indemnifying party of any claim or liability of which the party seeking indemnification becomes aware (including a copy of any related complaint, summons, notice or other instrument), cooperating with the indemnifying party in the defense of any such claim or liability (at the indemnifying party's expense), and not compromising or settling any claim or liability without prior written consent of the indemnifying party.

9.5 Procedure for Indemnification for Other Claims. A claim for indemnification for any matter not involving a third-party claim may be asserted by notice to the Party from whom indemnification is sought.

10. Term of Agreement.

10.1 Initial Term. The initial term of this Agreement (the "Term") shall commence on the date of this Agreement and shall continue, unless earlier termination pursuant to Section 13 hereof, for 10 consecutive calendar years after the Contract Operating Date.

10.2 Renewal Term. Six months prior to the end of the initial Term, Savage shall prepare and submit a new O&M agreement to TRC. The term of the new agreement shall be for a five year period. TRC may accept, reject or seek to negotiate the terms of the new agreement. If a mutually acceptable agreement is not reached within ninety days prior to the end of the initial term, the contractual relationship between the parties will terminate at the end of the initial Term.

11. Confidentiality. Each Party will treat as confidential all information which is not otherwise lawfully known to or already in the public domain, shall not disclose such information to any third party (except its attorneys, accountants, or other advisers who shall be similarly bound by this confidentiality clause) without the prior written consent of the other Party, shall return such information promptly to the other party upon request, and shall keep such information confidential both during and following the expiration of this Agreement. If the disclosure of such confidential information is required by law, written notice should be given to the other Party in order to permit such Party to have the opportunity to seek a protective order or otherwise object to its disclosure.

12. Warranties and Representations.

12.1 TRC's Warranties and Representations. TRC warrants and represents to Savage that TRC is a limited liability company duly organized, validly existing, and in good standing under the laws of the State of Colorado and is qualified to do business and is in good standing in the State of Montana and has full powers and authority to enter into the transactions contemplated hereunder, and to execute, deliver, and perform this Agreement.

12.2 Savage's Warranties and Representations. Savage warrants and represents to TRC that Savage (i) is a corporation duly organized, validly existing, and in good standing under the laws of the State of Utah; (ii) is qualified to do business and is in good standing in the State of Montana; (iii) has the full corporate power and authority to enter into the transactions contemplated hereunder and to execute, deliver, and perform, this Agreement; (iv) has the experience and technical expertise to perform its obligations under this Agreement; (v) will perform its duties under this Agreement in compliance with all applicable local, state, and federal laws.

12.3 Limitations to Savage's Warranties and Representations. Savage warrants that it will operate and maintain the Plant in a manner that is consistent with "Prudent Electrical Practices." Savage makes no warranty or guarantee of any kind, either expressed or implied, that the Plant can be operated and maintained in such a manner that it can achieve and/or sustain the capacity and availability levels set forth in the NorthWestern Agreement.

13. Termination of Agreement.

13.1 Termination by Mutual Consent. This Agreement may be terminated prior to the end of the Term by mutual written consent of Savage and TRC.

13.2 Termination for Cause. Either Party may terminate this Agreement at its discretion twenty (20) days after serving notice upon the other Party of the occurrence of any event of default as set forth below on the part of such other Party, unless such other Party shall have cured such event of default within the twenty (20) day period. An event of default shall consist of any of the following:

(a) The failure of a Party to pay any amount due hereunder as herein provided when due (except such amounts as are disputed in good faith by written notice to the other Party);

(b) The breach by a Party of any provision hereof;

(c) The admission by a Party in writing of such Party's inability to pay its debts as they become due; or the making of an assignment for the benefit of such Party's creditors; or the filing by or against a Party of a voluntary or involuntary petition in bankruptcy or of any answer or petition seeking any reorganization, arrangement, composition or other insolvency relief under the present or any future bankruptcy act or any other applicable federal, state or other insolvency statute, law or regulation, which proceeding shall remain unstayed for a period of sixty (60) days after the commencement thereof (or if a voluntary bankruptcy filing, if such filing is not dismissed within thirty (30) days); or

(d) The failure of TRC to deliver a Plant that has completed a "Successful Project Test" within a reasonable time period after the Initial Plant Startup Date.

13.3 Illegality. Either Party may terminate this Agreement at its discretion thirty (30) days after serving notice upon the other Party if such Party reasonably determines that, due to changes in or the application of federal, state, or local laws or regulations, it is illegal to continue to perform under this Agreement.

13.4 Effect of Termination. Termination for any reason shall not relieve either party from any obligation incurred prior to such termination. Termination for cause shall not relieve TRC of its obligation to pay Savage for services performed in accordance herewith, and reimbursable expenses incurred, through the effective date of termination. Nothing in this Section 13 shall affect the right of either Party to bring, an action against the other Party for a breach occurring prior to the termination or for a wrongful termination and to recover damages resulting therefrom.

13.5 Waiver. No failure or delay on the part of the Parties to exercise any right, power, or privilege hereunder shall operate as a waiver, nor shall any single or partial exercise of any right, power, or privilege preclude any other or further exercise thereof or the exercise of any other right, power, or privilege.

14. Resolution of Disputes; Arbitration.

14.1 Resolution of Disputes. If any dispute between the Parties arises from or in connection with this Agreement or the performance of either Party's obligations hereunder, upon written request by either Party, the Parties will meet within ten (10) days of such request and endeavor to resolve the dispute by agreement.

14.2 Arbitration. If the Parties are unable to resolve any dispute, claim or any other matter in question regarding this Agreement arising out of or with respect to this Agreement or the breach hereof (a "Dispute"), then, except as otherwise provided in this Section, the Dispute shall be settled by arbitration as follows:

(a) The Parties shall negotiate in good faith for of not less than thirty (30) days, unless the Dispute is earlier resolved. If, after thirty (30) days of negotiation, the

Dispute is not settled, either Party may give the other notice in writing of its intention to seek settlement of the Dispute by arbitration.

(b) The number of arbitrators shall be three (3). Each Party shall select one arbitrator and those two (2) arbitrators shall select the third (3rd) arbitrator. The Parties shall jointly request expedited treatment.

(c) The place of arbitration shall be Salt Lake City, Utah. Except as otherwise set forth in this Section 14, commercial arbitration rules of the American Arbitration Association then in effect shall be applicable to any arbitration, unless the Parties mutually agree in writing otherwise. The governing laws shall be the laws of the state of Montana, without regard to its conflict of law principles, and the United States of America. The arbitrators shall make their decisions in accordance with the applicable arbitration rules.

(d) In no event shall a demand for arbitration be made after the date when institution of legal or equitable proceedings based on the Dispute would otherwise be barred by the applicable statute of limitations.

(e) The arbitration hearing will conclude within sixty (60) days after it commences.

(f) Any award rendered by the arbitrators in connection with this Agreement shall be final and binding, and judgment may be entered upon it in accordance with applicable law in the states of Colorado, Montana or Utah or a United States court of competent jurisdiction. If either Party fails to comply (which in the case of the payment of money means payment of the sum awarded within thirty (30) days of the arbitrators' award) with the award rendered by the arbitrators, the non-complying Party shall, in addition to being required to pay the arbitrators' award: (i) pay to the other Party all reasonable costs and expenses (including reasonable attorneys' fees and expenses) incurred in connection with the arbitration or in connection with enforcement and/or collection of the arbitrators' award, and (ii) pay interest on any unpaid amounts from the dates such amounts become due and owing until paid at the prime rate published from time to time in *The Wall Street Journal* plus two percent (2%) or the highest rate allowed by applicable law, if less.

(g) The Parties' agreement to arbitrate shall be specifically enforceable under applicable law in any court of competent jurisdiction.

(h) The requirement that a Dispute (not otherwise resolved pursuant to Section 14.1) be resolved by arbitration shall not apply to a Dispute in which:

(i) a Party, having given the other Party at least ten (10) days' notice of the other Party's breach, in good faith seeks immediate equitable relief from a court of competent jurisdiction to enable the instituting Party to prevent irreparable harm arising from the breach pending arbitral relief;

(ii) a claim by one Party against the other arises out of the subject matter of any court litigation or proceeding commenced by a third party against the claimant in which the other Party is indispensable party or third-party defendant; or

(iii) a claim is asserted with respect to which a third party, which is not bound and will not, upon request of either Party, agree to arbitrate subject to the arbitration rules provided by this Section 14, is an indispensable or necessary party.

14.3 Injunctive Relief. Notwithstanding the foregoing, the Parties agree that, in the event a Party seeks equitable relief under this Agreement, then the Party seeking such relief shall be entitled, to the remedies of injunction, specific performance and other equitable relief in a court of proper jurisdiction to prevent or stop a breach or a threatened breach of any provision of this Agreement. This Section shall not be construed, however, as a waiver of any other rights that a Party may have for damages or other relief.

15. General Provisions.

15.1 Notices. All notices, consents, waivers, and other communications under this Agreement must be in writing and will be deemed to have been duly given when (a) delivered by hand (with written confirmation of receipt), (b) sent during normal business hours by telecopier (with written confirmation of receipt), provided that a copy is mailed by registered mail, return receipt requested, or (c) when received by the addressee, if sent by a nationally recognized overnight delivery service (receipt requested), in each case to the appropriate addresses and telecopier numbers set forth below (or to such other addresses and telecopier numbers as a Party may designate by notice to the other Parties):

If to TRC

Thompson River Co-Gen, LLC
285 2nd Avenue West
Kalispell, Montana 59901
Attn: Barry Bates
Fax No. 406-257-755

With a copy to

Tenenbaum & Kreye, LLP
Plaza Tower One, Suite 2025
6400 Fiddler's Green Circle
Englewood, Colorado 80111
Attn: A. Thomas Tenenbaum
Fax No. 720-529-9003

If to Savage:

Savage Services Corporation
6340 South 3000 East, Suite 600
Salt Lake City, Utah 84121
Attn: Executive V.P., Coal and Power Generation Services
Fax No: 801-944-6520

with a copy to:

Savage Services Corporation
6340 South 3000 East
Salt Lake City, Utah 84107
Attn: Executive V.P. and General Counsel
Fax No: 801-944-6554

15.2 Governing Law. This Agreement will be governed by the laws of the state of Montana without regard to conflicts of laws principles.

15.3 Inspection of Records. Upon reasonable prior notice, each Party shall allow the other to inspect the records supporting the calculations determined under this Agreement which may be required by law or this Agreement to be maintained by either Party. Where and when reasonable to do so, either Party may install its own temporary or permanent measuring device at its own expense to verify any measurement made by the other Party pursuant to this Agreement.

15.4 Audit Rights. TRC shall have the right, at its expense, to audit any book or record (excluding Savage's consolidated profit and loss statements and balance sheets) kept by Savage pursuant to this Agreement, during normal business hours, for a period ending two years after the year to which the record applies.

15.5 Jurisdiction; Service of Process. Any action or proceeding seeking to enforce any provision of, or based on any right arising out of, this Agreement may be brought against any of the parties in the courts of the state of Montana, or, if it has or can acquire jurisdiction, in the appropriate United States District Court within the state of Montana, and each of the Parties consents to the jurisdiction of such courts in any such action or proceeding and waives any objection to venue laid therein. Process in any action or proceeding referred to in the preceding sentence may be served on any Party anywhere in the world.

15.6 Waiver. The rights and remedies of the Parties to this Agreement are cumulative and not alternative. Neither the failure nor any delay by any Party in exercising any right, power, or privilege under this Agreement or the documents referred to in this Agreement will operate as a waiver of such right, power, or privilege, and no single or partial exercise of any such right, power, or privilege will preclude any other or further exercise of such right, power, or privilege or the exercise of any other right, power, or privilege. To the maximum extent permitted by applicable law, (a) no claim or right arising out of this Agreement or the documents referred to in this Agreement can be discharged by one Party, in whole or in part, by a waiver or renunciation of the claim or right unless in writing signed by the other Party; (b) no waiver that may be given by a Party will be applicable except in the specific instance for which it is given; and (c) no notice to or demand on one party will be deemed to be a waiver of any obligation of such party or of the right of the Party giving such notice or demand to take further action without notice or demand as provided in this Agreement or the documents referred to in this Agreement.

15.7 Entire Agreement; Modification. This Agreement supersedes all prior agreements between the Parties with respect to its subject matter and constitutes, along with the documents referred to in this Agreement, and the Exhibits and Schedules referred to herein, a complete and exclusive statement of the terms of the agreement between the Parties with respect to its subject matter. This Agreement has been jointly prepared by the Parties and may not be amended except by a written agreement executed by each of the Parties.

15.8 Assignments; Successors; No Third-Party Rights. Neither Party may assign any of its rights under this Agreement without the prior consent of the other Parties, which will not be unreasonably withheld. Subject to the preceding sentence, this Agreement will apply to, be binding in all respects upon, and inure to the benefit of the successors and permitted assigns of the Parties. Nothing expressed or referred to in this Agreement will be construed to give any Person other than the Parties to this Agreement any legal or equitable right, remedy, or claim under or with respect to this Agreement or any provision of this Agreement.

15.9 Severability. If any provision of this Agreement is held invalid or unenforceable by any court of competent jurisdiction, the other provisions of this Agreement will remain in full force and effect. Any provision of this Agreement held invalid or unenforceable only in part or degree will remain in full force and effect to the extent not held invalid or unenforceable.

15.10 Article/Section Headings; Construction. The Sections in this Agreement are provided for convenience only and will not affect its construction or interpretation. All references to "Section" refers to the corresponding Section of this Agreement. All words used in this Agreement will be construed to be of such gender or number as the circumstances require. Unless otherwise expressly provided, the word "including" does not limit the preceding words or terms.

15.11 Counterparts. This Agreement may be executed in one or more counterparts, each of which will be deemed to be an original copy of this Agreement and all of which, when taken together, will be deemed to constitute one and the same agreement.

In Witness Whereof, the Parties have executed and delivered this Agreement as of the date first written above.

Thompson River Co-Gen LLC

By: ______________________
Name:
Title:

Savage Services Corporation

By:
C. Fred Busch
Senior Vice President

Exhibit 2.5	Cogeneration Power Sale Agreement between Thompson River Co-Gen LLC and NorthWestern Energy, LLC, dated October 22, 2002.
Schedule 3.1	Projection of Initial Year Routine Operation or Maintenance Costs
Schedule 3.3	Thompson River Cogeneration Project, Fuel Specifications
Schedule 3.4	Examples of Non-Routine Operations and Maintenance Items
Schedule 3.5	Preliminary listing of Spare Parts