BART Determination
for
Leland Olds Station Units 1 and 2

I. Source Description

A. Owner/Operator: Basin Electric Power Cooperative

B. Source Type: Electric Utility Steam Generating Unit

C. BART Eligible Units

1. Unit 1 boiler

2. Unit 2 boiler

3. Auxiliary Boiler

4. Fire Pump

5. Materials Handling Equipment

a. Unit 2 - coal bunkers and conveyors
b. Unit 2 - transfer conveyors
c. Main flyash silo
d. 100 ton flyash silo
e. Coal unloading facility
f. Agglomerator
g. Coal unloading silo

D. Unit Description

1. Unit 1:

Generator Nameplate Capacity: 216 MWe
Boiler Rating: 2622 x 10^6 Btu/hr
Startup: 1966
Fuel: North Dakota Lignite (80-100%)
: PRB Subbituminous (0-20%)
Firing Method: Wall-fired
Existing Air Pollution Control Equipment: Low NO_x burners (1995) and electrostatic precipitator

2. Unit 2:

Generator Nameplate Capacity: 440 MWe
Boiler Rating: 5130 x 10^6 Btu/hr
Startup: 1975
Fuel: North Dakota Lignite (80-100%)
: PRB Subbituminious (0-20%)
Firing Method: Cyclone
Existing Air Pollution Control Equipment: Electrostatic precipitator

3. Auxiliary Boiler:

Boiler Rating: 51.6 x 10^6 Btu/hr
Fuel: #2 fuel oil

4. Fire Pump:

Rating: 200 Bhp
Fuel: Diesel fuel

5. Materials Handling Equipment:

a. Unit 2 coal bunkers and conveyors:
Existing Air Pollution Control Equipment: Rotoclones
b. Unit 2 transfer conveyors:
Existing Air Pollution Control Equipment: Rotoclones
c. Main Flyash Silo:
Existing Air Pollution Control Equipment: Baghouse
d. 100 Ton Flyash Silo:
Existing Air Pollution Control Equipment: Baghouse
e. Coal Unloading Facility:
Existing Air Pollution Control Equipment: Baghouse
f. Agglomerator:
Existing Air Pollution Control Equipment: Baghouse
g. Coal Unloading Silo:
Existing Air Pollution Control Equipment: Baghouse

E. Emissions

BART Eligible Unit	Pollutant	2000	2001	2002	2003	2004	2000-2004 Avg.
Unit 1 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu)	16,864 1.81	13,237 1.94	16,655 1.73	19,125 1.82	15,448 1.80	16,666 1.82

BART Eligible Unit	Pollutant	2000	2001	2002	2003	2004	2000-2004 Avg.
	NO_x (tons) NO_x (lb/10^6 Btu)	2,328 0.25	2,057 0.26	2,578 0.27	3,053 0.29	2,487 0.29	2,501 0.27
	PM (tons) PM (lb/10^6 Btu)	104 0.011	480 0.061	184 0.019	280 0.027	46 0.005	219 0.025
Unit 2 Boiler	SO_2 (tons) SO_2 (lb/10^6 Btu)	28,587 1.85	36,319 1.91	30,744 1.73	25,598 1.79	32,990 1.85	30,828 1.83
	NO_x (tons) NO_x (lb/10^6 Btu)	9,330 0.60	12,608 0.66	11,068 0.62	8,695 0.61	10,410 0.58	10,422 0.61
	PM (tons) PM (lb/10^6 Btu)	274 0.018	755 0.040	499 0.028	415 0.029	175 0.010	424 0.025
Auxiliary Boiler	SO_2 (tons) NO_x (tons)						0.03 0.01
Fire Pump	SO_2 (tons) NO_x (tons)						<0.01 <0.01
Unit 2 Coal Bunkers/ Conveyors	PM (tons)						1.6
Unit 2 Transfer Conveyors	PM (tons)						1.6
Main Flyash Silo	PM (tons)						1.0
100 Ton Flyash Silo	PM (tons)						0.1
Coal Unloading Facility	PM (tons)						12.4
Agglomerator	PM (tons)						<0.1
Coal Unloading Silo	PM (tons)						0.2

II. Site Characteristics

The Leland Olds Station is located on the banks of the Missouri River in eastern Mercer county near the town of Stanton, North Dakota. The original design of Unit 1 only incorporated a multiclone for air pollution control, the electrostatic precipitator was added in the 1970s. Unit 2 was built with an electrostatic precipitator. Because of the original design and the close proximity of the Missouri River, there are some space constraints at the facility. Basin Electric has not indicated that the space constraints are insurmountable. Therefore, site constraints are an economic issue when evaluating the various control alternatives. Basin Electric has prepared a comprehensive BART analysis which can be found in Appendix C of the SIP.

III. BART Evaluation of Unit 1

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber
Spray Dryer
Circulating Dry Scrubber
Flash Dryer Absorber
Powerspan ECO®
Fuel Switching
Coal Cleaning

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning. Therefore, these options were not considered further.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals[1]. The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Freedom Mine was tested. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

The Department considers the Powerspan ECO® technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the information provided by Basin Electric, the Department has calculated the uncontrolled emission rate as follows:

Sulfur content = 1.13%
HHV = 6548 Btu/lb
Emission Factor = 35(s) lb/ton

The emission factor 35(s) is used to conservatively estimate the uncontrolled emission rate. During the Department's periodic review of SO_2 PSD increment consumption, emission factors for the Leland Olds Station were was extensively addressed[3]. Based on actual continuous emissions monitoring data an emission factor of 37.4(s) was established for Unit 1 and 38.7(s) for Unit 2. Using the lower emission factor of 35(s) results in a higher cost effectiveness and a lower controlled emission rate. As shown in Step 6, the emission factor does not affect the decision regarding the type of control technology selected since the most effective technology is selected as BART.

E = $(35)(1.13\%)(10^6) \div (2000\ \text{lb/ton})(6548\ \text{Btu/lb})$
E = $3.02\ \text{lb}/10^6\ \text{Btu}$
E = $(2622 \times 10^6\ \text{Btu/hr})(3.02\ \text{lb}/10^6\ \text{Btu})$
E = 7918.4 lb/hr
E = 34,683 tons/yr

Alternative	**Control Efficiency (%)**	**Inlet Loading (tons/yr)**	**Emissions (tons/yr)**	**Emissions ($lb/10^6$ Btu)**
Wet Scrubber	95[a.]	34,683	1734	0.15
Circulating Dry Scrubber	93	34,683	2428	0.21
Spray Dryer	90	34,683	3468	0.30
Flash Dryer	90	34,683	3468	0.30

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Emissions (tons/yr)	Emissions ($lb/10^6$ Btu)
Absorber				
Fuel Switching	≈77	34,683	7977	0.69

[a] New wet scrubbers generally achieve SO_2 removal efficiencies of 95%[4,5]. Higher efficiencies may be achieved with higher sulfur eastern coals, however, North Dakota (Fort Union) lignite is much lower in sulfur content (1.13% for this analysis compared to 2.45% for interior bituminous coal[7]). EPA[6] indicates "Chlorine content improves the SO_2 removal ..." North Dakota lignite has some of the lowest chlorine levels of all the U.S. coals[7]. Based on the low chlorine content and lower sulfur content, lower SO_2 removal efficiencies would be expected on a power plant that burns North Dakota lignite than one that combusts eastern coal. In recent BACT assessments [8,9,10] for proposed power plants in North Dakota, the analyses indicated the efficiency of wet scrubbers would be 95% for North Dakota lignite. During three separate comment periods, no comments were received regarding the projected efficiency of a wet scrubber. The proposed BACT limits, and thus efficiency, will have to be met at all times including startup, shutdown and malfunction. The Department has determined that 95% removal efficiency is a reasonable upper limit that can be met on a continuous basis for a power plant combusting North Dakota lignite and using a wet scrubber.

Based on the future potential-to-emit, the cost effectiveness and incremental costs for the various alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($)*	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Wet FGD	32,949	19,310,000	586	353***
Circulating Dry Scrubber**	32,255	20,720,000	636	----
Spray Dryer	31,215	18,700,000	599	

Note: Flash Dryer Absorber not included since it costs more than a spray dryer with no additional emissions reduction.

* Costs provided by Basin Electric
** Inferior option
*** Incremental cost from spray dryer to wet FGD

Step 4: Evaluate Impacts and Document Results

Basin Electric has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of either a wet scrubber or spray dryer.

Step 5: Evaluate Visibility Results

The two primary alternatives are a wet scrubber operating at 95% removal efficiency and a spray dryer operating at 90% efficiency. The effects on visibility shown in the following tables are based on Basin Electric's estimate of SO_2 reductions. The Department estimates that the scrubbers will actually reduce emissions less than Basin Electric estimated since Basin included SO_2 removed in the bottom ash in their calculation of emissions removed by the scrubber. The visibility impact results are therefore conservative (overestimate the improvement).

Unit 1 Delta Deciview 90th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.096	0.073	0.023
2001	TRNP-SU	0.091	0.060	0.031
2002	TRNP-SU	0.133	0.124	0.009
Average	TRNP-SU			0.021
2000	TRNP-NU	0.109	0.066	0.043
2001	TRNP-NU	0.110	0.085	0.025
2002	TRNP-NU	0.135	0.072	0.043
Average	TRNP-NU			0.037
2000	Elkhorn Ranch	0.087	0.062	0.025
2001	Elkhorn Ranch	0.059	0.034	0.025
2002	Elkhorn Ranch	0.094	0.066	0.028
Average	Elkhorn Ranch			0.026
2000	Lostwood W. A.	0.169	0.125	0.044
2001	Lostwood W. A.	0.218	0.136	0.082
2002	Lostwood W. A.	0.127	0.098	0.029
Average	Lostwood W. A.			0.052
Overall Average				0.034

Unit 1 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**90% Reduction**	**95% Reduction**	**Difference**
2000	TRNP-SU	0.401	0.298	0.103
2001	TRNP-SU	0.393	0.276	0.117
2002	TRNP-SU	0.832	0.627	0.205
Average	TRNP-SU			0.142
2000	TRNP-NU	0.563	0.309	0.254
2001	TRNP-NU	0.470	0.336	0.134
2002	TRNP-NU	0.720	0.569	0.151
Average	TRNP-NU			0.180
2000	Elkhorn Ranch	0.378	0.210	0.168
2001	Elkhorn Ranch	0.328	0.215	0.113
2002	Elkhorn Ranch	0.670	0.472	0.198
Average	Elkhorn Ranch			0.160
2000	Lostwood W. A.	0.433	0.349	0.084
2001	Lostwood W. A.	0.650	0.511	0.139
2002	Lostwood W. A.	0.544	0.396	0.148
Average	Lostwood W. A.			0.124
Overall Average				0.151

Step 6: Select BART

The cost effectiveness is reasonable for all technologies evaluated and the incremental cost from one technology to another is not excessive. There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit has no existing air pollution control equipment for removing sulfur dioxide and the plant is expected to have a remaining useful life of at least 20 years. The degree of visibility improvement achieved by selecting a wet scrubber operating at 95% control efficiency versus a spray dryer operating at 90% control efficiency does not exceed 0.083 deciviews (90th percentile) or 0.198 deciviews (98% percentile) at any Class I area for the 2000-2002 time frame. Although the amount of visibility improvement achieved by selecting a wet scrubber versus a spray dryer or circulating dry scrubber is small, the Department believes the cost effectiveness and incremental cost of a new wet scrubber is very low. The Department has determined that BART is represented by the use of a wet scrubber. Based on an annual average controlled emission rate of 0.15 lb/10^6 Btu, the expected maximum 30-day rolling average emission rate is 0.19 lb/10^6 Btu. By allowing Basin Electric to comply with either the percent reduction requirement or the lb/10^6 Btu limitation, the presumptive levels for plants larger than 750 MWe can be established as the BART limit. BART is proposed as an emission reduction efficiency of 95% of the inlet sulfur dioxide concentration to the scrubber or 0.15 lb/10^6 Btu on a 30-day rolling average basis.

B. Filterable Particulate Matter

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	**Control Efficiency**	**Emissions**	
		(tons/yr)	**(lb/10^6 Btu)**
Baghouse	99.7+	108	0.013
New ESP	99.7	125	0.015
CoHPAC	99.7	125	0.015
Baseline (Existing ESP)	≈99.2	332*	0.040

* Based on the Department's estimate of baseline emissions (2001-2002).

Alternative	**Emissions* Reduction (tpy)**	**Annualized ** Cost ($)**	**Cost Effectiveness ($/ton)**	**Incremental Cost ($/ton)**
Baghouse	224	3,260,000	14,554	46,294***
New ESP	207	2,630,000	12,705	----
CoHPAC	207	2,473,000	11,947	----
Baseline (Existing ESP)	0	0	---	

* Reductions from the baseline emission rate.
** Costs provided by Basin Electric.
*** Baghouse compared to CoHPAC.

Step 4: Evaluate Impacts and Document the Results

Basin Electric has evaluated the energy and non-air quality effects of each option. The Department has determined that the effects will not preclude the selection of any of the options.

Step 5: Evaluate Visibility Impacts

The different alternatives were not modeled because of the high cost effectiveness. However, the baseline emission rate was modeled. The results are as follows:

Unit 1 Delta Deciview PM			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.0037	0.0048
2001	TRNP-SU	0.0006	0.0103
2002	TRNP-SU	0.0046	0.0119
Average	TRNP-SU	0.0030	0.0090
2000	TRNP-NU	0.0010	0.0098
2001	TRNP-NU	0.0013	0.0068
2002	TRNP-NU	0.0021	0.0371
Average	TRNP-NU	0.0015	0.0179
2000	Elkhorn Ranch	0.0020	0.0118
2001	Elkhorn Ranch	0.0004	0.0015
2002	Elkhorn Ranch	0.0040	0.0102
Average	Elkhorn Ranch	0.0021	0.0078
200	Lostwood W.A	0.0071	0.0111
2001	Lostwood W.A.	0.0059	0.0211
2002	Lostwood W.A.	0.0001	0.0053
Average	Lostwood W.A.	0.0044	0.0125
Overall Average		0.0028	0.0118

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filterable particulate emissions is the CoHPAC system. This system has a cost effectiveness of $11,947 per ton of particulate when compared to the current emission control system (ESP operating at approximately 99.2% efficiency). The Department considers this cost to be excessive.

There are no energy or non-air quality environmental impacts that would preclude the selection of any of the feasible control options. The unit is equipped with an electrostatic precipitator that is achieving 99.2%, or greater, control efficiency. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate emitted was eliminated, the most improvement in visibility at any Class I area would be approximately 0.0044 deciviews based on the three year average of the 90th percentile value (0.0125 deciviews based on the 98th percentile). The Department considers this amount of improvement to be negligible. Since none of the control technologies will eliminate all of the particulate matter emissions, the visibility improvement will be even less.

After considering all of the factors, the Department has determined that BART for filterable particulate matter is no additional controls. Since current actual emissions are less than the current allowable emissions, the Department proposes that BART is represented by an emission limit of 0.07 lb/10^6 Btu (average of 3 test runs).

C. Condensible Particulate Matter (PM_{10}).

Condensible particulate matter is made up of both organic and inorganic substances. Organic condensible particulate matter will be made up of organic substances, such as volatile organic compounds, which are in a gaseous state through the air pollution control devices but will eventually turn to a solid or liquid state. The primary inorganic substance expected from the boiler is sulfuric acid mist, with lesser amounts of hydrogen fluoride and ammonium sulfate.

Since sulfuric acid mist is the largest component of condensible particulate matter, controlling it will control most of the condensible particulate matter. The options for controlling sulfuric acid mist are the same options for controlling sulfur dioxide (see Section III.A.). Previously, BART for sulfur dioxide was determined to be represented by wet scrubber. This technology will achieve a 40-60% reduction as sulfuric acid mist emissions.

The control of volatile organic compounds at power plants is generally achieved through good combustion practices. The Department is not aware of any BACT determination at a power plant that resulted in any control technology being used. BACT has been found to be good combustion practices which are already in use since it minimizes the amount of fuel to generate electricity.

Basin Electric has indicated that the emission rate of condensible particulate matter could be as low as 0.0029 lb/10^6 Btu. AP-42, Compilation of Air Pollutant Emission Factors[2], suggests it could be as high as 0.02 lb/10^6 Btu. In either case, the emission rate is less than the current emissions of filterable particulate matter. The emissions of filterable particulate matter were determined to have a negligible impact on visibility.

Having considered all the factors, the Department has determined that BART for condensable particulate matter is represented by good sulfur dioxide control and good combustion control. Since the primary constituent of condensible particulate matter is sulfuric acid mist which is controlled proportionately to the sulfur dioxide controlled, the BART limit for sulfur dioxide can act as a surrogate for condensible particulate matter along with good combustion practices.

D. Nitrogen Oxides (NO_x)

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO)®
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced SNCR (HE-SNCR)
Rich Reagent Injection (RRI)
Rotomix (ROFA + SNCR)
Conventional Gas Reburn (CGR)
CGR + SNCR w/separated overfire air (SOFA)
Coal Reburn
Coal Reburn + SNCR
Fuel-lean Gas Reburn (FLGR)
FLGR + SNCR
Rotating Overfire Air (ROFA)
Separated Overfire Air (SOFA)
New Low NO_x Burners (LNB)
Combustion Improvements

Step 2: Eliminate Technically Infeasible Options

The Department agrees with Basin Electric determination that high dust SCR is not technically feasible at this time. However, the Department believes low dust or tail end SCR has a good probability of successful application on Unit 1 (see discussion in Appendix B.5). ECO® and coal reburn plus SNCR have not been demonstrated on a pulverized coal-fired boiler and are considered technically infeasible. Rich reagent injection was developed for cyclone boilers and has not been demonstrated for other types of units. Therefore, RRI is considered technically infeasible for Unit 1.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Based on the historic baseline emissions, the Department's estimated emissions using the various technologies would be as follows:

Alternative	Control Efficiency (%)*	Emissions**	
		(tons/yr)	lb/10^6 Btu)
SCR w/reheat	80	593	0.057
Coal Reburn + Boosted SOFA	48.7	1,522	0.146
Coal Reburn + SOFA	46.2	1,596	0.153
SNCR + Boosted SOFA	45.1	1,629	0.156
SNCR + Basic SOFA	42.0	1,721	0.165
SNCR + Close-coupled OFA	24.5	2,240	0.215
Boosted SOFA	24.3	2,246	0.216
SOFA	19.4	2,391	0.230
Baseline		2,967	0.285

* Control efficiency provided in Basin Electric's analysis except for SCR. In the ANPR for the Four Corners Power Plant, EPA noted that the Arizona DEQ had determined that an SCR efficiency of 75% was appropriate for a unit with LNB. Leland Olds Unit 1 is equipped with LNB. EPA also indicated they believed 80% for SCR was appropriate.

** Calculated from the historic baseline. The historic baseline was used since the increased sulfur in the coal will not affect NO_x emissions. The emission rate is an annual average rate.

The estimated costs for the various technologies are as follows:

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
SCR w/reheat (low dust)	2,374	18,634,000 - 26,856,000*	7,849 - 11,313	12,489 - 21,339***
SCR w/reheat (tail-end)	2,374	21,517,000 - 31,011,000*	9,061 - 13,628	15,592 - 25,812***
Coal Reburn + Boosted SOFA	1,445	7,032,000	4,866	14,176

Alternative	Emissions Reduction (tpy)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Coal Reburn + SOFA	1,371	5,983,000	4,364	80,727
SNCR + Boosted SOFA	1,338	3,819,000	2,854	7,826
SNCR + Basic SOFA	1,246	3,099,000	2,487	3,737**
SNCR + Close coupled OFA	727	3,361,000	4,623	
Boosted SOFA	721	1,137,000	1,577	6,848
SOFA	576	144,000	250	250

* Department estimate based on Unit 2 cost estimate.
** SNCR + Basic SOFA compared to Boasted SOFA.
*** Incremental cost of SCR versus coal reburn + boosted SOFA.

SCR technology has never been applied to a boiler that combusts North Dakota lignite There are many unknowns that will affect the cost of either LDSCR or TESCR at the Leland Olds Station including:

1) The catalyst deactivation rate
2) Catalyst volume required
3) Catalyst surface area required
4) Required reagent injection rate
5) Expected reagent slip
6) Whether formation of ammonium bisulfate and/or ammonium sulfate will be at an acceptable rate
7) An appropriate catalyst maintenance plan

All of these will affect either the initial construction cost and/or annual operation and maintenance costs. The amount of catalyst required will affect the initial capital cost as well as the replacement cost. The life of the catalyst and the amount of reagent required will have a large impact on the annual operating cost. If a wet electrostatic precipitator is required to control ammonium bisulfate/ammonium sulfate emissions, both the initial capital cost and operation and maintenance costs will rise dramatically. Given the many unknowns with North Dakota Lignite, estimating the cost of an SCR system is extremely difficult and subject to many different opinions regarding estimating procedures. The Department believes pilot scale testing would prove to be very beneficial in addressing the items of concern and provide a more detailed professionally reliable cost estimate. However, the BART process cannot mandate pilot testing be conducted to determine costs. The Department believes the cost estimate provided by Basin Electric for Unit 2 without pilot testing, although not ideal, will suffice based on the information that is available at the current time.

Step 4: Evaluate Impacts and Document Results

There are no energy or environmental impacts that would preclude the selection of any of the alternatives.

Step 5: Evaluate Visibility Impacts

The Department considers the cost effectiveness and/or incremental cost effectiveness of the top four alternatives to be excessive. Basin Electric has modeled a no controls option and the SNCR + Basic SOFA option. The results are as follows:

Unit 1 Delta Deciview 90th Percentile NO_x				
Year	**Unit**	**No Controls**	**SOFA + SNCR**	**Difference**
2000	TRNP-SU	0.241	0.228	0.013
2001	TRNP-SU	0.197	0.179	0.018
2002	TRNP-SU	0.360	0.321	0.039
Average	TRNP-SU	0.266	0.243	0.023
2000	TRNP-NU	0.212	0.180	0.032
2001	TRNP-NU	0.259	0.230	0.029
2002	TRNP-NU	0.295	0.273	0.022
Average	TRNP-NU	0.255	0.228	0.028
2000	Elkhorn Ranch	0.199	0.184	0.015
2001	Elkhorn Ranch	0.115	0.107	0.008
2002	Elkhorn Ranch	0.197	0.183	0.014
Average	Elkhorn Ranch	0.170	0.158	0.012
2000	Lostwood W.A.	0.412	0.366	0.046
2001	Lostwood W.A.	0.450	0.446	0.004
2002	Lostwood W.A.	0.303	0.276	0.027
Average	Lostwood W.A.	0.388	0.363	0.026
Overall Average		0.270	0.248	0.022

Unit 1 Delta deciviews 98th Percentile NO_x				
Year	**Unit**	**No Controls**	**SOFA + SNCR**	**Difference**
2000	TRNP-SU	0.897	0.819	0.078
2001	TRNP-SU	0.909	0.822	0.087
2002	TRNP-SU	1.756	1.610	0.146
Average	TRNP-SU	1.187	1.084	0.104
2000	TRNP-NU	0.981	0.865	0.116
2001	TRNP-NU	1.090	1.025	0.065
2002	TRNP-NU	1.814	1.654	0.160
Average	TRNP-NU	1.295	1.181	0.114
2000	Elkhorn Ranch	0.669	0.570	0.099
2001	Elkhorn Ranch	0.745	0.709	0.036
2002	Elkhorn Ranch	1.433	1.309	0.124
Average	Elkhorn Ranch	0.949	0.863	0.086
2000	Lostwood W.A.	1.051	0.954	0.097
2001	Lostwood W.A.	1.610	1.466	0.144
2002	Lostwood W.A	1.081	0.979	0.102
Average	Lostwood W.A.	1.247	1.133	0.114
Overall Average		1.170	1.065	0.105

Step 6: Select BART

The Department considers the cost effectiveness and/or incremental cost of the top four options to be excessive. The Department proposes that BART is represented by SNCR plus basic SOFA. Basin Electric has indicated that Unit 1 can achieve an emission limit around 0.166-0.168 $lb/10^6$ Btu on an annual average basis. A thirty-day rolling average emission rate is expected to be at least 5-15% higher than the annual average emission rate. Unit 1 is a wall-fired unit fired primarily on lignite. In the BART Guideline (40 CFR 51, Appendix Y) EPA established a presumptive level for these units at 0.29 $lb/10^6$ Btu (30 d.r.a.). The Department has determined that BART is an emission limit of 0.19 $lb/10^6$ Btu on a 30-day rolling average basis.

V. BART Evaluation of Unit II

A. Sulfur Dioxide

Step 1: Identify All Available Technologies

Wet Scrubber

Spray Dryer
Circulating Dry Scrubber
Flash Dryer Absorber
Powerspan ECO
Fuel Switching
Coal Cleaning

Step 2: Eliminate Technically Infeasible Options

Coal Cleaning: Coal cleaning and coal washing have never been used commercially on North Dakota lignite. Coal washing can have significant environmental effects. A wet waste from the washing process must be handled properly to avoid soil and water contamination. Since this facility is located on the banks of the Missouri River, water pollution is a major concern. The Department is not aware of any BACT determinations for low sulfur western coal burning facilities that has required coal cleaning.

K-Fuel® is a proprietary process offered by Evergreen Energy, Inc. which employs both mechanical and thermal processes to increase the quality of coal by removing moisture, sulfur, nitrogen, mercury and other heavy metals[1]. The process uses steam to help break down the coal to assist in the removal of the unwanted constituent. The K-Fuels® process would require a steam generating unit which will produce additional air contaminants. In addition to these concerns, the Department has determined that the technology is not proven commercially. The first plant was scheduled for operation on subbituminous coal sometime in 2005. Although Evergreen Energy, Inc. indicates the technology has been tested on lignite, there is no indication that lignite from the Freedom Mine was tested. Evergreen's website indicates that it has idled its Wyoming plant and directed its capital and management resources to supporting a new design. The use of the K-Fuel® process would pose significant technical and economic risks and would require extensive research and testing to determine its feasibility.

Therefore, the Department does not consider coal cleaning or the K-Fuel® process available or technically and economically feasible.

The Department considers the Powerspan ECO technology not to be commercially available since no full size plant has been installed or is operating at this time. All other technologies or alternatives are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on a potential-to-emit of 3.02 $lb/10^6$ Btu (see Section III.A.), the potential mass emission rate is:

E = $(3.02 \times 10^6\ lb/10^6\ Btu)(5130 \times 10^6\ Btu/hr)$
E = 14592.6 lb/hr
E = 67,858 tons/yr

Alternative	Control Efficiency (%)	Inlet Loading (tons/yr)	Emissions	
			(tons/yr)	($lb/10^6$ Btu)[a]
Wet Scrubber	95	67,858	3,393	0.15
Circulating Dry Scrubber	93	67,858	4,750	0.21
Spray Dryer	90	67,858	6,786	0.30
Flash Dryer Absorber	90	67,858	6,786	0.30
Fuel Switching	≈77	67,858	15,607	0.69

a. Annual Average Emission Rate

Alternative	Emissions Reductions (tons/yr)	Annualized Cost ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Wet Scrubber	64,465	29,840,000	463	1,099[a]
CDS	63,108	35,580,000	564	
Spray Dryer	61,072	32,890,000	539	
Flash Dryer	61.072	32,430,000	531	
Fuel Switching	<52,251	13,490,000	258	

a. Incremental cost difference between wet scrubbing and fuel switching. All other alternatives are inferior to the wet scrubber.

Step 4: Evaluate Impacts and Document Results

Basin Electric has evaluated the energy and non-air quality effects of each option. The Department has determined that these effects will not preclude the selection of any of the available options. Basin Electric has selected the wet scrubber alternative as BART for this unit. A wet scrubber is the most efficient control option. Therefore, no evaluation of costs is necessary.

Step 5: Evaluate Visibility Results

Basin Electric has selected a wet scrubber operating at 95% control efficiency as BART. The BART Guideline states that if a source commits to a BART determination that consists of the most stringent controls available, then there is no need to complete the remaining steps. Basin has committed to the most stringent controls available and the lowest possible emission rate. Although modeling is not required, Basin Electric has modeled the use of a wet scrubber on Unit 2. The results are shown in the following table.

Unit 2 Delta Deciview 90^{th} Percentile SO_2				
Year	**Unit**	**Uncontrolled**	**Wet Scrubber (95%)**	**Difference**
2000	TRNP-SU	0.674	0.178	0.496
2001	TRNP-SU	0.586	0.148	0.438
2002	TRNP-SU	1.161	0.336	0.825
Average	TRNP-SU	0.807	0.221	0.586
2000	TRNP-NU	0.681	0.146	0.535
2001	TRNP-NU	0.827	0.181	0.646
2002	TRNP-NU	0.761	0.212	0.549
Average	TRNP-NU	0.756	0.180	0.577
2000	Elkhorn Ranch	0.553	0.142	0.411
2001	Elkhorn Ranch	0.434	0.076	0.358
2002	Elkhorn Ranch	0.617	0.142	0.475
Average	Elkhorn Ranch	0.535	0.120	0.415
2000	Lostwood W.A.	1.109	0.307	0.802
2001	Lostwood W.A.	1.032	0.339	0.693
2002	Lostwood W.A.	0.796	0.209	0.587
Average	Lostwood W.A.	0.979	0.285	0.694
Overall Average		0.769	0.201	0.568

Unit 2 Delta Deciview 98th Percentile SO_2				
Year	**Unit**	**Uncontrolled**	**Wet Scrubber (95%)**	**Difference**
2000	TRNP-SU	2.340	0.728	1.612
2001	TRNP-SU	2.339	0.660	1.679
2002	TRNP-SU	4.924	1.445	3.479
Average	TRN-SU	3.201	0.944	2.257
2000	TRNP-NU	2.430	0.800	1.630
2001	TRNP-NU	2.954	0.877	2.077
2002	TRNP-NU	3.958	1.496	2.462
Average	TRNP-NU	3.114	1.058	2.056
2000	Elkhorn Ranch	1.581	0.471	1.110
2001	Elkhorn Ranch	2.288	0.477	1.811
2002	Elkhorn Ranch	3.450	1.134	2.316
Average	Elkhorn Ranch	2.440	0.694	1.746
2000	Lostwood W.A.	2.419	0.830	1.589
2001	Lostwood W.A.	4.158	1.391	2.767
2002	Lostwood W.A.	3.609	0.866	2.743
Average	Lostwood W.A.	3.395	1.029	2.366
Overall Average		3.038	0.931	2.106

Step 6: Select BART

After considering the cost of compliance, the energy and non-air quality environmental impacts, the remaining useful life (> 20 years) and the degree of visibility improvement, the Department proposes that BART is represented by a wet scrubber. Based on an annual controlled emission rate of 0.15 lb/10^6 Btu, a maximum 30-day rolling average emission rate of 0.19 lb/10^6 Btu is expected. By allowing Basin Electric to comply with either a percent reduction or a lb/10^6 Btu limitation, the presumptive emission limits for plants larger than 750 MWe can be established. The Department has determined that BART is 95% reduction efficiency from the inlet of the scrubber to the outlet of the scrubber, or 0.15 lb/10^6 Btu, on a 30-day rolling average basis.

B. Filterable Particulate Matter (PM/PM_{10})

Step 1: Identify All Available Technologies

New Baghouse
New Electrostatic Precipitator
Compact Hybrid Particulate Collector (CoHPAC)
Existing Electrostatic Precipitator

Step 2: Eliminate Technically Infeasible Options

All technologies are considered technically feasible.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Alternative	Control Efficiency (%)	Emissions*	
		(tons/yr)	(lb/10^6 Btu)
Baghouse	99.7+	239	0.013
New ESP	99.7	277	0.015
CoHPAC	99.7	277	0.015
Baseline (Existing ESP)	≈ 99.3	627*	0.034

* Based on the Department's estimate of baseline emissions (2001-2002).

Alternative	Emissions* Reduction (tpy)	Annualized Cost** ($)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Baghouse	388	5,892,000	15,186	44,265***
New ESP	350	4,948,000	14,137	
CoHPAC	350	4,210,000	12,029	
Baseline	0	0	---	

* Reductions from baseline emission rate.
** Costs provided by Basin Electric.
*** CoHPAC compared to a baghouse.

Step 4: Evaluate Impacts and Document Results

Basin Electric has evaluated the energy and non-air quality environmental impacts associated with each alternative and determined that these impacts would not prelude the selection of any of the alternatives as BART. The Department agrees with this determination.

Step 5: Evaluate Visibility Results

The different alternatives were not modeled because of the high cost effectiveness. However, the baseline emission rate was modeled. The results are as follows:

Unit 2 Delta Deciview PM			
Year	**Unit**	**90th Percentile**	**98th Percentile**
2000	TRNP-SU	0.0018	0.0070
2001	TRNP-SU	0.0013	0.0084
2002	TRNP-SU	0.0068	0.0158
Average	TRNP-SU	0.0033	0.0104
2000	TRNP-NU	0.0037	0.0053
2001	TRNP-NU	0.0007	0.0059
2002	TRNP-NU	0.0006	0.0293
Average	TRNP-NU	0.0017	0.0135
2000	Elkhorn Ranch	0.0028	0.0040
2001	Elkhorn Ranch	0.0055	0.0069
2002	Elkhorn Ranch	0.0048	0.0121
Average	Elkhorn Ranch	0.0044	0.0076
2000	Lostwood W. A.	0.0139	0.0249
2001	Lostwood W. A.	0.0015	0.0258
2001	Lostwood W. A.	0.0013	0.0274
Average	Lostwood W.A.	0.0056	0.0260
Overall Average		0.0038	0.0144

Step 6: Select BART

The alternative (excluding the baseline alternative) with the least cost for reducing filter particulate matter emissions is the CoHPAC system which has a cost effectiveness of $12,029 per ton when compared to the current emission control systems (ESP operating at 99.3% control efficiency). The Department considers this cost to be excessive. There are no energy or non-air quality impacts that would preclude the selection of any of the feasible control options.

The unit is equipped with an electrostatic precipitator that is achieving 99.3% control efficiency. The average emission rate for this unit for 2000-2004 was 0.025 $lb/10^6$ Btu. The plant is expected to have a remaining useful life of at least 20 years.

If all of the particulate matter emitted was eliminated, the most improvement in visibility at any Class I area would be 0.0056 deciviews based on the 90th percentile (0.0260 deciviews based on 98th percentile). The Department considers this amount of improvement to be negligible. Since none of the control alternatives will eliminate all of the particulate matter emissions, the visibility improvement will even be less.

After considering all of the factors, the Department has determined that BART for filterable particulate matter is no additional controls. Since the current actual emissions are less than the current allowable emissions, the Department proposes that BART is represented by an emission limit of 0.07 $lb/10^6$ Btu (average of three test runs).

C. Condensible Particulate Matter (PM_{10})

See the discussion for Unit 1 in Section III.C. Any additional control technology for controlling condensible particulate matter will result in less than a 0.0056 deciview improvement at any Class I area. The Department considers the use of a wet scrubber and good combustion practices to represent BART for condensible particulate matter from Unit 2. The BART limit for sulfur dioxide (95% reduction) and good combustion practices will act as a surrogate for condensible particulate matter.

D. Nitrogen Oxides

Step 1: Identify All Available Technologies

Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO)®
Selective Non-Catalytic Reduction (SNCR)
Hydrocarbon Enhanced - SNCR with or without Advanced Separated Overfire Air (ASOFA)
Rich Reagent Injection (RRI) + SNCR + ASOFA
Rotomix (ROFA + SNCR)
Conventional Gas Reburn plus SNCR (CGB + SNCR)
Coal Reburn
Coal Reburn + SNCR
Fuel Lean Gas Reburn (FLGR)
Seperated Overfire Air (SOFA)
Advanced SOFA (ASOFA)
Rotating Overfire Air (ROFA)
Combustion Improvements
Oxygen Enhanced Combustion (OEC)

Step 2: Eliminate Technically Infeasible Options

The Department does not consider high dust SCR to be technically feasible at this time. However, the Department believes low dust or tail end SCR has a good probability of successful application on Unit 2 (see discussion in Appendix B.5). Basin Electric has determined the following technologies are also technically infeasible:

ECO
HE-SNCR
Rotamix
CGR + SNCR
Coal Reburn + SNCR
FLGR + SNCR
OEC

The Department agrees with Basin Electric's determination regarding technical feasibility. ROFA and SOFA are similar and only SOFA will be evaluated further.

Step 3: Evaluate Control Effectiveness of Each Remaining Control Technology

Based on the historic baseline emissions, the expected emissions are as follows:

Alternative	**Control Efficiency* (%)**	**Emissions****	
		(tons/yr)	**(lb/10^6 Btu)**
SCR w/reheat + ASOFA	90	1,202	0.07
RRI + SNCR + ASOFA	60.3	4,773	0.266
SNCR + ASOFA	54.5	5,470	0.305
Coal Reburn + ASOFA	51.8	5,795	0.323
SNCR	37	7,574	0.422
ASOFA	28	8,657	0.482
SOFA/ROFA	<28	>8,657	>0.482
Baseline		12,023	0.67

*Control efficiency specified by Basin Electric in their analysis.

**Based on historic baseline emissions. The lb/10^6 Btu emission rate is an annual average.

The estimated costs for the most efficient alternatives are as follows:

Alternative	Emissions Reduction (tons/yr)	Annualized Cost ($/ton)	Cost Effectiveness ($/ton)	Incremental Cost ($/ton)
Low Dust SCR + ASOFA	10,821	38,746,000 – 55,842,000	3,581 – 5,161	5,978 – 10,765
Tail-end SCR + ASOFA	10,821	43,830,000-63,170,000	4,050-5,838	7,401-12,817
RRI + SNCR + ASOFA	7,250	17,400,000	2,400	9,369
SNCR + ASOFA	6,553	10,870,000	1,659	3,021**
*Coal Reburn + ASOFA	6,228	14,860,000	2,386	
ASOFA	3,366	1,241,000	369	369

Note: See discussion for Unit 1 regarding the accuracy of the cost estimate for SCR.

* Inferior alternative since it costs more than SCNR + ASOFA with less emissions reduction.
** Incremental cost difference between SCNCR + ASOFA and ASOFA.

Step 4: Evaluate Impacts and Document Results

Basin Electric has not identified any environmental or energy impact that would preclude of the use of any of the previously evaluated emission control alternatives.

Step 5: Evaluate Visibility Impacts

The top three alternatives were evaluated with respect to the impact on visibility impairment. The results are as follows:

Unit 2 Delta Deciview 90th Percentile				
Year	**Unit**	**SCR + ASOFA**	**ASOFA+RRI+SNCR**	**Difference**
2000	TRNP-SU	0.061	0.124	0.063
2001	TRNP-SU	0.060	0.104	0.044
2002	TRNP-SU	0.105	0.201	0.096
Average	TRNP-SU	0.075	0.143	0.068
2000	TRNP-NU	0.056	0.107	0.051
2001	TRNP-NU	0.073	0.132	0.059
2002	TRNP-NU	0.082	0.147	0.065
Average	TRNP-NU	0.070	0.129	0.058
2000	Elkhorn Ranch	0.047	0.104	0.057
2001	Elkhorn Ranch	0.037	0.057	0.020
2002	Elkhorn Ranch	0.057	0.101	0.044
Average	Elkhorn Ranch	0.047	0.087	0.040
2000	Lostwood W.A.	0.114	0.215	0.101
2001	Lostwood W.A.	0.097	0.224	0.127
2002	Lostwood W.A.	0.074	0.135	0.061
Average	Lostwood W.A.	0.095	0.191	0.096
Overall Average		0.072	0.138	0.066

Unit 2 Delta Deciview 98^{th} Percentile				
Year	**Unit**	**SCR + ASOFA**	**ASOFA+RRI+SNCR**	**Difference**
2000	TRNP-SU	0.280	0.492	0.212
2001	TRNP-SU	0.217	0.484	0.267
2002	TRNP-SU	0.531	0.961	0.430
Average	TRNP-SU	0.343	0.646	0.303
2000	TRNP-NU	0.232	0.502	0.270
2001	TRNP-NU	0.303	0.609	0.306
2002	TRNP-NU	0.432	0.991	0.559
Average	TRNP-NU	0.322	0.701	0.378
2000	Elkhorn Ranch	0.154	0.334	0.180
2001	Elkhorn Ranch	0.218	0.317	0.099
2002	Elkhorn Ranch	0.385	0.767	0.382

Unit 2 Delta Deciview 98th Percentile				
Year	**Unit**	**SCR + ASOFA**	**ASOFA+RRI+SNCR**	**Difference**
Average	Elkhorn Ranch	0.252	0.473	0.220
2000	Lostwood W.A.	0.255	0.606	0.351
2001	Lostwood W.A.	0.399	0.909	0.510
2002	Lostwood W.A.	0.331	0.589	0.258
Average	Lostwood W.A.	0.328	0.701	0.373
Overall Average		0.311	0.630	0.319

Unit 2 Delta Deciview 90th Percentile				
Year	**Unit**	**SCR + ASOFA**	**SNCR + ASOFA**	**Difference**
2000	TRNP-SU	0.061	0.135	0.074
2001	TRNP-SU	0.060	0.114	0.054
2002	TRNP-SU	0.105	0.225	0.120
Average	TRNP-SU	0.075	0.158	0.083
2000	TRNP-NU	0.056	0.121	0.065
2001	TRNP-NU	0.073	0.146	0.073
2002	TRNP-NU	0.082	0.151	0.069
Average	TRNP-NU	0.070	0.139	0.069
2000	Elkhorn Ranch	0.047	0.114	0.067
2001	Elkhorn Ranch	0.037	0.057	0.020
2002	Elkhorn Ranch	0.057	0.109	0.052
Average	Elkhorn Ranch	0.047	0.093	0.046
2000	Lostwood W.A.	0.114	0.238	0.124
2001	Lostwood W.A.	0.097	0.232	0.135
2002	Lostwood W.A.	0.074	0.149	0.075
Average	Lostwood W.A.	0.095	0.206	0.111
Overall Average		0.072	0.149	0.077

Unit 2 Delta Deciview 98th Percentile				
Year	**Unit**	**SCR + ASOFA**	**SNCR + ASOFA**	**Difference**
2000	TRNP-SU	0.280	0.536	0.256
2001	TRNP-SU	0.217	0.526	0.309
2002	TRNP-SU	0.531	1.050	0.519
Average	TRNP-SU	0.343	0.70	0.361
2000	TRNP-NU	0.232	0.556	0.324
2001	TRNP-NU	0.303	0.658	0.355
2002	TRNP-NU	0.432	1.091	0.659
Average	TRNP-NU	0.322	0.768	0.446
2000	Elkhorn Ranch	0.154	0.372	0.218
2001	Elkhorn Ranch	0.218	0.346	0.128
2002	Elkhorn Ranch	0.385	0.836	0.451
Average	Elkhorn Ranch	0.252	0.518	0.266
2000	Lostwood W.A.	0.255	0.647	0.392
2001	Lostwood W.A.	0.399	0.999	0.600
2002	Lostwood W.A.	0.331	0.643	0.312
Average	Lostwood W.A.	0.328	0.763	0.435
Overall Average		0.311	0.688	0.377

Unit 2 Delta Deciview 90th Percentile NO_x				
Year	**Unit**	**ASOFA + RRI + SNCR**	**ASOFA + SNCR**	**Difference**
2000	TRNP-SU	0.124	0.135	0.011
2001	TRNP-SU	0.104	0.114	0.010
2002	TRNP-SU	0.201	0.225	0.024
Average	TRNP-SU	0.143	0.158	0.015
2000	TRNP-NU	0.107	0.121	0.014
2001	TRNP-NU	0.132	0.146	0.014
2002	TRNP-NU	0.147	0.151	0.04
Average	TRNP-NU	0.129	0.139	0.011
2000	Elkhorn Ranch	0.104	0.114	0.010
2001	Elkhorn Ranch	0.057	0.057	0.000
2002	Elkhorn Ranch	0.101	0.109	0.008
Average	Elkhorn Ranch	0.087	0.093	0.006
2000	Lostwood W.A.	0.215	0.238	0.023
2001	Lostwood W.A.	0.224	0.232	0.008
2002	Lostwood W.A.	0.135	0.149	0.014

Unit 2 Delta Deciview 90th Percentile NO_x				
Year	**Unit**	**ASOFA + RRI + SNCR**	**ASOFA + SNCR**	**Difference**
Average	Lostwood W.A.	0.191	0.206	0.015
Overall Average		0.138	0.149	0.012

Unit 2 Delta Deciview 98th Percentile NO_x				
Year	**Unit**	**ASOFA + RRI + SNCR**	**ASOFA + SNCR**	**Difference**
2000	TRNP-SU	0.492	0.536	0.044
2001	TRNP-SU	0.484	0.526	0.042
2002	TRNP-SU	0.961	1.050	0.089
Average	TRNP-SU	0.646	0.704	0.058
2000	TRNP-NU	0.502	0.556	0.054
2001	TRNP-NU	0.609	0.658	0.049
2002	TRNP-NU	0.991	1.091	0.100
Average	TRNP-NU	0.701	0.768	0.068
2000	Elkhorn Ranch	0.334	0.372	0.038
2001	Elkhorn Ranch	0.317	0.346	0.029
2002	Elkhorn Ranch	0.767	0.836	0.069
Average	Elkhorn Ranch	0.473	0.518	0.045
2000	Lostwood W.A.	0.606	0.647	0.041
2001	Lostwood W.A.	0.909	0.999	0.090
2002	Lostwood W.A.	0.589	0.643	0.054
Average	Lostwood W.A.	0.701	0.763	0.062
Overall Average		0.630	0.688	0.058

Step 6: Select BART

The Department considers both the cost effectiveness and incremental cost of SCR to be excessive. SCR will only produce an average of 0.066 decivews improvement in the North Dakota Class I areas based on the 90th percentile (0.319 deciviews based on the 98th percentile) versus RRI + ASOFA + SNCR. Because the single source modeling under the BART guidelines overestimates the visibility improvement in North Dakota (see Section 7.4.2 of SIP), the Department conducted modeling which included all sources of emissions in the modeling inventory to determine the true

Section 7.4.2 of SIP), the Department conducted modeling which included all sources of emissions in the modeling inventory to determine the true impact on visibility of SCR + ASOFA versus SNCR + ASOFA. The average improvement in visibility for the 20% worst days was only 0.01 decivews at both TRNP and LWA. The Department considers this amount of improvement to be negligible. Based on the excessive cost and negligible visibility improvement, SCR was eliminated as a BART alternative.

RRI + SNCR + ASOFA and SNCR + ASOFA are both considered to have reasonable cost effectiveness. However, the incremental cost ($9,369/ton) going from SNCR + ASOFA to RRI + SNCR + ASOFA is considered excessive. Use of RRI + SNCR + ASOFA will only increase visibility improvement by an average of 0.012 deciviews (90^{th} percentile) or 0.058 deciviews (98^{th} percentile) during the 2000-2002 time period. Given the high incremental cost and negligible visibility improvement, RRI + ASOFA + SNCR was eliminated as a BART alternative.

After considering all of the factors, the Department has determined that BART is represented by SNCR + ASOFA. With SNCR + ASOFA, an emission rate of 0.305 lb/10^6 Btu on an annual average basis is expected. Basin Electric believes that an emission rate of 0.35 lb/10^6 Btu is achievable based on a 30-day rolling average. The Department's experience with power plants suggest that the maximum 30-day rolling average NO_x emission rate is 5-15% higher than the annual average emission rate. Therefore, the Department has determined that BART is an emission limit of 0.35 lb/10^6 Btu on a 30-day rolling average basis.

V. BART Evaluation for Auxiliary Boiler

The auxiliary boiler is a #2 fuel-oil fired boiler with a nominal rating of 51.6 x 10^6 Btu/hr. The auxiliary boiler is only used when both units at the Leland Olds Station are down. During the baseline period (2000-2004), the unit was operated approximately 3.6 hours per year. The annual average emissions from the unit for this period were:

NO_x	0.01 tons
SO_2	0.03 tons
PM	0.001 tons

Based on the small quantity of emissions, it is apparent that no add-on control equipment will be cost effective. Any reduction in emissions will have a virtually no effect on visibility impairment. Therefore, the Department proposes that BART is no additional controls. The current permit limits the fuel used in the boiler to #2 fuel oil. BART is the use of #2 fuel oil.

VI. BART Evaluation for Emergency Fire Pump

The emergency fire pump, is driven by a 200 horsepower diesel engine. The pump is used for emergency purposes only and most of the emissions generated are due to testing and maintenance activities. During the baseline period (2000-2004), the engine operated 4.3 hours per year and the actual annual emissions were:

NO_x	0.0002 tons
SO_2	0.0003 tons
PM	0.00001 tons

Based on the small quantity of emissions, no add-on control equipment will be cost effective. Any reduction of emissions will not affect visibility impairment. Therefore, the Department proposes that BART is no additional controls.

VII. BART Evaluation for Materials Handling Sources

The materials handling sources at Leland Olds Station that emit to the atmosphere are as follows:

EUI	Description	Existing Control Equipment	Current Emission Limit (lb/hr)	Baseline Emissions (tons/yr)
M7	Unit 2 East bunker conveyor	Rotoclone	1.0	0.82*
M8	Unit 2 West bunker conveyor	Rotoclone	1.0	0.82*
M9	Unit 2 Bunker house transfer conveyor (west)	Rotoclone	1.0	0.82*
M10	Unit 2 Bunker house transfer conveyor (east)	Rotoclone	1.0	0.82*
M11	Main flyash silo	Baghouse	0.26	1.0
M12	100 Ton flyash silo	Baghouse	0.1	0.01
M13	Coal unloading facility	Baghouse	16.97	12.4
M14	Agglomerator	Baghouse	0.06	0.04
M16	Coal unloading silo	Baghouse	0.26	0.19

*Department estimate

Based on the small quantity emissions from those sources that are controlled by rotoclones (M7-M10), it is apparent that no additional control equipment will be cost effective. The other materials handling units are controlled using a baghouse which is considered the most efficient control device. Therefore, the Department proposes that

BART for the materials handling units is no additional controls and the current emission limit for the units is BART.

VIII. Summary

Source Unit	Proposed* BART Limit/Work Practice				Emissions Reduction** (tons/yr)		
	PM	SO_2	NO_x	Units	PM	SO_2	NO_x
Unit 1 Boiler	0.07	0.15 or 95% reduction	0.19	$lb/10^6$ Btu	0	15,290	757
Unit 2 Boiler	0.07	0.15 or 95% reduction	0.35	$lb/10^6$ Btu	0	28,297	4,519
Auxiliary Boiler	Use #2 Fuel Oil			N/A	0	0	0
Fire Pump	Use low sulfur diesel fuel			N/A	0	0	0
M7	1.0	---	---	lb/hr	0	---	---
M8	1.0	---	---	lb/hr	0	---	---
M9	1.0	---	---	lb/hr	0	---	---
M10	1.0	---	---	lb/hr	0	---	---
M11	0.26	---	---	lb/hr	0	---	---
M12	0.1	---	---	lb/hr	0	---	---
M13	16.97	---	---	lb/hr	0	---	---
M14	0.06	---	---	lb/hr	0	---	---
M16	0.26	---	---	lb/hr	0	---	---
Total						43,587	5,276

* PM limit is the average of three 2-hour test runs. SO_2 and NO_x limits are a 30-day rolling average.

** Reductions from 2000-2004 average emission rate assuming 30-day rolling average equals the annual average emission rate.

IX. Permit to Construct

The emission limits, monitoring, recordkeeping and reporting requirements will be included in a federally enforceable Air Pollution Control Permit to Construct that will be issued to the owner/operator of the facility. The Permit to Construct is included in Appendix D.

A. Monitoring

1. Monitoring for SO_2 and NO_x will be accomplished using the continuous emission monitors required by 40 CFR 75 for the Acid Rain Program. Monitoring for particulate matter shall be in accordance with 40 CFR 64, Compliance Assurance Monitoring. If the owner/operator of the BART-eligible unit chooses to comply with the SO_2 percent reduction requirements, monitoring of the SO_2 inlet rate to the scrubber shall be accomplished by either:

   a. A continuous emission monitor that complies with the requirements of 40 CFR 75; or

   b. Coal sampling in accordance with Method 19 of 40 CFR 60, Appendix A plus development of an emission factor based on actual stack testing.

2. For purposes of determining compliance with the SO_2 reduction requirement, the reduction efficiency shall be determined as follows:

$$\% \text{ Reduction} = \frac{\text{Inlet } SO_2 \text{ Rate} - \text{Outlet } SO_2 \text{ Rate}}{\text{Inlet } SO_2 \text{ Rate}} \times 100$$

Where:

Inlet SO_2 Rate is in units of lb/10^6 Btu, lb/hr or ppmvd @ 3% O_2.
Outlet SO_2 Rate is in the same units as the inlet SO_2 rate.

3. The owner/operator will be allowed to average emissions (bubble) for SO_2 and/or NO_x for the two units using the following formulas:

$$\text{Average AER} = \frac{[(AER_1)(HI_1)+(AER_2)(HI_2)]}{(HI_1 + HI_2)}$$

$$\text{Average ER} = \frac{[(ER_1)(HI_1)+(ER_2)(HI_2)]}{(HI_1 + HI_2)}$$

Where:

AER	=	Allowable Emission Rate (lb/MMBtu or % Reduction)
ER_1	=	Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 1
ER_2	=	Actual Emission Rate (lb/MMBtu or % Reduction) of Unit 2
HI_1	=	Actual Heat Input (MMBtu) of Unit 1

HI_2 = Actual Heat Input (MMBtu) of Unit 2

Notes: ER is a 30-day rolling average.
HI is a 30-day rolling average.
30-day rolling average for the 30 successive boiler operating days (must be on a consistent basis of lb/MMBtu or % reduction).

B. Recordkeeping and Reporting

The owner/operator will be required to conduct recordkeeping and reporting as required by NDAC 33-15-14-06, Title V Permit to Operate and NDAC 33-15-21, Acid Rain Program (40 CFR 72, 75 and 76).

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