Final Report

BART Analysis for Jim Bridger Unit 1

Prepared For:

PacifiCorp

1407 West North Temple
Salt Lake City, Utah 84116

December 2007

Prepared By:

CH2MHILL

215 South State Street, Suite 1000
Salt Lake City, Utah 84111

Final Report

BART Analysis for Jim Bridger Unit 1

Submitted to

PacifiCorp

December 2007

CH2MHILL

Executive Summary

Background

In response to the Regional Haze Rule and Best Available Retrofit Technology (BART) regulations and guidelines, CH2M HILL was requested to perform a BART analysis for PacifiCorp's Jim Bridger Unit 1 (hereafter referred to as Jim Bridger 1). A BART analysis has been conducted for the following criteria pollutants: nitrogen oxide (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}). The Jim Bridger Station consists of four 530-megawatt (MW) units with a total generating capacity of 2,120 MW. Because the total generating capacity of the Jim Bridger Station exceeds 750 MW, presumptive BART limits apply to Jim Bridger 1, based on the United States Environmental Protection Agency's (EPA) guidelines. Best Available Retrofit Technology emissions limits must be achieved within 5 years after the State Implementation Plan (SIP) is approved by the EPA. A compliance date of 2014 was assumed for this analysis.

In completing the BART analysis, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified. The following technology alternatives were investigated, listed below by pollutant:

- NO_x emission controls:
  - Low-NO_x burners (LNBs) with over-fire air (OFA)
  - Rotating opposed fire air (ROFA)
  - LNBs with selective non-catalytic reduction (SNCR) system
  - LNBs with selective catalytic reduction (SCR) system
- SO_2 emission controls:
  - Optimize current operation of existing wet sodium flue gas desulfurization (FGD) system
  - Upgrade wet sodium FGD system to achieve an SO_2 emission rate of 0.10 pound (lb) per million British thermal units (MMBtu)
  - New dry FGD system
- PM_{10} emission controls:
  - Sulfur trioxide (SO_3) injection flue gas conditioning system on existing electrostatic precipitator (ESP)
  - Polishing fabric filter

BART Engineering Analysis

The specific steps in a BART engineering analysis are identified in the Code of Federal Regulations (CFR) at 40 CFR 51, Appendix Y, Section IV. The evaluation must include:

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance
- The degree of visibility improvement that may reasonably be anticipated from the use of BART

The following steps are incorporated into the BART analysis:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies
- Step 4 – Evaluate Impacts and Document the Results
  - The costs of compliance with the control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance
- Step 5 – Evaluate Visibility Impacts
  - The degree of visibility improvement that may reasonably be anticipated from the use of BART

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analyses are in 2006 dollars, and costs have not been escalated to the assumed 2014 BART implementation date.

Coal Characteristics

The main source of coal burned at Jim Bridger 1 will be the Bridger Underground Mine. Secondary sources are the Bridger Surface Mine, the Bridger Highwall Mine, the Black Butte Mine, and the Leucite Hills Mine. These coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. These coals have higher nitrogen content than coals from the Powder River Basin (PRB), which represent the bulk of sub-bituminous coal used in the U.S. This BART analysis has considered the higher nitrogen content and different combustion characteristics of PRB coals as compared to those coals used at Jim Bridger 1, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

Recommendations

CH2M HILL recommends installing the following control devices, which include LNBs with OFA, upgrading the existing FGD system, and operating the existing ESP with an SO_3 flue gas conditioning system. This combination of control devices is identified as Scenario 1 throughout this report.

NO_x Emission Control

The BART presumptive NO_x limit assigned by EPA for tangentially-fired boilers burning sub-bituminous coal is 0.15 lb per MMBtu. However, as documented in this analysis, the characteristics of the Jim Bridger coals are more closely aligned with bituminous coals, with a presumptive BART NO_x limit of 0.28 lb per MMBtu.

CH2M HILL recommends the existing LNB with OFA as BART for Jim Bridger 1, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts. Nitrogen oxide reductions are expected to be similar to those realized at Jim Bridger 2. CH2M HILL recommends that the unit be permitted at a rate of 0.26 lb per MMBtu.

SO_2 Emission Control

CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for Jim Bridger 1, based on the significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and minimal non-air quality environmental impacts. This upgrade approach will meet the BART presumptive SO_2 limit of 0.15 lb per MMBtu.

PM_{10} Emission Control

CH2M HILL recommends finalizing the permitting of the flue gas conditioning system to enhance the performance of the existing ESP as BART for Jim Bridger 1, based on the significant reduction in PM_{10} emissions, reasonable control costs, and the advantages of minimal additional power requirements and no non-air quality environmental impacts.

BART Modeling Analysis

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from Jim Bridger 1 at Class I areas. The Class I areas potentially affected are located more than 50 kilometers, but less than 300 kilometers, from the Jim Bridger Plant.

The Class I areas include the following wilderness areas (WA):

- Bridger WA
- Fitzpatrick WA
- Mt. Zirkel WA

Because Jim Bridger 1 will simultaneously control NO_x, SO_2, and PM_{10} emissions, four post-control atmospheric dispersion modeling scenarios were developed to cover the range of effectiveness for combining the individual NO_x, SO_2, and PM_{10} control technologies under evaluation. These modeling scenarios, and the controls assumed, are as follows:

- **Scenario 1**: New LNB with OFA modifications, upgraded wet FGD system, and flue gas conditioning for enhanced ESP performance. As indicated previously, this scenario represents PacifiCorp's preliminary BART selection.
- **Scenario 2**: New LNB with OFA modifications, upgraded wet FGD system, and new polishing fabric filter.
- **Scenario 3**: New LNB with OFA modifications and SCR, upgraded wet FGD system, and flue gas conditioning for enhanced ESP performance.
- **Scenario 4**: New LNB with OFA modifications and SCR, upgraded wet FGD system, and new polishing fabric filter.

Visibility improvements for all emission control scenarios were analyzed, and the results were compared utilizing a least-cost envelope, as outlined in the *New Source Review Workshop Manual*[1].

Least-cost Envelope Analysis

EPA has adopted the Least-cost Envelope Analysis Methodology as an accepted methodology for selecting the most reasonable, cost-effective controls. Incremental cost-effectiveness comparisons focus on annualized cost and emission reduction differences between dominant alternatives. The dominant set of control alternatives is determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for total emissions reductions for all control alternatives identified in the BART analysis.

To evaluate the impacts of the modeled control scenarios on the three Class I areas, the total annualized cost, cost per deciview (dV) reduction, and cost per reduction in number of days above 0.5 dV were analyzed. This report provides a comparison of the average incremental costs

[1] EPA, 1990. *New Source Review Workshop Manual.* Draft. Environmental Protection Agency. October, 1990.

between relevant scenarios for the three Class I areas; the total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98^{th} percentile delta-deciview (ΔdV) reduction.

Results of the least-cost envelope analysis validate the selection of Scenario 1, based on incremental cost and visibility improvements. Scenario 2 (LNB with OFA, upgraded wet FGD, and polishing fabric filter) is eliminated, because it is to the left of the curve formed by the dominant control alternative scenario, which indicates a scenario with lower improvement and/or higher costs. Scenario 3 (LNB with OFA and SCR, upgraded wet FGD, and flue gas conditioning for enhanced ESP performance) is not selected due to very high incremental costs, on the basis of both a cost per day of improvement and cost per dV reduction. While Scenario 4 (LNB with OFA and SCR, upgraded wet FGD, and polishing fabric filter) provides some potential visibility advantage over Scenario 1, the projected improvement is less than 0.5 dV, and the projected costs are excessive. Therefore, Scenario 1 represents BART for Jim Bridger 1.

Just-Noticeable Differences in Atmospheric Haze

Studies have been conducted that demonstrate only dV differences of approximately 1.5 to 2.0 dV or more are perceptible by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the control scenarios. Thus, the results indicate that even though PacifiCorp will be spending many millions of dollars at this single unit, and over $1 billion when considering its entire coal fleet, only minimal discernable visibility improvements may result.

Contents

Tables

Figures

Appendices

Acronyms and Abbreviations

°F	Degrees Fahrenheit
°C	Degrees Celsius
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
CALDESK	Program to Display Data and Results
CALMET	Meteorological Data Preprocessing Program for CALPUFF
CALPOST	Post-processing Program for Calculating Visibility Impacts
CALPUFF	Gaussian Puff Dispersion Model
CFR	Code of Federal Regulations
CO	Carbon Monoxide
COHPAC	Compact Hybrid Particulate Collector
dV	Deciview
ΔdV	Delta Deciview, Change in Deciview
EIA	Energy Information Administration
ESP	Electrostatic Precipitator
EPA	United States Environmental Protection Agency
Fuel NO_x	Oxidation of Fuel-bound Nitrogen
FGC	Flue Gas Conditioning
FGD	Flue Gas Desulfurization
f (RH)	Relative Humidity Factors
kW	Kilowatt
LAER	Lowest Achievable Emission Rate
lb	Pound(s)
LNB	Low-NO_x Burner
LOI	Loss on Ignition
MMBtu	Million British Thermal Units
MM5	Mesoscale Meteorological Model, Version 5
MW	Megawatt
N_2	Nitrogen
NO_x	Nitrogen Oxide
NSR Manual	*New Source Review Workshop Manual* (EPA, 1990)
OFA	Over-fire Air

PM	Particulate Matter
PM_{10}	Particulate Matter less than 10 Micrometers in Aerodynamic Diameter
$PM_{2.5}$	Particulate Matter less than 2.5 Micrometers in Aerodynamic Diameter
PRB	Powder River Basin
ROFA	Rotating Opposed Fire Air
S&L	Sargent & Lundy
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SNCR	Selective Non-catalytic Reduction
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
Thermal NO_x	High Temperature Fixation of Atmospheric Nitrogen in Combustion Air
TRC	TRC Company, Inc.
USGS	U.S. Geological Survey
WA	Wilderness Area
WDEQ-AQD	Wyoming Department of Environmental Quality – Air Quality Division

1.0 Introduction

Best Available Retrofit Technology (BART) guidelines were established as a result of U.S. Environmental Protection Agency (EPA) regulations intended to reduce the occurrence of regional haze in national parks and other Class I protected air quality areas in the United States (40 Code of Federal Regulations [CFR] Part 51). These guidelines provide guidance for states when determining which facilities must install additional controls, and the type of controls that must be used. Facilities eligible for BART installation were built between 1962 and 1977, and have the potential to emit more than 250 tons per year of visibility-impairing pollutants.

The Wyoming Department of Environmental Quality (WDEQ) BART regulations state that each source subject to BART must submit a BART application for a construction permit by December 15, 2006. PacifiCorp received an extension from the WDEQ to submit the BART report for Jim Bridger Unit 1 (hereafter referred to as Jim Bridger 1) by January 12, 2007. The BART report that was submitted to WDEQ in January 2007 included a BART analysis, and a proposal and justification for BART at the source. This revised report—submitted in October 2007—incorporates editorial revisions and new model runs since the January 2007 version.

The State of Wyoming has identified those eligible, in-state facilities that are required to reduce emissions under BART, and will set BART emissions limits for those facilities. This information will be included in the State of Wyoming State Implementation Plan (SIP), which the State has estimated will be formally submitted to the EPA by early 2008. The EPA BART guidelines also state that the BART emission limits must be fully implemented within 5 years of EPA's approval of the SIP.

Five elements related to BART address the issue of emissions for the identified facilities:

- Any existing pollution control technology in use at the source
- The cost of the controls
- The remaining useful life of the source
- The energy and non-air quality environmental impacts of compliance
- The degree of improvement in visibility that may reasonably be anticipated from the use of such technology

This report documents the BART analysis that was performed on Jim Bridger 1 by CH2M HILL for PacifiCorp. The analysis was performed for the pollutants nitrogen oxide (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}), because they are the primary criteria pollutants that affect visibility.

Section 2 of this report provides a description of the present unit operation, including a discussion of coal sources and characteristics. The BART Engineering Analysis is provided in Section 3, by pollutant type. Section 4 provides the methodology and results of the BART Modeling Analysis, followed by recommendations in Section 5 and references in Section 6. Appendices provide more detail on the economic analysis and the 2006 Wyoming BART Protocol.

2.0 Present Unit Operation

The Jim Bridger Station consists of four units with a total generating capacity of 2,120 megawatts (MW). Jim Bridger 1 is a nominal 530 net MW unit located approximately 35 miles northeast of Rock Springs, Wyoming. Unit 1 is equipped with a tangentially fired, pulverized-coal boiler with low-NO_x burners (LNBs) manufactured by Combustion Engineering. The unit was constructed with a Flakt wire frame electrostatic precipitator (ESP). The unit contains a Babcock & Wilcox wet sodium flue gas desulfurization (FGD) system with three absorber towers installed in 1990. An Emerson Ovation distributed control system was installed in 2006.

Jim Bridger 1 was placed in service in 1974. Its current economic depreciation life is through 2040; however, this analysis is based on a 20-year life for BART control technologies. Assuming a BART implementation date of 2014, this will result in an approximate remaining useful life for Jim Bridger 1 of 20 years from the installation date of any new or modified BART-related equipment. This report does not attempt to quantify any additional life extension costs needed to allow the unit and these control devices at Jim Bridger 1 to operate until 2040.

Table 2-1 lists additional unit information and study assumptions for this analysis.

The BART presumptive NO_x limit for tangential-fired boilers burning sub-bituminous coal is 0.15 pound per million British thermal units (lb per MMBtu) and the BART presumptive NO_x limit for burning bituminous coal is 0.28 lb per MMBtu. The main sources of coal burned at Jim Bridger 1 are the Bridger Mine and secondarily the Black Butte Mine and Leucite Hills Mine. These coals are ranked as sub-bituminous, but are closer in characteristics to bituminous coal in many of the parameters influencing NO_x formation. These coals have higher nitrogen content than coals from the Powder River Basin (PRB), which represent the bulk of sub-bituminous coal used in the U.S. This BART analysis has considered the higher nitrogen content and the different combustion characteristics of PRB coals, as compared to those coals used at Jim Bridger 1, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates. Coal sources and characteristics are summarized in Table 2-2. The primary source of coal will be the Bridger Underground Mine, and data on coal from this source were used in the modeling analysis. For the coal analysis that is presented in Section 3, the data from all the coal sources were used.

TABLE 2-1
Unit Operation and Study Assumptions
Jim Bridger 1

General Plant Data	
Site Elevation (feet above mean sea level)	6669
Stack Height (feet)	500
Stack Exit ID (feet) /Exit Area (square feet)	24 /452.4
Stack Exit Temperature (degrees Fahrenheit)	140
Stack Exit Velocity (feet per second)	84.0
Stack Flow (actual cubic feet per minute)	2,281,182
Latitude (degree: minute: second)	41:44:07 north
Longitude (degree: minute: second)	108:47:12 west
Annual Unit Capacity Factor (percentage)	90
Net Unit Output (megawatts)	530
Net Unit Heat Rate (British thermal units (Btu) per kilowatt-hour)(100% load)	10,400 (as measured by fuel throughput)
Boiler Heat Input (million Btu (MMBtu) per hour)(100% load)	6,000 (as measured by continuous emission monitoring)
Type of Boiler	Tangentially fired
Boiler Fuel	Coal
Coal Sources	Bridger Mine, Black Butte Mine, Leucite Hills Mine
Coal Heating Value (Btu per pound [lb])[(a)]	9,660
Coal Sulfur Content (percentage by weight [wt. %])[(a)]	0.58
Coal Ash Content (wt. %)[(a)]	10.3
Coal Moisture Content (wt. %)[(a)]	19.3
Coal Nitrogen Content (wt. %)[(a)]	0.98
Current Nitrogen Oxide (NO_x) Controls	Low-NO_x burners
NO_x Emission Rate (lb/MMBtu)	0.45
Current Sulfur Dioxide (SO_2) Controls	Sodium-based wet scrubber
SO_2 Emission Rate (lb/MMBtu)	0.267
Current PM_{10}[(b)] Controls	Electrostatic Precipitator
PM_{10} Emission Rate (lb/MMBtu)[(c)]	0.045

NOTES:
[(a)]Coal characteristics based on Bridger Underground Mine (primary coal source)
[(b)]PM_{10} refers to particulate matter less than 10 micrometers in aerodynamic diameter
[(c)]Based on maximum historic emission rate from 1999 to 2001, prior to installation of the sulfur trioxide (SO_3) injection system.

TABLE 2-2
Coal Sources and Characteristics
Jim Bridger 1

								Ultimate Analysis (% dry basis)					
Mines	**Moisture (%)**	**Ash (%)**	**Volatile Matter (%)**	**Fixed Carbon (%)**	**British thermal units per pound (Btu/lb)**	**Sulfur (%)**	**Moisture and Ash Free (Btu/lb)**	**Hydrogen**	**Carbon**	**Sulfur**	**Nitrogen**	**Oxygen**	**Ash**
Bridger Mine Underground	19.3	10.3	32.2	38.3	9660	0.58	13712	4.66	69.2	0.72	1.22	11.8	12.4
Maximum	Not enough data yet to run statistical analysis for variability												
Minimum	Not enough data yet to run statistical analysis for variability												
Bridger Mine Surface	19.1	10.6	32.3	38.0	9390	0.57	13340	4.38	37.4	0.71	1.26	13.2	13.0
Maximum	20.5	12.5	35.5	41.9	9800	0.72	13500	4.69	4.0	0.90	1.43	14.8	15.8
Minimum	17.5	9.0	31.0	36.0	9000	0.49	13100	4.00	64.3	0.60	1.14	11.7	11.2
Bridger Mine Highwall	18.0	9.5	33.0	39.5	9700	0.58	13500	No samples of separate highwall coal					
Maximum	Not enough data yet to run statistical analysis for variability												
Minimum	Not enough data yet to run statistical analysis for variability												
Black Butte Mine	20.0	9.2	33.3	35.6	9450	0.45	13330	4.43	68.7	0.56	1.47	13.4	11.5
Maximum	21.1	10.8	35.4	41.9	10275	0.62	13500	4.66	70.5	0.78	1.69	14.8	13.6
Minimum	18.0	7.6	29.9	36.8	9180	0.33	13140	4.21	66.1	0.41	1.25	11.6	9.7
Leucite Hills Mine (through 2009)	19.4	11.5	30.7	38.3	9080	0.64	13140	4.20	66.0	0.81	1.48	13.2	14.4
Maximum	23.0	15.0	33.0	43.0	10250	0.90	13800	4.70	70.0	1.20	1.64	17.1	19.0
Minimum	17.0	8.0	28.3	33.6	8000	0.40	12300	3.70	61.0	0.50	1.32	10.5	10.0

3.0 BART Engineering Analysis

This section presents the required BART engineering analysis.

3.1 Applicability

In compliance with regional haze requirements, the State of Wyoming must prepare and submit visibility SIPs to the EPA for Class I areas. The State has estimated that the formal submittal of the SIPs will occur by early 2008. The first phase of the regional haze program is the implementation of BART emission controls on all BART eligible units, within 5 years after EPA approval of the SIP.

3.2 BART Process

The specific steps in a BART engineering analysis are identified in 40 CFR 51, Appendix Y, Section IV. The evaluation must include:

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance
- The degree of visibility improvement that may reasonably be anticipated from the use of BART

The following steps are incorporated into the BART analysis:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
  - The identification of available, technically feasible, retrofit control options
  - Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)
- Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

- Step 4 – Evaluate Impacts and Document the Results
  - The costs of compliance with the control options
  - The remaining useful life of the facility
  - The energy and non-air quality environmental impacts of compliance
- Step 5 – Evaluate Visibility Impacts
  - The degree of visibility improvement that may reasonably be anticipated from BART use

In order to minimize costs in the BART analysis, consideration was made of any pollution control equipment in use at the source, the costs of compliance associated with the control options, and the energy and non-air quality environmental impacts of compliance using these existing control devices. In some cases, enhancing the performance of the existing control equipment was considered. Other scenarios with new control equipment were also developed.

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analysis are in 2006 dollars, and costs have not been escalated to the assumed 2014 BART implementation date.

3.2.1 BART NO_x Analysis

Nitrogen oxide formation in coal-fired boilers is a complex process that is dependent on a number of variables, including operating conditions, equipment design, and coal characteristics.

Formation of NO_x

During coal combustion, NO_x is formed in three different ways. The dominant source of NO_x formation is the oxidation of fuel-bound nitrogen (fuel NO_x). During combustion, part of the fuel-bound nitrogen is released from the coal with the volatile matter, and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (nitric oxide and nitrogen dioxide) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_x formation is due to high temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_x). A very small amount of NO_x is called prompt NO_x. Prompt NO_x results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

In a conventional pulverized coal burner, air is introduced with turbulence to promote good mixing of fuel and air, which provides stable combustion. However, not all of the oxygen in the air is used for combustion. Some of the oxygen combines with the fuel nitrogen to form NO_x.

Coal characteristics directly and significantly affect NO_x emissions from coal combustion. Coal ranking is a means of classifying coals according to their degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous and on to anthracite. Lower rank coals, such as the sub-bituminous coals from the PRB, produce lower NO_x emissions than higher rank bituminous coals, due to their higher reactivity and lower nitrogen content. The fixed carbon to volatile matter ratio (fuel ratio), coal oxygen content, and rank are good relative indices of the reactivity of a coal. Lower rank coals release more organically bound nitrogen earlier in the combustion process than do higher rank bituminous coals. When used with LNBs, sub-bituminous coals create a longer time for the kinetics to promote more stable molecular nitrogen, and hence result in lower NO_x emissions.

Coals from the PRB are classified as sub-bituminous C and demonstrate the high reactivity and low NO_x production characteristics described above. Based on data from the Energy Information Administration (EIA), PRB coals currently represent 88 percent of total U.S. sub-bituminous production and 73 percent of western coal production (Energy Information Administration, 2006). Most references to western coal and sub-bituminous coal infer PRB origin and characteristics. Emissions standards differentiating between bituminous and sub-bituminous coals are presumed to use PRB coal as the basis for the sub-bituminous standards, due to its dominant market presence and unique characteristics.

There are a number of western coals that are classified as sub-bituminous, however, they border on being ranked as bituminous and do not display many of the qualities of PRB coals, including most of the low NO_x forming characteristics. Coals from the Bridger, Black Butte, and Leucite Hills mines fall into this category.

As defined by the American Society for Testing and Materials, the only distinguishing characteristic that classifies the coals used at Jim Bridger 1 as sub-bituminous rather than bituminous – is that they are “agglomerating” as compared to “non-agglomerating.” Agglomerating as applied to coal is “the property of softening when it is heated to above about 400 degrees Celsius (°C) in a non-oxidizing atmosphere, and then appearing as a coherent mass after cooling to room temperature.” Because the agglomerating property of coals is the result of particles transforming into a plastic or semi-liquid state when heated, it reflects a change in surface area of the particle. Thus, with the application of heat, agglomerating coals would tend to develop a non-porous surface, while the surface of non-agglomerating coals would become even more porous with combustion. As shown in Figure 3-1, the increased porosity provides more particle surface area, resulting in more favorable combustion conditions. This non-agglomerating property assists in making sub-bituminous coals more amenable to controlling NO_x, by allowing less air to be introduced during the initial ignition portion of the combustion process. The coals from the Bridger, Black Butte and Leucite Hills mines just barely fall into the category of non-agglomerating coals. While each of these coals is considered non-agglomerating, they either do not exhibit those properties of non-agglomerating coals or exhibit them to only a minor degree. The conditions during combustion of typical non-agglomerating coals that make it easier to control NO_x emissions do not exist during combustion of the Bridger blends of coals.

FIGURE 3-1
Illustration of the Effect of Agglomeration on the Speed of Coal Combustion
Jim Bridger 1

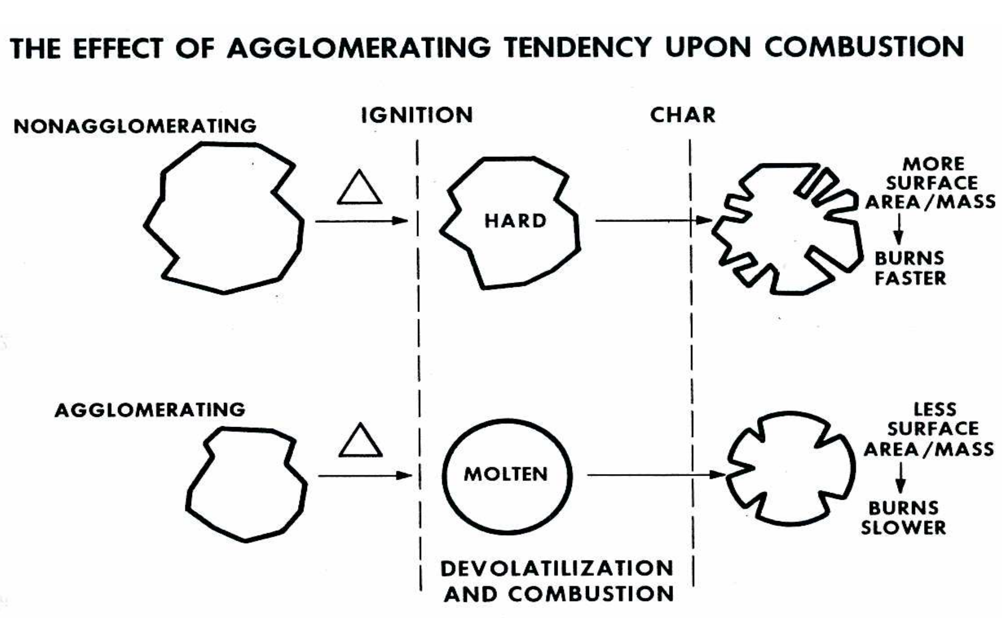


Table 3-1 shows key characteristics of a typical PRB coal, compared to coals from the Bridger Mine, Black Butte, and Leucite Hills, as well as coal from Twentymile, which is a representative western bituminous coal.

TABLE 3-1
Coal Characteristics Comparison
Jim Bridger 1

Parameter	Typical Powder River Basin	Bridger Mine	Black Butte	Leucite Hills	Twentymile
Nitrogen (% dry)	1.10	1.26	1.47	1.48	1.85
Oxygen (% dry)	16.2	13.2	13.4	13.2	7.19
Coal rank	Sub C	Sub B	Sub B	Sub B	Bitum. high volatility B

As shown in Table 3-1, although Bridger, Black Butte, and Leucite Hills are classified as sub-bituminous, they all exhibit higher nitrogen content and lower oxygen content than the PRB coal. The higher nitrogen content is an indication that more nitrogen is available to the combustion process and higher NO_x emissions are likely. Oxygen content can be correlated to the reactivity of the coal, with more reactive coals generally containing higher levels of oxygen. More reactive coals tend to produce lower NO_x emissions, and they are also more conducive to reduction of NO_x emissions through the use of combustion control measures, such as LNBs and over-fire air (OFA). These characteristics indicate that higher NO_x formation is likely with coal from the Bridger, Black Butte, and Leucite Hills mines, rather than with PRB coal. The Bridger, Black Butte, and Leucite Hills coals all contain quality characteristics that fall between a typical PRB coal and Twentymile. Twentymile is a clearly bituminous coal that produces higher NO_x, as has been demonstrated at power plants burning this fuel.

Figures 3-2 and 3-3 graphically illustrate the relationship of nitrogen and oxygen content to the BART presumptive NO_x limits for the coals listed in Table 3-1. Each chart identifies the presumptive BART limit associated with a typical bituminous and sub-bituminous coal, and demonstrates how the Jim Bridger coal falls between these two general coal classifications.

The Bridger blend data point represents a combination of coals from the Bridger Mine, Black Butte, and Leucite Hills that has been used at Jim Bridger 1, and indicates the average NO_x emission rate achieved during the years 2003 to 2005. The Jim Bridger 2 data point consists of the same blend of coals as Jim Bridger 1, and represents the NO_x emission rate achieved after installation of Alstom's current state-of-the-art TFS2000 LNB and OFA system. The long-term sustainable emission rate for this system is expected to be 0.24 lb per MMBtu. All four units at Jim Bridger consist of identical boilers; while there may be some differences in performance among them, installation of the TFS2000 firing system at Jim Bridger 1 would likely result in performance and NO_x emission rates comparable to those at Jim Bridger 2.

Figures 3-2 and 3-3 both demonstrate that for the Jim Bridger units with the TFS2000 low NO_x emission system installed and burning a combination of the Bridger, Black Butte, and Leucite Hill coals, the likely NO_x emission rate will be closer to the bituminous end (0.28) of the BART presumptive NO_x limit range, rather than the BART presumptive NO_x limit of 0.15 lb per MMBtu for sub-bituminous coal. All these factors are consistent with the observed sustainable rate of 0.24 lb per MMBtu.

FIGURE 3-2
Plot of Typical Nitrogen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Jim Bridger 1

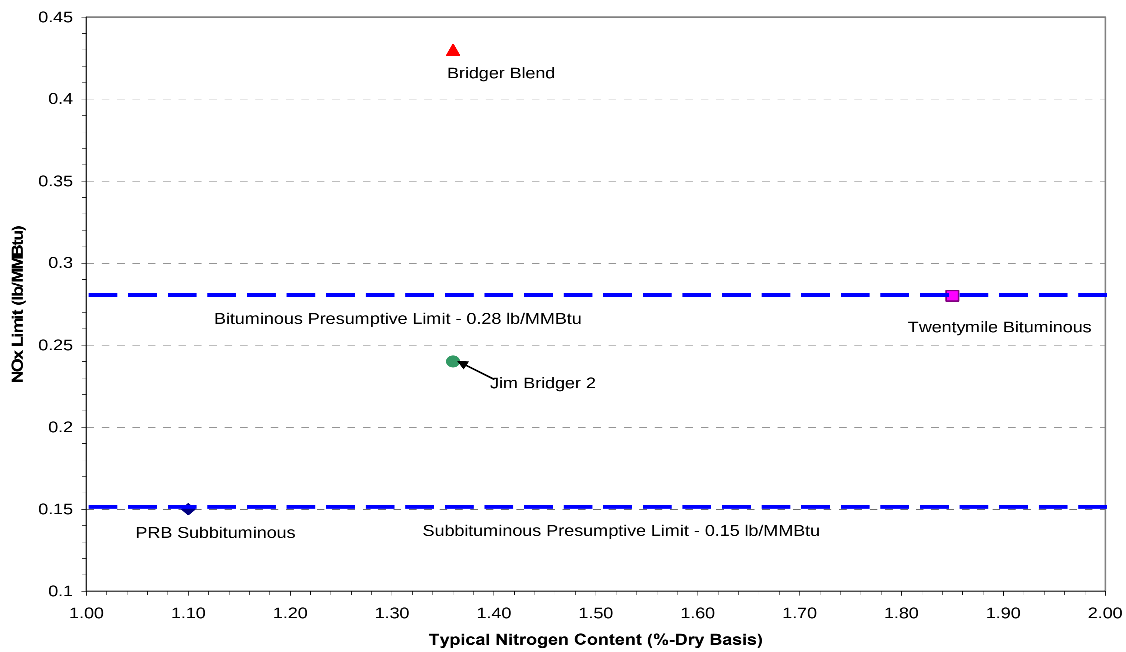
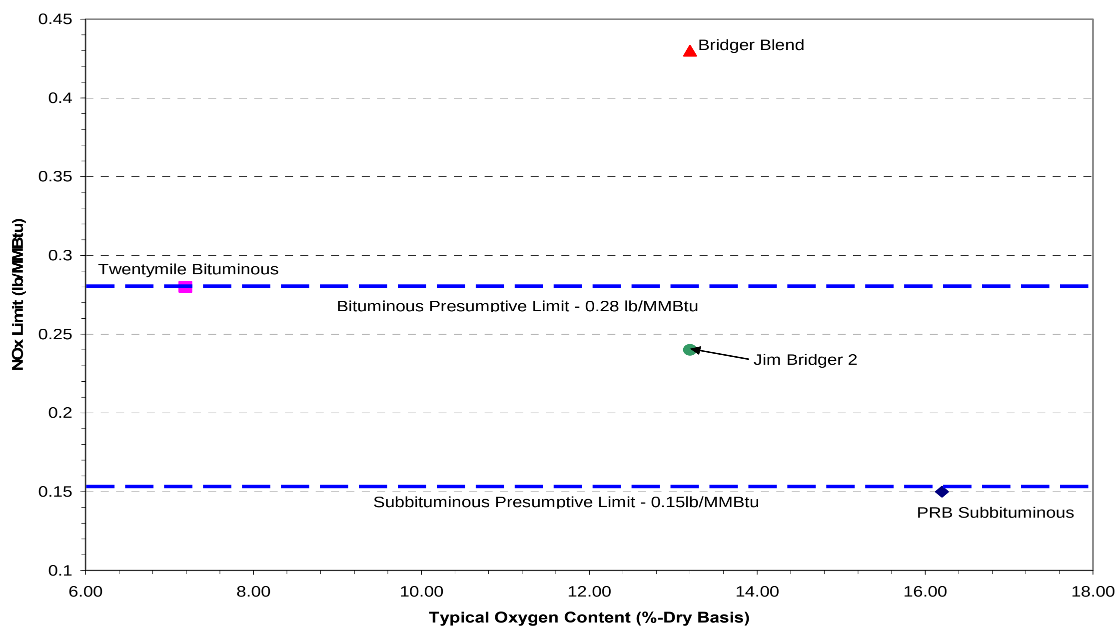


FIGURE 3-3
Plot of Typical Oxygen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Jim Bridger 1



Coal quality characteristics also impact the design and operation of the boiler and associated auxiliary equipment. Minor changes in quality can sometimes be accommodated through operational adjustments or changes to equipment. It is important to note, however, that consistent variations in quality or assumptions of "average" quality for performance projections can be problematic. This is particularly troublesome when dealing with performance issues that are very sensitive to both coal quality and combustion conditions, such as NO_x formation. There is significant variability in the quality of coals burned at Jim Bridger 1. In addition to burning coal from Black Butte and Leucite Hills, Jim Bridger 1 burns coal supplied from the Bridger Mine consisting of three sources: underground, surface, and highwall operations. Each of these coal sources has different quality characteristics, as well as inherent variability in composition of the coal within the mine.

Several of the coal quality characteristics and their effect on NO_x formation have been previously discussed. There are some additional considerations that illustrate the complexity of achieving and maintaining consistent low NO_x emissions with pulverized coal on a shorter term, such as a 30-day rolling average basis.

Good combustion is based on the "three Ts": time, temperature, and turbulence. These parameters along with a "design" coal are taken into consideration when designing a boiler and associated firing equipment such as fans, burners, and pulverizers. If a performance requirement, such as NO_x emission limits, is subsequently changed, conflicts with other performance issues can result.

Jim Bridger 1 is located at an altitude of 6,669 feet above sea level. At this elevation, atmospheric pressure is lower (11.5 pounds per square inch) as compared with sea level pressure of 14.7 pounds per square inch. This lower pressure means that less oxygen is available for combustion for each volume of air. In order to provide adequate oxygen to meet the requirements for efficient combustion, larger volumes of air are required. When adjusting air flows and distribution to lower NO_x using LNBs and OFA, original boiler design restrictions again limit the modifications that can be made and still achieve satisfactory combustion performance.

Another significant factor in controlling NO_x emissions is the fineness of the coal entering the burners. Fineness is influenced by the grindability index (Hardgrove) of the coal. Finer coal particles promote release of volatiles and assist char burnout due to more surface area exposed to air. Nitrogen oxide reduction with high volatile coals is improved with greater fineness and with proper air staging. The lower rank sub-bituminous coals such as PRB coals are quite friable and easy to grind. Coals with lower Hardgrove Grindability Index values, such as those used at Jim Bridger 1, are more difficult to grind and can contribute to higher NO_x levels. In addition, coal fineness can deteriorate over time periods between pulverizer maintenance and service as pulverizer grinding surfaces wear.

In summary, when all the factors of agglomeration versus non-agglomeration, nitrogen and oxygen content of the coals, and the grindability index are taken into account, this analysis demonstrates that, for the coal used at Jim Bridger 1, the more applicable presumptive BART limit is 0.28 lb per MMBtu. The BART analysis for NO_x emissions from Jim Bridger 1 is further described below.

Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to Jim Bridger 1, including those control technologies identified as Best Available Control Technology (BACT) or lowest achievable emission rate (LAER) by permitting agencies across the United States. A broad range of information sources have been reviewed in an effort to identify potentially applicable emission control technologies.
Jim Bridger 1 NO_x emissions are currently controlled through the use of good combustion practices and OFA.

The following potential NO_x control technology options were considered:

- New/modified LNBs with advanced OFA
- Rotating Opposed Fire Air (ROFA)
- Conventional selective non-catalytic reduction (SNCR) system
- Selective catalytic reduction (SCR) system

Step 2: Eliminate Technically Infeasible Options

For Jim Bridger 1, a tangential-fired configuration burning sub-bituminous coal, technical feasibility will primarily be determined by physical constraints, boiler configuration, and on the ability to achieve the regulatory presumptive limit (used as a guide) of 0.28 lb per MMBtu of NO_x. Jim Bridger 1 has an uncontrolled NO_x emission rate of 0.45 lb per MMBtu.

For this BART analysis, information pertaining to LNBs, OFA, SNCR, and SCR were based on the *Multi-Pollutant Control Report* (Sargent and Lundy, 2002, hereafter referred to as the S&L Study). Updated cost estimates for SCR and SNCR were used (Sargent and Lundy, 2006). PacifiCorp provided additional emissions data and costs developed by boiler vendors for LNBs and OFA. Also, CH2M HILL solicited a proposal from Mobotec for their ROFA technology.

With SNCR, an amine-based reagent such as ammonia, or more commonly urea, is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NO_x to nitrogen and water. Nitrogen oxide reductions of up to 60 percent have been achieved, although 15 to 30 percent is more realistic for most applications. Selective non-catalytic reduction is typically applied on smaller units. Adequate reagent distribution in the furnaces of large units can be problematic.

Table 3-2 summarizes the control technology options evaluated in this BART analysis, along with projected NO_x emission rates. All technologies can meet the applicable presumptive BART limit of 0.28 lb per MMBTU.

TABLE 3-2
NO_x Control Technology Emission Rate Ranking
Jim Bridger 1

Technology	Projected Emission Rate (pounds per million British thermal units)
Presumptive Best Available Retrofit Technology (BART) Limit	0.28
Low-NO_x Burners (LNBs) with Over-fire Air (OFA)	0.24
Rotating Opposed Fire Air (ROFA)	0.22
LNB with OFA and Selective Non-catalytic Reduction (SNCR)	0.20
LNB with OFA and Selective Catalytic Reduction (SCR)	0.07

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Preliminary vendor proposals, such as those used to support portions of this BART analysis, may be technically feasible and provide expected or guaranteed emission rates; however, the proposals include inherent uncertainties. These proposals are usually prepared in a limited time frame, may be based on incomplete information, may contain over-optimistic conclusions, and are non-binding. Therefore, emission rate values obtained in such preliminary proposals must be qualified, and it must be recognized that contractual guarantees are established only after more detailed analysis has been completed. The following subsections describe the control technologies and the control effectiveness evaluated in this BART analysis.

New LNBs with OFA System. The mechanism used to lower NO_x with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

Both LNBs and OFA are considered to be a capital cost, combustion technology retrofit. For LNB retrofits to units configured with tangential-firing such as Jim Bridger 1, it is generally necessary to increase the burner spacing; this prevents interaction of the flames from adjacent burners and reduces burner zone heat flux. These modifications usually require boiler waterwall tube replacement.

Information provided to CH2M HILL by PacifiCorp—based on the S&L Study and data from boiler vendors—indicates that new LNB and OFA retrofit at Jim Bridger 1 would result in an expected NO_x emission rate of 0.24 lb per MMBtu. PacifiCorp has indicated that this rate corresponds to a vendor guarantee, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls. This emission rate represents a significant reduction from the current NO_x emission rate, and is below the more applicable presumptive NO_x emission rate of 0.28 lb per MMBtu.

ROFA. Mobotec markets ROFA as an improved second generation OFA system. Mobotec states that "the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow, so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. The combustion air is also mixed more effectively." A typical ROFA installation will have a booster fan(s) to supply the high velocity air to the ROFA boxes, and Mobotec would propose two 4,000 to 4,300 Hp fans for Jim Bridger 1.

Mobotec expects to achieve a NO_x emission rate of 0.18 lb per MMBtu using ROFA technology. An operating margin of 0.04 lb per MMBtu was added to the expected rate due to Mobotec's limited ROFA experience with western sub-bituminous coals. Under the Mobotec proposal, primarily based on ROFA equipment, the operation of existing LNB and OFA ports will be analyzed. While a typical installation does not require modification to the existing LNB system, and the existing OFA ports are not used, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. The Mobotec proposal includes bent tube assemblies for OFA port installation. Mobotec does not provide installation services, because they believe that the Owner can more cost effectively contract for these services. However, they do provide one onsite construction supervisor during installation and startup.

SNCR. Selective non-catalytic reduction is generally utilized to achieve modest NO_x reductions on smaller units. With SNCR, an amine-based reagent such as ammonia—or more commonly urea—is injected into the furnace within a temperature range of 1,600°F to 2,100°F, where it reduces NO_x to nitrogen and water. Nitrogen oxide reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NO_x, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The ammonia may render fly ash unsaleable, react with sulfur to foul heat exchange surfaces, and/or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NO_x reduction generally resulting in lower reagent utilization and higher operating cost.

Reductions from higher baseline concentrations (inlet NO_x) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption. To reduce reagent costs, S&L has assumed that combustion modifications including LNBs and advanced OFA are capable of achieving a projected NO_x emission rate of 0.24 lb per MMBtu. A further reduction of 15 percent in NO_x emission rates for SNCR would result in a projected emission rate of 0.20 lb per MMBtu.

SCR. SCR works on the same chemical principle as SNCR but SCR uses a catalyst to promote the chemical reaction. Ammonia is injected into the flue-gas stream, where it reduces NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the reaction takes place on the surface of a vanadium/titanium-based catalyst at a temperature range between 580° F to 750° F. Due to the catalyst, the SCR process is more efficient than SNCR and results in lower NO_x emissions. The most common type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. The high-dust configuration is assumed for Jim Bridger 1. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher removal rate, a full-scale SCR was used as the basis for analysis at Jim Bridger 1.

Sargent and Lundy prepared the design conditions and cost estimates for SCR at Jim Bridger 1. As with SNCR, it is generally more cost effective to reduce NO_x emission levels as much as possible through combustion modifications, in order to minimize the catalyst surface area and ammonia requirements of the SCR. The S&L design basis for LNB with OFA and SCR results in a projected NO_x emission rate of 0.07 lb per MMBtu. Additional catalyst surface was included in the SCR design to accommodate the characteristics of the coal used at Jim Bridger 1.

Level of Confidence for Vendor Post-control Emissions Estimates. In order to determine the level of NO_x emissions needed to consistently achieve compliance with an established goal, a review of typical NO_x emissions from coal-fired generating units was completed. As a result of this review, it was noted that NO_x emissions can vary significantly around an average emissions level. This variance can be attributed to many reasons, including coal characteristics, unit load, boiler operation including excess air, boiler slagging, burner equipment condition, coal mill fineness, and so forth.

The steps utilized for determining a level of confidence for the vendor expected value are as follows:

- Establish expected NO_x emissions value from vendor.
- Evaluate vendor experience and historical basis for meeting expected values.
- Review and evaluate unit physical and operational characteristics and restrictions. The fewer variations there are in operations, coal supply, etc., the more predictable and less variant the NO_x emissions are.
- For each technology expected value, there is a corresponding potential for actual NO_x emissions to vary from this expected value. From the vendor information presented, along with anticipated unit operational data, an adjustment to the expected value can be made.

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Installation of LNBs and modification to the existing OFA systems are not expected to significantly impact the boiler efficiency or forced draft fan power usage. Therefore, these technologies will not have energy impacts.

The Mobotec ROFA system requires installation and operation of two 4,000 to 4,300 horsepower ROFA fans (6,410 kilowatts [kW] total). The SNCR system would require approximately 530 kW of additional power.

Selective catalytic reduction retrofit impacts the existing flue gas fan systems, due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase. Total additional power requirements for SCR installation at Jim Bridger 1 are estimated at approximately 3,280 kW, based on the S&L Study.

Environmental Impacts. Mobotec has predicted that carbon monoxide (CO) emissions, and unburned carbon in the ash, commonly referred to as LOI (loss on ignition), would be the same or lower than prior levels for the ROFA system.

The installation of SNCR and SCR could impact the saleability and disposal of fly ash due to ammonia levels, and could potentially create a visible stack plume, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

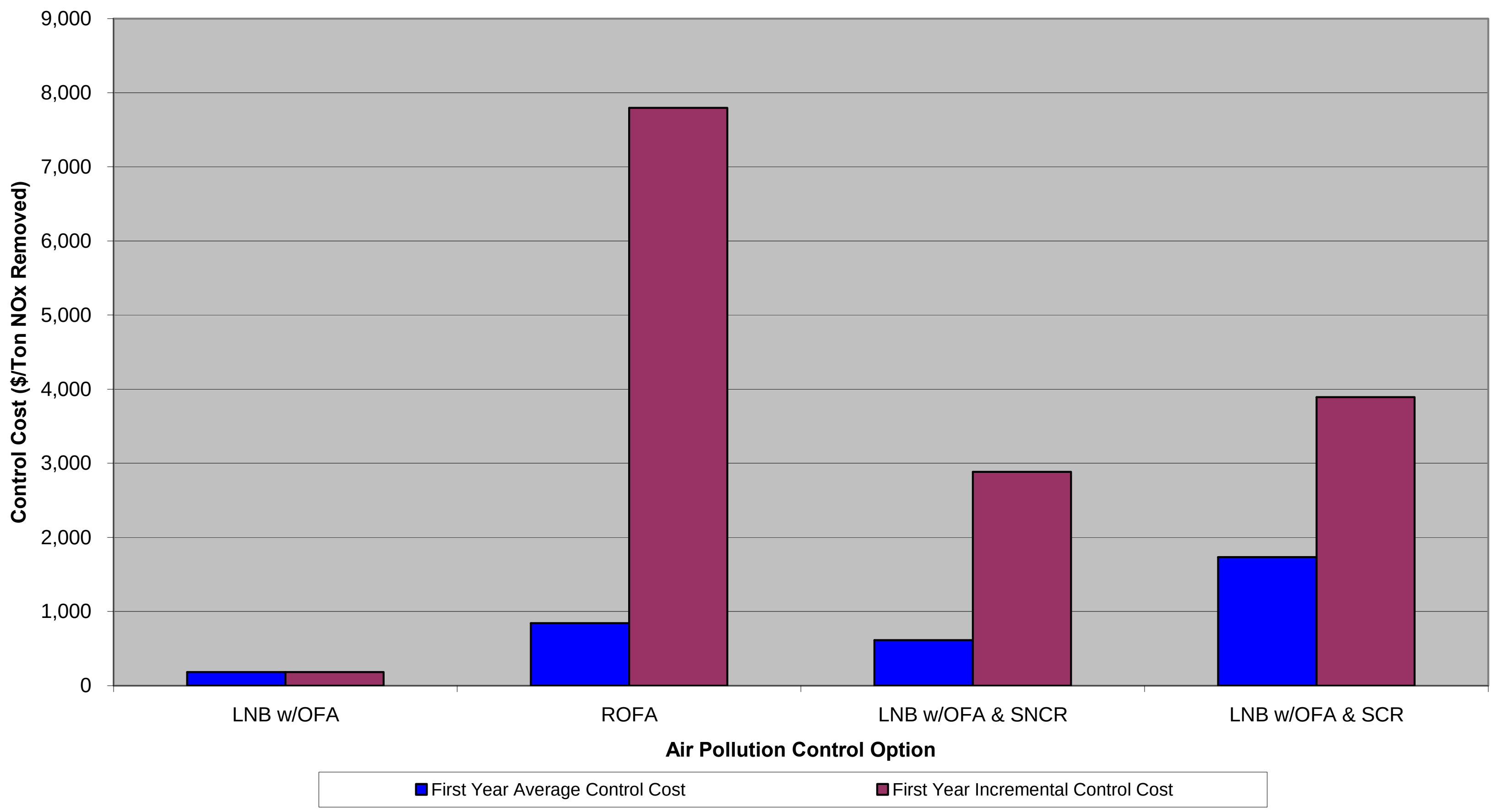
Economic Impacts. Costs and schedules for the LNBs and OFA, SNCR, and SCR were furnished to CH2M HILL by PacifiCorp, developed using S&L's internal proprietary database, and supplemented (as needed) by vendor-obtained price quotes. The relative accuracy of these cost estimates is stated by S&L to be in the range of plus or minus 20 percent. Cost for the ROFA system was obtained from Mobotec.

A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-3, and the first year control costs are shown in Figure 3-4. The complete economic analysis is contained in Appendix A.

TABLE 3-3
NO_x Control Cost Comparison
Jim Bridger 1

Factor	Low-NO_x Burners (LNBs) with Over-fire Air (OFA)	Rotating Opposed Fire Air (ROFA)	LNB with OFA and Selective Non-catalytic Reduction (SNCR)	LNB with OFA and Selective Catalytic Reduction (SCR)
Total Installed Capital Costs	$8.7 million	$20.5 million	22.1 million	$129.6 million
Total First Year Fixed and Variable Operation and Maintenance Costs	$0.1 million	$2.6 million	$1.5 million	$3.3 million
Total First Year Annualized Cost	$0.9 million	$4.6 million	$3.6 million	$15.6 million
Power Consumption (megawatts)	0	6.4	0.5	3.3
Annual Power Usage (1,000 megawatt-hours per year)	0	50.6	4.2	25.8
Nitrogen Oxide (NO_x) Design Control Efficiency	46.7%	51.1%	55.6%	84.4%
NO_x Removed per Year (Tons)	4,967	5,440	5,913	8,987
First Year Average Control Cost (dollars per ton [$/Ton] of NO_x Removed)	$181/ton	$843/ton	$613/ton	$1,736/ton
Incremental Control Cost ($/Ton of NO_x Removed)	$181/ton	$7,797/ton	$2,885/ton	$3,894/ton

FIGURE 3-4
First Year Control Cost for NO_x Air Pollution Control Options
Jim Bridger 1



Preliminary BART Selection. PacifiCorp selects LNBs with OFA as BART for Jim Bridger 1 based on its significant reduction in NO_x emissions, reasonable control cost, and no additional power requirements or environmental impacts. This scenario does not meet the EPA presumptive limit of 0.15 lb per MMBtu for sub-bituminous coal, but it does meet an emission rate that falls between the bituminous coal presumptive limit of 0.28 lb per MMBtu and the 0.15 lb per MMBtu limit for sub-bituminous coal, which, as discussed in the section on coal quality, is appropriate for this unit.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

3.2.2 BART SO_2 Analysis

Sulfur dioxide forms in the boiler during the combustion process, and is primarily dependent on coal sulfur content. The BART analysis for SO_2 emissions on Jim Bridger 1 is described below.

Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources were reviewed, in an effort to identify potentially applicable emission control technologies for SO_2 at Jim Bridger 1; this included control technologies identified as BACT or LAER by permitting agencies across the United States.

The following potential SO_2 control technology options were considered:

- Optimize current operation of existing wet sodium FGD system
- Upgrade wet sodium FGD system to meet SO_2 emission rate of 0.10 lb per MMBtu
- New dry FGD system

Step 2: Eliminate Technically Infeasible Options

Technical feasibility will primarily be based on the regulatory presumptive limit (used as a guideline) of 95 percent reduction in SO_2 emissions, or 0.15 lb per MMBtu. Based on the coal that Jim Bridger 1 currently burns, the unit would be required to achieve an 87.5 percent SO_2 removal efficiency to meet the presumptive limit of 0.15 lb per MMBtu.

Table 3-4 summarizes the control technology options evaluated in this BART analysis, along with projected SO_2 emission rates. Only one technology option can meet the applicable presumptive BART limit of 0.15 lb per MMBtu.

TABLE 3-4
SO_2 Control Technology Emission Rates
Jim Bridger 1

Technology	Projected Emission Rate (pounds per million British thermal units)
Presumptive Best Available Retrofit Technology (BART) Limit	0.15
Upgrade Existing Wet Sodium System	0.10
Optimize Existing Wet Sodium System	0.20
New Dry Flue Gas Desulfurization System	0.21

Wet Sodium FGD System. Wet sodium FGD systems operate by treating the flue gas in large scrubber vessels with a soda ash solution. The scrubber mixes the flue gas and alkaline reagent using a series of spray nozzles to distribute the reagent across the scrubber vessel. The sodium in the reagent reacts with the SO_2 in the flue gas to form sodium sulfite and sodium bisulfite, which are removed from the scrubber and disposed.

The wet sodium FGD system at Jim Bridger 1 currently achieves approximately 78 percent SO_2 removal to achieve an SO_2 outlet emission rate of 0.27 lb per MMBtu. Optimizing the existing wet FGD system is projected to achieve an SO_2 outlet emission rate of 0.20 lb per MMBtu (83.3 percent SO_2 removal). Optimization would be accomplished by partially closing the bypass damper to reduce the routine bypass flue gas flow used to reheat the treated flue gas from the scrubber, relocating the opacity monitor, and modifying the system to minimize scaling problems.

Upgrading the wet FGD system would achieve an SO_2 outlet emission rate of 0.10 lb per MMBtu (91.7 percent SO_2 removal). Upgrading the system would involve closing the bypass damper to eliminate the routine bypass flue gas flow used to reheat the treated flue gas from the scrubber, relocating the opacity monitor, adding new fans, adding a stack liner and drains for wet operation, and using a refined soda ash reagent. It is considered to be technically infeasible for the present wet FGD system to achieve a 95 percent SO_2 removal (0.06 lb per MMBtu) on a continuous basis since this high level of removal must be incorporated into the original design of the scrubber.

Optimizing the existing wet sodium scrubbing FGD system is projected to achieve an outlet emission rate of 0.20 lb per MMBtu, which would not meet the presumptive limit of 0.15 lb per MMBtu of SO_2. Therefore, this option is eliminated as technically infeasible for this analysis. An upgraded wet sodium scrubbing FGD system is projected to achieve an outlet emission rate of 0.10 lb per MMBtu (91.7 percent SO_2 removal), which would meet the presumptive limit of 0.15 lb per MMBtu of SO_2 for Jim Bridger 1.

New Dry FGD System. The lime spray dryer typically injects lime slurry in the top of the absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form dry calcium sulfate particles. At Jim Bridger 1 this dry particulate matter would be captured downstream in the existing ESP, along with the fly ash. A lime spray dryer system typically produces a dry waste product suitable for landfill disposal.

The dry FGD system with the existing ESP is projected to achieve 82.5 percent SO_2 removal at Jim Bridger 1. This would result in a controlled SO_2 emission rate of 0.21 lb per MMBtu, based on an uncontrolled SO_2 emission rate of 1.20 lb per MMBtu. Therefore, this option cannot meet the presumptive limit of 0.15 lb per MMBtu of SO_2, and is eliminated from further analysis.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. One such benchmark is the presumptive BART emission limit because Jim Bridger 1 is required to meet this limit. As indicated previously, the presumptive limit for SO_2 on a BART-eligible coal burning unit is 95 percent removal, or 0.15 lb per MMBtu.

The projected emission rate for an upgraded wet sodium FGD system for Jim Bridger 1 would be 0.10 lb per MMBtu. This option would meet the presumptive SO_2 limit of 0.15 lb per MMBtu.

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Upgrading the existing wet sodium FGD system would require an additional 530 kW of power.

Environmental Impacts. There will be incremental additions to scrubber waste disposal and makeup water requirements, and a reduction of the stack gas temperature from 140°F to 120°F due to elimination of reheating by the bypassed flue gas.

Economic Impacts. A summary of the costs and amount of SO_2 removed for the upgraded wet sodium FGD system is provided in Table 3-5. The complete economic analysis is contained in Appendix A.

Preliminary BART Selection. CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for Jim Bridger 1, based on significant reduction in SO_2 emissions (meeting presumptive limit of 0.15 lb per MMBtu), reasonable control costs, and the advantages of minimal additional power requirements and environmental impacts.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

TABLE 3-5
SO_2 Control Cost Comparison (Incremental to Existing FGD System)
Jim Bridger 1

Factor	Upgraded Wet FGD
Total Installed Capital Costs	$13.0 million
Total First Year Fixed and Variable Operation and Maintenance Costs	$1.3 million
Total First Year Annualized Cost	$2.5 million
Additional Power Consumption (megawatts)	0.5
Additional Annual Power Usage (1,000 megawatt-hours per year)	4.2
Incremental Sulfur Dioxide (SO_2) Design Control Efficiency	62.5% (91.7% based on Uncontrolled SO_2)
Incremental Tons SO_2 Removed per Year	3,950
First Year Average Control Cost (dollars per ton [$/Ton] of SO_2 Removed)	632
Incremental Control Cost ($/Ton of SO_2 Removed)	632

3.2.3 BART PM_{10} Analysis

Jim Bridger 1 is currently equipped with an ESP. Electrostatic precipitators remove particulate matter (PM) from the flue gas stream by charging fly ash particles with a very high direct current voltage, and attracting these charged particles to grounded collection plates. A layer of collected PM forms on the collecting plates and is removed by periodically rapping the plates. The collected ash particles drop into hoppers below the precipitator and are removed periodically by the fly ash-handling system. Historically, the ESP at Jim Bridger 1 has controlled PM_{10} emissions to levels below 0.045 lb per MMBtu.

The BART analysis for PM_{10} emissions at Jim Bridger 1 is described below. For the modeling analysis in Section 4, PM_{10} was used as an indicator for PM, and PM_{10} includes particulate matter less than 2.5 micrometers in aerodynamic diameter ($PM_{2.5}$) as a subset.

Step 1: Identify All Available Retrofit Control Technologies

Two retrofit control technologies have been identified for additional PM control:

- Flue gas conditioning
- Polishing fabric filter (baghouse) downstream of existing ESP

Another available control technology is replacing the existing ESP with a new fabric filter. However, because the environmental benefits that would be achieved by a replacement fabric filter are also achieved by installing a polishing fabric filter downstream of the existing ESP at lower costs, installation of a full-size fabric filter was not considered in the analysis.

Step 2: Eliminate Technically Infeasible Options

Flue Gas Conditioning. If the fly ash from coal has high resistivity, such as fly ash from sub-bituminous coal, the ash is not collected effectively in an ESP. This is because the high resistivity makes the particles less willing to accept an electrical charge. Adding flue gas conditioning (FGC), which is typically accomplished by injection of sulfur trioxide (SO_3), will lower the resistivity of the particles so that they will accept more charge and allow the ESP to collect the ash more effectively. Flue gas conditioning systems can account for large improvements in collection efficiency for small ESPs. Therefore, the technology is retained as technically feasible.

Polishing Fabric Filter. A polishing fabric filter could be added downstream of the existing ESP at Jim Bridger 1. One such technology is licensed by the Electric Power Research Institute, and referred to as a COHPAC (Compact Hybrid Particulate Collector). The COHPAC collects the ash that is not collected by the ESP, thus acting as a polishing device. The ESP needs to be kept in service for the COHPAC fabric filter to operate effectively.

The COHPAC fabric filter is about one-half to two-thirds the size of a full-size fabric filter, because the COHPAC has a higher air-to-cloth ratio (7 to 9:1), compared to a full-size pulse jet fabric filter (3.5 to 4:1). This technology is retained as technically feasible.

Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The existing ESP at Jim Bridger 1 is achieving a controlled PM emission rate of 0.045 lb per MMBtu. Utilizing flue conditioning upstream of the existing ESP is projected to reduce PM emissions to approximately 0.030 lb per MMBtu. Adding a COHPAC fabric filter downstream of the existing ESP is projected to reduce PM emissions to approximately 0.015 lb per MMBtu.

The PM_{10} control technology emission rates are summarized in Table 3-6.

TABLE 3-6
PM_{10} Control Technology Emission Rates
Jim Bridger 1

Control Technology	Short-Term Expected PM_{10}[(a)] Emission Rate (pounds per million British thermal units)
Flue Gas Conditioning	0.030
Polishing Fabric Filter	0.015

NOTES:
[(a)] PM_{10} refers to particulate matter less than 10 micrometers in aerodynamic diameter

Step 4: Evaluate Impacts and Document the Results

This step involves the consideration of energy, environmental, and economic impacts associated with each control technology. The remaining useful life of the plant is also considered during the evaluation.

Energy Impacts. Energy is required to overcome the additional pressure drop from the COHPAC fabric filter and associated ductwork. Therefore, a COHPAC retrofit will require an internal diameter fan upgrade and upgrade of the auxiliary power supply system.

A COHPAC fabric filter at Jim Bridger 1 would require approximately 3.4 MW of power, equating to an annual power usage of approximately 26.7 million kW hours.

There is only a small power requirement of approximately 50 kW associated with flue gas conditioning.

Environmental Impacts. There are no negative environmental impacts from the addition of either a COHPAC polishing fabric filter or FGC system.

Economic Impacts. A summary of the costs and PM removed for COHPAC and FGC is recorded in Table 3-7, and the first-year control costs for FGC and fabric filters are shown in Figure 3-5. The complete economic analysis is contained in Appendix A.

TABLE 3-7
PM_{10} Control Cost Comparison (Incremental to Existing ESP)
Jim Bridger 1

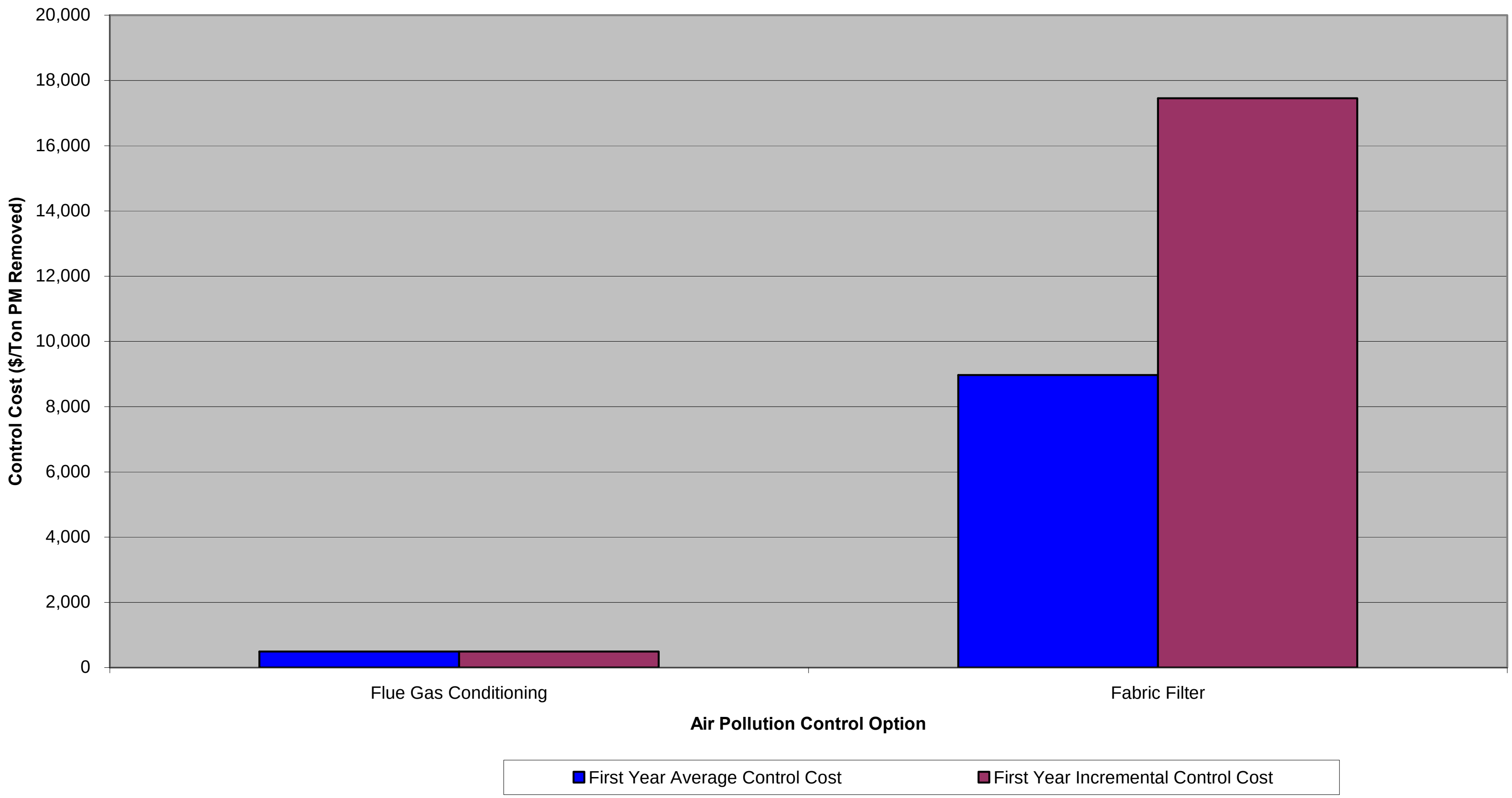
Factor	Flue Gas Conditioning	Polishing Fabric Filter
Total Installed Capital Costs	$0	$48.4 million
Total First Year Fixed and Variable Operation and Maintenance Costs	$0.2 million	$1.8 million
Total First Year Annualized Cost	$0.2 million	$6.4 million
Additional Power Consumption (megawatts)	0.05	3.4
Additional Annual Power Usage (1,000 megawatt-hours per year)	0.4	26.7
Incremental Particulate Matter (PM) Design Control Efficiency	33.3%	66.7%
Incremental Tons PM Removed per Year	355	710
First Year Average Control Cost (dollars per ton [$/Ton] of PM Removed)	495	8,973
Incremental Control Cost ($/Ton of PM Removed)	495	17,452

Preliminary BART Selection. PacifiCorp selects FGC as BART for Jim Bridger 1 based on its significant reduction in PM emissions, reasonable control cost, minimum additional power requirements, and no environmental impacts.

Step 5: Evaluate Visibility Impacts

Please see Section 4, BART Modeling Analysis.

FIGURE 3-5
First Year Control Cost for PM Air Pollution Control Options
Jim Bridger 1



4.0 BART Modeling Analysis

4.1 Model Selection

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from Jim Bridger 1 at nearby Class I areas. The Class I areas potentially affected are located more than 50 kilometers, but less than 300 kilometers, from the Jim Bridger 1 facility. The Class I areas include the following wilderness areas (WA):

- Bridger WA
- Fitzpatrick WA
- Mt. Zirkel WA

The CALPUFF modeling system includes the CALMET meteorological model, a Gaussian puff dispersion model (CALPUFF) with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode. Version numbers of the various programs in the CALPUFF system used by CH2M HILL were as follows:

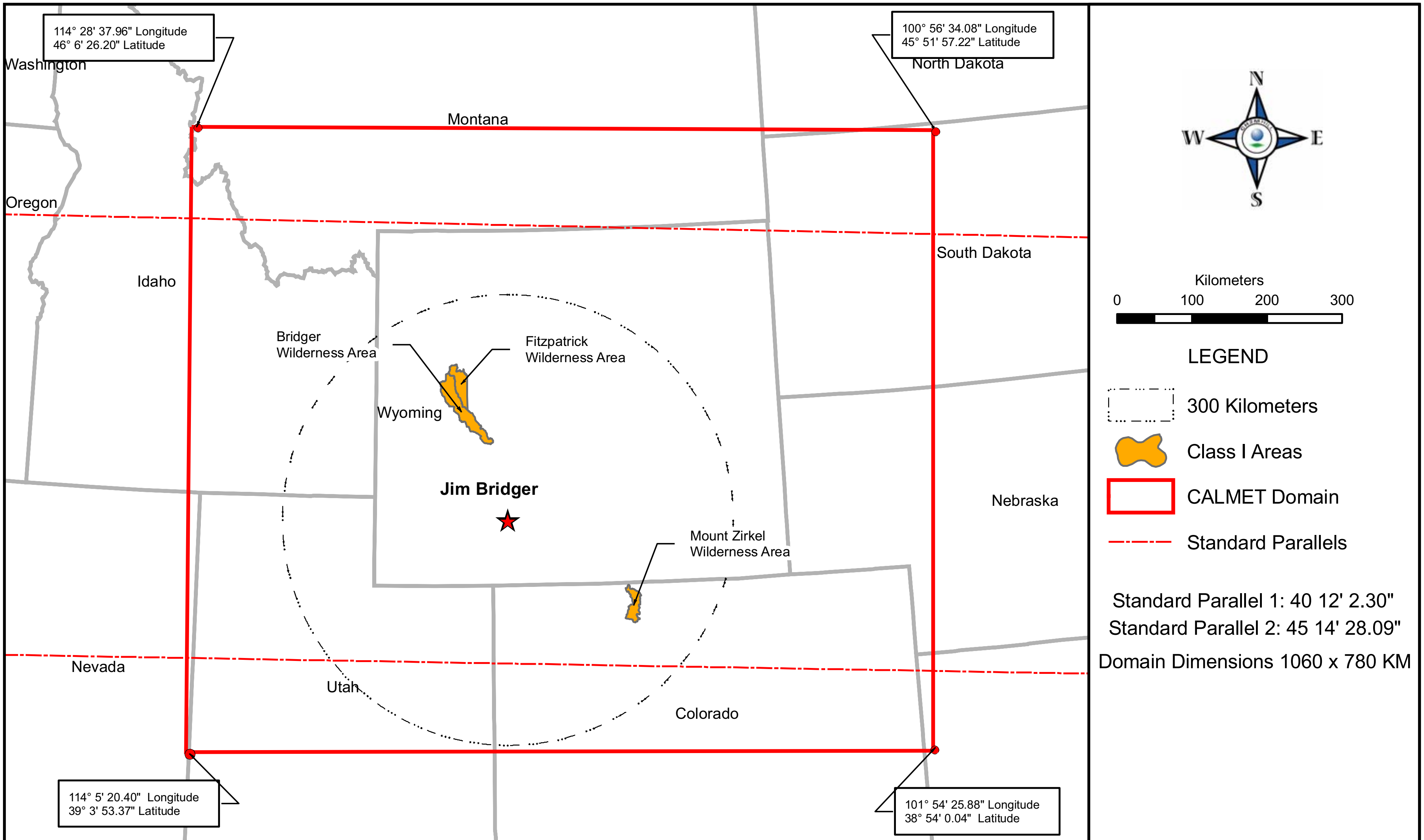
- CALMET Version 5.53a, Level 040716
- CALPUFF Version 5.711a, Level 040716
- CALPOST Version 5.51, Level 030709

4.2 CALMET Methodology

4.2.1 Dimensions of the Modeling Domain

CH2M HILL used the CALMET model to generate a three-dimensional wind field and other meteorological parameters suitable for use by the CALPUFF model. A modeling domain was established to encompass the Jim Bridger 1 facility and allow for a 50-kilometer buffer around the Class I areas that were within 300 kilometers of the facility. Grid resolution was 4 kilometer. Figure 4-1 shows the extent of the modeling domain. Except when specifically instructed otherwise by the Wyoming Department of Environmental Quality-Air Quality Division (WDEQ-AQD), CH2M HILL followed the methodology spelled out in the WDEQ-AQD BART Modeling Protocol, a copy of which is included in this report as Appendix B.

CH2M HILL used the Lambert Conformal Conic map projection for the analysis due to the large extent of the domain. The latitude of the projection origin and the longitude of the central meridian were chosen at the approximate center of the domain. Standard parallels were drawn to represent one-sixth and five-sixths of the north-south extent of the domain to minimize distortion in the north-south direction.



PACIFICORP

Figure 4-1
Jim Bridger Source-Specific
Class I Areas to be Addressed

CH2MHILL

SLC \\SLCDB\GIS\PROJECTS\HUNTER\MAPFILES\JIM_BRIDGER_CLASSI.MXD 11/9/2006 MSLAYDEN

The default technical options listed in TRC Companies, Inc.'s (TRC) current example CALMET.inp file were used for CALMET. Vertical resolution of the wind field included ten layers, with vertical face heights as follows (in meters):

- 0, 20, 40, 100, 140, 320, 580, 1020, 1480, 2220, 3500

Other user-specified model options were set to values established by WDEQ-AQD, which appear in Table 3 of Appendix B. Table 4-1 lists the key user-specified options used for this analysis.

TABLE 4-1
User-specified CALMET Options
Jim Bridger 1

CALMET Input Parameter	Value
CALMET Input Group 2	
Map projection (PMAP)	Lambert Conformal
Grid spacing (DGRIDKM)	4
Number vertical layers (NZ)	10
Top of lowest layer (m)	20
Top of highest layer (m)	3500
CALMET Input Group 4	
Observation mode (NOOBS)	0
CALMET Input Group 5	
Prog. Wind data (IPROG)	14
(RMAX1)	30
(RMAX2)	50
Terrain influence (TERRAD)	15
(R1)	5
(R2)	25
CALMET Input Group 6	
Max mixing ht (ZIMAX)	3500

4.2.2 CALMET Input Data

CH2M HILL ran the CALMET model to produce 3 years of analysis: 2001, 2002, and 2003. WDEQ-AQD provided 12-kilometer resolution Mesoscale Meteorological Model, Version 5 (MM5) meteorological data fields that covered the entire modeling domain for each study year.

These three data sets were chosen because they are current and have been evaluated for quality. The MM5 data were used as input to CALMET as the "initial guess" wind field. The initial guess wind field was adjusted by CALMET for local terrain and land use effects to generate a

Step 1 wind field, and further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001 through 2003 were obtained from the National Climatic Data Center. CH2M HILL processed the data from the National Weather Service's Automated Surface Observing System network for all stations that are in the domain. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC Web site was used to convert the DATSAV3 files to CD-144 format for input into the SMERGE preprocessor and CALMET.

Land use and terrain data were obtained from the U.S. Geological Survey (USGS). Land use data were obtained in Composite Theme Grid format from the USGS, and the Level I USGS land use categories were mapped into the 14 primary CALMET land use categories. Surface properties such as albedo, Bowen ratio, roughness length, and leaf area index were computed from the land use values. Terrain data were taken from USGS 1-degree Digital Elevation Model data, which primarily derive from USGS 1:250,000 scale topographic maps. Missing land use data were filled with values that were assumed appropriate for the missing area.

Precipitation data were obtained from the National Climatic Data Center. All available data in fixed-length, TD-3240 format were obtained for the modeling domain. The list of available stations that have collected complete data varies by year, but CH2M HILL processed all available stations/data within the domain for each year. Precipitation data were prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Upper-air data were prepared for the CALMET model with the READ62 preprocessor for the following stations:

- Denver, Colorado
- Salt Lake City, Utah
- Riverton, Wyoming
- Rapid City, South Dakota

Figure 4-2 shows the locations of surface and upper air stations within the MM5 modeling domain.

4.2.3 Validation of CALMET Wind Field

CH2M HILL used the CALDESK data display and analysis system (v2.97, Enviromodeling Ltd.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. The CALDESK displays were compared to observed weather conditions, as depicted in surface and upper-air weather maps (National Oceanic and Atmospheric Administration, 2006).

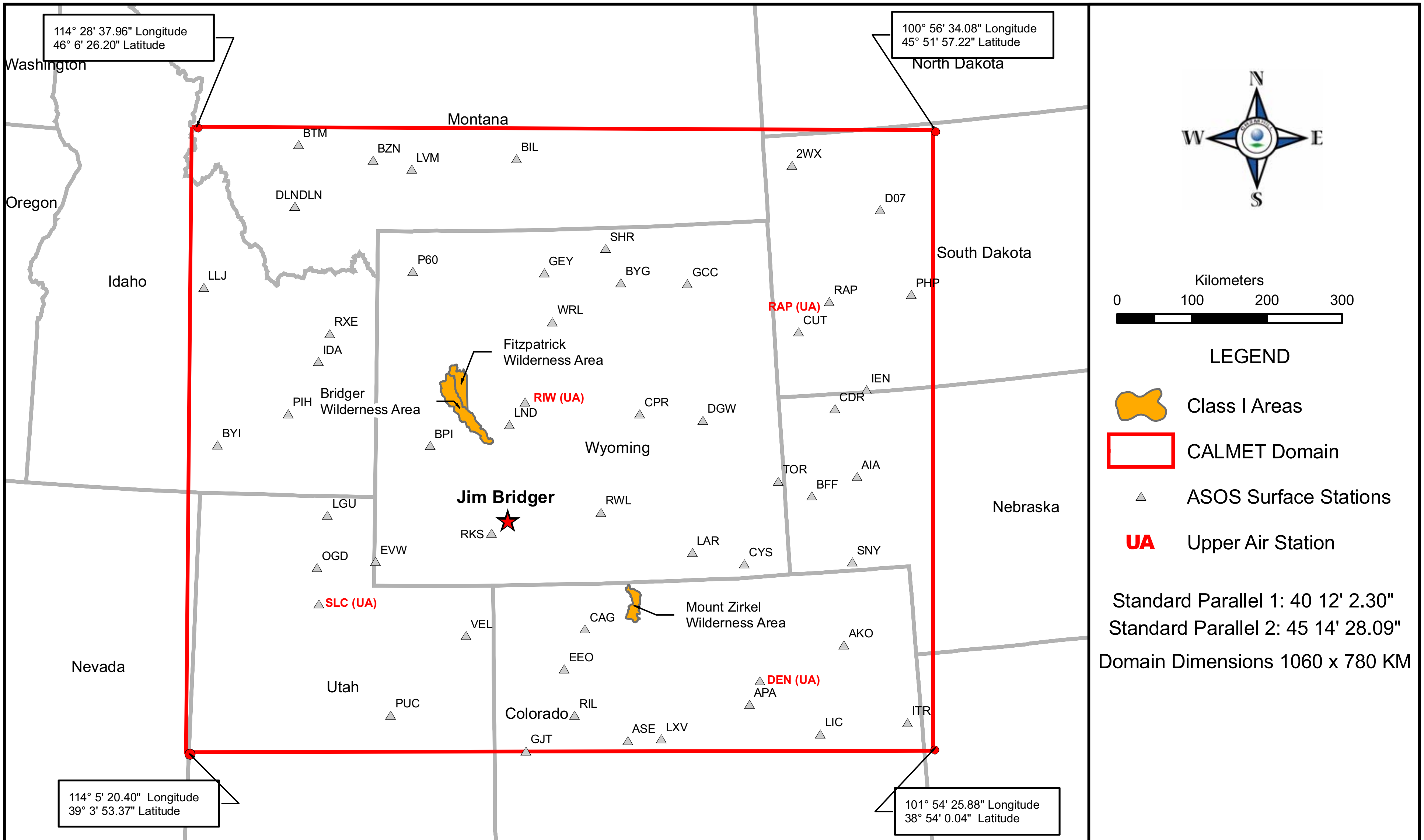


Figure 4-2
Surface and Upper Air Stations Used in the Jim Bridger BART Analysis

PACIFICORP

CH2MHILL

SLC \\SLCDB\GIS\PROJECTS\HUNTER\MAPFILES\JIM_BRIDGER_ASOS.MXD 11/9/2006 MSLAYDEN

4.3 CALPUFF Modeling Approach

For the BART control technology visibility improvement modeling, CH2M HILL followed WDEQ-AQD guidance provided (WDEQ-AQD, 2006).

CH2M HILL drove the CALPUFF model with the meteorological output from CALMET over the modeling domain described earlier. The CALPUFF model was used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios for Jim Bridger 1.

4.3.1 Background Ozone and Ammonia

Hourly values of background ozone concentrations were used by CALPUFF for the calculation of SO_2 and NO_x transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL obtained hourly ozone data from the following stations located within the modeling domain for 2001, 2002, and 2003:

- Rocky Mountain National Park, Colorado
- Craters of the Moon National Park, Idaho
- Highland, Utah
- Thunder Basin National Grasslands, Wyoming
- Yellowstone National Park, Wyoming
- Centennial, Wyoming
- Pinedale, Wyoming

For periods of missing hourly ozone data, the chemical transformation relied on a monthly default value of 44 parts per billion. Background ammonia was set to 2 parts per billion. Both of these background values were taken from the guidance document (WDEQ-AQD, 2006).

4.3.2 Stack Parameters

The stack parameters used for the baseline modeling reflect those that are in place under the current permit for Jim Bridger 1. Post-control stack parameters reflect the anticipated changes associated with installation of the control technology alternatives that are being evaluated. The maximum heat input rate of 6,000 MMBtu per hour was used to calculate a maximum emission rate. Measured velocities and stack flow rates were used in the modeling to represent a worst-case situation.

4.3.3 Emission Rates

Pre-control emission rates for Jim Bridger 1 reflect peak 24-hour average emissions that may occur under the source's current permit. The emission rates reflect actual emissions under normal operating conditions, as described by the EPA in the *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule* (40 CFR Part 51).

CH2M HILL used available continuous emission monitoring data to determine peak 24-hour emission rates. Data reflected operations from the most recent 3- to 5-year period, unless a more recent period was more representative. Allowable short-term (24-hour or shorter period) emissions or short-term emission limits were used if continuous emission monitoring data were not available.

Emissions were modeled for the following pollutants:

- SO_2
- NO_x
- Coarse particulate ($PM_{2.5}$<diameter<PM_{10})
- Fine particulate (diameter<$PM_{2.5}$)
- Sulfates

Post-control emission rates reflect the effects of the emissions control scenario under consideration. Modeled pollutants were the same as those listed for the pre-control scenario.

4.3.4 Post-control Scenarios

Four post-control modeling scenarios were developed to cover the range of effectiveness for the combination of the individual NO_x, SO_2, and PM control technologies being evaluated. The selection of each control device was made based on the engineering analyses described in Section 3 for reasonable technologies that would meet or exceed the presumptive BART levels for each pollutant.

- **Scenario 1**: New LNB with OFA modifications, upgraded wet FGD system, and flue gas conditioning for enhanced ESP performance. As indicated previously, this scenario represents CH2M HILL's preliminary BART recommendation.
- **Scenario 2**: New LNB with OFA modifications, upgraded wet FGD system, and new polishing fabric filter
- **Scenario 3**: New LNB with OFA modifications and SCR, upgraded wet FGD system, and flue gas conditioning for enhanced ESP performance.
- **Scenario 4**: New LNB with OFA modifications and SCR, upgraded wet FGD system, and new polishing fabric filter.

The ROFA option and LNB with OFA and SCR option for NO_x control were not included in the modeling scenarios because their control effectiveness is between the LNB with OFA option and the SCR option. Modeling of NO_x, SO_2, and PM controls alone was not performed because any final BART solution will include a combination of control technologies for NO_x, SO_2, and PM.

Table 4-2 presents the stack parameters and emission rates used for the Jim Bridger 1 analysis for baseline and post-control modeling. In accordance with the WDEQ BART modeling protocol, elemental carbon stack emissions and organic aerosol emissions were not modeled.

TABLE 4-2
BART Model Input Data
Jim Bridger 1

	Baseline	Post-control Scenario 1	Post-control Scenario 2	Post-control Scenario 3	Post-control Scenario 4
	Current Operations with Wet Flue Gas Desulfurization (FGD) and Electrostatic Precipitator (ESP)	**Low-NO_x Burner (LNB) with Over-fire Air (OFA), Upgrade Wet FGD, and Flue Gas Conditioning (FGC) for Enhanced ESP Performance**	**LNB with OFA, Upgrade Wet FGD, New Fabric Filter**	**LNB with OFA and Selective Catalytic Reduction (SCR), Upgrade Wet FGD, and FGC for Enhanced ESP Performance**	**LNB with OFA and SCR, Upgrade Wet FGD, New Fabric Filter**
Sulfur Dioxide (SO_2) Stack Emissions pounds per hour (lb/hr)	1,602	600	600	600	600
Nitrogen Oxide (NO_x) Stack Emissions (lb/hr)	2,700	1,440	1,440	420	420
PM_{10} Stack Emissions (lb/hr)	270	180	90.0	180	90.0
Coarse Particulate ($PM_{2.5}$<diameter<PM_{10}) Stack Emissions (lb/hr)[a]	116	77.4	51.3	77.4	51.3
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[b]	154	103	38.7	103	38.7
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	55.2	55.2	55.2	94.8	94.8
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	54.1	54.1	54.1	92.9	92.9
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)				7.02	7.02
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)				5.10	5.10
$(NH_4)HSO_4$ Stack Emissions (lb/hr)				12.2	12.2
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)				10.2	10.2
Total Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	108	108
Stack Conditions					
Stack Height (meters)	152	152	152	152	152
Stack Exit Diameter (meters)	7.32	7.32	7.32	7.32	7.32
Stack Exit Temperature (Kelvin)	333	322	333	333	333
Stack Exit Velocity (meters per second)[c]	25.6	24.7	27.4	27.4	27.4

NOTES:

[a]Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43 percent ESP and 57 percent Baghouse. PM_{10} and $PM_{2.5}$ refer to particulate matter less than 10 and 2.5 micrometers, respectively, in aerodynamic diameter.

[b]Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57 percent ESP and 43 percent Baghouse.

[c]Scenarios 2, 3, and 4 were not remodeled at the lower, correct velocity of 81.24 feet per second due to lack of time and the fact that the conclusions to select Scenario 1 would not have changed.

Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)

4.3.5 Modeling Process

The CALPUFF modeling for the control technology options for Jim Bridger 1 followed this sequence:

- Model pre-control (baseline) emissions
- Model preferred post-control scenario (if applicable)
- Determine degree of visibility improvement
- Model other control scenarios
- Determine degree of visibility improvement
- Factor visibility results into the BART five-step evaluation

4.3.6 Receptor Grids

Discrete receptors for the CALPUFF modeling were placed at uniform receptor spacing along the boundary and in the interior of each area of concern. Class I area receptors were taken from the National Park Service database for Class I area modeling receptors. The TRC COORDS program was used to convert all latitude/longitude coordinates to Lambert Conformal Conic coordinates, including receptors, meteorological stations, and source locations.

4.4 CALPOST

The CALPOST processor was used to determine 24-hour average visibility results with output specified in deciview (dV) units. Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values were used to calculate the delta-dV (Δ dV) change relative to natural background. The following default light extinction coefficients for each pollutant, as shown below, were used:

- Ammonium sulfate 3.0
- Ammonium nitrate 3.0
- PM coarse (PM_{10}) 0.6
- PM fine ($PM_{2.5}$) 1.0
- Organic carbon 4.0
- Elemental carbon 10.0

CALPOST visibility Method 6 was used to determine the visibility impacts. Monthly relative humidity factors [*f* (RH)] were used in the light extinction calculations to account for the hygroscopic characteristics of nitrate and sulfate particles. Table 5 of the Wyoming BART Air Modeling Protocol (Appendix B) lists the monthly *f* (RH) factors for the Class I areas. These values were used for the particular Class I area being modeled.

The natural background conditions as a reference for determining the Δ dV change represented the 20 percent best natural visibility days. The EPA BART guidance document provided dV values for the 10 percent best days for each Class I area, but did not provide individual species concentration data for the 20 percent best background conditions. Species concentrations corresponding to the 20 percent best days were calculated for each Class I area by scaling back the annual average species concentrations given in Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule* (EPA, 2003). A separate scaling factor was derived for each Class I area such that, when multiplied by the Guidance table annual concentrations, the 20 percent best days dV value for that area would be calculated. This procedure was taken from *Protocol for BART-Related Visibility Improvement Modeling Analysis in North Dakota* (North Dakota Department of Health, 2005). However, the Wyoming BART Air Modeling Protocol (see Appendix B) provided natural background concentrations of aerosol components to use in the BART analysis. Table 4-3 lists the annual average species concentrations from the BART protocol.

TABLE 4-3
Average Natural Levels of Aerosol Components
Jim Bridger 1

Aerosol Component	Average Natural Concentration (micrograms per cubic meter) for Mt. Zirkel Class I Wilderness Area	Average Natural Concentration (micrograms per cubic meter) for Fitzpatrick and Bridger Class I Wilderness Areas
Ammonium Sulfate	0.046	0.045
Ammonium Nitrate	0.038	0.038
Organic Carbon	0.179	0.178
Elemental Carbon	0.008	0.008
Soil	0.190	0.189
Coarse Mass	1.141	1.136

NOTES:
Data in this table was taken from Table 6 of the Wyoming BART Air Modeling Protocol

4.5 Presentation of Modeling Results

This section presents the results of the CALPUFF visibility improvement modeling analysis for Jim Bridger 1.

4.5.1 Visibility Changes for Baseline vs. Preferred Scenario

CH2M HILL modeled Jim Bridger 1 for the baseline and the post-control scenarios. The post-control scenario included emission rates for SO_2, NO_x, and PM_{10} that would be achieved if BART state-of-the-art technology were installed on Unit 1.

Baseline (and post-control) 98^{th} percentile results were greater than 0.5 ΔdV for the Bridger, WA, Fitzpatrick, WA, and Mt. Zirkel, WA. The 98^{th} percentile results for each Class I area are presented in Table 4-4.

TABLE 4-4
Costs and Visibility Modeling Results for Baseline vs. Post-control Scenarios at Class I Areas
Jim Bridger 1

Scenario	Total First Year Annualized Cost	Class I Area	Modeling Results: Highest Delta Deciview (ΔdV)	Modeling Results: 98th Percentile (ΔdV)	Modeling Results: Number (No.) of Days Above 0.5 dV	Cost per dV Reduction	Cost per Reduction in No. of Days Above 0.5 dV	Incremental Cost per dV Reduction	Incremental Cost per Reduction in No. of Days Above 0.5 dV
2001									
Baseline: Current Operation with Wet Flue Gas Desulfurization (FGD), Electrostatic Precipitator (ESP)		Bridger WA	2.504	0.746	14	--	--		
		Fitzpatrick WA	2.177	0.418	7	--	--		
		Mt. Zirkel WA	1.966	1.236	27	--	--		
Scenario 1: Low-NO_x Burners (LNBs) with Over-fire Air (OFA), upgrade wet FGD, Flue Gas Conditioning (FGC) for enhanced ESP performance	$3,392,440	Bridger WA	1.364	0.384	7	$9,371,381	$484,634		
	$3,392,440	Fitzpatrick WA	1.369	0.221	3	$17,220,508	$848,110		
	$3,392,440	Mt. Zirkel WA	1.167	0.736	16	$6,784,880	$308,404		
Scenario 2: LNB with OFA, upgrade wet FGD, polishing fabric filter	$9,759,059	Bridger WA	1.393	0.372	6	$26,093,741	$1,219,882	$530,551,575	$6,366,619
	$9,759,059	Fitzpatrick WA	1.171	0.211	3	$47,145,212	$2,439,765	$636,661,890	n/a
	$9,759,059	Mt. Zirkel WA	1.099	0.676	15	$17,426,891	$813,255	$106,110,315	$6,366,619
Scenario 3: LNB with OFA and Selective Catalytic Reduction (SCR), upgrade wet FGD, FGC for enhanced ESP performance	$18,093,916	Bridger WA	0.876	0.279	3	$38,745,002	$1,644,901	$89,622,116	$2,778,286
	$18,093,916	Fitzpatrick WA	0.675	0.127	1	$62,178,405	$3,015,653	$99,224,485	$4,167,428
	$18,093,916	Mt. Zirkel WA	0.756	0.453	5	$23,108,449	$822,451	$37,376,039	$833,486
Scenario 4: LNB with OFA and SCR, upgrade wet FGD, polishing fabric filter	$24,460,535	Bridger WA	0.838	0.268	3	$51,172,667	$2,223,685	$578,783,537	n/a
	$24,460,535	Fitzpatrick WA	0.654	0.125	1	n/a	$4,076,756	$3,183,309,451	n/a
	$24,460,535	Mt. Zirkel WA	0.729	0.436	2	$30,575,668	$978,421	$374,506,994	$2,122,206
2002									
Baseline: Current Operation with Wet FGD, ESP		Bridger WA	4.104	1.448	26	--	--		
		Fitzpatrick WA	1.894	0.704	11	--	--		
		Mt. Zirkel WA	2.801	1.496	34	--	--		
Scenario 1: LNB with OFA, upgrade wet FGD, FGC for enhanced ESP performance	$3,392,440	Bridger WA	2.454	0.845	14	$5,625,937	$282,703		
	$3,392,440	Fitzpatrick WA	1.078	0.378	5	$10,406,258	$565,407		
	$3,392,440	Mt. Zirkel WA	1.544	0.816	13	$4,988,882	$161,545		
Scenario 2: LNB with OFA, upgrade wet FGD, polishing fabric filter	$9,759,059	Bridger WA	2.326	0.780	13	$14,609,370	$750,697	$97,947,983	$6,366,619
	$9,759,059	Fitzpatrick WA	1.002	0.347	6	$27,336,300	$1,951,812	$205,374,803	n/a
	$9,759,059	Mt. Zirkel WA	1.496	0.777	13	$13,573,100	$464,717	$163,246,639	n/a
Scenario 3: LNB with OFA and SCR, upgrade wet FGD, FGC for enhanced ESP performance	$18,093,916	Bridger WA	1.321	0.519	9	$19,476,766	$1,064,348	$31,934,317	$2,083,714
	$18,093,916	Fitzpatrick WA	0.549	0.226	1	$37,853,380	$1,809,392	$68,883,114	$1,666,971
	$18,093,916	Mt. Zirkel WA	0.887	0.473	4	$17,687,112	$603,131	$27,417,292	$926,095
Scenario 4: LNB with OFA and SCR, upgrade wet FGD, polishing fabric filter	$24,460,535	Bridger WA	1.295	0.500	8	$25,802,252	$1,358,919	$335,085,205	$6,366,619
	$24,460,535	Fitzpatrick WA	0.539	0.223	1	$50,853,502	$2,446,053	$2,122,206,301	n/a
	$24,460,535	Mt. Zirkel WA	0.869	0.465	4	$23,725,058	$815,351	$795,827,363	n/a

TABLE 4-4
Costs and Visibility Modeling Results for Baseline vs. Post-control Scenarios at Class I Areas
Jim Bridger 1

Scenario	Total First Year Annualized Cost	Class I Area	Modeling Results: Highest Delta Deciview (ΔdV)	Modeling Results: 98th Percentile (ΔdV)	Modeling Results: Number (No.) of Days Above 0.5 dV	Cost per dV Reduction	Cost per Reduction in No. of Days Above 0.5 dV	Incremental Cost per dV Reduction	Incremental Cost per Reduction in No. of Days Above 0.5 dV
2003									
Baseline: Current Operation with wet FGD, ESP		Bridger WA	1.706	0.761	16	--	--		
		Fitzpatrick WA	1.933	0.373	7	--	--		
		Mt. Zirkel WA	1.958	1.232	35	--	--		
Scenario 1: LNB with OFA, upgrade wet FGD, FGC for enhanced ESP performance	$3,392,440	Bridger WA	0.997	0.411	5	$9,692,686	$308,404		
	$3,392,440	Fitzpatrick WA	1.112	0.199	2	$19,496,782	$678,488		
	$3,392,440	Mt. Zirkel WA	1.042	0.736	16	$17,854,948	$178,549		
Scenario 2: LNB with OFA, upgrade wet FGD, polishing fabric filter	$9,759,059	Bridger WA	0.985	0.408	5	$27,646,059	$887,187	$2,122,206,301	n/a
	$9,759,059	Fitzpatrick WA	1.087	0.186	2	$52,187,481	$1,951,812	$489,739,916	n/a
	$9,759,059	Mt. Zirkel WA	1.057	0.686	15	$17,873,734	$487,953	$127,332,378	$6,366,619
Scenario 3: LNB with OFA and SCR, upgrade wet FGD, FGC for enhanced ESP performance	$18,093,916	Bridger WA	0.853	0.258	3	$35,971,999	$1,391,840	$55,565,712	$4,167,428
	$18,093,916	Fitzpatrick WA	0.681	0.118	2	$70,956,532	$3,618,783	$122,571,423	n/a
	$18,093,916	Mt. Zirkel WA	0.669	0.433	5	$22,645,702	$603,131	$32,944,098	$833,486
Scenario 4: LNB with OFA and SCR, upgrade wet FGD, polishing fabric filter	$24,460,535	Bridger WA	0.810	0.248	3	$47,681,354	$1,881,580	$636,661,890	n/a
	$24,460,535	Fitzpatrick WA	0.662	0.114	2	$94,442,219	$4,892,107	$1,591,654,726	n/a
	$24,460,535	Mt. Zirkel WA	0.636	0.422	5	$30,198,191	$815,351	$578,783,537	n/a
3-year Averages									
Baseline: Current Operation with wet FGD, ESP		Bridger WA		0.985	18.7				
		Fitzpatrick WA		0.498	8.3				
		Mt. Zirkel WA		1.321	32.0				
Scenario 1: LNB with OFA, upgrade wet FGD, FGC for enhanced ESP performance	$3,392,440	Bridger WA		0.547	8.7	$7,739,407	$339,244		
	$3,392,440	Fitzpatrick WA		0.266	3.3	$14,601,607	$678,488		
	$3,392,440	Mt. Zirkel WA		0.763	15.0	$6,072,387	$199,555		
Scenario 2: LNB with OFA, upgrade wet FGD, polishing fabric filter	$9,759,059	Bridger WA		0.520	8.0	$20,987,224	$914,912	$238,748,209	$9,549,928
	$9,759,059	Fitzpatrick WA		0.248	3.7	$38,984,257	$2,091,227	$353,701,050	n/a
	$9,759,059	Mt. Zirkel WA		0.713	14.3	$16,042,289	$552,400	$128,186,958	$9,549,928
Scenario 3: LNB with OFA and SCR, upgrade wet FGD, FGC for enhanced ESP performance	$18,093,916	Bridger WA		0.352	5.0	$28,584,385	$1,323,945	$49,612,243	$2,778,286
	$18,093,916	Fitzpatrick WA		0.157	1.3	$53,009,519	$2,584,845	$91,591,833	$3,572,081
	$18,093,916	Mt. Zirkel WA		0.453	4.7	$20,837,523	$661,973	$32,057,141	$862,227
Scenario 4: LNB with OFA and SCR, upgrade wet FGD, polishing fabric filter	$24,460,535	Bridger WA		0.339	4.7	$37,845,077	$1,747,181	$477,496,418	$19,099,857
	$24,460,535	Fitzpatrick WA		0.154	1.3	$71,037,371	$3,494,362	$2,122,206,301	n/a
	$24,460,535	Mt. Zirkel WA		0.441	3.7	$27,785,537	$863,313	$530,551,575	$6,366,619

NOTES:
Sample Calculations: Cost per dV Reduction for Scenario 1 for 2001: = $3,392,440 / (0.7964 - 0.427) = $9,193,605
Sample Calculations: Cost per Reduction in No. of Days Exceeding 0.5 dV for 2001: = $3,392,440 / (20 - 7) = $260,957

5.0 Preliminary Assessment and Recommendations

As a result of the completed technical and economic evaluations, and consideration of the modeling analysis for Jim Bridger 1, the preliminary recommended BART controls for NO_x, SO_2, and PM are as follows:

- New LNBs and modifications to the OFA system for NO_x control
- Upgrade wet sodium FGD for SO_2 control
- Add flue gas conditioning upstream of existing ESPs for PM control

The above recommendations were identified as Scenario 1 for the modeling analysis described in Section 4. Visibility improvements for all emission control scenarios were analyzed, and the results are compared below, utilizing a least-cost envelope, as outlined in the *New Source Review Workshop Manual* (EPA, 1990, hereafter referred to as the NSR Manual).

5.1 Least-cost Envelope Analysis

The total annualized cost, cost per dV reduction, and cost per reduction in number of days above 0.5 dV for the scenarios modeled in Section 4 to determine the impact on the three Class I areas are listed in Tables 5-1 through 5-3. A comparison of the incremental costs between relevant scenarios is shown in Tables 5-4 through 5-6. The total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile ΔdV reduction are shown in Figures 5-1 to 5-6 for the three Class I areas.

5.1.1 Analysis Methodology

On page B-41 of the NSR Manual, EPA states that "Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for a total emissions reductions for all control alternatives identified in the BACT analysis..."

An analysis of incremental cost effectiveness has been conducted. This analysis was performed in the following way. First, the control option scenarios are ranked in ascending order of annualized total costs as shown in Tables 5-1 through 5-3. The incremental cost-effectiveness data, expressed per day and per dV, represents a comparison of the different scenarios, and is summarized in Tables 5-4 through 5-6 for each of the three wilderness areas. Then the most reasonable smooth curve of least-cost control option scenarios is plotted for each analysis. Figures 5-1 through 5-6 present the two analyses (cost per dV reduction and cost per reduction in number of days above 0.5 dV) for each of the three Class I areas impacted by the operation of Jim Bridger 1.

In Figure 5-1, the four scenarios are compared as a graph of total annualized cost versus number of days above 0.5 dV. EPA states that "In calculating incremental costs, the analysis should only be conducted for control options that are dominant among all possible options." In Figure 5-1, the dominant set of control options, Scenarios 1, 3, and 4, represent the least-cost envelope depicted by the curvilinear line connecting them. Scenario 2 is an inferior option and should not be considered in the derivation of incremental cost effectiveness. Scenario 2 represents an inferior control, because Scenario 1 provides approximately the same amount of visibility impact reduction for less cost than Scenario 2. The incremental cost effectiveness is determined by the difference in total annual costs between two contiguous scenarios divided by the difference in emissions reduction.

TABLE 5-1
Control Scenario Results for the Bridger Class I Wilderness Area
Jim Bridger 1

Scenario	Controls	98^{th} Percentile deciview (dV) Reduction	Average Number of Days Above 0.5 dV (Days)	Total Annualized Cost (Million$)	Cost per dV Reduction (Million$/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV (Million$/Day Reduced)
Base	Current Operation with Wet Flue Gas Desulfurization (FGD), and Electrostatic Precipitator (ESP)	0.00	0.0	$0.0	$0.0	$0.0
1	Low-NO_x Burners (LNBs) with Over-fire Air (OFA), Upgrade Wet FGD, and Flue Gas Conditioning (FGC) for Enhanced ESP Performance	0.44	10.0	$3.4	$7.7	$0.3
2	LNB with OFA, Upgrade Wet FGD, New Fabric Filter	0.47	10.7	$9.8	$21.0	$0.9
3	LNB with OFA and Selective Catalytic Reduction (SCR), Upgrade Wet FGD, and FGC for Enhanced ESP Performance	0.63	13.7	$18.1	$28.6	$1.3
4	LNB with OFA and SCR, Upgrade Wet FGD, New Fabric Filter	0.65	14.0	$24.5	$37.8	$1.7

TABLE 5-2
Control Scenario Results for the Fitzpatrick Class I Wilderness Area
Jim Bridger 1

Scenario	Controls	98th Percentile deciview (dV) Reduction	Average Number of Days Above 0.5 dV (Days)	Total Annualized Cost (Million$)	Cost per dV Reduction (Million$/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV (Million$/Day Reduced)
Base	Current Operation with Wet Flue Gas Desulfurization (FGD) and Electrostatic Precipitator (ESP)	0.00	0.0	$0.0	$0.0	$0.0
1	Low-NO_x Burner (LNB) with Over-fire Air (OFA), Upgrade Wet FGD, and Flue Gas Conditioning (FGC) for Enhanced ESP Performance	0.23	5.0	$3.4	$14.6	$0.7
2	LNB with OFA, Upgrade Wet FGD, New Fabric Filter	0.25	4.7	$9.8	$39.0	$2.1
3	LNB with OFA and Selective Catalytic Reduction (SCR), Upgrade Wet FGD, and FGC for Enhanced ESP Performance	0.34	7.0	$18.1	$53.0	$2.6
4	LNB with OFA and SCR, Wet FGD, Fabric Filter	0.34	7.0	$24.5	$71.0	$3.5

TABLE 5-3
Control Scenario Results for the Mt. Zirkel Class I Wilderness Area
Jim Bridger 1

Scenario	Controls	98th Percentile deciview (dV) Reduction	Average Number of Days Above 0.5 dV (Days)	Total Annualized Cost (Million$)	Cost per dV Reduction (Million$/dV Reduced)	Cost per Reduction in No. of Days Above 0.5 dV (Million$/Day Reduced)
Base	Current Operation with Wet Flue Gas Desulfurization (FGD) and Electrostatic Precipitator (ESP)	0.00	0.0	$0.0	$0.0	$0.0
1	Low-NO_x Burner (LNB) with Over-fire Air (OFA), Upgrade Wet FGD, and Flue Gas Conditioning (FGC) for Enhanced ESP Performance	0.56	17.0	$3.4	$6.1	$0.2
2	LNB with OFA, Upgrade Wet FGD, New Fabric Filter	0.61	17.7	$9.8	$16.0	$0.6
3	LNB with OFA and Selective Catalytic Reduction (SCR), Upgrade Wet FGD, and FGC for Enhanced ESP Performance	0.87	27.3	$18.1	$20.8	$0.7
4	LNB with OFA and SCR, Upgrade Wet FGD, New Fabric Filter	0.88	28.3	$24.5	$27.8	$0.9

TABLE 5-4
Bridger Class I Wilderness Area Incremental Analysis Data
Jim Bridger 1

Options Compared	Incremental Reduction in Days Above 0.5 deciview (dV) (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Baseline and Scenario 1	10.0	0.44	$0.3	$7.7
Scenario 1 and Scenario 2	0.7	0.03	$9.5	$238.7
Scenario 1 and Scenario 3	3.7	0.19	$4.0	$75.5
Scenario 1 and Scenario 4	4.0	0.21	$5.3	$101.3

TABLE 5-5
Fitzpatrick Class I Wilderness Area Incremental Analysis Data
Jim Bridger 1

Options Compared	Incremental Reduction in Days Above 0.5 deciview (dV) (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Baseline and Scenario 1	5.0	0.23	$0.7	$14.6
Scenario 1 and Scenario 2	n/a	0.02	n/a	$353.7
Scenario 1 and Scenario 3	2.0	0.11	$7.4	$134.9
Scenario 1 and Scenario 4	2.0	0.11	$10.5	$188.1

TABLE 5-6
Mt. Zirkel Class I Wilderness Area Incremental Analysis Data
Jim Bridger 1

Options Compared	Incremental Reduction in Days Above 0.5 deciview (dV) (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Baseline and Scenario 1	17.0	0.56	$0.2	$6.1
Scenario 1 and Scenario 2	0.7	0.05	$9.5	$128.2
Scenario 1 and Scenario 3	10.3	0.31	$1.4	$47.5
Scenario 1 and Scenario 4	11.3	0.32	$1.9	$65.5

FIGURE 5-1
Least-cost Envelope Bridger Class I WA Days Reduction
Jim Bridger 1

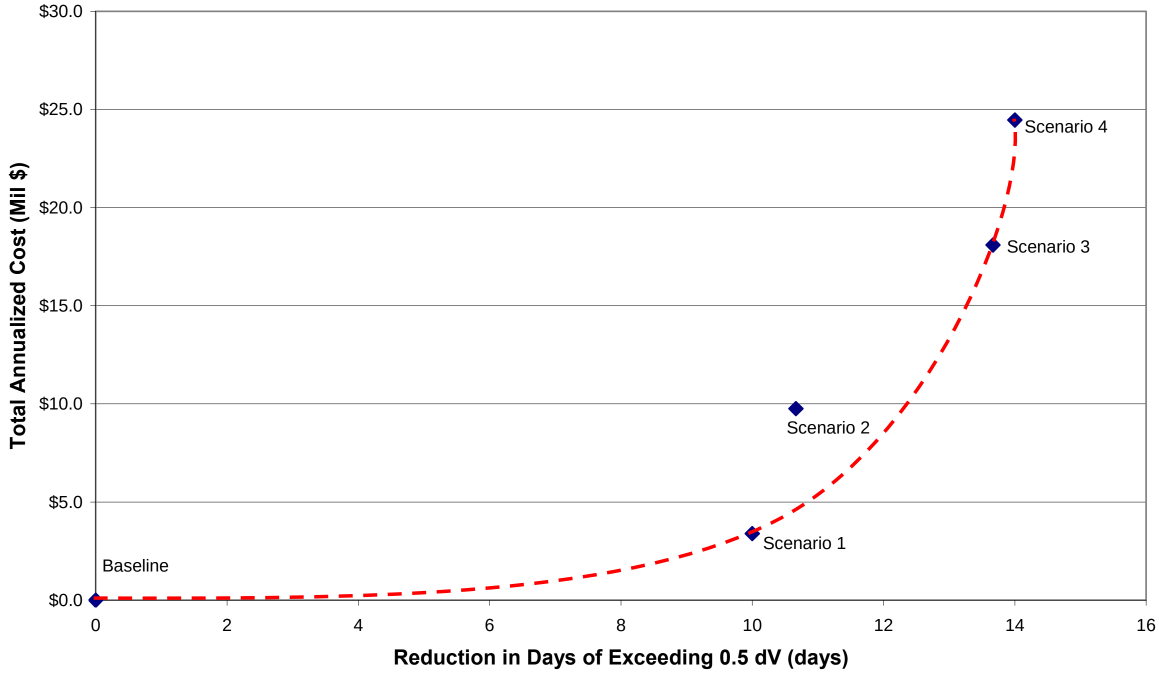


FIGURE 5-2
Least-cost Envelope Bridger Class I WA 98th Percentile Reduction
Jim Bridger 1

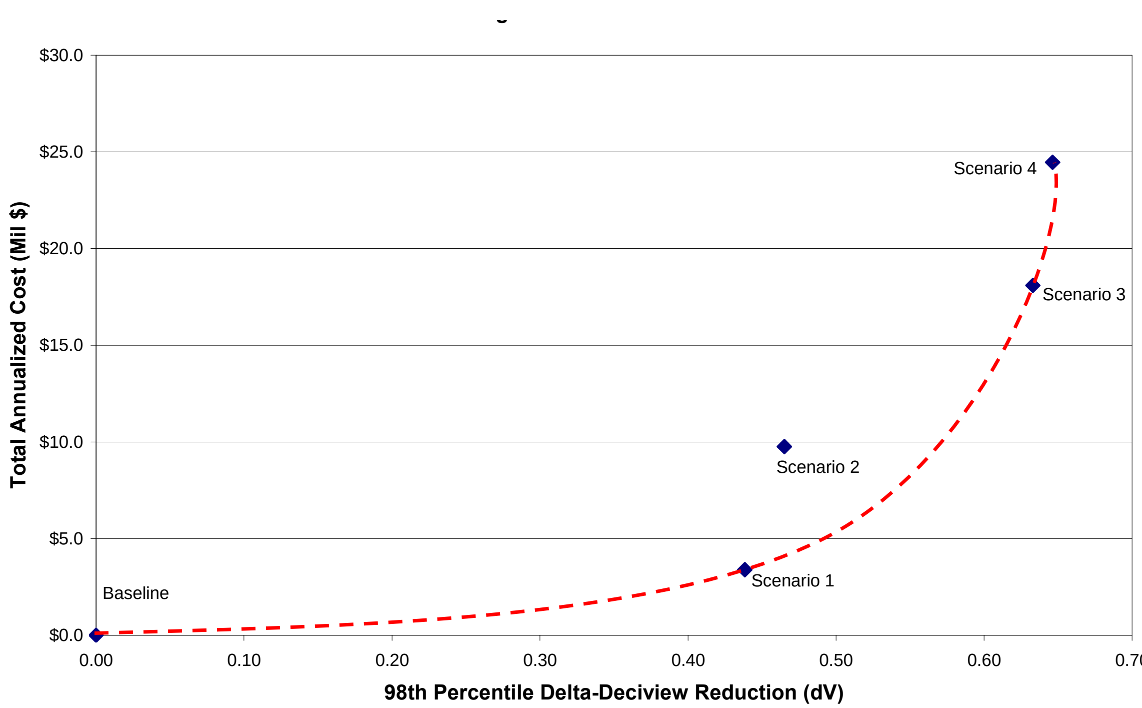


FIGURE 5-3
Least-cost Envelope Fitzpatrick Class I WA Days Reduction
Jim Bridger 1

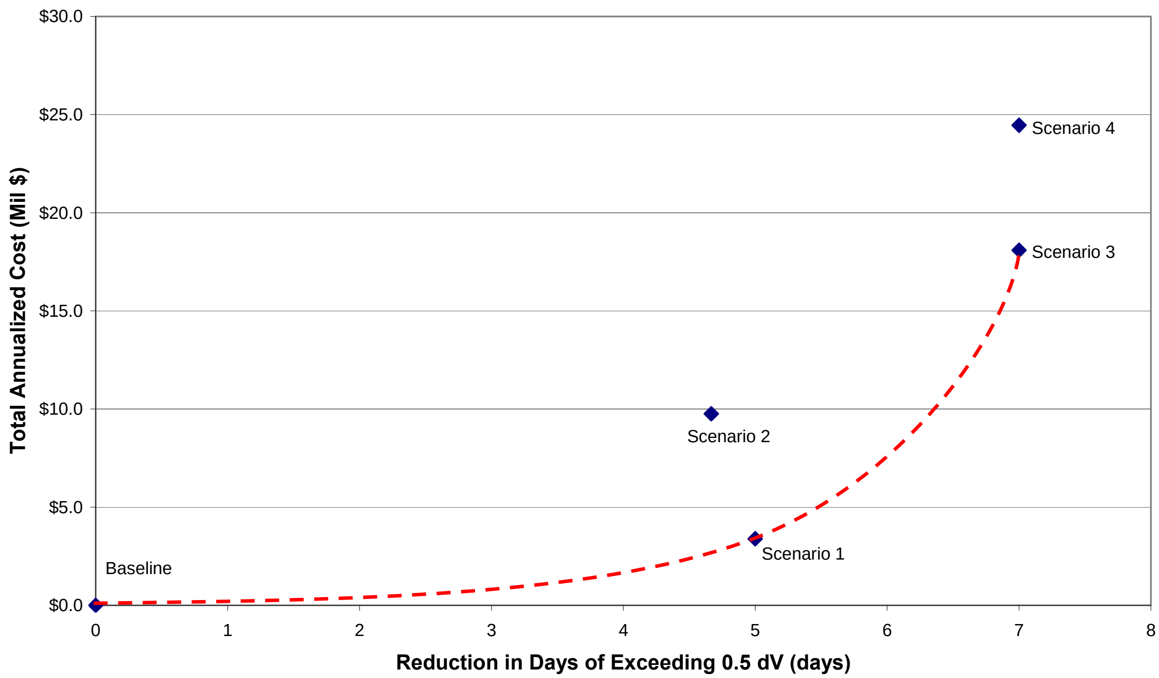


FIGURE 5-4
Least-cost Envelope Fitzpatrick Class I WA 98th Percentile Reduction
Jim Bridger 1

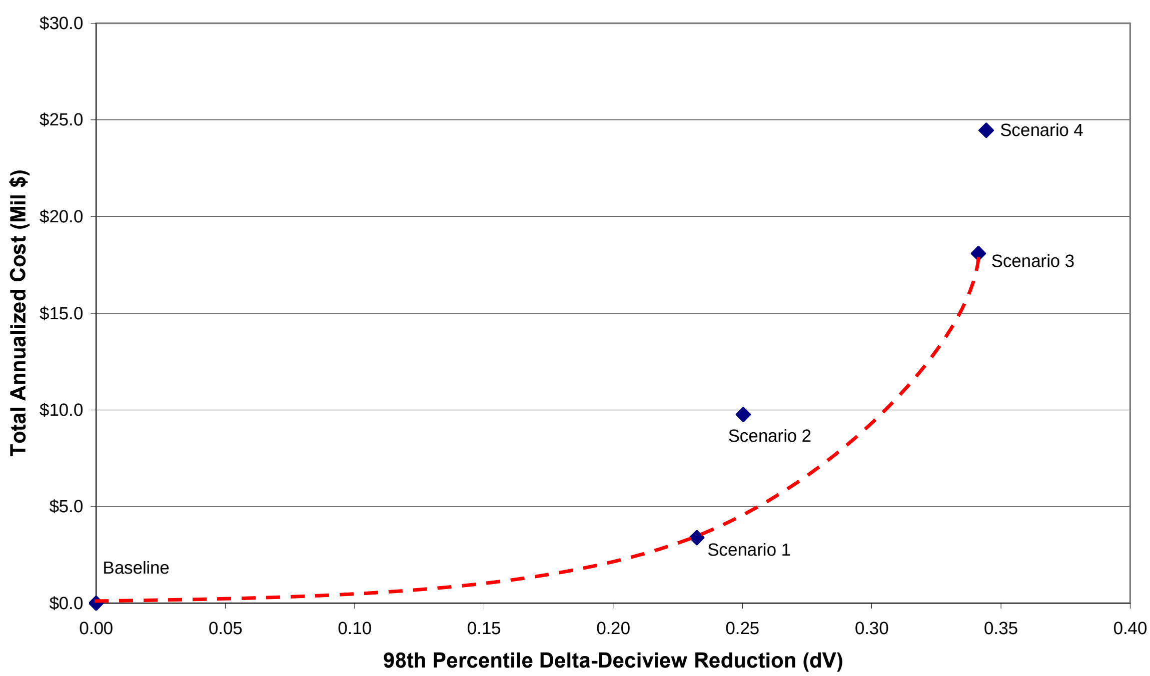


FIGURE 5-5
Least-cost Envelope Mt. Zirkel Class I WA Days Reduction
Jim Bridger 1

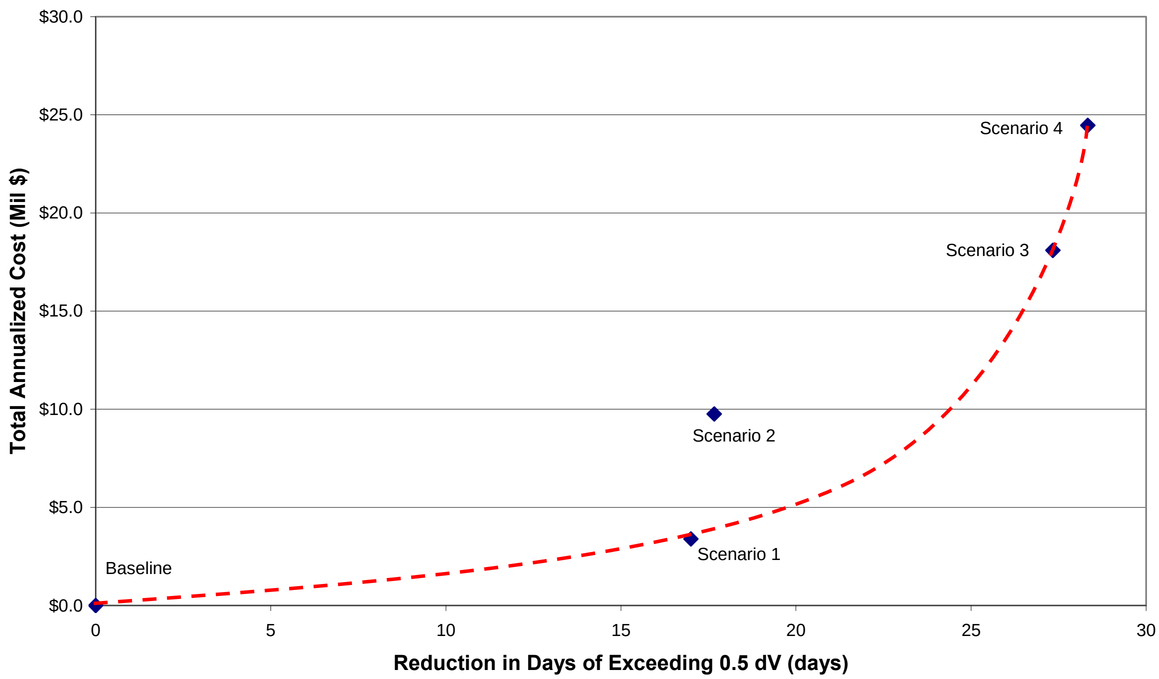
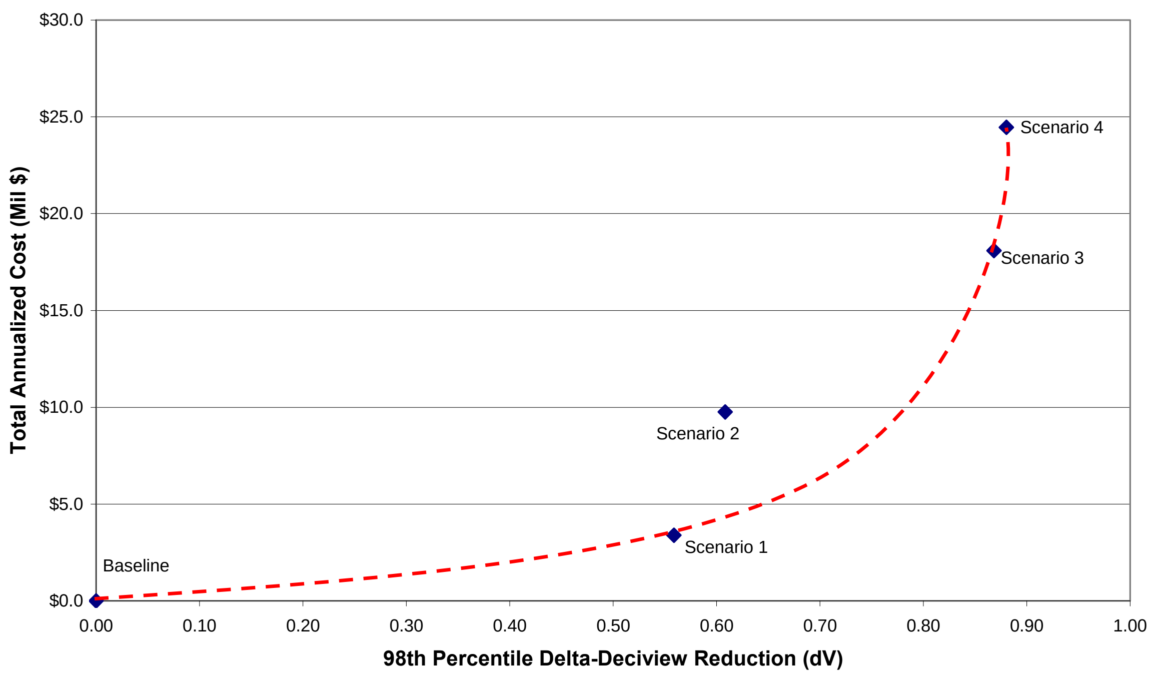


FIGURE 5-6
Least-cost Envelope Mt. Zirkel Class I WA 98th Percentile Reduction
Jim Bridger 1



5.1.2 Analysis Results

Results of the least-cost analysis, shown in Tables 5-1 through 5-6 and Figures 5-1 through 5-6 on the preceding pages, confirm the selection of Scenario 1, based on incremental cost and visibility improvements. Scenario 2 is eliminated because it is to the left of the curve formed by the dominant control alternative scenarios, which indicates a scenario with lower improvement and/or higher costs. Scenario 3 is not selected due to very high incremental costs on the basis of both a cost per day of improvement and a cost per dV reduction. While Scenario 4 provides some potential visibility advantage over Scenario 1, the projected improvement is less than half a dV, and the projected costs are excessive.

Analysis of the results for the Jim Bridger WA Class I Area in Tables 5-1 and 5-4 and Figures 5-1 and 5-2 illustrates the conclusions stated above. The greatest reduction in 98th percentile dV and number of days exceeding 0.5 dV is between the Baseline and Scenario 1. The average incremental cost effectiveness for Scenario 1 compared to the Baseline for the Bridger Wilderness area (Table 5-4) is reasonable at $300,000 per day and $7.7 million per dV. However, the incremental cost effectiveness for Scenario 3 compared to Scenario 1 is excessive at $4 million per day and $75.5 million per dV. Therefore, Scenario 1 represents BART for Jim Bridger 1.

5.2 Recommendations

5.2.1 NO_x Emission Control

The BART presumptive NO_x limit assigned by EPA for tangentially-fired boilers burning sub-bituminous coal is 0.15 lb per MMBtu. However, as documented in Section 3.2.1, the characteristics of the Jim Bridger coals are more closely aligned with bituminous coals, with a presumptive BART NO_x limit of 0.28 lb per MMBtu.

CH2M HILL recommends the existing low-NO_x burners with over-fire air (LNB with OFA) as BART for Jim Bridger 1, based on the projected significant reduction in NO_x emissions, reasonable control costs, and the advantages of no additional power requirements or non-air quality environmental impacts. Nitrogen oxide reductions are expected to be similar to those realized at Jim Bridger 2. CH2M HILL recommends that the unit be permitted at a rate of 0.26 lb per MMBtu.

5.2.2 SO_2 Emission Control

CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for Jim Bridger 1, based on the significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and minimal non-air quality environmental impacts. This upgrade approach will meet the BART presumptive SO_2 limit of 0.15 lb per MMBtu.

5.2.3 PM_{10} Emission Control

CH2M HILL recommends finalizing the permitting of the FGC system to enhance the performance of the existing ESP as BART for Jim Bridger 1, based on the significant reduction in PM_{10} emissions, reasonable control costs, and the advantages of minimal additional power requirements and no non-air quality environmental impacts.

5.3 Just-Noticeable Differences in Atmospheric Haze

Conclusions reached in the reference document "Just-Noticeable Differences in Atmospheric Haze" by Dr. Ronald Henry of the University of Southern California (Henry, 2002), state that only dV differences of approximately 1.5 to 2.0 dV, or more are perceivable by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the scenarios. Thus the results indicate that even though many millions of dollars will be spent, only minimal if any noticeable visibility improvements may result.

Finally, it should be noted that none of the data were corrected for natural obscuration where water in various forms (fog, clouds, snow or rain) or other naturally caused aerosols obscure the atmosphere. During the period of 2001 through 2003, there were several mega-wildfires that lasted for many days and could have had a significant impact on background visibility in these Class I areas. If natural obscuration were to reduce the reduction in visibility impacts modeled for the Jim Bridger 1 facility, the effect would be to increase the costs per dV reduction that are presented in this report.

6.0 References

40 CFR Part 51. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule.* July 6, 2005.

Energy Information Administration, 2006. *Official Energy Statistics from the U.S. Government: Coal.* http://www.eia.doe.gov/fuelcoal.html. Accessed October 2006.

EPA, 1990. *New Source Review Workshop Manual—Prevention of Significant Deterioration and Nonattainment Area Permitting*. Draft. October 1990.

EPA, 2003. *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*. Environmental Protection Agency. EPA-454/8-03-005. September 2003.

Henry, Ronald, 2002. "Just-Noticeable Differences in Atmospheric Haze," *Journal of the Air & Waste Management Association.* Volume 52, p. 1238.

National Oceanic and Atmospheric Administration, 2006. U.S. Daily Weather Maps Project. http://docs.lib.noaa.gov/rescue/dwm/data_rescue_daily_weather_maps.html. Accessed October 2006.

North Dakota Department of Health, 2005. *Protocol for BART-Related Visibility Improvement Modeling Analysis in North Dakota*. North Dakota Department of Health. October 26, 2005.

Sargent & Lundy, 2002. *Multi-Pollutant Control Report.* October 2002.

Sargent & Lundy, 2006. *Multi-Pollutant Control Report.* Revised. October 2006.

WDEQ-AQD, 2006. *BART Air Modeling Protocol—Individual Source Visibility Assessments for BART Control Analyses*. Wyoming Department of Environmental Quality – Air Quality Division. September 2006.

APPENDIX A

Economic Analysis

PacifiCorp BART Analysis Scenarios

Select Unit:	3	Jim Bridger Unit 1

Index No.	Name of Unit
1	Dave Johnston Unit 3
2	Dave Johnston Unit 4
3	Jim Bridger Unit 1
4	Jim Bridger Unit 2
5	Jim Bridger Unit 3
6	Jim Bridger Unit 4
7	Naughton Unit 1
8	Naughton Unit 2
9	Naughton Unit 3
10	Wyodak Unit 1

Dave Johnston				Naughton					
DJ Unit 3		DJ Unit 4		NTN Unit 1		NTN Unit 2		NTN Unit 3	
Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost
Baseline - Current Operation with ESP		Baseline - Current Operation with Venturi Scrubber		Baseline - Current Operation with ESP		Baseline - Current Operation with ESP		Baseline - Current Operation with Wet FGD and ESP	
Scenario 1 - LNB with OFA, Dry FGD, Existing ESP	**N/A** N/A	Scenario 1 - LNB with OFA, Dry FGD, Fabric Filter	**N/A** N/A	Scenario 1 - LNB with OFA, Dry FGD, ESP	**N/A** N/A	Scenario 1 - LNB with OFA, Dry FGD, ESP	**N/A** N/A	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A
Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A
Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Dry FGD, New Fabric Filter	**N/A** N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Existing ESP, New Stack	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP, New Stack	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, ESP, New Stack	**N/A** N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A

Jim Bridger								Wyodak	
JB Unit 1		JB Unit 2		JB Unit 3		JB Unit 4		WDK Unit 1	
Scenario	First Year Cost	Scenario	First Year	Scenario	First Year Cost	Scenario	First Year Cost	Scenario	First Year Cost
Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Wet FGD and ESP		Baseline - Current Operation with Dry FGD, Fabric Filter	
Scenario 1 - LNB with OFA, Wet FGD, ESP	**$ 3,392,440** $ 3,392,440 $ 3,392,440	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Wet FGD, ESP	**N/A** N/A N/A	Scenario 1 - LNB with OFA, Dry FGD, Fabric Filter	**N/A** N/A
Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**$ 9,759,059** $ 9,759,059 $ 9,759,059	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA, Wet FGD, New Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 2 - LNB with OFA and SCR, Dry FGD, Fabric Filter	**N/A** N/A
Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**$ 18,093,916** $ 18,093,916 $ 18,093,916	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, ESP	**N/A** N/A N/A	Scenario 3 - LNB with OFA and SCR, Wet FGD, Fabric Filter, New Stack	**N/A** N/A
Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**$ 24,460,535** $ 24,460,535 $ 24,460,535	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - LNB with OFA and SCR, Wet FGD, Fabric Filter	**N/A** N/A N/A	Scenario 4 - N/A	**N/A** N/A

ECONOMIC ANALYSIS SUMMARY

Jim Bridger Unit 1 **Boiler Design:** **Tangential-Fired PC**

Parameter	Current Operation	NOx Control				SO2 Control	PM Control	
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
Case	**1**	**2**	**3**	**4**	**5**	**8**	**9**	**10**
NOx Emission Control System	LNCFS-1 & Windbox Mods.	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	LNCFS-1 & Windbox Mods.	LNCFS-1 & Windbox Mods.	LNCFS-1 & Windbox Mods.
SO2 Emission Control System	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Upgraded Wet FGD	Wet FGD	Wet FGD
PM Emission Control System	ESP	ESP	ESP	ESP	ESP	ESP	Flue Gas Conditioning	Fabric Filter
TOTAL INSTALLED CAPITAL COST ($)	**0**	**8,700,001**	**20,528,122**	**22,127,239**	**129,575,495**	**12,999,900**	**0**	**48,386,333**
FIRST YEAR O&M COST ($)								
Operating Labor ($)	0	0	0	0	0	0	0	0
Maintenance Material ($)	0	28,000	42,000	123,000	190,000	25,550	0	51,099
Maintenance Labor ($)	0	42,000	63,000	184,500	285,000	17,033	10,000	76,649
Administrative Labor ($)	0	0	0	0	0	0	0	0
TOTAL FIXED O&M COST	**0**	**70,000**	**105,000**	**307,500**	**475,000**	**42,583**	**10,000**	**127,749**
Makeup Water Cost	0	0	0	0	0	30,503	0	0
Reagent Cost	0	0	0	1,005,811	912,848	533,206	145,854	0
SCR Catalyst / FF Bag Cost	0	0	0	0	594,000	0	0	300,040
Waste Disposal Cost	0	0	0	0	0	442,958	0	0
Electric Power Cost	0	0	2,528,012	208,926	1,291,005	208,926	19,710	1,335,944
TOTAL VARIABLE O&M COST	**0**	**0**	**2,528,012**	**1,214,737**	**2,797,853**	**1,215,593**	**165,564**	**1,635,984**
TOTAL FIRST YEAR O&M COST	**0**	**70,000**	**2,633,012**	**1,522,237**	**3,272,853**	**1,258,176**	**175,564**	**1,763,732**
FIRST YEAR DEBT SERVICE ($)	0	827,612	1,952,796	2,104,916	12,326,235	1,236,652	0	4,602,887
TOTAL FIRST YEAR COST ($)	**0**	**897,612**	**4,585,808**	**3,627,153**	**15,599,088**	**2,494,828**	**175,564**	**6,366,619**
Power Consumption (MW)	**0.0**	**0.0**	**6.4**	**0.5**	**3.3**	**0.5**	**0.1**	**3.4**
Annual Power Usage (Million kW-Hr/Yr)	**0.0**	**0.0**	**50.6**	**4.2**	**25.8**	**4.2**	**0.4**	**26.7**
CONTROL COST ($/Ton Removed)								
NOx Removal Rate (%)	**0.0%**	**46.7%**	**51.1%**	**55.6%**	**84.4%**	**0.0%**	**0.0%**	**0.0%**
NOx Removed (Tons/Yr)	**0**	**4,967**	**5,440**	**5,913**	**8,987**	**0**	**0**	**0**
First Year Average Control Cost ($/Ton NOx Rem.)	**0**	**181**	**843**	**613**	**1,736**	**0**	**0**	**0**
Incremental Control Cost ($/Ton NOx Removed)	**0**	**181**	**7,797**	**2,885**	**3,894**	**0**	**0**	**0**
		2-1	3-2	4-2	5-4			
SO2 Removal Rate (%)	**77.8%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**62.5%**	**0.0%**	**0.0%**
SO2 Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**3,950**	**0**	**0**
First Year Average Control Cost ($/Ton SO2 Rem.)	**0**	**0**	**0**	**0**	**0**	**632**	**0**	**0**
Incremental Control Cost ($/Ton SO2 Removed)	**Base**	**0**	**0**	**0**	**0**	**632**	**0**	**0**
						8-1		
PM Removal Rate (%)	**99.47%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**33.33%**	**66.67%**
PM Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**0**	**355**	**710**
First Year Average Control Cost ($/Ton PM Rem.)	**0**	**0**	**0**	**0**	**0**	**0**	**495**	**8,973**
Incremental Control Cost ($/Ton PM Removed)	**Base**	**0**	**0**	**0**	**0**	**0**	**495**	**17,452**
							9-1	10-9
PRESENT WORTH COST ($)	**0**	**9,555,250**	**52,697,883**	**40,725,706**	**169,562,733**	**28,372,107**	**2,145,015**	**69,935,356**

INPUT CALCULATIONS

Jim Bridger Unit 1 **Boiler Design:** **Tangential-Fired PC**

Parameter	Current Operation	NOx Control				SO2 Control	PM Control		Comments
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter	
Case	1	2	3	4	5	8	9	10	
NOx Emission Control System	LNCFS-1 & Windbox Mods.	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	LNCFS-1 & Windbox Mods.	LNCFS-1 & Windbox Mods.	LNCFS-1 & Windbox Mods.	
SO2 Emission Control System	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Wet FGD	Upgraded Wet FGD	Wet FGD	Wet FGD	
PM Emission Control System	ESP	ESP	ESP	ESP	ESP	ESP	Flue Gas Conditioning	Fabric Filter	
Unit Design and Coal Characteristics									
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	
Net Power Output (kW)	530,000	530,000	530,000	530,000	530,000	530,000	530,000	530,000	
Net Plant Heat Rate (Btu/kW-Hr)	11,320	11,320	11,320	11,320	11,320	11,320	11,320	11,320	
Boiler Fuel	Bridger Mine Underground	Bridger Mine Underground	Bridger Mine Underground	Bridger Mine Underground	Bridger Mine Underground	Bridger Mine Underground	Bridger Mine Underground	Bridger Mine Underground	
Coal Heating Value (Btu/Lb)	9,660	9,660	9,660	9,660	9,660	9,660	9,660	9,660	
Coal Sulfur Content (wt.%)	0.58%	0.58%	0.58%	0.58%	0.58%	0.581%	0.58%	0.58%	
Coal Ash Content (wt.%)	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	
Boiler Heat Input, each (MMBtu/Hr)	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	
Coal Flow Rate (Lb/Hr)	621,077	621,077	621,077	621,077	621,077	621,077	621,077	621,077	
(Ton/Yr)	2,448,284	2,448,284	2,448,284	2,448,284	2,448,284	2,448,284	2,448,284	2,448,284	
(MMBtu/Yr)	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	
Emissions									
Uncontrolled SO2 (Lb/Hr)	7,210	1,602	1,602	1,602	1,602	1,602	1,602	1,602	
(Lb/MMBtu)	1.20	0.27	0.27	0.27	0.27	0.27	0.27	0.27	
(Lb Moles/Hr)	112.54	25.00	25.00	25.00	25.00	25.00	25.00	25.00	
(Tons/Yr)	28,421	6,315	6,315	6,315	6,315	6,315	6,315	6,315	
SO2 Removal Rate (%)	77.8%	0.0%	0.0%	0.0%	0.0%	62.5%	0.0%	0.0%	
(Lb/Hr)	5,608	0	0	0	0	1,002	0	0	
(Ton/Yr)	22,106	0	0	0	0	3,950	0	0	
SO2 Emission Rate (Lb/Hr)	1,602	1,602	1,602	1,602	1,602	600	1,602	1,602	
(Lb/MMBtu)	0.27	0.27	0.27	0.27	0.27	0.10	0.27	0.27	
(Ton/Yr)	6,315	6,315	6,315	6,315	6,315	2,365	6,315	6,315	
Uncontrolled NOx (Lb/Hr)	2,700	2,700	2,700	2,700	2,700	2,700	2,700	2,700	
(Lb/MMBtu)	0.45	0.45	0.45	0.45	0.45	0.45	0.45	0.45	
(Lb Moles/Hr)	89.96	89.96	89.96	89.96	89.96	89.96	89.96	89.96	
(Tons/Yr)	10,643	10,643	10,643	10,643	10,643	10,643	10,643	10,643	
NOx Removal Rate (%)	0.0%	46.7%	51.1%	55.6%	84.4%	0%	0.0%	0%	
(Lb/Hr)	0	1,260	1,380	1,500	2,280	0	0	0	
(Lb Moles/Hr)	0.00	41.98	45.98	49.98	75.97	0.00	0.00	0.00	
(Ton/Yr)	0	4,967	5,440	5,913	8,987	0	0	0	
NOx Emission Rate (Lb/Hr)	2,700	1,440	1,320	1,200	420	2,700	2,700	2,700	
(Lb/MMBtu)	0.45	0.24	0.22	0.20	0.07	0.45	0.45	0.45	
(Ton/Yr)	10,643	5,676	5,203	4,730	1,656	10,643	10,643	10,643	
Uncontrolled Fly Ash (Lb/Hr)	51,177	270	270	270	270	270	270	270	
(Lb/MMBtu)	8.530	0.045	0.045	0.045	0.045	0.045	0.045	0.045	
(Lb Moles/Hr)	1,705.3	9.0	9.0	9.0	9.0	9.0	9.0	9.0	
(Tons/Yr)	201,739	1,064	1,064	1,064	1,064	1,064	1,064	1,064	
Fly Ash Removal Rate (%)	99.47%	0.00%	0.00%	0.00%	0.00%	0.00%	33.33%	66.67%	
(Lb/Hr)	50,907	0	0	0	0	0	90	180	
(Ton/Yr)	200,674	0	0	0	0	0	355	710	
Fly Ash Emission Rate (Lb/Hr)	270	270	270	270	270	270	180	90	
(Lb/MMBtu)	0.045	0.045	0.045	0.045	0.045	0.045	0.030	0.015	
(Ton/Yr)	1,064	1,064	1,064	1,064	1,064	1,064	710	355	

Parameter	Current Operation	NOx Control				SO2 Control	PM Control		Comments
		LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter	
Case	1	2	3	4	5	8	9	10	
General Plant Data									
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	
Annual On-Site Power Plant Capacity Factor	0.90	0.90	0.90	0.90	0.90	0.90	0.90	0.90	
Economic Factors									
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	
Installed Capital Costs									
NOx Emission Control System ($2006)	0	8,700,001	20,528,122	22,127,239	129,575,495	0	0	0	
SO2 Emission Control System ($2006)	0	0	0	0	0	12,999,900	0	0	
PM Emission Control System ($2006)	0	0	0	0	0	0	0	48,386,333	
Total Emission Control Systems ($2006)	0	8,700,001	20,528,122	22,127,239	129,575,495	12,999,900	0	48,386,333	
NOx Emission Control System ($/kW)	0	16	39	42	244	0	0	0	
SO2 Emission Control System ($/kW)	0	0	0	0	0	25	0	0	
PM Emission Control System ($/kW)	0	0	0	0	0	0	0	91	
Total Emission Control Systems ($/kW)	0	16	39	42	244	25	0	91	
Total Fixed Operating & Maintenance Costs									
Operating Labor ($)	0	0	0	0	0	0	0	0	
Maintenance Material ($)	0	28,000	42,000	123,000	190,000	25,550	0	51,099	
Maintenance Labor ($)	0	42,000	63,000	184,500	285,000	17,033	10,000	76,649	
Administrative Labor ($)	0	0	0	0	0	0	0	0	
Total Fixed O&M Cost ($)	0	70,000	105,000	307,500	475,000	42,583	10,000	127,749	
Annual Fixed O&M Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Water Cost									
Makeup Water Usage (Gpm)	0	0	0	0	0	53	0	0	
Unit Price ($/1000 Gallons)	1.22	1.22	1.22	0.00	1.22	1.22	1.22	1.22	
First Year Water Cost ($)	0	0	0	0	0	30,503	0	0	
Annual Water Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Reagent Cost	None	None	None	Urea	Anhydrous NH3	Soda Ash	Elemental Sulfur	None	
Unit Cost ($/Ton)	0.00	0.00	0.00	370	400	80.00	370	0.00	
($/Lb)	0.000	0.000	0.000	0.185	0.200	0.040	0.185	0.000	
Molar Stoichiometry	0.00	0.00	0.00	0.45	1.00	1.02	0.00	0.00	
Reagent Purity (Wt.%)	100%	100%	100%	100%	100%	100%	100%	90%	
Reagent Usage (Lb/Hr)	0	0	0	690	579	1,691	100	0	
First Year Reagent Cost ($)	0	0	0	1,005,811	912,848	533,206	145,854	0	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost					SCR Catalyst	Bags		Bags	
Annual SCR Catalyst (m3) / No. FF Bags	0	0	0	0	198	0	0	2,885	
SCR Catalyst ($/m3) / Bag Cost ($/ea.)	3,000	3,000	3,000	3,000	3,000	104	3,000	104	
First Year SCR Catalyst / Bag Replace. Cost ($)	0	0	0	0	594,000	0	0	300,040	
Annual SCR Catalyst / Bag Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
FGD Waste Disposal Cost									
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)	0	0	0	0	0	4,618	0	0	
FGD Waste Disposal Unit Cost ($/Dry Ton)	24.33	24.33	24.33	24.33	24.33	24.33	24.33	24.33	
First Year FGD Waste Disposal Cost ($)	0	0	0	0	0	442,958	0	0	
Annual Waste Disposal Cost Esc. Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
Auxiliary Power Cost									
Auxiliary Power Requirement (% of Plant Output)	0.00%	0.00%	1.21%	0.10%	0.62%	0.10%	0.01%	0.64%	
(MW)	0.00	0.00	6.41	0.53	3.28	0.53	0.05	3.39	
Unit Cost ($2006/MW-Hr)	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	
First Year Auxiliary Power Cost ($)	0	0	2,528,012	208,926	1,291,005	208,926	19,710	1,335,944	
Annual Power Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	

Input Tables

Table 1 - Cases

Index No.	Name of Unit | Case --->	Existing	NOx Control				SO2 Control			PM Control	
		1	2	3	4	5	6	7	8	9	10
1	Dave Johnston Unit 3	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP	Dry FGD w/Fabric Filter	Wet FGD w/ESP	N/A	Fabric Filter
2	Dave Johnston Unit 4	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	Dry FGD w/Fabric Filter	Wet FGD w/Fabric Filter	N/A	Fabric Filter
3	Jim Bridger Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
4	Jim Bridger Unit 2	Current Operation	Exist. LNB w/OFA	ROFA	SNCR	SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
5	Jim Bridger Unit 3	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
6	Jim Bridger Unit 4	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
7	Naughton Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
8	Naughton Unit 2	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Dry FGD w/ESP	Dry FGD w/Fabric Filter	Wet FGD w/ESP	Flue Gas Conditioning	Fabric Filter
9	Naughton Unit 3	Current Operation	Exist. LNB w/OFA	ROFA	SNCR	SCR	N/A	N/A	Upgraded Wet FGD	Flue Gas Conditioning	Fabric Filter
10	Wyodak Unit 1	Current Operation	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR	Upgraded Dry FGD	N/A	Wet FGD	Flue Gas Conditioning	Fabric Filter

Table 2 - Unit Design and Coal Characteristics

Index No.	Name of Unit	Current Emission Control Systems			Unit Design			Coal Quality			
		NOx	SO2	PM	Boiler Design	Net Power Output (kW)	Net Plant Heat Rate (Btu/kW-Hr)	Coal	Heating Value, HHV (Btu/Lb)	Sulfur Content (Wt.%)	Ash Content (Wt.%)
1	Dave Johnston Unit 3	None	None	ESP	3-Cell Burner, Opposed Wall-Fired PC	250,000	11,200	Dry Fork PRB	7,784	0.47%	5.01%
2	Dave Johnston Unit 4	Windbox Mods.	Lime Added to Venturi Scrubber	Venturi Scrubber	Tangential-Fired PC	360,000	11,390	Dry Fork PRB	7,784	0.47%	5.01%
3	Jim Bridger Unit 1	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
4	Jim Bridger Unit 2	LNB - TFS 2000	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
5	Jim Bridger Unit 3	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
6	Jim Bridger Unit 4	LNCFS-1 & Windbox Mods.	Wet FGD	ESP	Tangential-Fired PC	530,000	11,320	Bridger Mine Underground	9,660	0.58%	10.30%
7	Naughton Unit 1	None	None	ESP	Tangential-Fired PC	173,000	10,694	Kemmerer Mine	9,970	0.60%	4.64%
8	Naughton Unit 2	None	None	ESP	Tangential-Fired PC	226,000	10,574	Kemmerer Mine	9,970	0.60%	4.64%
9	Naughton Unit 3	LNCFS II LNB	Wet FGD	ESP	Tangential-Fired PC	356,000	10,336	Kemmerer Mine	9,970	0.60%	4.64%
10	Wyodak Unit 1	LNB	Dry FGD	ESP	Opposed Wall-Fired PC	335,000	12,087	Clovis Point Mine	7,977	0.65%	7.46%

Table 3 - Emissions

Index No.	Name of Unit	Current Emission Rates (Lb/MMBtu) Controlled SO2	Controlled NOx	Controlled PM	NOx Control Emission Rates (Lb/MMBtu) Case 2	Case 3	Case 4	Case 5	SO2 Control Emission Rates (Lb/MMBtu) Case 6	Case 7	Case 8	PM Emission Rates (Lb/MMBtu) Case 9	Case 10
1	Dave Johnston Unit 3	1.20	0.70	0.200	0.27	0.21	0.20	0.07	0.21	0.15	0.10	N/A	0.015
2	Dave Johnston Unit 4	0.33	0.48	0.061	0.15	0.19	0.12	0.07	N/A	0.15	0.10	N/A	0.015
3	Jim Bridger Unit 1	0.27	0.45	0.045	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
4	Jim Bridger Unit 2	0.27	0.24	0.074	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
5	Jim Bridger Unit 3	0.27	0.45	0.057	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
6	Jim Bridger Unit 4	0.17	0.45	0.030	0.24	0.22	0.20	0.07	N/A	N/A	0.10	0.030	0.015
7	Naughton Unit 1	1.20	0.58	0.056	0.24	0.28	0.18	0.07	0.18	0.15	0.10	0.040	0.015
8	Naughton Unit 2	1.20	0.54	0.064	0.24	0.28	0.18	0.07	0.18	0.15	0.10	0.040	0.015
9	Naughton Unit 3	0.50	0.45	0.094	0.35	0.30	0.25	0.07	N/A	N/A	0.10	0.040	0.015
10	Wyodak Unit 1	0.50	0.50	0.030	0.23	0.22	0.18	0.07	0.25	N/A	0.10	0.025	0.015

Table 4 - Case 1 O&M Costs (Current Operation)

Index No.	Name of Unit	Annual Fixed O&M Costs Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	None	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	None	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	None	-	-
7	Naughton Unit 1	$ -	$ -	$ -	$ -	-	None	-	-
8	Naughton Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
10	Wyodak Unit 1	$ -	$ -	$ -	$ -	-	None	-	-

Table 5 - Case 2 O&M Costs (LNB w/OFA)

Index No.	Name of Unit	Annual Fixed O&M Costs Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Variable Operating Requirements Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 40,000	$ 60,000	$ -	-	None	-	-
2	Dave Johnston Unit 4	$ -	$ 36,000	$ 54,000	$ -	-	None	-	-
3	Jim Bridger Unit 1	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	None	-	-
5	Jim Bridger Unit 3	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
6	Jim Bridger Unit 4	$ -	$ 28,000	$ 42,000	$ -	-	None	-	-
7	Naughton Unit 1	$ -	$ 32,000	$ 48,000	$ -	-	None	-	-
8	Naughton Unit 2	$ -	$ 32,000	$ 48,000	$ -	-	None	-	-
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	None	-	-
10	Wyodak Unit 1	$ -	$ 24,000	$ 36,000	$ -	-	None	-	-

Table 6 - Case 3 O&M Costs (Mobotec ROFA)

		Annual Fixed O&M Costs				Variable Operating Requirements			
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 60,000	$ 90,000	$ -	-	None	-	2.76
2	Dave Johnston Unit 4	$ -	$ 54,000	$ 81,000	$ -	-	None	-	4.33
3	Jim Bridger Unit 1	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
4	Jim Bridger Unit 2	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
5	Jim Bridger Unit 3	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
6	Jim Bridger Unit 4	$ -	$ 42,000	$ 63,000	$ -	-	None	-	6.41
7	Naughton Unit 1	$ -	$ 48,000	$ 72,000	$ -	-	None	-	1.42
8	Naughton Unit 2	$ -	$ 48,000	$ 72,000	$ -	-	None	-	2.61
9	Naughton Unit 3	$ -	$ 48,000	$ 72,000	$ -	-	None	-	4.47
10	Wyodak Unit 1	$ -	$ 36,000	$ 54,000	$ -	-	None	-	5.22

Table 7 - Case 4 O&M Costs (LNB w/OFA & SNCR))

		Annual Fixed O&M Costs				Variable Operating Requirements			
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 98,000	$ 147,000	$ -	-	Urea	0.41	0.23
2	Dave Johnston Unit 4	$ -	$ 105,000	$ 157,500	$ -	-	Urea	0.45	0.33
3	Jim Bridger Unit 1	$ -	$ 123,000	$ 184,500	$ -	-	Urea	0.45	0.53
4	Jim Bridger Unit 2	$ -	$ 95,000	$ 142,500	$ -	-	Urea	0.45	0.53
5	Jim Bridger Unit 3	$ -	$ 122,000	$ 183,000	$ -	-	Urea	0.45	0.52
6	Jim Bridger Unit 4	$ -	$ 123,000	$ 184,500	$ -	-	Urea	0.45	0.53
7	Naughton Unit 1	$ -	$ 83,000	$ 124,500	$ -	-	Urea	0.45	0.16
8	Naughton Unit 2	$ -	$ 93,000	$ 139,500	$ -	-	Urea	0.51	0.22
9	Naughton Unit 3	$ -	$ 75,000	$ 112,500	$ -	-	Urea	0.45	0.33
10	Wyodak Unit 1	$ -	$ 93,000	$ 139,500	-	-	Urea	0.45	0.34

Table 8 - Case 5 O&M Costs (LNB w/OFA & SCR))

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual SCR Catalyst Replace. (m3)	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 155,000	$ 232,500	$ -	-	Anhydrous NH3	1.00	128	1.57
2	Dave Johnston Unit 4	$ -	$ 166,000	$ 249,000	$ -	-	Anhydrous NH3	1.00	123	2.29
3	Jim Bridger Unit 1	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	198	3.28
4	Jim Bridger Unit 2	$ -	$ 162,000	$ 243,000	$ -	-	Anhydrous NH3	1.00	198	3.25
5	Jim Bridger Unit 3	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	200	3.22
6	Jim Bridger Unit 4	$ -	$ 190,000	$ 285,000	$ -	-	Anhydrous NH3	1.00	214	3.36
7	Naughton Unit 1	$ -	$ 132,000	$ 198,000	$ -	-	Anhydrous NH3	1.00	67	0.98
8	Naughton Unit 2	$ -	$ 160,000	$ 240,000	$ -	-	Anhydrous NH3	1.00	101	1.34
9	Naughton Unit 3	$ -	$ 156,000	$ 234,000	$ -	-	Anhydrous NH3	1.00	167	1.99
10	Wyodak Unit 1	$ -	$ 181,000	$ 271,500	$ -	-	Anhydrous NH3	1.00	160	2.42

Table 9 - Case 6 O&M Costs (Dry FGD)

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 506,128	$ 714,175	$ 476,928	$ -	173	Lime	1.15	-	2.49
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	Lime	-	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	Lime	-	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
7	Naughton Unit 1	$ 506,128	$ 587,643	$ 391,762	$ -	120	Lime	1.40	-	1.64
8	Naughton Unit 2	$ 506,128	$ 860,174	$ 573,044	$ -	165	Lime	1.40	-	2.25
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
10	Wyodak Unit 1	$ -	$ 21,900	$ 14,600	-	25	Lime	1.10	-	0.11

Table 10 - Case 7 O&M Costs (Dry FGD w/Fabric Filter)

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 506,128	$ 714,175	$ 476,928	$ -	173	Lime	1.15	1,457	3.88
2	Dave Johnston Unit 4	$ 506,128	$ 1,102,288	$ 734,858	$ -	248	Lime	1.10	1,798	4.54
3	Jim Bridger Unit 1	$ -	$ -	$ -	$ -	-	Lime	-	-	-
4	Jim Bridger Unit 2	$ -	$ -	$ -	$ -	-	Lime	-	-	-
5	Jim Bridger Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
6	Jim Bridger Unit 4	$ -	$ -	$ -	$ -	-	Lime	-	-	-
7	Naughton Unit 1	$ 506,128	$ 632,660	$ 459,286	$ -	120	Lime	1.15	865	2.66
8	Naughton Unit 2	$ 506,128	$ 905,190	$ 640,568	$ -	165	Lime	1.15	1,193	3.63
9	Naughton Unit 3	$ -	$ -	$ -	$ -	-	Lime	-	-	-
10	Wyodak Unit 1	$ -	$ -	$ -	-	-	Lime	-	-	-

Table 11 - Case 8 O&M Costs (Wet FGD)

		Annual Fixed O&M Costs				Variable Operating Requirements				
Index No.	Name of Unit	Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ 809,804	$ 1,182,587	$ 788,391	$ -	230	Lime	1.02	-	3.45
2	Dave Johnston Unit 4	$ 809,804	$ 1,430,784	$ 953,856	$ -	330	Lime	1.02	1,798	6.29
3	Jim Bridger Unit 1	$ -	$ 25,550	$ 17,033	$ -	53	Soda Ash	1.02	-	0.53
4	Jim Bridger Unit 2	$ -	$ 25,550	$ 17,033	$ -	53	Soda Ash	1.02	-	0.53
5	Jim Bridger Unit 3	$ -	$ 25,550	$ 17,033	$ -	52	Soda Ash	1.02	-	0.52
6	Jim Bridger Unit 4	$ -	$ 25,550	$ 17,033	$ -	27	Soda Ash	1.02	-	0.53
7	Naughton Unit 1	$ 809,804	$ 963,589	$ 642,393	$ -	160	Lime	1.05	-	2.40
8	Naughton Unit 2	$ 809,804	$ 1,226,386	$ 817,591	$ -	220	Lime	1.05	-	3.30
9	Naughton Unit 3	$ -	$ 21,900	$ 14,600	$ -	66	Soda Ash	1.02	-	0.33
10	Wyodak Unit 1	$ 303,677	$ 328,496	$ 218,998	$ -	82	Lime	1.02	-	1.75

Table 12 - Case 9 O&M Costs (Flue Gas Conditioning)

Index No.	Name of Unit	Annual Fixed O&M Costs				Variable Operating Requirements				
		Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Usage (Lb/Hr)	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ -	$ -	$ -	-	None	-	-	-
2	Dave Johnston Unit 4	$ -	$ -	$ -	$ -	-	None	-	-	-
3	Jim Bridger Unit 1	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
4	Jim Bridger Unit 2	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
5	Jim Bridger Unit 3	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
6	Jim Bridger Unit 4	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	100	-	0.05
7	Naughton Unit 1	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	33	-	0.05
8	Naughton Unit 2	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	43	-	0.05
9	Naughton Unit 3	$ -	$ -	$ 10,000	$ -	-	Elemental Sulfur	67	-	0.05
10	Wyodak Unit 1	$ -	$ -	$ 10,000	-	-	Elemental Sulfur	63	-	0.05

Table 13 - Case 10 O&M Costs (Fabric Filter)

Index No.	Name of Unit	Annual Fixed O&M Costs				Variable Operating Requirements				
		Oper. Labor	Maint. Materials	Maint. Labor	Admin. Labor	Makeup Water Use (Gpm)	Reagent	Reagent Molar Stoich.	Annual FF Bag Replace.	Aux. Power Usage (MW)
1	Dave Johnston Unit 3	$ -	$ 45,016	$ 67,524	$ -	-	None	-	1,457	1.38
2	Dave Johnston Unit 4	$ -	$ 68,133	$ 102,199	$ -	-	None	-	1,798	2.35
3	Jim Bridger Unit 1	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.39
4	Jim Bridger Unit 2	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.37
5	Jim Bridger Unit 3	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,827	3.33
6	Jim Bridger Unit 4	$ -	$ 51,099	$ 76,649	$ -	-	None	-	2,885	3.39
7	Naughton Unit 1	$ -	$ 45,016	$ 67,524	$ -	-	None	-	865	1.01
8	Naughton Unit 2	$ -	$ 45,016	$ 67,524	$ -	-	None	-	1,193	1.38
9	Naughton Unit 3	$ -	$ 48,666	$ 72,999	$ -	-	None	-	1,799	2.06
10	Wyodak Unit 1	$ -	$ 48,666	$ 72,999	$ -	-	None	-	1,798	2.06

Table 14 - Major Materials Design and Supply Costs

Index No.	Name of Unit | Case --->	NOx Control				SO2 Control			PM Control	
		2	3	4	5	6	7	8	9	10
1	Dave Johnston Unit 3	$ 3,221,912	$ 3,556,617	$ 5,773,000	$ 49,355,000	$ 83,871,000	$ 142,077,000	$ 108,865,669	$ -	$ 18,359,000
2	Dave Johnston Unit 4	$ 2,673,501	$ 4,343,192	$ 7,171,085	$ 66,200,000	$ -	$ 137,267,000	$ 178,174,384	$ -	$ 30,853,530
3	Jim Bridger Unit 1	$ 2,981,982	$ 6,056,955	$ 9,528,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
4	Jim Bridger Unit 2	$ -	$ 6,056,955	$ 9,528,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
5	Jim Bridger Unit 3	$ 2,981,982	$ 6,056,955	$ 9,419,000	$ 80,923,000	$ -	$ -	$ 8,010,093	$ -	$ 29,814,000
6	Jim Bridger Unit 4	$ 2,981,982	$ 6,056,955	$ 9,528,000	$ 93,009,000	$ -	$ -	$ 3,549,000	$ -	$ 29,814,000
7	Naughton Unit 1	$ 2,502,123	$ 2,675,792	$ 7,257,000	$ 37,292,000	$ 26,819,000	$ 42,301,000	$ 44,000,000	$ 800,000	$ 15,482,000
8	Naughton Unit 2	$ 2,570,674	$ 3,123,533	$ 8,784,000	$ 47,934,000	$ 39,262,000	$ 57,621,000	$ 56,000,000	$ 800,000	$ 18,359,000
9	Naughton Unit 3	$ -	$ 4,351,377	$ 11,203,578	$ 67,373,000	$ -	$ -	$ 2,963,000	$ 800,000	$ 20,106,000
10	Wyodak Unit 1	$ 3,187,636	$ 4,500,245	$ 7,234,860	$ 72,479,000	$ 996,100	$ -	$ 178,174,384	$ 1,247,061	$ 20,106,000

CAPITAL COST

Jim Bridger Unit 1

Parameter	NOx Control								SO2 Control						PM Control			
	LNB w/OFA		ROFA		LNB w/OFA & SNCR		LNB w/OFA & SCR		N/A		N/A		Upgraded Wet FGD		Flue Gas Conditioning		Fabric Filter	
Case	2		3		4		5		6		7		8		9		10	
NOx Emission Control System	LNB w/OFA		ROFA		LNB w/OFA & SNCR		LNB w/OFA & SCR		LNCFS-1 & Windbox Mods.		LNCFS-1 & Windbox Mods.		LNCFS-1 & Windbox Mods.		LNCFS-1 & Windbox Mods.		LNCFS-1 & Windbox Mods.	
SO2 Emission Control System	Wet FGD		Wet FGD		Wet FGD		Wet FGD		N/A		N/A		Upgraded Wet FGD		Wet FGD		Wet FGD	
PM Emission Control System	ESP		ESP		ESP		ESP		ESP		ESP		ESP		Flue Gas Conditioning		Fabric Filter	
CAPITAL COST COMPONENT	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost	Factor/Source	Cost
LNB w/OFA or ROFA		LNB w/OFA		ROFA		LNB w/OFA		LNB w/OFA										
Major Materials Design and Supply	Vendor	$2,981,982	Vendor	$6,056,955	Vendor	$2,981,982	Vendor	$2,981,982	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0	Vendor	$0
Construction	85.3%	$2,544,638	85.3%	$5,168,628	85.3%	$2,544,638	85.3%	$2,544,638	85.3%	$0	85.3%	$0	85.3%	$0	85.3%	$0	85.3%	$0
Balance of Plant	51.7%	$1,541,451	51.7%	$3,130,970	51.7%	$1,541,451	51.7%	$1,541,451	51.7%	$0	51.7%	$0	51.7%	$0	51.7%	$0	51.7%	$0
Electrical (Allowance)	0.0%	$0	30.0%	$1,817,087	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Owner's Costs	13.2%	$395,063	13.2%	$802,446	13.2%	$395,063	13.2%	$395,063	13.2%	$0	13.2%	$0	13.2%	$0	13.2%	$0	13.2%	$0
Surcharge	16.4%	$489,805	16.4%	$994,884	16.4%	$489,805	16.4%	$489,805	16.4%	$0	16.4%	$0	16.4%	$0	16.4%	$0	16.4%	$0
AFUDC	12.2%	$364,352	12.2%	$740,067	12.2%	$364,352	12.2%	$364,352	12.2%	$0	12.2%	$0	12.2%	$0	12.2%	$0	12.2%	$0
Subtotal		$8,317,291		$18,711,036		$8,317,291		$8,317,291		$0		$0		$0		$0		$0
Contingency	12.8%	$382,709	30.0%	$1,817,087	12.8%	$382,709	12.8%	$382,709	12.8%	$0	12.8%	$0	12.8%	$0	12.8%	$0	12.8%	$0
Total Capital Cost for LNB w/OFA or ROFA		$8,700,001		$20,528,122		$8,700,001		$8,700,001		$0		$0		$0		$0		$0
SNCR or SCR						SNCR		SCR										
Major Materials Design and Supply	S&L Report	$0	S&L Report	$0	S&L Report	$9,528,000	S&L Report	$80,923,000	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0
Contingency	20.0%	$0	20.0%	$0	20.0%	$1,905,600	20.0%	$16,184,600	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0
Labor Premium	5.6%	$0	5.6%	$0	5.6%	$532,901	5.6%	$4,526,023	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0
EPC Premium	0.0%	$0	0.0%	$0	0.0%	$0	8.4%	$6,835,566	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0
Boiler Reinforcement (Allowance)	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Sales Tax	1.1%	$0	1.1%	$0	1.1%	$104,999	1.1%	$891,771	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0
Escalation	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0	0.0%	$0
Contingency on Adders	2.8%	$0	2.8%	$0	2.8%	$267,451	2.8%	$2,271,509	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0
Surcharge and AFUDC	11.4%	$0	11.4%	$0	11.4%	$1,088,288	11.4%	$9,243,025	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0
Total Capital Cost for SNCR or SCR		$0		$0		$13,427,239		$120,875,494		$0		$0		$0		$0		$0
Dry or Wet FGD, FGC or Fabric Filter										Dry FGD		Dry FGD w/FF		Wet FGD		FGC		Fabric Filter
Major Materials Design and Supply	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$0	S&L Report	$8,010,093	S&L Report	$0	S&L Report	$29,814,000
Contingency	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$0	20.0%	$1,602,019	20.0%	$0	20.0%	$5,962,800
Labor Premium	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$0	5.6%	$448,005	5.6%	$0	5.6%	$1,667,497
EPC Premium	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$0	8.4%	$676,613	8.4%	$0	8.4%	$2,518,389
Boiler Reinforcement (Allowance)	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$225,404	2.8%	$0	2.8%	$838,966
Sales Tax	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$0	1.1%	$88,271	1.1%	$0	1.1%	$328,550
Escalation	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$0	10.1%	$809,740	10.1%	$0	10.1%	$3,013,897
Contingency on Adders	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$0	2.8%	$224,843	2.8%	$0	2.8%	$836,879
Surcharge and AFUDC	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$0	11.4%	$914,913	11.4%	$0	11.4%	$3,405,355
Total Capital Cost for Dry/Wet FGD, FGC or FF		$0		$0		$0		$0		$0		$0		$12,999,900		$0		$48,386,333

Jim Bridger Unit 1					LNB w/OFA						
Year	**Date**	**TOTAL FIXED O&M COST**	**Makeup Water Cost**	**Reagent Cost**	**SCR Catalyst / FF Bag Cost**	**Waste Disposal Cost**	**Electric Power Cost**	**TOTAL VARIABLE O&M COST**	**DEBT SERVICE**	**TOTAL ANNUAL COST**	**Control Cost ($/Ton NOx Removed)**
0	2013										
1	2014	70,000	-	-	-	-	-	-	827,612	897,612	181
2	2015	71,400	-	-	-	-	-	-	827,612	899,012	181
3	2016	72,828	-	-	-	-	-	-	827,612	900,440	181
4	2017	74,285	-	-	-	-	-	-	827,612	901,897	182
5	2018	75,770	-	-	-	-	-	-	827,612	903,382	182
6	2019	77,286	-	-	-	-	-	-	827,612	904,898	182
7	2020	78,831	-	-	-	-	-	-	827,612	906,443	183
8	2021	80,408	-	-	-	-	-	-	827,612	908,020	183
9	2022	82,016	-	-	-	-	-	-	827,612	909,628	183
10	2023	83,656	-	-	-	-	-	-	827,612	911,269	183
11	2024	85,330	-	-	-	-	-	-	827,612	912,942	184
12	2025	87,036	-	-	-	-	-	-	827,612	914,648	184
13	2026	88,777	-	-	-	-	-	-	827,612	916,389	185
14	2027	90,552	-	-	-	-	-	-	827,612	918,165	185
15	2028	92,364	-	-	-	-	-	-	827,612	919,976	185
16	2029	94,211	-	-	-	-	-	-	827,612	921,823	186
17	2030	96,095	-	-	-	-	-	-	827,612	923,707	186
18	2031	98,017	-	-	-	-	-	-	827,612	925,629	186
19	2032	99,977	-	-	-	-	-	-	827,612	927,589	187
20	2033	101,977	-	-	-	-	-	-	827,612	929,589	187
Present Worth		855,250	-	-	-	-	-	-	8,700,001	9,555,250	96
(% of PW)		9.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	91.0%	100.0%	

Jim Bridger Unit 1					ROFA						
Year	**Date**	**TOTAL FIXED O&M COST**	**Makeup Water Cost**	**Reagent Cost**	**SCR Catalyst / FF Bag Cost**	**Waste Disposal Cost**	**Electric Power Cost**	**TOTAL VARIABLE O&M COST**	**DEBT SERVICE**	**TOTAL ANNUAL COST**	**Control Cost ($/Ton NOx Removed)**
0	2013										
1	2014	105,000	-	-	-	-	2,528,012	2,528,012	1,952,796	4,585,808	843
2	2015	107,100	-	-	-	-	2,578,573	2,578,573	1,952,796	4,638,468	853
3	2016	109,242	-	-	-	-	2,630,144	2,630,144	1,952,796	4,692,182	863
4	2017	111,427	-	-	-	-	2,682,747	2,682,747	1,952,796	4,746,970	873
5	2018	113,655	-	-	-	-	2,736,402	2,736,402	1,952,796	4,802,853	883
6	2019	115,928	-	-	-	-	2,791,130	2,791,130	1,952,796	4,859,854	893
7	2020	118,247	-	-	-	-	2,846,953	2,846,953	1,952,796	4,917,995	904
8	2021	120,612	-	-	-	-	2,903,892	2,903,892	1,952,796	4,977,299	915
9	2022	123,024	-	-	-	-	2,961,970	2,961,970	1,952,796	5,037,789	926
10	2023	125,485	-	-	-	-	3,021,209	3,021,209	1,952,796	5,099,489	937
11	2024	127,994	-	-	-	-	3,081,633	3,081,633	1,952,796	5,162,423	949
12	2025	130,554	-	-	-	-	3,143,266	3,143,266	1,952,796	5,226,616	961
13	2026	133,165	-	-	-	-	3,206,131	3,206,131	1,952,796	5,292,092	973
14	2027	135,829	-	-	-	-	3,270,254	3,270,254	1,952,796	5,358,878	985
15	2028	138,545	-	-	-	-	3,335,659	3,335,659	1,952,796	5,427,000	998
16	2029	141,316	-	-	-	-	3,402,372	3,402,372	1,952,796	5,496,484	1,010
17	2030	144,142	-	-	-	-	3,470,419	3,470,419	1,952,796	5,567,358	1,023
18	2031	147,025	-	-	-	-	3,539,828	3,539,828	1,952,796	5,639,649	1,037
19	2032	149,966	-	-	-	-	3,610,624	3,610,624	1,952,796	5,713,386	1,050
20	2033	152,965	-	-	-	-	3,682,837	3,682,837	1,952,796	5,788,598	1,064
Present Worth		1,282,875	-	-	-	-	30,886,886	30,886,886	20,528,122	52,697,883	484
(% of PW)		2.4%	0.0%	0.0%	0.0%	0.0%	58.6%	58.6%	39.0%	100.0%	

Jim Bridger Unit 1 — LNB w/OFA & SNCR

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	307,500	-	1,005,811	-	-	208,926	1,214,737	2,104,916	3,627,153	613
2	2015	313,650	-	1,025,927	-	-	213,105	1,239,032	2,104,916	3,657,598	619
3	2016	319,923	-	1,046,446	-	-	217,367	1,263,812	2,104,916	3,688,651	624
4	2017	326,321	-	1,067,375	-	-	221,714	1,289,088	2,104,916	3,720,326	629
5	2018	332,848	-	1,088,722	-	-	226,148	1,314,870	2,104,916	3,752,634	635
6	2019	339,505	-	1,110,496	-	-	230,671	1,341,168	2,104,916	3,785,589	640
7	2020	346,295	-	1,132,706	-	-	235,285	1,367,991	2,104,916	3,819,202	646
8	2021	353,221	-	1,155,361	-	-	239,990	1,395,351	2,104,916	3,853,488	652
9	2022	360,285	-	1,178,468	-	-	244,790	1,423,258	2,104,916	3,888,459	658
10	2023	367,491	-	1,202,037	-	-	249,686	1,451,723	2,104,916	3,924,130	664
11	2024	374,841	-	1,226,078	-	-	254,680	1,480,757	2,104,916	3,960,514	670
12	2025	382,338	-	1,250,599	-	-	259,773	1,510,373	2,104,916	3,997,626	676
13	2026	389,984	-	1,275,611	-	-	264,969	1,540,580	2,104,916	4,035,481	683
14	2027	397,784	-	1,301,124	-	-	270,268	1,571,392	2,104,916	4,074,092	689
15	2028	405,740	-	1,327,146	-	-	275,673	1,602,819	2,104,916	4,113,475	696
16	2029	413,855	-	1,353,689	-	-	281,187	1,634,876	2,104,916	4,153,646	703
17	2030	422,132	-	1,380,763	-	-	286,811	1,667,573	2,104,916	4,194,621	709
18	2031	430,574	-	1,408,378	-	-	292,547	1,700,925	2,104,916	4,236,415	717
19	2032	439,186	-	1,436,546	-	-	298,398	1,734,943	2,104,916	4,279,045	724
20	2033	447,969	-	1,465,276	-	-	304,366	1,769,642	2,104,916	4,322,528	731
Present Worth		3,756,990	-	12,288,849	-	-	2,552,627	14,841,477	22,127,239	40,725,706	344
(% of PW)		9.2%	0.0%	30.2%	0.0%	0.0%	6.3%	36.4%	54.3%	100.0%	

Jim Bridger Unit 1 — LNB w/OFA & SCR

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton NOx Removed)
0	2013										
1	2014	475,000	-	912,848	594,000	-	1,291,005	2,797,853	12,326,235	15,599,088	1,736
2	2015	484,500	-	931,105	605,880	-	1,316,825	2,853,810	12,326,235	15,664,545	1,743
3	2016	494,190	-	949,727	617,998	-	1,343,162	2,910,886	12,326,235	15,731,311	1,750
4	2017	504,074	-	968,722	630,358	-	1,370,025	2,969,104	12,326,235	15,799,413	1,758
5	2018	514,155	-	988,096	642,965	-	1,397,425	3,028,486	12,326,235	15,868,876	1,766
6	2019	524,438	-	1,007,858	655,824	-	1,425,374	3,089,056	12,326,235	15,939,729	1,774
7	2020	534,927	-	1,028,015	668,940	-	1,453,881	3,150,837	12,326,235	16,011,999	1,782
8	2021	545,626	-	1,048,575	682,319	-	1,482,959	3,213,854	12,326,235	16,085,714	1,790
9	2022	556,538	-	1,069,547	695,966	-	1,512,618	3,278,131	12,326,235	16,160,904	1,798
10	2023	567,669	-	1,090,938	709,885	-	1,542,870	3,343,693	12,326,235	16,237,597	1,807
11	2024	579,022	-	1,112,757	724,083	-	1,573,728	3,410,567	12,326,235	16,315,824	1,815
12	2025	590,603	-	1,135,012	738,564	-	1,605,202	3,478,779	12,326,235	16,395,616	1,824
13	2026	602,415	-	1,157,712	753,336	-	1,637,306	3,548,354	12,326,235	16,477,004	1,833
14	2027	614,463	-	1,180,866	768,402	-	1,670,053	3,619,321	12,326,235	16,560,019	1,843
15	2028	626,752	-	1,204,484	783,770	-	1,703,454	3,691,708	12,326,235	16,644,695	1,852
16	2029	639,287	-	1,228,573	799,446	-	1,737,523	3,765,542	12,326,235	16,731,064	1,862
17	2030	652,073	-	1,253,145	815,435	-	1,772,273	3,840,853	12,326,235	16,819,161	1,871
18	2031	665,115	-	1,278,208	831,743	-	1,807,719	3,917,670	12,326,235	16,909,019	1,881
19	2032	678,417	-	1,303,772	848,378	-	1,843,873	3,996,023	12,326,235	17,000,675	1,892
20	2033	691,985	-	1,329,847	865,346	-	1,880,751	4,075,944	12,326,235	17,094,164	1,902
Present Worth		5,803,480	-	11,153,043	7,257,405	-	15,773,310	34,183,758	129,575,495	169,562,733	943
(% of PW)		3.4%	0.0%	6.6%	4.3%	0.0%	9.3%	20.2%	76.4%	100.0%	

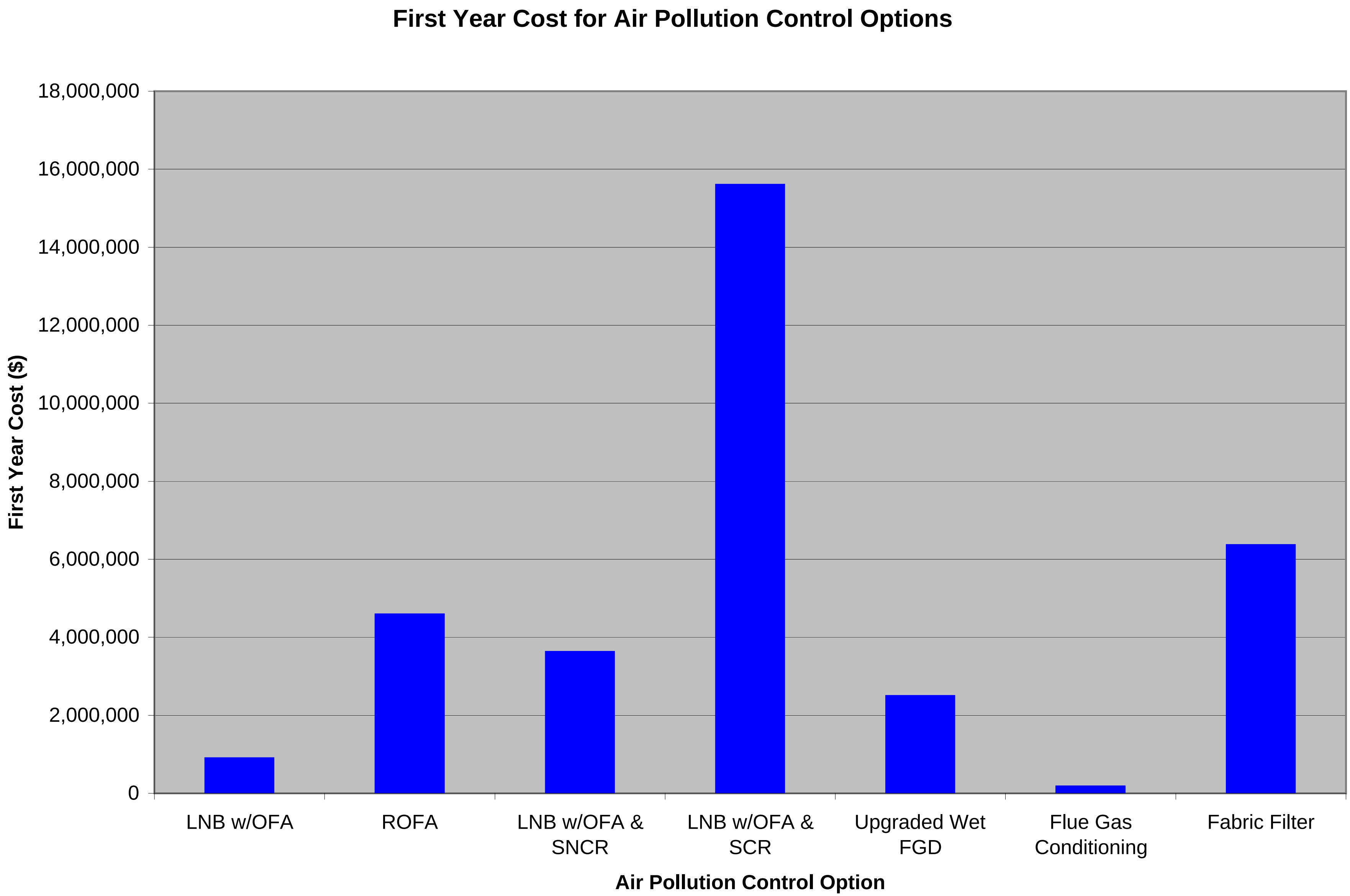
Jim Bridger Unit 1 — Upgraded Wet FGD

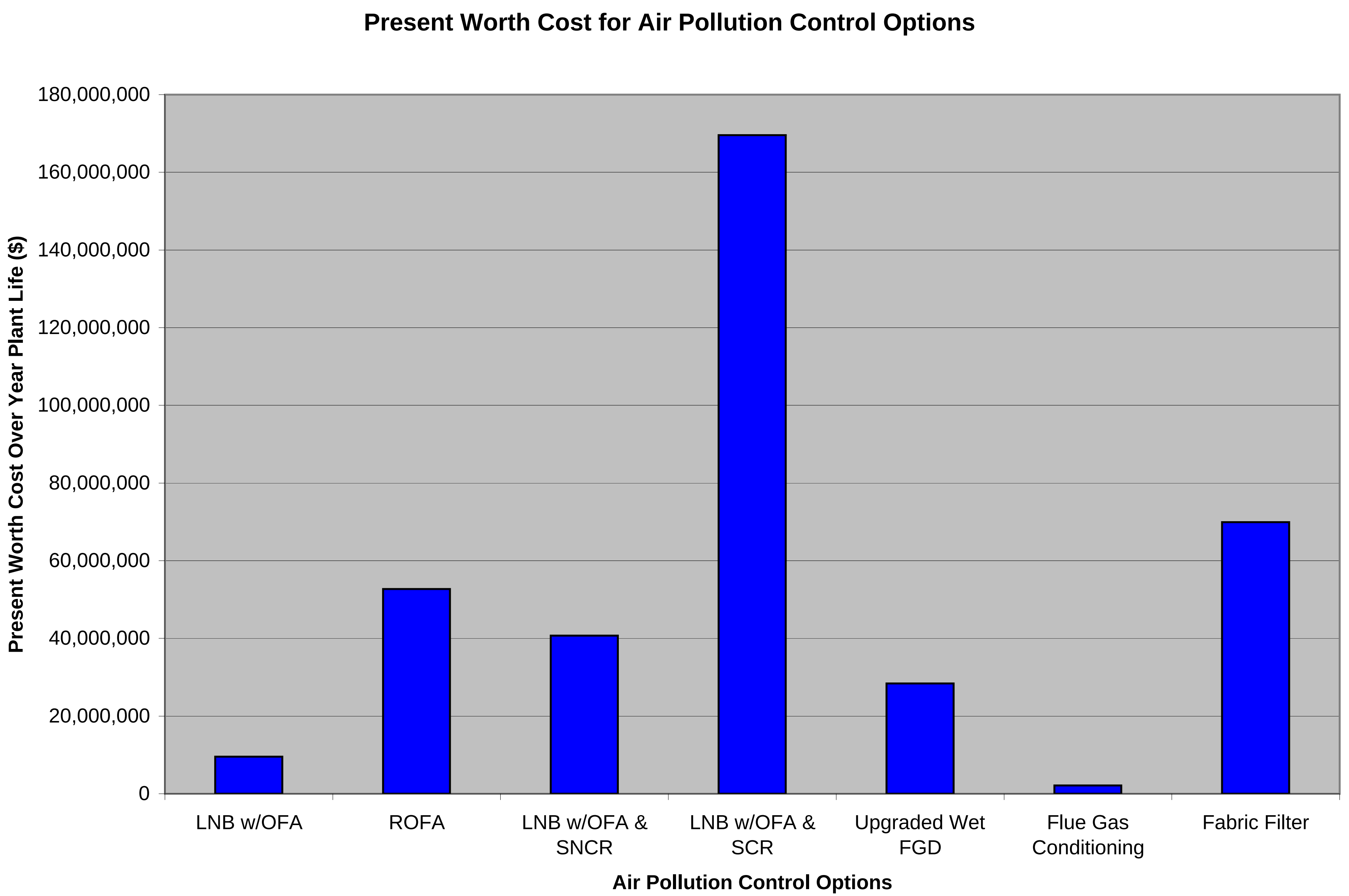
Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton SO2 Removed)
0	2013										
1	2014	42,583	30,503	533,206	-	442,958	208,926	1,215,593	1,236,652	2,494,828	632
2	2015	43,435	31,113	543,870	-	451,818	213,105	1,239,905	1,236,652	2,519,991	638
3	2016	44,303	31,735	554,747	-	460,854	217,367	1,264,703	1,236,652	2,545,658	645
4	2017	45,189	32,370	565,842	-	470,071	221,714	1,289,997	1,236,652	2,571,838	651
5	2018	46,093	33,017	577,159	-	479,472	226,148	1,315,797	1,236,652	2,598,542	658
6	2019	47,015	33,678	588,702	-	489,062	230,671	1,342,113	1,236,652	2,625,780	665
7	2020	47,955	34,351	600,476	-	498,843	235,285	1,368,955	1,236,652	2,653,562	672
8	2021	48,914	35,038	612,486	-	508,820	239,990	1,396,334	1,236,652	2,681,901	679
9	2022	49,893	35,739	624,735	-	518,996	244,790	1,424,261	1,236,652	2,710,806	686
10	2023	50,890	36,454	637,230	-	529,376	249,686	1,452,746	1,236,652	2,740,289	694
11	2024	51,908	37,183	649,975	-	539,964	254,680	1,481,801	1,236,652	2,770,361	701
12	2025	52,946	37,926	662,974	-	550,763	259,773	1,511,437	1,236,652	2,801,036	709
13	2026	54,005	38,685	676,234	-	561,778	264,969	1,541,666	1,236,652	2,832,323	717
14	2027	55,085	39,459	689,758	-	573,014	270,268	1,572,499	1,236,652	2,864,237	725
15	2028	56,187	40,248	703,554	-	584,474	275,673	1,603,949	1,236,652	2,896,788	733
16	2029	57,311	41,053	717,625	-	596,164	281,187	1,636,028	1,236,652	2,929,991	742
17	2030	58,457	41,874	731,977	-	608,087	286,811	1,668,749	1,236,652	2,963,858	750
18	2031	59,626	42,711	746,617	-	620,249	292,547	1,702,123	1,236,652	2,998,402	759
19	2032	60,819	43,566	761,549	-	632,654	298,398	1,736,166	1,236,652	3,033,637	768
20	2033	62,035	44,437	776,780	-	645,307	304,366	1,770,889	1,236,652	3,069,577	777
Present Worth		520,271	372,679	6,514,628	-	5,412,000	2,552,627	14,851,935	12,999,900	28,372,107	359
(% of PW)		1.8%	1.3%	23.0%	0.0%	19.1%	9.0%	52.3%	45.8%	100.0%	

Jim Bridger Unit 1 — Flue Gas Conditioning

Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	10,000	-	145,854	-	-	19,710	165,564	-	175,564	495
2	2015	10,200	-	148,771	-	-	20,104	168,875	-	179,075	505
3	2016	10,404	-	151,747	-	-	20,506	172,253	-	182,657	515
4	2017	10,612	-	154,781	-	-	20,916	175,698	-	186,310	525
5	2018	10,824	-	157,877	-	-	21,335	179,212	-	190,036	536
6	2019	11,041	-	161,035	-	-	21,761	182,796	-	193,837	546
7	2020	11,262	-	164,255	-	-	22,197	186,452	-	197,714	557
8	2021	11,487	-	167,540	-	-	22,641	190,181	-	201,668	568
9	2022	11,717	-	170,891	-	-	23,093	193,985	-	205,701	580
10	2023	11,951	-	174,309	-	-	23,555	197,864	-	209,815	591
11	2024	12,190	-	177,795	-	-	24,026	201,822	-	214,012	603
12	2025	12,434	-	181,351	-	-	24,507	205,858	-	218,292	615
13	2026	12,682	-	184,978	-	-	24,997	209,975	-	222,658	628
14	2027	12,936	-	188,678	-	-	25,497	214,175	-	227,111	640
15	2028	13,195	-	192,451	-	-	26,007	218,458	-	231,653	653
16	2029	13,459	-	196,300	-	-	26,527	222,827	-	236,286	666
17	2030	13,728	-	200,226	-	-	27,058	227,284	-	241,012	679
18	2031	14,002	-	204,231	-	-	27,599	231,830	-	245,832	693
19	2032	14,282	-	208,315	-	-	28,151	236,466	-	250,749	707
20	2033	14,568	-	212,482	-	-	28,714	241,195	-	255,764	721
Present Worth		122,179	-	1,782,023	-	-	240,814	2,022,837	-	2,145,015	302
(% of PW)		5.7%	0.0%	83.1%	0.0%	0.0%	11.2%	94.3%	0.0%	100.0%	

Jim Bridger Unit 1					Fabric Filter						
Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	127,749	-	-	300,040	-	1,335,944	1,635,984	4,602,887	6,366,619	8,973
2	2015	130,304	-	-	306,041	-	1,362,663	1,668,703	4,602,887	6,401,894	9,023
3	2016	132,910	-	-	312,162	-	1,389,916	1,702,078	4,602,887	6,437,874	9,074
4	2017	135,568	-	-	318,405	-	1,417,714	1,736,119	4,602,887	6,474,573	9,125
5	2018	138,279	-	-	324,773	-	1,446,069	1,770,841	4,602,887	6,512,007	9,178
6	2019	141,045	-	-	331,268	-	1,474,990	1,806,258	4,602,887	6,550,190	9,232
7	2020	143,866	-	-	337,894	-	1,504,490	1,842,383	4,602,887	6,589,136	9,287
8	2021	146,743	-	-	344,652	-	1,534,579	1,879,231	4,602,887	6,628,861	9,343
9	2022	149,678	-	-	351,545	-	1,565,271	1,916,816	4,602,887	6,669,380	9,400
10	2023	152,671	-	-	358,576	-	1,596,577	1,955,152	4,602,887	6,710,710	9,458
11	2024	155,725	-	-	365,747	-	1,628,508	1,994,255	4,602,887	6,752,866	9,518
12	2025	158,839	-	-	373,062	-	1,661,078	2,034,140	4,602,887	6,795,866	9,578
13	2026	162,016	-	-	380,523	-	1,694,300	2,074,823	4,602,887	6,839,726	9,640
14	2027	165,256	-	-	388,134	-	1,728,186	2,116,319	4,602,887	6,884,462	9,703
15	2028	168,562	-	-	395,896	-	1,762,749	2,158,646	4,602,887	6,930,094	9,767
16	2029	171,933	-	-	403,814	-	1,798,004	2,201,819	4,602,887	6,976,638	9,833
17	2030	175,371	-	-	411,891	-	1,833,965	2,245,855	4,602,887	7,024,113	9,900
18	2031	178,879	-	-	420,128	-	1,870,644	2,290,772	4,602,887	7,072,538	9,968
19	2032	182,456	-	-	428,531	-	1,908,057	2,336,588	4,602,887	7,121,931	10,038
20	2033	186,106	-	-	437,102	-	1,946,218	2,383,319	4,602,887	7,172,312	10,109
Present Worth		1,560,813	-	-	3,665,845	-	16,322,365	19,988,210	48,386,333	69,935,356	4,928
(% of PW)		2.2%	0.0%	0.0%	5.2%	0.0%	23.3%	28.6%	69.2%	100.0%	


First Year Cost for Air Pollution Control Options
18,000,000
16,000,000
14,000,000
12,000,000
10,000,000
8,000,000
6,000,000
4,000,000
2,000,000
0
First Year Cost ($)
LNB w/OFA
ROFA
LNB w/OFA & SNCR
LNB w/OFA & SCR
Upgraded Wet FGD
Flue Gas Conditioning
Fabric Filter
Air Pollution Control Option


Present Worth Cost for Air Pollution Control Options
Present Worth Cost Over Year Plant Life ($)
180,000,000
160,000,000
140,000,000
120,000,000
100,000,000
80,000,000
60,000,000
40,000,000
20,000,000
0
LNB w/OFA
ROFA
LNB w/OFA & SNCR
LNB w/OFA & SCR
Upgraded Wet FGD
Flue Gas Conditioning
Fabric Filter
Air Pollution Control Options

APPENDIX B

2006 Wyoming BART Protocol

BART Air Modeling Protocol

Individual Source Visibility Assessments for BART Control Analyses

September, 2006

State of Wyoming
Department of Environmental Quality
Air Quality Division
Cheyenne, WY 82002

Table of Contents

1.0 INTRODUCTION

The U.S. EPA has issued final amendments to the Regional Haze Regulations, along with Guidelines for Best Available Retrofit Technology (BART) Determinations.[1] The guidelines address the methodology for determining which facilities must apply BART (sources subject-to-BART) and the evaluation of control options.

The State of Wyoming used air quality modeling in accordance with the EPA Guidelines to determine the Wyoming sources which are subject-to-BART. This Protocol defines the specific methodology to be used by those sources for determining the improvement in visibility to be achieved by BART controls.

The methodology presented in this Protocol is consistent with EPA guidance and the Air Quality Division (AQD) determination of subject-to-BART sources. It is intended that all Wyoming sources that must conduct BART analyses will use this Protocol for their evaluation of control technology visibility improvement. Any deviations from the procedures described herein must be approved by the Division prior to implementation.

---

(1) 40 CFR Part 51: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. 70 Federal Register, 39103-39172, July 6, 2005.

2.0 OVERVIEW

Wyoming AQD determined that eight facilities (sources) in the state are subject-to-BART. The sources are listed in Table 1. Division modeling indicated that each of these sources causes or contributes to visibility impairment in one or more Class I areas. Each source must conduct a BART analysis to define Best Available Retrofit Technology (BART) applicable to that source, and quantify the improvement in Class I visibility associated with BART controls. This Protocol sets out the procedures for quantifying visibility improvement. Other aspects of the full BART analysis are not addressed here.

There are many Class I areas within and surrounding Wyoming (See Figure 1). On the basis of distance from subject-to-BART sources, topography, meteorology, and prior modeling, the AQD has determined that only five Class I areas need be addressed in BART individual source analyses. These are Badlands and Wind Cave National Parks in South Dakota, Mt. Zirkel Wilderness Area in Colorado, and Bridger and Fitzpatrick Wilderness Areas in Wyoming. Sources in eastern Wyoming have been shown to have greatest visibility impacts at the two South Dakota Class I areas, and western Wyoming sources have maximum impacts at Bridger and Fitzpatrick Wilderness Areas, and Mt. Zirkel. Visibility improvement at these highest impact areas will provide the best measure of the effectiveness of BART controls.

Each facility should carry out modeling with the CALPUFF modeling system for the Class I areas specified in Table 2. The AQD will provide meteorological input for CALMET for the years 2001, 2002, and 2003. The model domain covered by the AQD meteorological data is centered in southwest Wyoming, and extends roughly from Twin Falls, ID in the west to the Missouri River in the east, and from Denver in the south to Helena, MT in the north. The domain is shown, along with Class I areas, in Figure 1.

Sources may wish to utilize a smaller domain for CALPUFF modeling. Smaller domains are acceptable if they provide adequate additional area beyond the specific source and Class I areas being addressed. Figure 1 includes a "southwest Wyoming" domain which represents the minimum acceptable area for sources impacting the Bridger and Fitzpatrick Wilderness Areas, and the Mt. Zirkel Wilderness Area, and a "northeast Wyoming" domain as a minimum area for Badlands and Wind Cave National Parks modeling.

The CALPUFF model should be used with each of the three years of meteorological data to calculate visibility impacts for a baseline (existing emissions) case, and for cases reflecting BART controls. The control scenarios are to include individual scenarios for proposed BART controls for each pollutant (SO_2, NO_x, and particulate matter), and a combined scenario representing application of all proposed BART controls. If desired, additional modeling may be performed for controls that are not selected as BART. This might be done, for example, to provide data useful in identifying the control technologies that represent BART. However, visibility modeling is required only for the proposed BART controls.

Table 1. Wyoming Sources Subject-to-BART

Basin Electric	Laramie River Power Plant	Boilers #1,2,3
FMC Corporation	Granger Soda Ash Plant	Boilers #1,2
FMC Corporation	Green River Sodium Plant	Three boilers
General Chemical Co.	Green River Soda Ash	Two boilers
PacifiCorp	Dave Johnson Power Plant	Boilers #3,4
PacifiCorp	Jim Bridger Power Plant	Boilers #1-4
PacifiCorp	Naughton Power Plant	Boilers #1,2,3
PacifiCorp	Wyodak Power Plant	Boiler

Results of visibility modeling will be presented as a comparison between baseline impacts and those calculated for the BART control scenarios. Quantitative measures of impact will be the 98th percentile deciview change (Δdv) relative to the 20% best days natural background, and the number of days with deciview change exceeding 0.5 (EPA Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations, 70 FR 39103). Results should be presented for each year.

Table 2. Source-Specific Class I Areas to be Addressed

Source	Class I Areas to be Evaluated
Basin Electric Laramie River	Wind Cave NP, Badlands NP
FMC Corporation Granger Soda Ash	Bridger WA, Fitzpatrick WA
FMC Corporation Sodium Products	Bridger WA, Fitzpatrick WA
General Chemical Green River Soda Ash	Bridger WA, Fitzpatrick WA
Pacificorp Dave Johnston	Wind Cave NP, Badlands NP
Pacificorp Jim Bridger	Bridger WA, Fitzpatrick WA, Mt. Zirkel WA
Pacificorp Naughton Plant	Bridger WA, Fitzpatrick WA
Pacificorp Wyodak	Wind Cave NP, Badlands NP

3.0 EMISSIONS DATA FOR MODELING

CALPUFF model input requires source (stack) – specific emission rates for each pollutant, and stack parameters (height, diameter, exit gas temperature, and exit gas velocity). Per EPA BART guidance, these parameters must be representative of maximum actual 24-hour average emitting conditions for baseline (existing) operation, and maximum proposed 24-hour average emissions for future (BART) operations.

3.1 Baseline Modeling

Sources are required to utilize representative baseline emission conditions if data are available; baseline emissions must be documented. Possible sources of emission data are stack tests, CEM data, fuel consumption data, etc. Remember that emissions should represent maximum 24-hour rates. EPA BART guidance states that you should "Use the 24-hour average actual emission rate from the highest emitting day of the meteorological period modeled (for the pre-control scenario)." Thus, baseline conditions should reference data from 2001 through 2003 (or 2004).

As a minimum, modeled emissions must include:

SO_2	sulfur dioxide
NO_x	oxides of nitrogen
$PM_{2.5}$	particles with diameter less than 2.5μm
$PM_{10-2.5}$	particles with diameters greater than 2.5μm but less than or equal to 10 μm

If the fraction of PM_{10} in the $PM_{2.5}$ (fine) and $PM_{10-2.5}$ (coarse) categories cannot be determined all particulate matter should be assumed to be $PM_{2.5}$.

In addition, direct emissions of sulfate (SO_4) should be included where possible. Sulfate can be emitted as sulfuric acid (H_2SO_4), sulfur trioxide (SO_3), or as sulfate compounds; emissions should be quantified as the equivalent mass of SO_4.

When test or engineering data are not available to specify SO_4 emissions or the relative fractions of fine and coarse particles, use can be made of speciation profiles available from Federal Land Managers at the website http://ww2.nature.nps.gov/air/permits/ect/index.cfm. Profiles are available for a number of source type and control technology combinations. The FLM speciation factors are acceptable if data are available for the appropriate source type.

Emissions of VOC (volatile organic compounds), condensable organics measured in stack tests, and elemental carbon components of PM_{10} do not need to be included for BART modeling. The only other pollutant noted in EPA BART guidance is ammonia (NH_3). Though ammonia is not believed to be a significant contributor to visibility impairment in most cases in Wyoming, it could be important for sources with significant ammonia emissions – for example from some NO_x control systems. Sources that are expected to emit ammonia (in pre-or post-control configurations) should include ammonia emissions in their model input.

If quantitative baseline emissions data are unavailable and sources believe that the maximum 24-hour emission rates estimated by the Division (presented in the Subject-to-BART final report) are representative of baseline conditions for their facility, they may be used for baseline modeling. However, emissions of sulfate and ammonia (if applicable) should be included based on the best available test information or speciation factors from current literature.

3.2 Post-Control Modeling

All pollutants described above should be included for each post-control scenario. Post-control emissions (maximum 24-hour average) will generally be the baseline emissions multiplied by a control factor appropriate to the BART control. However, some proposed controls may simply increase the efficiency of existing controls; others may result in an increase in emissions of one pollutant while controlling another. These factors must all be considered in defining emission rates for post-control modeling. Any changes in stack parameters resulting from control application must also be included.

The required visibility assessment will include the effect of each proposed BART control. For example, if a source proposes to add a scrubber for SO_2 control, low NO_x burners for NO_x control, and a baghouse for particulate control, four sets of visibility results should be developed:

- Use of SO_2 control alone
- Use of NO_x control alone
- Use of particulate control alone
- Use of proposed combination of all three controls

All pollutants should be modeled in each CALPUFF model run, but the modeled emissions should reflect only the specific controls or combination of controls addressed in that run.

Additional modeling could be necessary in situations where a facility is comprised of more than one subject-to-BART source, and different BART controls are applicable to different sources. Excessive modeling to address multiple control combinations is not necessary; however, visibility modeling should quantify the effect of BART controls on all affected sources for each pollutant, and of all facility BART controls combined.

4.0 METEOROLOGICAL DATA

Wyoming AQD will provide MM5 meteorological data fields for years 2001, 2002, and 2003 that can be utilized as input to CALMET. The MM5 output will have 12 kilometer resolution and cover the full domain shown in Figure 1.

Mesoscale meteorological data (MM5) were developed and evaluated as part of the AQD's southwest Wyoming NO_2 increment analysis. Three years of MM5 data at 36 km resolution were used to initialize 12 km MM5 simulations. The 12km MM5 modeling used identical physics options to the original 36 km runs. CALMM5 was then used as a preprocessor to produce CALMET – ready MM5 data input files. Quality assurance was performed by comparing the original MM5 output on the 36km national RPO grid to the 12 km MM5 output and observations.

The CALMET model (version 5.53a, level 040716) should be used to prepare meteorological input for CALPUFF. The user may select a domain smaller than the MM5 domain for CALMET and CALPUFF modeling if desired. Figure 1 shows minimum domain areas for modeling of western and eastern Wyoming BART sources. Four kilometer resolution should be specified for CALMET output.

CALMET processing should use the AQD MM5 data, and appropriate surface, upper air, and precipitation data. Figure 2 shows the locations of surface and upper air stations within the MM5 model domain. The MM5 data are used as the initial guess wind field; this wind field is then adjusted by CALMET for terrain and land use to generate a step 1 wind field, and refined using surface and upper air data to create the final step 2 wind field.

Surface, upper air, and precipitation data can be obtained from the National Climatic Data Center. Land use and terrain data are available from the U.S. Geological Survey. Data can be formatted for use in CALMET with standard conversion and processing programs available with the CALMET/CALPUFF software.

Table 3 provides a listing of applicable CALMET input variables for BART meteorological processing. The table includes inputs that are specific to Wyoming BART modeling. Inputs not shown in Table 3 are not relevant to the present application, are dependent on the specific model domain of the user, use model default values, or are obvious from the context.

Table 3. CALMET Control File Inputs

Variable	Description	Value
	Input Group 1	
IBYR	Year	2001
		2002
		2003
IBTZ	Base time zone	7
IRTYPE	Run type	1
LCALGRD	Compute data fields for CALGRID	T
	Input Group 2	
PMAP	Map projection	LCC
DGRIDKM	Grid spacing (km)	4
NZ	Number of layers	10
ZFACE	Cell face heights (m)	0
		20
		40
		100
		140
		320
		580
		1020
		1480
		2220
		3500
	Input Group 4	
NOOBS	No observation Mode	0
	Input Group 5	
IWFCOD	Model selection variable	1
IFRADJ	Froude number adjustment	1
IKINE	Kinematic effects	0
IOBR	Use O'Brien procedure	0
ISLOPE	Slope flow effects	1
IEXTRP	Extrapolate surface wind observations	-4
ICALM	Extrapolate calm surface winds	0
BIAS	Biases for weights of surface and upper air stations	All 0
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14
ISTEPPG	Time Step (hours)	1
LVARY	Use varying radius of influence	F

Table 3. CALMET Control File Inputs (continued)

Variable	Description	Value
RMAX 1	Maximum radius of influence (km)	30
RMAX 2	Maximum radius of influence (km)	50
RMIN	Minimum radius of influence (km)	0.1
TERRAD	Radius of influence for terrain (km)	15
R1	Relative weighting of first guess wind field and observations (km)	5
R2	Relative weighting aloft (km)	25
IDIOPT 1	Surface temperature	0
IDIOPT 2	Upper air lapse rate	0
ZUPT	Lapse rate depth (m)	200
IDIOPT 3	Average wind components	0
IUPWND	Upper air station	-1
ZUPWND (1) ZUPWND (2)	Bottom and top of layer for domain scale winds (m)	1, 1000 1, 1000
IDIOPT4	Surface wind components	0
IDIOPT5	Upper air wind components	0
	Input Group 6	
IAVEZI	Spatial averaging	1
MNMDAV	Max search radius	1
HAFANG	Half angle for averaging (deg)	30
ILEVZI	Layer of winds in averaging	1
ZIMAX	Maximum overland mixing height (m)	3500
ITPROG	3D temperature source	1
IRAD	Interpolation type	1
TRADKM	Radius of influence – temperature (km)	500
NUMTS	Maximum number of Stations	5
IAVET	Spatial averaging of temperatures	1
NFLAGP	Precipitation interpolation	2

5.0 CALPUFF MODEL APPLICATION

The CALPUFF model (version 5.711a, level 040716) will be used to calculate pollutant concentrations at receptors in each Class I area. Application of CALPUFF should, in general, follow the guidance presented in the Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 report (EPA – 454/R98-019) and the EPA Regional Haze Regulations and Guidelines for BART Determinations (70 FR 39103).

Appropriate CALPUFF control file inputs are in Table 4. Note should be taken of the basis for several of the recommended CALPUFF inputs.

- Building downwash effects need not be included. Because of the transport distances involved and the fact that most sources have tall stacks, building downwash is unlikely to have a significant effect on model-predicted concentrations

- Puff splitting is not required. The additional computation time necessary for puff splitting is not justified for purposes of BART analyses.

- Hourly ozone files should be used to define background ozone concentration. Data are available from the following sites within the model domain.
  Rocky Mountain NP, CO
  Craters of the Moon NP, ID
  AIRS – Highland UT
  Mountain Thunder, WY
  Yellowstone NP, WY
  Centennial, WY
  Pinedale, WY

  The background ozone concentration shown in Table 4 is used only when hourly data are missing.

- A constant background ammonia concentration of 2.0 ppb is specified. This value is based upon monitoring data from nearby states and IWAQM guidance. Experience suggests that 2.0 ppb is conservative in that it is unlikely to significantly limit nitrate formation in the model computations.

- MESOPUFF II chemical transformation rates should be used.

- The species to be modeled should be the seven identified in CALPUFF: SO_2, SO_4, NO_x, HNO_3, NO_3, $PM_{2.5}$, and $PM_{10\text{-}2.5}$. If ammonia (NH_3) is emitted it should be added to the species list. In most cases, all pollutants modeled will also be emitted, except for HNO_3 and NO_3.

Concentration calculations should be made for receptors covering the areas of the Class I areas being addressed. Receptors in each Class I area will be those designated by the Federal Land Managers and available from the National Park Service website.

Table 4. CALPUFF Control File Inputs

Variable	Description	Value
	Input Group 1	
METRUN	Control parameter for running all periods in met file	1
IBYR	Starting year	2001 2002 2003
XBTZ	Base time zone	7
NSPEC	Number of chemical species modeled	7 (or 8)
NSE	Number of species emitted	5 (or 6)
METFM	Meteorological data format	1
	Input Group 2	
MGAUSS	Vertical distribution in near field	1
MCTADJ	Terrain adjustment method	3
MCTSG	Subgrid scale complex terrain	0
MSLUG	Elongated puffs	0
MTRANS	Transitional plume rise	1
MTIP	Stack tip downwash	1
MSHEAR	Vertical wind shear	0
MSPLIT	Puff splitting allowed?	0
MCHEM	Chemical mechanism	1
MAQCHEM	Aqueous phase transformation	0
MWET	Wet removal	1
MDRY	Dry deposition	1
MDISP	Dispersion Coefficients	3
MROUGH	Adjust sigma for roughness	0
MPARTL	Partial plume penetration of inversions	1
MPDF	PDF for convective conditions	0
	Input Group 4	
PMAP	Map projection	LCC
DGRIDKM	Grid spacing	4

Table 4. CALPUFF Control File Inputs (continued)

ZFACE	Cell face heights (m)	0
		20
		40
		100
		140
		320
		580
		1020
		1480
		2220
		3500
	Input Group 6	
NHILL	Number of terrain features Input Group 7	0
Dry Gas Depo	Chemical parameters for dry gas deposition	Defaults
	Input Group 8	
Dry Part. Depo	Size parameters for dry particle deposition SO_4, NO_3, PM25 PM10	 Defaults 6.5, 1.0
	Input Group 11	
MOZ	Ozone Input option	1
BCK03	Background ozone – all months (ppb)	44.0
BCKNH3	Background ammonia – all months (ppb)	2.0
	Input Group 12	
XMAXZI	Maximum mixing height (m)	3500
XMINZI	Minimum mixing height (m)	50

6.0 POST PROCESSING

Visibility impacts are calculated from the CALPUFF concentration results using CALPOST. CALPOST version 5.51, level 030709 should be used; the output from CALPOST will provide the highest deciview impact on each day from all receptors within each Class I area modeled.

For some CALPUFF applications such as deposition calculations, the POSTUTIL program is used prior to CALPOST. POSTUTIL is also used to repartition total nitrate by accounting for ammonia limiting. The ammonia limiting calculation in POSTUTIL should not be applied for Wyoming BART modeling. If you believe that ammonia limiting is appropriate for a specific BART analysis, justification should be discussed with the Division prior to its used.

Visibility calculations by CALPOST for BART purposes use Method 6. This method requires input of monthly relative humidity factors, f(RH), for each Class I area. The EPA guidance document provides appropriate data for each area. Table 5 lists monthly f(RH) factors to use for the Wyoming, Colorado, and South Dakota areas to be addressed in BART modeling. The factors shown in Table 5 include averages for the adjacent Class I areas, and are within 0.2 units of the Guideline table values for the individual Class I areas.

Natural background conditions as a reference for determination of the delta-dv change due to a source should be representative of the 20% best natural visibility days. EPA BART guidance provides the 20% best days deciview values for each Class I area on an annual basis, but does not provide species concentration data for the 20% best background conditions. These concentrations are needed for input to CALPOST.

Annual species concentrations corresponding to the 20% best days were calculated for each Class I area to be addressed, by scaling back the annual average concentrations given in Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule (Table 2-1). A separate scaling factor was derived for each Class I area such that, when multiplied by the Guidance table annual concentrations, the 20% best days deciview value for that area would be calculated. The scaled aerosol concentrations were averaged for the Bridger and Fitzpatrick WAs, and for Wind Cave and Badlands NPs, because of their geographical proximity and similar annual background visibility. The 20% best days aerosol concentrations to be used for each month for Wyoming BART evaluations are listed in Table 6.

Table 7 is a list of inputs for CALPOST. These inputs should be used for all BART visibility calculations. Output from CALPOST should be configured to provide a ranked list of the highest delta-deciview values in each Class I area. The 98th percentile delta-deciview value and the number of values exceeding 0.5 can then be determined directly from the CALPOST output.

Table 5. Monthly f(RH) Factors for Class I Areas

Month	Wind Cave NP Badlands NP	Bridger WA Fitzpatrick WA	Mt. Zirkel WA
January	2.65	2.50	2.20
February	2.65	2.30	2.20
March	2.65	2.30	2.00
April	2.55	2.10	2.10
May	2.70	2.10	2.20
June	2.60	1.80	1.80
July	2.30	1.50	1.70
August	2.30	1.50	1.80
September	2.20	1.80	2.00
October	2.25	2.00	1.90
November	2.75	2.50	2.10
December	2.65	2.40	2.10

Table 6. Natural Background Concentrations of Aerosol Components for 20% Best Days for BART Analyses ($\mu g/m^3$)

Aerosol Component	Wind Cave NP Badlands NP	Fitzpatrick WA Bridger WA	Mt. Zirkel WA
Ammonium Sulfate	.047	.045	.046
Ammonium Nitrate	.040	.038	.038
Organic Carbon	.186	.178	.179
Elemental Carbon	.008	.008	.008
Soil	.198	.189	.190
Coarse Mass	1.191	1.136	1.141

Table 7. CALPOST Control File Inputs

Variable	Description	Value
	Input Group 1	
ASPEC	Species to Process	VISIB
ILAYER	Layer/deposition code	1
A,B	Scaling factors	0,0
LBACK	Add background concentrations?	F
BTZONE	Base time zone	7
LVSO4	Species to be included in extinction	T
LVNO3		T
LVOC		F
LVPMC		T
LVPMF		T
LVEC		F
LVBK	Include background?	T
SPECPMC	Species name for particulates	PM10
SPECPMF		PM25
EEPMC	Extinction efficiencies	0.6
EEPMF		1.0
EEPMCBK		0.6
EESO4		3.0
EENO3		3.0
EEOC		4.0
EESOIL		1.0
EEEC		10.0
MVISBK	Visibility calculation method	6
RHFAC	Monthly RH adjustment factors	Table 5
BKSO4	Background concentrations	Table 6
BKNO3		Table 6
BKPMC		Table 6
BK OC		Table 6
BKSOIL		Table 6
BKEC		Table 6
BEXTRAY	Extinction due to Rayleigh scattering	10.0

7.0 REPORTING

A report on the BART visibility analysis should be submitted that clearly compares impacts for post-control emissions to those for baseline emissions. Data for baseline and BART scenarios should include both the 98th percentile values and the number of days with delta-deciview values exceeding 0.5. Results should be given for each model year.

Table 8 is an example of a recommended format for presentation of model input and model results. The example is for baseline conditions; similar tables should be provided for each control scenario (SO_2, NO_x, and PM10) and for the combination of all BART controls. Your report tables need not follow the exact format shown in Table 8; but the same information should be provided in a concise and clear form. If additional scenarios were modeled or you wish to present supplemental information, they should be provided in an appendix or separate from the specified final results.

Table 8. Example Format for Presentation of Model Input and Results

Baseline Conditions Model Input Data

Source (Unit) Description And ID	SO_2 Emission Rate (lb/day)	NO_x Emission Rate (lb/day)	$PM_{2.5}$ Emission Rate (lb/day)	$PM_{10-2.5}$ Emission Rate (lb/day)	SO_4 Emission Rate (lb/day)	NH_3 Emission Rate (lb/day)	Location Easting UTM (m)	Location Northing UTM (m)	Stack Height (m)	Stack Diameter (m)	Exit Velocity (m/s)	Exit Gas Temp (deg K)

Baseline Visibility Modeling Results

Name of Facility	Class I Area	2001		2002		2003	
		98th Percentile Value (dv)	No. of days exceeding 0.5 dv	98th Percentile Value (dv)	No. of days exceeding 0.5 dv	98th Percentile Value (dv)	No. of days exceeding 0.5 dv