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February 1, 2012

VIA ELECTRONIC AND U.S. MAIL

PUC Filing Center
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308-2148

Re: UE 233 – Idaho Power Company's Application for Authority to Increase its Rates and Charges for Electric Service to its Customers in the State of Oregon

Attention Filing Center:

Enclosed in the above-referenced docket are an original and five copies of Idaho Power's Supplemental Testimony of John Castensen. A copy of this filing has been served on all parties to this proceeding as indicated on the attached Certificate of Service.

Please contact me with any questions.

Very truly yours,

Wendy McIndoo

Wendy McIndoo
Office Manager

Enclosures

cc: Service List

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document in UE 233 on the following named person(s) on the date indicated below by email addressed to said person(s) at his or her last-known address(es) indicated below.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

DOCKET NO. UE 233

IN THE MATTER OF THE APPLICATION	)
OF IDAHO POWER COMPANY FOR	)
AUTHORITY TO INCREASE ITS RATES	)
AND CHARGES FOR ELECTRIC	)
SERVICE TO ITS CUSTOMERS IN THE	)
STATE OF OREGON.	)
	)

IDAHO POWER COMPANY

SUPPLEMENTAL TESTIMONY

OF

JOHN CARSTENSEN

February 1, 2012

Q. Please state your name and business address.

A. My name is John Carstensen and my business address is 1221 West Idaho Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Project Engineering Leader in the Power Supply department.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Mechanical Engineering from Brigham Young University.

Q. Please describe your work experience with Idaho Power.

A. In April 1991, I accepted a position as Engineer with Idaho Power in the Generation Engineering department. In December 1994, I changed departments from Generation Engineering to Thermal Production. I am currently an Engineering Project Leader in the Joint Projects Department. I am responsible for the operations, maintenance, and engineering for Idaho Power's three co-owned coal-fired facilities (Jim Bridger, Boardman, and North Valmy). I am the Idaho Power representative on the Ownership and Engineering committees for these facilities.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to establish the prudence of approximately $8.2 million of incremental investment at Unit 3 of the Jim Bridger power plant ("Jim Bridger Unit 3") related to the installation of pollution control equipment during 2011 ("the Jim Bridger Unit 3 Scrubber Upgrade Project"). The Company has requested that the Oregon jurisdictional share of this investment be included in rate base and the associated revenue requirement be recovered through rates as part of this proceeding.

My testimony provides an overview of the project and details the specific equipment installed. My testimony also provides the regulatory requirements that drove the project. Finally, my testimony will describe the economic analyses that were prepared to support the decision to pursue the project and demonstrate the prudence of the investment.

Q. Please briefly describe Jim Bridger Unit 3.

A. Jim Bridger Unit 3 is one of four pulverized coal units making up the Jim Bridger Station, located approximately 35 miles northeast of Rock Springs, Wyoming. Jim Bridger Unit 3 is co-owned by Idaho Power and PacifiCorp, and is operated by PacifiCorp.

Q. Please briefly describe the Jim Bridger Unit 3 Scrubber Upgrade Project.

A. In 2011, PacifiCorp and Idaho Power initiated a project that would upgrade the existing scrubbers, designed to improve the removal of sulfur dioxide ("SO_2") from the plant emissions. The work was completed in the spring of 2011, during a planned outage. The Company's share of the capital investment in the project is $8.2 million during the test year.

Q. Was the investment in the Jim Bridger Unit 3 Scrubber Upgrade Project required to comply with existing regulations?

A. Yes. The investment in the scrubber upgrade presented in this case was required to comply with existing regulations including Regional Haze Rules, National Ambient Air Quality Standards, the Regional SO_2 Milestone and Backstop Trading Program developed in alignment with existing federal regulations and administered in Utah and Wyoming, state-issued construction and operating permits, and state implementation plans.

Q. Please describe the Regional Haze Rule.

A. The Regional Haze Rule ("RHR") was established by the Federal Environmental Protection Agency ("EPA") in 1999 to address regional haze in 156 national parks and wilderness areas in the United States. Under these regulations, states are required to develop strategies to reduce emissions that contribute to regional haze and demonstrate "reasonable progress" toward emissions reductions. In compliance with these regulations, the states of Wyoming, Utah, and New Mexico formed the Regional SO_2 Milestone and Backstop Trading Program, which established annual emissions targets from 2003 to 2018. Emissions targets under the Regional SO_2 Milestone and Backstop Trading Program represent "reasonable progress" under the RHR. Failure to meet the annual targets would trigger increased emissions regulations including the implementation of an emissions cap and trading program.

Q. What events initially led the owners to consider the upgrade of the scrubbers?

A. The Regional SO_2 Milestone and Backstop Trading Program for the combined states of Wyoming, Utah, and New Mexico established an SO_2 reduction plan that created specific milestones of SO_2 emissions reductions that would be required for compliance. A consensus was reached between PacifiCorp and the State of Wyoming to develop a plan what would achieve these milestones, and would also meet the expected requirements of upcoming environmental regulations, such as Regional Haze Best Available Retrofit Technology ("RH BART"), National Ambient Air Quality Standards (which includes the 1 Hour SO_2 Standards), along with meeting the surrogate level for compliance with the Mercury and Air Toxics Standards ("MATS") Acid Gas requirement. It was determined that each of the four Jim Bridger units would need to meet an emission limit of 0.15 lb/MMBtu, along with emission reductions from the other Wyoming coal-fired plants in order for the State of Wyoming to meet the established milestones. This rate of 0.15 lb/MMBtu is also considered "Presumptive BART" by the Federal EPA in the Regional Haze Rules, Appendix Y, for the boiler type and coal that is used at the Jim Bridger plant. The Jim Bridger Unit 3 Scrubber Upgrade Project is the last of the four upgrades that have been completed at the Jim Bridger plant.

Q. Please provide a brief overview of the National Ambient Air Quality Standards and MATS.

A. As required by the Clean Air Act, the Federal EPA established the National Ambient Air Quality Standard, which establishes allowable levels (as measured in parts per million) of pollutants considered to be harmful to public health and the environment. The standard regulates carbon monoxide, lead, nitrogen oxides (NOx), ozone, particle pollution, and SO_2.

MATS, established by the Federal EPA in 2011, sets emissions limits for coal-fired generators larger than 25 megawatts. The rule establishes numerical limits for mercury, SO_2, toxic non-mercury metals, and all toxic gases. According to the EPA, the goal of MATS is to prevent 90 percent of the mercury in coal burned at power plants from being emitted into the air.

Q. How did the owners ultimately conclude that the scrubber upgrade was needed?

A. PacifiCorp, completed detailed analyses of the appropriate technology to be applied to this BART-eligible facility to achieve established emissions control objectives. After a thorough analysis, the owners concluded that upgrading the scrubbers presented a cost-effective method to bring the Jim Bridger Unit 3 into compliance with current, proposed and probable environmental regulations. Further, the scrubber upgrade investment described in my testimony is required by the permit terms and conditions issued in response to the environmental requirements described herein and support the Company's ongoing efforts to reduce SO_2 emissions in Wyoming.

The Company believes that this investment is complementary to and consistent with RH BART planning requirements intended to improve the visibility in certain national parks and wilderness areas, and that it exemplifies a reasonable approach to achieving emission reductions in Wyoming. The emission reductions that result from this project have been incorporated into the approved operating permit for Jim Bridger Unit 3. Additional information supporting the post-project cost-effectiveness of this unit is provided in testimony below.

Q. Please describe how the scrubber upgrade works.

A. The scrubber upgrade project at Jim Bridger Unit 3 will result in improved SO_2 removal by upgrading the existing system equipment such as recycle pumps, reagent supply piping and appurtenances, scrubber vessel internals (trays, piping, and nozzles); induced draft fans; install variable frequency drives; and install the associated power distribution, controls, and appurtenances.

Q. Are Jim Bridger Unit 3 SO_2 emissions reductions required to comply with the Regional SO_2 Milestone and Backstop Trading Program?

A. Yes. Jim Bridger Unit 3 emissions must comply with all requirements of the Regional SO_2 Milestone and Backstop Trading Program, in accordance with Chapter 14, Sections 2 and 3, of the Wyoming Air Quality Standards and Regulations ("WAQSR"). The SO_2 Backstop Trading Program utilizes presumptive BART SO_2 emission rate for Jim Bridger Unit 3 of 0.15 lb/MMBtu. The investment in the Jim Bridger Unit 3 wet flue gas desulfurization ("FGD") system will meet this emission threshold and will also support compliance with the EPA's MATS for acid gases.

Q. How does the Company's Jim Bridger Unit 3 Scrubber Upgrade Project specifically support the Regional Haze Program being administered by the State of Wyoming, and the associated Regional SO_2 Milestone and Backstop Trading Program?

A. Jim Bridger Unit 3 was previously configured with a wet scrubber with permitted SO_2 emission limits of 0.30 lb/MMBtu. The Jim Bridger Unit 3 Scrubber Upgrade Project will result in the removal of approximately 4,500 tons of SO_2 emissions per year and will support continued operation of this cost-effective generation facility, while maintaining compliance with permitted SO_2 emissions limits consistent with presumptive BART performance and supporting established regional compliance milestones.

Q. Are operational capabilities afforded by the Jim Bridger Unit 3 Scrubber Upgrade Project also expected to support compliance with the Mercury and Air Toxics Standards requirements proposed in March 2011 and the final rule signed in December 2011?

A. Yes. Based on the MATS emission limits, the operational capabilities afforded by the Jim Bridger Unit 3 Scrubber Upgrade Project will directly support MATS compliance related to the reduction of acid gas emissions by using the SO_2 surrogate instead of meeting the reduced requirements for each of the 10 acid gases.

Q. Please describe the engineering and economic analyses that support the decision to pursue this project.

A. In compliance with Regional Haze regulations and guidelines, PacifiCorp commissioned a study prepared by CH2M HILL that contained a number of engineering and economic analyses related to Jim Bridger Unit 3. The analyses were conducted for the Final Report - BART Analysis for Jim Bridger Unit 3, and the Addendum to Jim Bridger Unit 3 BART Report as submitted to the Wyoming Division of Air Quality on January 12, 2007, and March 26, 2008, respectively. These analyses assessed costs and benefits of a range of alternatives in the form of different scenarios of pollution control equipment. These scenarios include low NOx burners ("LNBs") with over-fire air ("OFA"), sodium based FGD, SO_3 (sulfur trioxide) injection, and selective catalytic reduction ("SCR"). The economic analyses modeled technology alternatives and evaluated the potential reductions in NOx, SO_2, and PM10 (particulate matter less than 10 microns in aerodynamic diameter) emissions rates associated with the respective scenarios. A comparison was completed on the basis of costs, design control efficiencies, and tons of pollutant removed. The Final Report - BART Analysis for Jim Bridger Unit 3 is included as Exhibit 1301 and the Addendum to Jim Bridger Unit 3 BART Report is included as Exhibit 1302.

While the CH2M HILL analysis compared four separate comprehensive pollution control investment scenarios, the Jim Bridger 3 Scrubber Upgrade Project was included in all four scenarios analyzed. As can be seen on page 29 of Exhibit 1301 (page S-14 of the report), the Jim Bridger 3 Scrubber Upgrade Project, identified as "Upgrade Existing Wet Sodium System," was determined by CH2M HILL to be the only technically feasible retrofit technology to meet the regulatory presumptive limit of 95 percent reduction in SO_2 emissions or 0.15 lb/MMBtu. Therefore, the scrubber upgrade project was ultimately included as part of CH2M HILL's recommended least-cost pollution control investment scenario.

Q. What economic analysis methodology was applied by CH2M HILL in its BART scenario analyses for Jim Bridger Unit 3?

A. CH2M HILL applied the EPA's preferred methodology referred to as the Least-Cost Envelope Analysis Methodology. CH2M HILL describes this approach on page ES-4 of the Final Report - BART Analysis for Jim Bridger Unit 3, Exhibit 1, p. 5:

"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 a total emissions reductions for all control alternatives identified in the BART analysis."

Q. Was the Company's $8.2 million investment in the Jim Bridger Unit 3 Scrubber Upgrade Project consistent with the conclusions and recommendations reached in the CH2M HILL reports?

A. Yes. CH2M HILL recommended an upgrade to the existing wet sodium FGD system at the Jim Bridger plant and concluded that the upgrade would be considered BART for compliance with the Regional Haze Program. This is 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.

Q. Has the Wyoming Division of Air Quality acknowledged the analyses, conclusions, and recommendations contained in the Final Report - BART Analysis for Jim Bridger Unit 3 and the Addendum to Jim Bridger Unit 3 BART Report?

A. Yes. On December 31, 2009, the Wyoming Division of Air Quality issued a RH BART permit to PacifiCorp for the Jim Bridger power plant. This permit stated that Jim Bridger Unit 3 will comply with the provisions of the Regional SO_2 Milestone and Backstop Trading Program which is also consistent with the RH BART Analysis and with the presumptive BART SO_2 emission limit of 0.15 lb/MMBtu.

Q. Have the costs of the project been prudently managed?

A. Yes. The scrubber upgrade project described above has been contracted under lump-sum, turnkey, Engineer, Procure and Construct ("EPC") contract terms which resulted from competitive bidding processes. As the plant operator and majority owner, PacifiCorp management provided oversight of the project and closely managed any project execution plan changes or potential contract scope changes. PacifiCorp and Idaho Power share the belief that this project and its timing appropriately balance the need for emission reductions over time with the costs and other concerns of our customers, our state utility regulatory commissions, and other stakeholders.

Q. Please summarize your testimony.

A. The pollution control equipment investment presented in this case is required to comply with current, proposed, and probable environmental regulations. This investment allows for the continued operation of a low-cost coal-fired generation facility, while achieving significant environmental improvements. The capital investment included in this case is reasonable and prudent, and the Company should be granted full cost recovery for this investment.

Q. Does that conclude your testimony?

A. Yes, it does.

Idaho Power/1301
Witness: John Carstensen

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of John Carstensen
Final Report – BART Analysis for Jim Bridger Unit 3

February 1, 2012

Final Report

BART Analysis for Jim Bridger Unit 3

Prepared For:

PacifiCorp
1407 West North Temple
Salt Lake City, Utah 84116

January 12, 2007

Prepared By:

CH2MHILL
215 South State Street, Suite 1000
Salt Lake City, Utah 84111

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 3 (hereafter referred to as Jim Bridger 3). A BART analysis has been conducted for the following criteria pollutants: oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 microns 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 3, based on the United States Environmental Protection Agency's (EPA) guidelines. BART emissions limits must be achieved within five 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:

NOx emission controls:

- Low NO_x burners with over-fire air
- Rotating opposed fire air
- Low NO_x burners with selective non-catalytic reduction system (SNCR)
- Low NO_x burners 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 lb/MMBtu
- New dry FGD system

PM_{10} emission controls:

- Sulfur trioxide (SO_3) injection flue gas conditioning system on existing electrostatic precipitator
- 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:

1. The identification of available, technically feasible, retrofit control options

2. Consideration of any pollution control equipment in use at the source (which affects the availability of options and their impacts)
3. The costs of compliance with the control options
4. The remaining useful life of the facility
5. The energy and non-air quality environmental impacts of compliance
6. The degree of visibility improvement which may reasonably be anticipated from the use of BART

These steps are incorporated into the BART analysis as follows:

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 which 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 3 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 subbituminous, 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 subbituminous coal use 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 3, and has evaluated the effect of these qualities on NO_x formation and achievable emission rates.

Recommendations

NO_x Emission Control

The BART presumptive NO_x limit assigned by EPA for tangentially-fired boilers burning subbituminous coal is 0.15 lb/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 NOx limit of 0.28 lb/MMBtu.

CH2M HILL recommends low-NOx burners with over-fire air (LNB w/OFA) as BART for Jim Bridger 3, 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. NO_x 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/MMBtu.

SO_2 Emission Control

CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for Jim Bridger 3, 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/MMBtu.

PM_{10} Emission Control

CH2M HILL recommends finalizing the permitting of the flue gas conditioning system to enhance the performance of the existing electrostatic precipitator (ESP) as BART for Jim Bridger 3, 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.

Control Scenario 1

These BART selections, which include installing low NOx burners with over-fire air, upgrading the existing FGD system, and operating the existing electrostatic precipitator with an SO_3 flue gas conditioning system, are identified as Scenario 1 throughout this report.

BART Modeling Analysis

CH2M HILL used the CALPUFF modeling system to assess the visibility impacts of emissions from Jim Bridger 3 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 3 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 w/OFA modifications, upgraded wet FGD system, and flue gas conditioning for enhanced ESP performance. As indicated previously, this scenario represents CH2M HILL HILL's preliminary BART recommendation.
- **Scenario 2**: New LNB w/OFA modifications, upgraded wet FGD system, and new polishing fabric filter.
- **Scenario 3**: New LNB w/OFA modifications and SCR, upgraded wet FGD system, and flue gas conditioning for enhanced ESP performance.
- **Scenario 4**: New LNB w/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 draft EPA 1990 New Source Review Workshop Manual (NSR Manual).

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 a 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 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 98th 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 w/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 w/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 w/OFA and SCR, upgraded wet FGD, and polishing fabric filter) provides some potential visibility advantage over Scenario 1, the projected improvement is less than half a dV, and the projected costs are excessive. Therefore, Scenario 1 represents BART for Jim Bridger 3.

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 only minimal discernable visibility improvements may result, even though PacifiCorp will be spending many millions of dollars at this single unit, and over a billion dollars when considering its entire fleet of coal-fired power plants.

Contents

Acronyms and Abbreviations .... **iv**
1.0 Introduction **1-1**
2.0 Present Unit Operation **2-1**
3.0 BART Engineering Analysis **3-1**
3.1 Applicability 3-1
3.2 BART Process 3-1
3.2.1 BART NO_x Analysis 3-2
3.2.2 BART SO_2 Analysis 3-14
3.2.3 BART PM_{10} Analysis 3-16
4.0 BART Modeling Analysis **4-1**
4.1 Model Selection 4-1
4.2 CALMET Methodology 4-1
4.2.1 Dimensions of the Modeling Domain 4-1
4.2.2 CALMET Input Data 4-3
4.2.3 Validation of CALMET Wind Field 4-6
4.3 CALPUFF Modeling Approach 4-6
4.3.1 Background Ozone and Ammonia 4-6
4.3.2 Stack Parameters 4-7
4.3.3 Emission Rates 4-7
4.3.4 Post Control Scenarios 4-7
4.3.5 Modeling Process 4-10
4.3.6 Receptor Grids 4-10
4.4 CALPOST 4-10
Presentation of Modeling Results 4-11
Degree of Visibility Change for Baseline vs. Preferred Scenario 4-11
5.0 Preliminary Assessment and Recommendations **5-1**
5.1 Least-Cost Envelope Analysis 5-1
5.1.1 Analysis Methodology 5-1
5.1.2 Analysis Results 5-8
5.2 Recommendations 5-8
5.2.1 NO_x Emission Control 5-8
5.2.2 SO_2 Emission Control 5-8
5.2.3 PM_{10} Emission Control 5-8
5.3 Just-Noticeable Differences in Atmospheric Haze 5-9
6.0 References **6-1**

Tables

2-1 Unit Operation and Study Assumptions 2-1
2-2 Coal Sources and Characteristics 2-3
3-1 Coal Characteristics Comparison 3-4
3-2 NO_x Control Technology Projected Emission Rates 3-8
3-3 NO_x Control Cost Comparison 3-11
3-4 SO_2 Control Technology Emission Rates 3-14
3-5 SO_2 Control Cost Comparison (Incremental to Existing FGD System) 3-16
3-6 PM_{10} Control Technology Emission Rates 3-18
3-7 PM_{10} Control Cost Comparison (Incremental to Existing ESP) 3-18
4-1 User-Specified CALMET Options 4-3
4-2 BART Model Input Data 4-8
4-3 Average Natural Levels of Aerosol Components 4-11
4-4 Costs and Visibility Modeling Results for Baseline Vs. Post-Control Scenarios at Class I Areas 4-12
5-1 Control Scenario Results for the Bridger Class 1 Wilderness Area 5-2
5-2 Control Scenario Results for the Fitzpatrick Class 1 Wilderness Area 5-3
5-3 Control Scenario Results for the Mt. Zirkel Class 1 Wilderness Area 5-3
5-4 Bridger Class I Wilderness Area Incremental Analysis Data 5-4
5-5 Fitzpatrick Class I Wilderness Area Incremental Analysis Data 5-4
5-6 Mt. Zirkel Class I Wilderness Area Incremental Analysis Data 5-4

Figures

3-1 Illustration of the Effect of Agglomeration on the Speed of Coal Combustion 3-3
3-2 Plot of Typical Nitrogen Content of Various Coals and Applicable Presumptive BART NO_x Limits 3-5
3-3 Plot of Typical Oxygen Content of Various Coals and Applicable Presumptive BART NO_x Limits 3-5
3-4 First Year Control Cost for NO_X Air Pollution Control Options 3-13
3-5 First Year Control Cost for PM Air Pollution Control Options 3-20
4-1 Extent of Modeling Domain 4-2
4-2 Surface and Upper Air Station Locations 4-5
5-1 Least Cost Envelope Bridger Class I WA Days Reduction 5-5
5-2 Least Cost Envelope Bridger Class I WA 98th Percentile Reduction 5-5
5-3 Least Cost Envelope Fitzpatrick Class I WA Days Reduction 5-6
5-4 Least Cost Envelope Fitzpatrick Class I WA 98th Percentile Reduction 5-6
5-5 Least Cost Envelope Mt. Zirkel Class I WA Days Reduction 5-7
5-6 Least Cost Envelope Mt. Zirkel Class I WA 98th Percentile Reduction 5-7

Appendices

A Economic Analysis
B 2006 Wyoming BART Protocol
C Just-Noticeable Differences in Atmospheric Haze - Ronald C. Henry Report

Acronyms and Abbreviations

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
COHPAC	Compact Hybrid Particulate Collector
dV	deciview
DEQ	Department of Environmental Quality
ESP	electrostatic precipitator
EPA	United States Environmental Protection Agency
Fuel NO_x	oxidation of fuel bound oxides of nitrogen
FGC	flue gas conditioning
FGD	flue gas desulfurization
f (RH)	relative humidity factors
ID	internal diameter
kW	kilowatts
kW-Hr	kilowatt-hour
LAER	lowest achievable emission rate
LNB	Low-NO_x burner
LOI	loss on ignition
MMBtu	Million British Thermal Units
MM5	Mesoscale Meteorological Model, Version 5
MW	megawatts
N_2	nitrogen
NO	nitric oxide
NO_x	nitrogen oxides
NWS	National Weather Service
OFA	over fire air
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter
PRB	Powder River Basin
ROFA	Rotating Opposed Fire Air

S&L	Sargent & Lundy
SCR	selective catalytic reduction system
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction system
SO_2	sulfur dioxide
SO_3	sulfur trioxide
Thermal NO_x	high temperature fixation of atmospheric nitrogen in combustion air
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 United States 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[1]. 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/year of visibility-impairing pollutants.

The Wyoming Department of Environmental Quality (DEQ) 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 Wyoming DEQ to submit the BART report for Jim Bridger Unit 3 by January 12, 2007. This report to the Wyoming DEQ must include a BART analysis, and a proposal and justification for BART at the source.

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 five years of EPA's approval of the SIP.

There are five basic elements related to BART, when addressing 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 environmental impacts of compliance
- The degree of improvement in visibility which may reasonably be anticipated from the use of such technology

This report documents the BART analysis that was performed on Jim Bridger 3 by CH2M HILL for PacifiCorp. The analysis was performed for the pollutants NO_x, SO_2, and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}), because they are the primary criteria pollutants that affect visibility.

Section 2.0 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 3.0, by pollutant type. Section 4.0 provides the methodology and results of the BART Modeling Analysis, followed by recommendations in Section 5.0. References are

[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.

provided in Section 6.0. Appendices provide more detail on the Economic Analysis, the 2006 Wyoming BART Protocol, and a paper by Dr. Ronald Henry, titled, *Just Noticeable Differences in Atmospheric Haze*.

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 3 is a nominal 530 net MW unit located approximately 35 miles northeast of Rock Springs, Wyoming. Unit 3 is equipped with a tangentially fired pulverized coal boiler with low NO_x burners 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 1988. An Emerson Ovation distributed control system (DCS) was installed in 2003.

Jim Bridger 3 was placed in service in 1976. 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 3 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 3 to operate until 2040.

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

TABLE 2-1
Unit Operation and Study Assumptions
Jim Bridger 3

General Plant Data	
Site Elevation feet above MSL	6669
Stack Height feet	500
Stack Exit ID feet /Exit Area sq. ft.	24 /452.4
Stack Exit Temperature °F	140
Stack Exit Velocity ft/sec	84.04
Stack Flow ACFM	2,281,182
Latitude deg: min : sec	41:44:18.54 north
Longitude deg: min : sec	108:47:12.82 west
Annual Unit Capacity Factor (%)	90
Net Unit Output (MW)	530
Net Unit Heat Rate (Btu/kW-Hr)(100% load)	10,400 (as measured by fuel throughput)
Boiler Heat Input (MMBtu/Hr)(100% load)	6,000 (as measured by CEM)
Type of Boiler	Tangentially fired
Boiler Fuel	Coal
Coal Sources	Bridger Mine, Black Butte Mine, Leucite Hills Mine
Coal Heating Value (Btu/lb)*	9,660
Coal Sulfur Content (wt. %)*	0.58

TABLE 2-1
Unit Operation and Study Assumptions
Jim Bridger 3

Coal Ash Content (wt. %)*	10.3
Coal Moisture Content (wt. %)*	19.3
Coal Nitrogen Content (wt. %)*	0.98
Current NO_x Controls	Low NO_x burners
NOx Emission Rate (lb/MMBtu)	0.45
Current SO_2 Controls	Sodium based wet scrubber
SO_2 Emission Rate (lb/MMBtu)	0.3
Current PM_{10} Controls	Electrostatic Precipitator
PM_{10} Emission Rate (lb/MMBtu)**	0.057

* Coal characteristics based on Bridger Underground Mine (primary coal source)

** Based on maximum historic emission rate from 1999 – 2001, prior to installation of the SO_3 injection system.

The BART presumptive NO_x limit for tangential-fired boilers burning subbituminous coal is 0.15 lb/MMBtu and the BART presumptive NO_x limit for burning bituminous coal is 0.28 lb/MMBtu. The main sources of coal burned at Jim Bridger 3 are the Bridger Mine and secondarily the Black Butte Mine and Leucite Hills Mine. These coals are ranked as subbituminous, 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 subbituminous coal use 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 3, 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 3.2.1, the data from all the coal sources were used.

TABLE 2-2
Coal Sources and Characteristics
Jim Bridger 3

								Ultimate Analysis (% dry basis)					
Mines	**Moist. %**	**Ash %**	**Volatile Matter %**	**Fixed Carbon %**	**Btu/lb**	**Sulfur %**	**MAF (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
Max	Not enough data yet to run statistical analysis for variability												
Min	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
Max	20.5	12.5	35.5	41.9	9800	0.72	13500	4.69	4.0	0.90	1.43	14.8	15.8
Min	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					
Max	Not enough data yet to run statistical analysis for variability												
Min	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
Max	21.1	10.8	35.4	41.9	10275	0.62	13500	4.66	70.5	0.78	1.69	14.8	13.6
Min	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
Max	23.0	15.0	33.0	43.0	10250	0.90	13800	4.70	70.0	1.20	1.64	17.1	19.0
Min	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 five years after EPA approval of the SIP.

3.2 BART Process

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:

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

These steps are incorporated into the BART analysis as follows:

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 which may reasonably be anticipated from the use of BART

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.

All costs included in the BART analysis are in 2006 dollars (not escalated to 2014 BART implementation date).

3.2.1 BART NO_x Analysis

NO_x 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.

3.2.1.1 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 (NO and NO_2) 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 subbituminous to bituminous and on to anthracite. Lower rank coals, such as the subbituminous 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 low NO_x burners, subbituminous 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 subbituminous 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. subbituminous production and 73 percent of western coal production. Most references to "western" coal and subbituminous coal infer PRB origin and characteristics. Emissions standards differentiating between bituminous and subbituminous coals are presumed to use

PRB coal as the basis for the subbituminous standards, due to their dominant market presence and unique characteristics.

There are a number of western coals that are classified as subbituminous, 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 3 as subbituminous rather than bituminous – that is, 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° 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 by Figure 3-1, the increased porosity provides more particle surface area resulting in more favorable combustion conditions. This non-agglomerating property assists in making subbituminous 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 for the Bridger blends of coals.

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

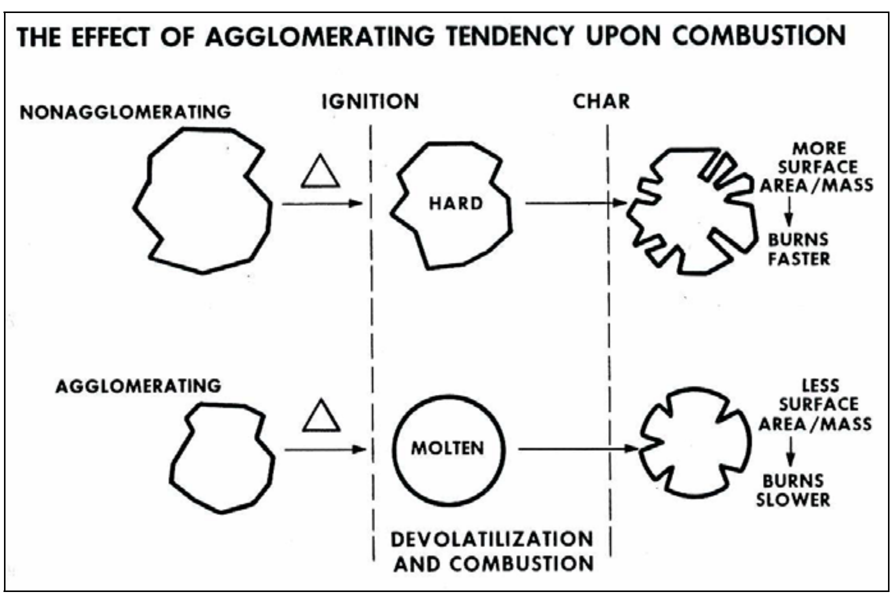


Table 3-1 shows key characteristics of a typical PRB coal compared to coals from the Bridger Mine, Black Butte, and Leucite Hills, as well as Twentymile, which is a representative western bituminous coal.

TABLE 3-1
Coal Characteristics Comparison
Jim Bridger 3

Parameter	Typical PRB	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 subbituminous, 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 low NO_x burners 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 subbituminous 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 3, and indicates the average NO_x emission rate achieved during the years 2003-2005. The Jim Bridger 2 data point consists of the same blend of coals as Jim Bridger 3, 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/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 3 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/MMBtu for subbituminous coal. All these factors are consistent with the observed sustainable rate of 0.24 lb/MMBtu.

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

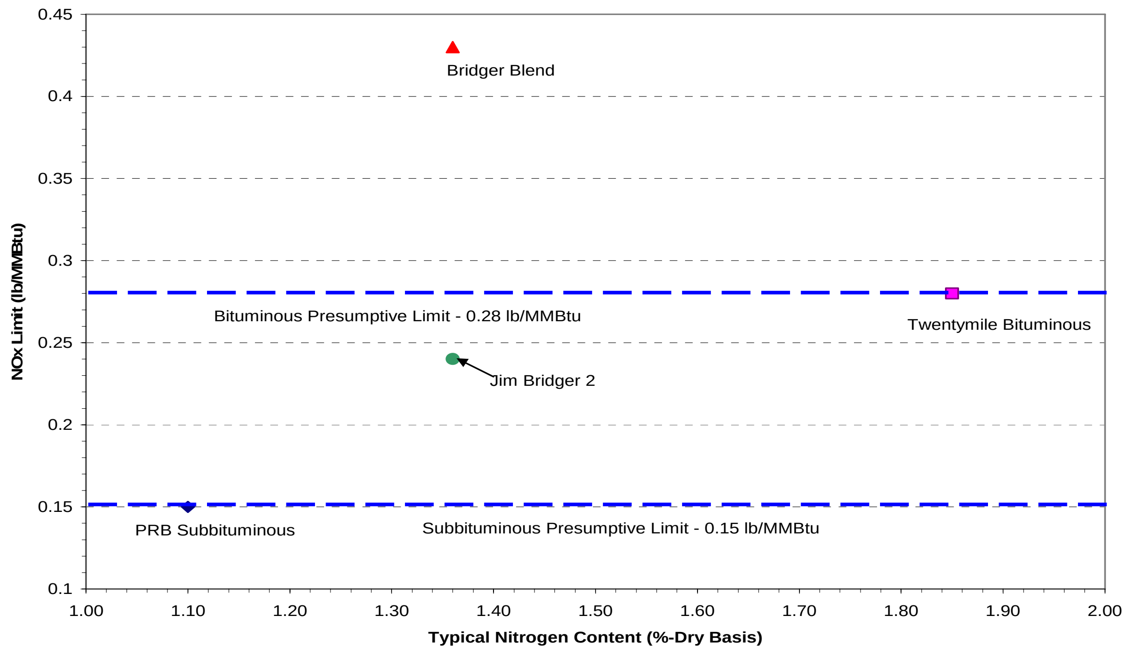
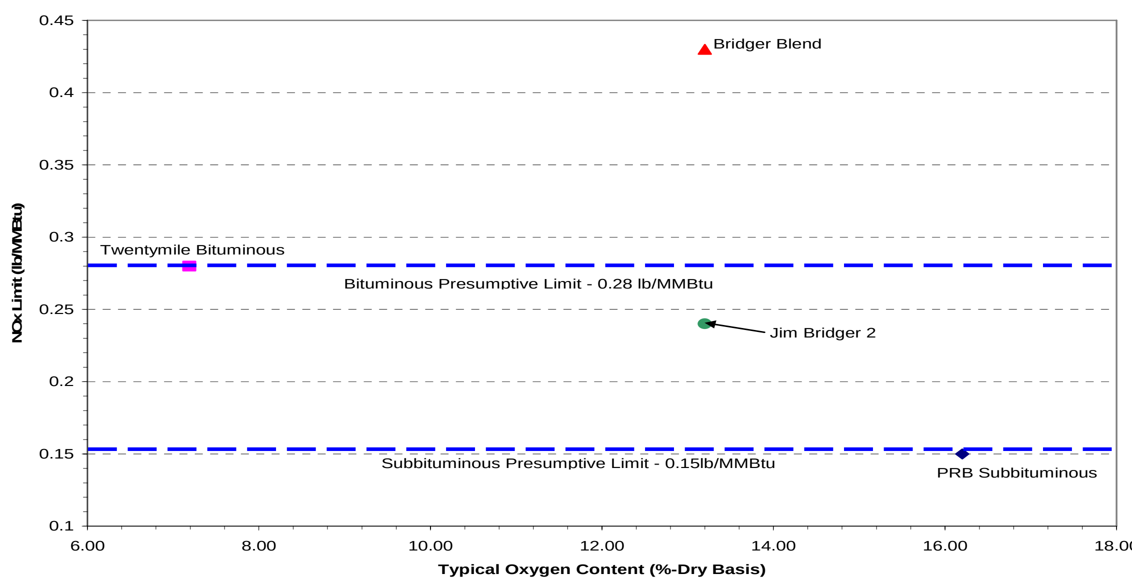


FIGURE 3-3
Plot of Typical Oxygen Content of Various Coals and Applicable Presumptive BART NO_x Limits
Jim Bridger 3



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 3. In addition to burning coal from Black Butte and Leucite Hills, Jim Bridger 3 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 o0f 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 and between other performance issues can result.

Jim Bridger 3 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 reduce NO_x emissions using low NO_x burners and overfire air, 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. NO_x reduction with high volatile coals is improved with greater fineness and with proper air staging. The lower rank subbituminous 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 3, 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 3, the more applicable presumptive BART limit for NO_x emissions is 0.28 lb/MMBtu. The BART analysis for NO_x emissions from Jim Bridger 3 is further described below.

3.2.1.2 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 3, 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. NO_x emissions at Jim Bridger 3 are currently controlled through the use of good combustion practices and OFA.

The following potential NO_x control technology options were considered:

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

3.2.1.3 Step 2: Eliminate Technically Infeasible Options

For Jim Bridger 3, a tangential-fired configuration burning subbituminous 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 NO_x/MMBtu. Jim Bridger 3 has an uncontrolled NO_x emission rate of 0.45 lb/MMBtu.

For this BART analysis, information pertaining to LNBs, OFA, SNCR, and SCR were based on the Multi-Pollutant Control Report dated October, 2002 (S&L Study). The cost estimates for SCR and SNCR were updated by Sargent & Lundy (S&L) in October 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° F to 2,100° F, where it reduces NO_x to nitrogen and water. NO_x reductions of up to 40 to 60 percent have been achieved, although 15 to 30 percent is more realistic for most applications. SNCR 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/MMBTU.

TABLE 3-2
NO_x Control Technology Projected Emission Rates
Jim Bridger 3

Technology	Projected Emission Rate (lb/MMBtu)
Presumptive BART Limit	0.28
LNB w/OFA	0.24
ROFA	0.22
LNB w/OFA & SNCR	0.20
LNB w/OFA & SCR	0.07

3.2.1.4 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, they 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 low NO_x burners 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 3, 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 3 would result in an expected NO_x emission rate of 0.24 lb/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/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 would 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 3.

Mobotec proposes to achieve a NO_x emission rate of 0.18 lb/MMBtu using ROFA technology. An operating margin of 0.04 lb/MMBtu was added to the expected rate due to Mobotec's limited ROFA experience with western subbituminous coals. Under the Mobotec proposal, which is primarily based on ROFA equipment, the operation of existing LNB and OFA ports would 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 would determine the quantity and location of new ROFA ports. The Mobotec proposal includes bent tube assemblies for OFA port installation.

Mobotec would not provide installation services, because they believe that the Owner can more cost effectively contract for these services. However, they would 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. NO_x 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, capable of achieving a projected NO_x emission rate of 0.24 lb/MMBtu. At a further reduction of 15 percent in NO_x emission rates for SNCR would result in a projected emission rate of 0.20 lb/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 3. 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 3.

S&L prepared the design conditions and cost estimates for SCR at Jim Bridger 3. 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 w/OFA and SCR results in a projected NO_x emission rate of 0.07 lb/MMBtu. Additional catalyst surface was included in the SCR design to accommodate the characteristics of the coal used at Jim Bridger 3.

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. Variations may result for 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:

1. Establish expected NO_x emissions value from vendor.
2. Evaluate vendor experience and historical basis for meeting expected values.
3. 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.
4. 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.

3.2.1.5 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 would require installation and operation of two 4,000 to 4,300 Hp ROFA fans (6,410 kW total). The SNCR system would require approximately 520 kW of additional power.

SCR 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 3 are estimated at approximately 3,220 kW, based on the S&L Study.

Environmental Impacts. Mobotec has predicted that 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.

SNCR and SCR installation could impact the salability 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 ±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 presented in Figure 3-4. The complete Economic Analysis is contained in Appendix A.

TABLE 3-3
NO_x Control Cost Comparison
Jim Bridger 3

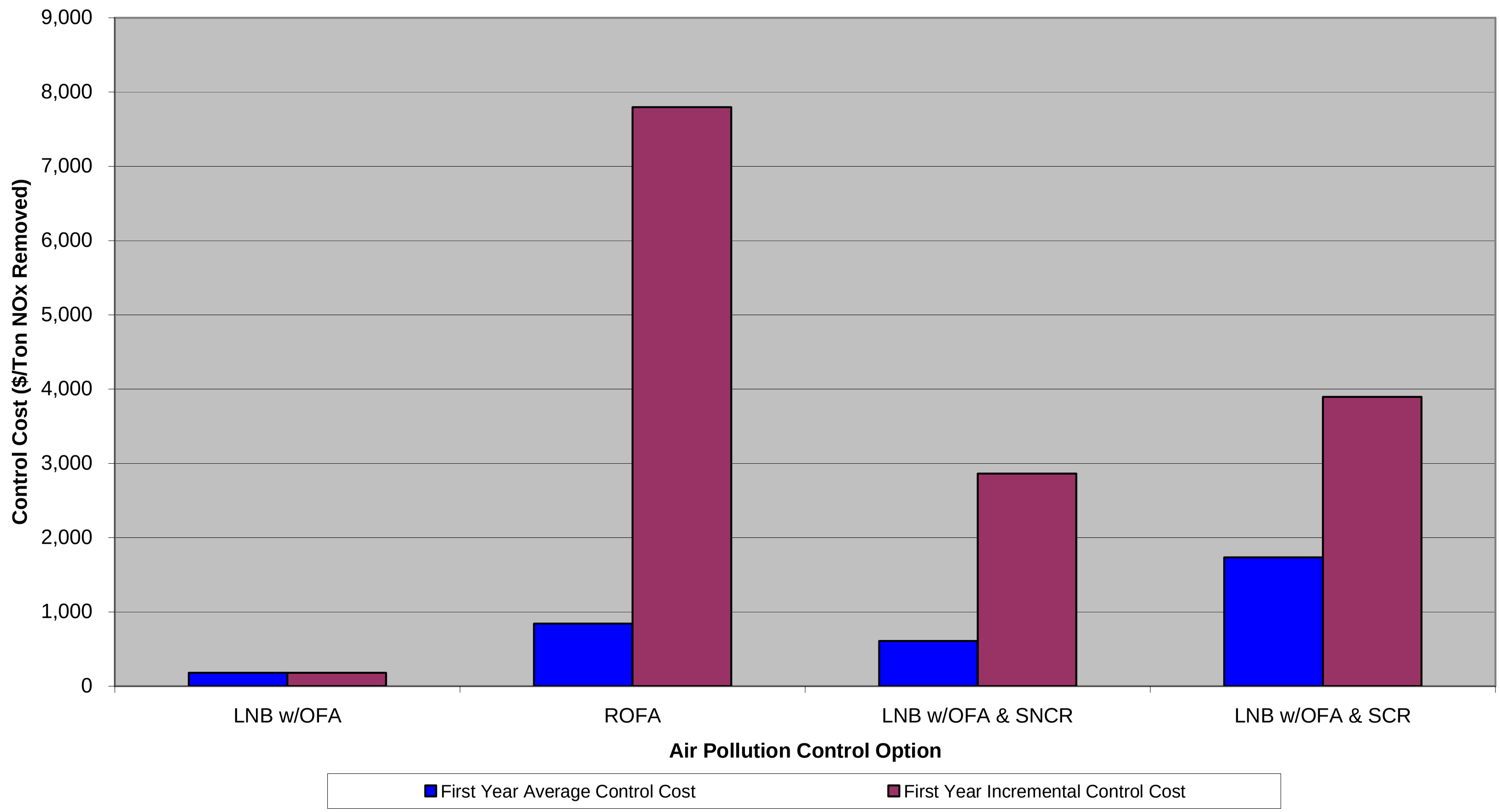
Factor	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR
Total Installed Capital Costs	$8.7 Million	$20.5 Million	22.0 Million	$129.6 Million
Total First Year Fixed & Variable O&M Costs	$0.1 Million	$2.6 Million	$1.5 Million	$3.3 Million
Total First Year Annualized Cost	$0.9 Million	$4.6 Million	$3.6 Million	$15.6 Million
Power Consumption (MW)	0	6.4	0.5	3.3
Annual Power Usage (1000 MW-Hr/Yr)	0	50.6	4.1	25.4
NO_x Design Control Efficiency	46.7%	51.1%	55.6%	84.4%
NO_x Removed per Year (Tons)	4,967	5,440	5,913	8,987
First Year Average Control Cost ($/Ton of NO_x Removed)	$181/ton	$843/ton	$610/ton	$1,734/ton
Incremental Control Cost ($/Ton of NO_x Removed)	$181/ton	$7,797/ton	$2,863/ton	$3,896/ton

Preliminary BART Selection. CH2M HILL recommends selection of low-NO_x burners with OFA as BART for Jim Bridger 3 based on its significant reduction in NO_x emissions, reasonable control cost, and no additional power requirements or environmental impacts. LNB w/OFA does not meet the EPA presumptive limit of 0.15 lb/MMBtu for subbituminous coal, but it does meet an emission rate that falls between the presumptive limit of 0.28 lb/MMBtu for bituminous coal and the limit of 0.15 lb/MMBtu for subbituminous coal. As discussed in the section on coal quality, the recommended technology and the achieved emission rate are deemed appropriate as BART for NOx emissions from the coals combusted at Jim Bridger 3.

3.2.1.6 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

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



3.2.2 BART SO_2 Analysis

SO_2 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 3 is described below.

3.2.2.1 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 3. 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/MMBtu
- New dry FGD system

3.2.2.2 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/MMBtu. Based on the coal that Jim Bridger 3 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/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/MMBtu.

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

Technology	Projected Emission Rate (lb/MMBtu)
Presumptive BART Limit	0.15
Upgrade Existing Wet Sodium System	0.10
Optimize Existing Wet Sodium System	0.20
New Dry FGD 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 3 currently achieves approximately 78 percent SO_2 removal to achieve an SO_2 outlet emission rate of 0.27 lb/MMBtu. Optimizing the existing wet FGD system would achieve an SO_2 outlet emission rate of 0.20 lb/MMBtu (83.3 percent SO_2

removal) by partially closing the bypass damper to reduce 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/MMBtu (91.7 percent SO_2 removal) by closing the bypass damper to eliminate 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 95 percent SO_2 removal (0.06 lb/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/MMBtu which would not meet the presumptive limit of 0.15 lb SO_2/MMBtu. 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/MMBtu (91.7 percent SO_2 removal) which would meet the presumptive limit of 0.15 lb SO_2/MMBtu for Jim Bridger 3.

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 3 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 3. This would result in a controlled SO_2 emission rate of 0.21 lb/MMBtu, based on an uncontrolled SO_2 emission rate of 1.20 lb/MMBtu. Therefore, this option cannot meet the presumptive limit of 0.15 lb SO_2/MMBtu, and is eliminated from further analysis as technically infeasible.

3.2.2.3 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 3 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/MMBtu.

The projected emission rate for an upgraded wet sodium FGD system for Jim Bridger 3 would be 0.10 lb/MMBtu. This option would meet the presumptive SO_2 limit of 0.15 lb/MMBtu.

3.2.2.4 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 520 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 the bypassed flue gas which had provided approximately 20°F of reheat.

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.

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

Factor	Upgraded Wet FGD
Total Installed Capital Costs	\$13.0 Million
Total First Year Fixed & Variable O&M Costs	\$1.3 Million
Total First Year Annualized Cost	\$2.5 Million
Additional Power Consumption (MW)	0.5
Additional Annual Power Usage (1000 MW-Hr/Yr)	4.1
Incremental 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 (\$/Ton of SO_2 Removed)	632
Incremental Control Cost (\$/Ton of SO_2 Removed)	632

Preliminary BART Selection. CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for Jim Bridger 3 based on its significant reduction in SO_2 emissions (meeting presumptive limit of 0.15 lb/MMBtu), reasonable control costs, and the advantages of minimal additional power requirements and environmental impacts.

3.2.2.5 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

3.2.3 BART PM_{10} Analysis

Jim Bridger 3 is currently equipped with an electrostatic precipitator (ESP). ESPs remove particulate matter 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 particulate matter 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 3 has controlled PM_{10} emissions to levels below 0.057 lb/MMBtu.

The BART analysis for PM_{10} emissions at Jim Bridger 3 is described below. For the modeling analysis in Section 4.0, PM_{10} was used as an indicator for PM, and PM_{10} includes $PM_{2.5}$ as a subset.

3.2.3.1 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 fabric filter was not considered in the analysis.

3.2.3.2 Step 2: Eliminate Technically Infeasible Options

Flue Gas Conditioning. If the fly ash from coal has high resistivity, such as fly ash from subbituminous 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.

Polishing Fabric Filter. A polishing fabric filter could be added downstream of the existing ESP at Jim Bridger 3. 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).

3.2.3.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The existing ESP at Jim Bridger 3 is achieving a controlled PM emission rate of 0.057 lb/MMBtu. Utilizing flue conditioning upstream of the existing ESP is projected to reduce PM emissions to approximately 0.030 lb/MMBtu. Adding a COHPAC fabric filter downstream of the existing ESP is projected to reduce PM emissions to approximately 0.015 lb/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 3

Control Technology	Short-Term Expected PM_{10} Emission Rate (Lb/MMBtu)
Flue Gas Conditioning	0.030
Polishing Fabric Filter	0.015

3.2.3.4 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 ID fan upgrade and upgrade of the auxiliary power supply system.

A COHPAC fabric filter at Jim Bridger 3 would require approximately 3.3 MW of power, equating to an annual power usage of approximately 26.3 million kW-Hr.

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 a COHPAC polishing fabric filter or flue gas conditioning system.

Economic Impacts. A summary of the costs and PM removed for COHPAC and flue gas conditionings are recorded in Table 3-7, and the first-year control costs for flue gas conditioning 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 3

Factor	Flue Gas Conditioning	Polishing Fabric Filter
Total Installed Capital Costs	$0	$48.4 Million
Total First Year Fixed & Variable O&M Costs	$0.2 Million	$1.7 Million
Total First Year Annualized Cost	$0.2 Million	$ 6.3 Million
Additional Power Consumption (MW)	0.05	3.43
Additional Annual Power Usage (Million kW-Hr/Yr)	0.4	26.3
Incremental PM Design Control Efficiency	47.4%	73.7%
Incremental Tons PM Removed per Year	639	993

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

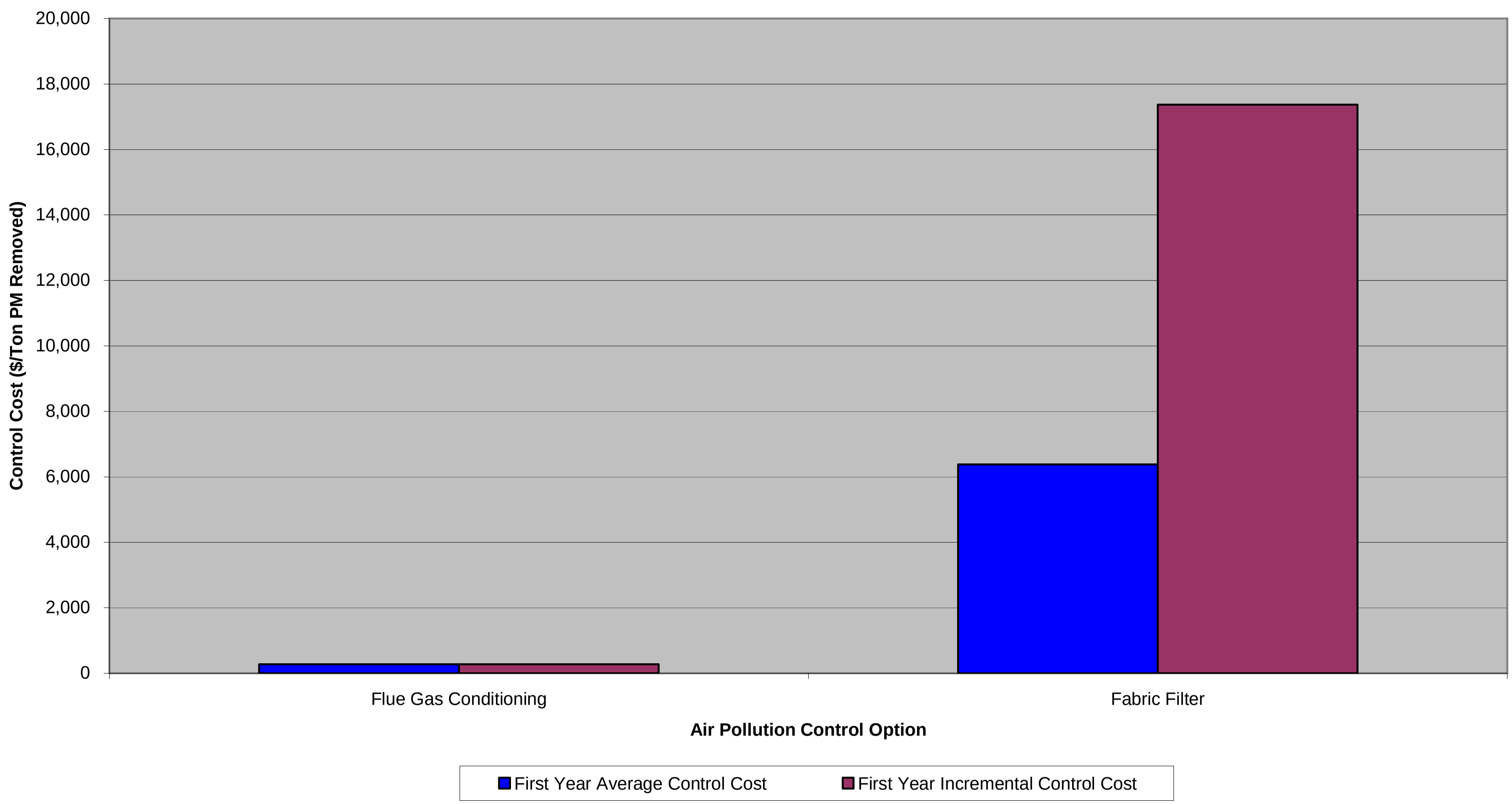
Factor	Flue Gas Conditioning	Polishing Fabric Filter
First Year Average Control Cost ($/Ton of PM Removed)	275	6,381
Incremental Control Cost ($/Ton of PM Removed)	275	17,371

Preliminary BART Selection. CH2M HILL recommends selection of flue gas conditioning upstream of the existing ESP as BART for Jim Bridger 3 based on the significant reduction in PM emissions, reasonable control costs, and advantages of minimal additional power requirements and no environmental impacts.

3.2.3.5 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

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



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 3 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 3 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 3 facility and allow for a 50-km buffer around the Class I areas that were within 300 km of the facility. Grid resolution was 4 km. 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 1/6 and 5/6 of the north-south extent of the domain to minimize distortion in the north-south direction.

FIGURE 4-1
Extent of Modeling Domain
Jim Bridger 3

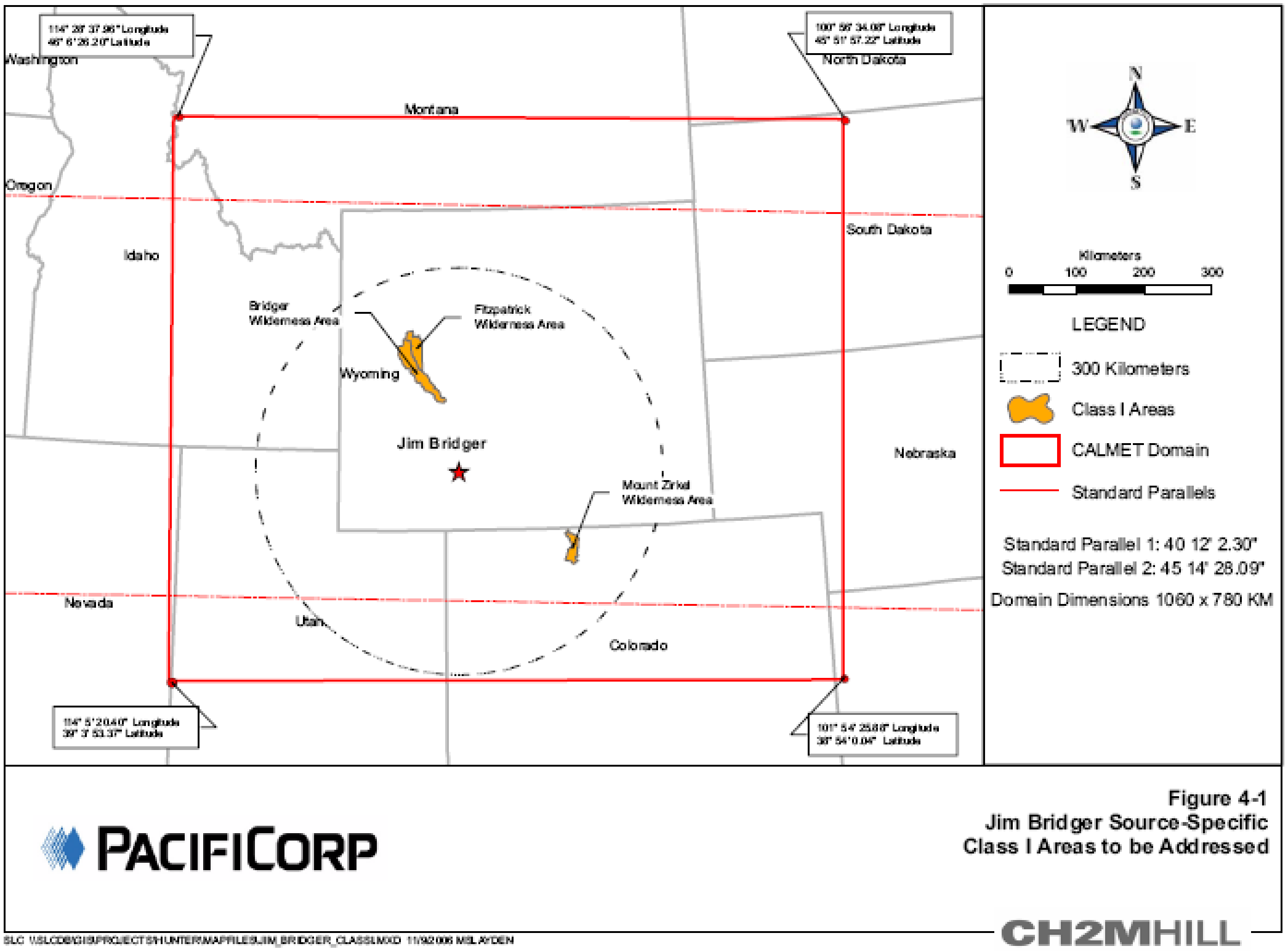


Figure 4-1
Jim Bridger Source-Specific
Class I Areas to be Addressed

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 3

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 three years of analysis: 2001, 2002, and 2003. WDEQ-AQD provided 12-km 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 2001-2003 were obtained from the National Climatic Data Center. CH2M HILL processed the data from the National Weather Service's Automated Surface Observing System (ASOS) 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 website 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.

FIGURE 4-2
Surface and Upper Air Station Locations
Jim Bridger 3

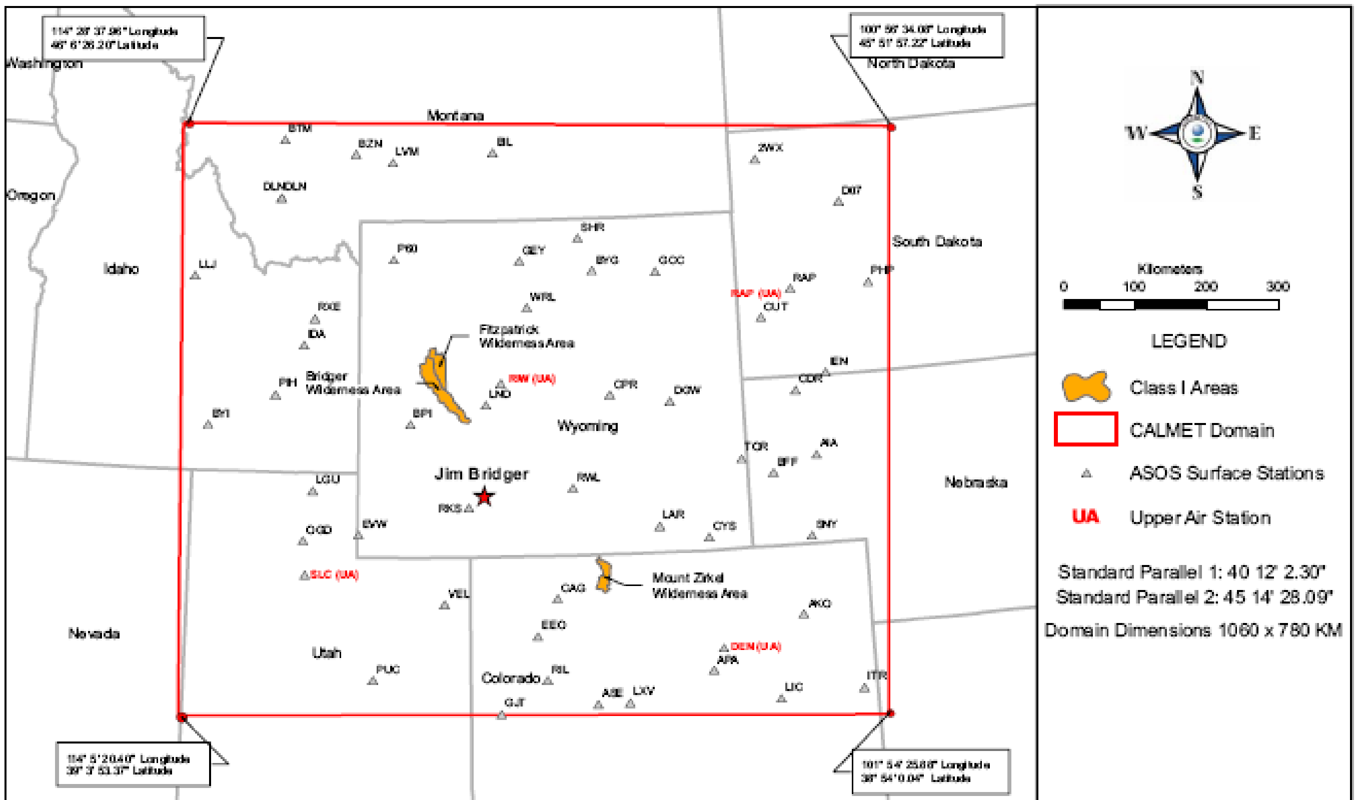


Figure 4-2
Surface and Upper Air Stations Used in the Jim Bridger BART Analysis

SLC \\SLCDB\GIS\PROJECTS\HUNTER\MAPFILES\JIM_BRIDGER_ASOS.MXD 11/8/2006 MSLAYDEN

Idaho Power/1301
Carstensen/40

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 from the National Oceanic and Atmospheric Administration Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/rescue/dwm/data_rescue_daily_weather_maps.html).

4.3 CALPUFF Modeling Approach

For the BART control technology visibility improvement modeling, CH2M HILL followed WDEQ-AQD guidance provided in the document titled *BART Air Modeling Protocol - Individual Source Visibility Assessments for BART Control Analyses* (September, 2006).

A modeling protocol titled *Modeling Protocol for BART Control Technology Improvement Modeling Analysis* (CH2M HILL, August, 2006) was submitted to WDEQ-AQD for review. In the protocol, CH2M HILL described how the general CALMET/CALPUFF approach recommended by the WDEQ-AQD would be used to model Jim Bridger 3.

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 3.

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 WDEQ-AQD document *BART Air Modeling Protocol - Individual Source Visibility Assessments for BART Control Analyses* (September, 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 3. 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/hr 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 3 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; July 6, 2005, pg 39129).

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 performed in Section 3 for reasonable technologies that would meet or exceed the presumptive BART levels for each pollutant.

- **Scenario 1**: New LNB w/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 w/OFA modifications, upgraded wet FGD system and new polishing fabric filter

- **Scenario 3**: New LNB w/OFA modifications and SCR, upgraded wet FGD system and flue gas conditioning for enhanced ESP performance.

- **Scenario 4**: New LNB w/OFA modifications and SCR, upgraded wet FGD system and new polishing fabric filter.

The ROFA option and LNB w/OFA & SCR option for NO_x control were not included in the modeling scenarios because their control effectiveness is between the LNB w/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 3 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 3

	Baseline	**Post Control Scenario 1**	**Post Control Scenario 2**	**Post Control Scenario 3**	**Post Control Scenario 4**
	Current Operations with wet FGD and ESP	**LNB with OFA, Upgrade Wet FGD & FGC for Enhanced ESP Performance**	**LNB with OFA, Upgrade Wet FGD, New Fabric Filter**	**LNB with OFA and SCR, Upgrade Wet FGD & FGC for Enhanced ESP Performance**	**LNB with OFA and SCR, Upgrade Wet FGD, New Fabric Filter**
Heat Input (MMBtu/hr)	6,000	6,000	6,000	6,000	6,000
SO_2 Stack Emissions (lb/MMBTU)	0.3	0.10	0.10	0.10	0.10
SO_2 Stack Emissions (lb/hr)	1,600	600	600	600	600
NO_x Stack Emissions (lb/MMBTU)	0.45	0.24	0.24	0.07	0.07
NO_x Stack Emissions (lb/hr)	2,700	1,440	1,440	420	420
PM_{10} Stack Emissions (lb/MMBTU)	0.057	0.030	0.015	0.030	0.015
PM_{10} Stack Emissions (lb/hr)	342	180	90.0	180	90
PM_{10}-$PM_{2.5}$ Stack Emissions (lb/hr) (1)	147	77.4	51.3	77.4	51.3
$PM_{2.5}$-PM_0 Stack Emissions (lb/hr) (1)	195	103	38.7	103	38.7
HF Stack Emissions (lb/MMBTU)	0.00055	0.00055	0.00055	0.00055	0.00055
HF Stack Emissions (lb/hr)	3.3	3.3	3.3	3.3	3.3
HCl Stack Emissions (lb/MMBTU)	0.00075	0.00075	0.00075	0.00075	0.00075
HCl Stack Emissions (lb/hr)	4.5	4.5	4.5	4.5	4.5
H_2SO_4 Stack Emissions (lb/MMBtu)	0.0092	0.0092	0.0092	0.0158	0.0158
H_2SO_4 Stack Emissions (lb/hr)	55.2	55.20	55.20	94.80	94.80
H_2SO_4 as SO_4 Stack Emissions (lb/hr)	54.1	54.07	54.07	92.87	92.87
$(NH_4)_2SO_4$ Stack Emissions (lb/MMBtu)				0.00117	0.00117

TABLE 4-2
BART Model Input Data
Jim Bridger 3

	Baseline	Post Control Scenario 1	Post Control Scenario 2	Post Control Scenario 3	Post Control Scenario 4
	Current Operations with wet FGD and ESP	**LNB with OFA, Upgrade Wet FGD & FGC for Enhanced ESP Performance**	**LNB with OFA, Upgrade Wet FGD, New Fabric Filter**	**LNB with OFA and SCR, Upgrade Wet FGD & FGC for Enhanced ESP Performance**	**LNB with OFA and SCR, Upgrade Wet FGD, New Fabric Filter**
$(NH_4)_2SO_4$ 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/MMBtu)				0.00204	0.00204
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)				12.2	12.2
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)				10.22	10.22
Total Filterable PM_{10} (lb/hr) (incl. $PM_{2.5}$)	350	188	97.8	187.8	97.8
Total Sulfate (as SO_4) (lb/hr)	54.1	54.1	54.1	108.2	108.2
Stack Conditions					
Stack Height (feet)	500	500	500	500	500
Stack Height (m)	152	152	152	152	152
Stack Exit Diameter (feet)	24.00	24.00	24.00	24.00	24.00
Stack Exit Diameter (m)	7.32	7.32	7.32	7.32	7.32
Stack Exit Temperature (degF)	140	120	140	140	140
Stack Exit Temperature (K)	333.2	322.0	333.2	333.2	333.2
Stack Exit Flow (acfm)	2,281,182	2,208,010	2,437,627	2,437,627	2,437,627
Stack Exit Area (ft^2)	452	452	452	452	452
Stack Exit Velocity (fps)	84.04	81.24	89.81	89.81	89.81
Stack Exit Velocity (m/s)	25.62	24.76	27.37	27.37	27.37

Notes:

(1) Based on AP-42, Table 1.1-6, as percent of PM_{10}. See factors below.

	ESP	Baghouse
PM_{10}-$PM_{2.5}$ Stack Emissions (lb/hr)	43	57
$PM_{2.5}$-PM_0 Stack Emissions (lb/hr)	57	43

(2) Scenarios 2, 3, and 4 were not remodeled at the lower, correct velocity of 81.24 fps due to lack of time and the fact that the conclusions to select Scenario 1 would not have changed.

4.3.5 Modeling Process

The CALPUFF modeling for the control technology options for Jim Bridger 3 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 BART "5-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 (NPS) 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. 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 days. 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*. 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; October 26, 2005). The Wyoming BART Air Modeling Protocol did provide 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 3

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

Note: Taken from Table 6 of the Wyoming BART Air Modeling Protocol

Presentation of Modeling Results

This section presents the results of the CALPUFF visibility improvement modeling analysis for Jim Bridger 3.

Degree of Visibility Change for Baseline vs. Preferred Scenario

CH2M HILL modeled Jim Bridger 3 for the baseline conditions and post-control Scenario 1. The post-control scenario included emission rates for NO_x, SO_2, and PM_{10} that would be achieved if BART technology were installed on Unit 3.

Baseline (and post-control) 98th percentile results were greater than 0.5 ΔdV for the Bridger WA, Fitzpatrick WA, and Mt. Zirkel WA. The 98th 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 3

Scenario	First Year Cost	Class I Area	Highest Delta- (dV)	98th Percentile Delta- (dV)	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 FGD and ESP		Bridger WA	2.794	0.805	20	--	--		
		Fitzpatrick WA	2.542	0.48	7	--	--		
		Mt. Zirkel WA	2.291	1.454	35	--	--		
Scenario 1 - LNB w/OFA, upgraded wet FGD system, FGC for enhanced ESP performance.	$3,387,923	Bridger WA	1.563	0.422	7	$8,845,751	$260,609		
	$3,387,923	Fitzpatrick WA	1.624	0.265	3	$15,757,779	$846,981		
	$3,387,923	Mt. Zirkel WA	1.382	0.871	21	$5,811,188	$241,994		
Scenario 2 - LNB w/OFA, upgraded wet FGD system, and new polishing fabric filter.	$9,726,040	Bridger WA	1.564	0.407	7	$24,437,287	$748,157	$422,541,167	NA
	$9,726,040	Fitzpatrick WA	1.392	0.253	3	$42,845,991	$2,431,510	$528,176,459	NA
	$9,726,040	Mt. Zirkel WA	1.31	0.807	21	$15,032,519	$694,717	$99,033,086	NA
Scenario 3 - LNB w/OFA and SCR, upgraded wet FGD system, FGC for enhanced ESP performance	$18,074,111	Bridger WA	1.021	0.405	3	$45,185,279	$1,063,183	$4,174,035,686	$2,087,018
	$18,074,111	Fitzpatrick WA	0.8	0.163	2	$57,016,124	$3,614,822	$92,756,349	$8,348,071
	$18,074,111	Mt. Zirkel WA	0.896	0.537	8	$19,710,045	$669,412	$30,918,783	$642,159
Scenario 4 - LNB w/OFA and SCR, upgraded wet FGD system, new polishing fabric filter.	$24,412,229	Bridger WA	0.985	0.394	3	$59,397,151	$1,436,013	$576,192,500	NA
	$24,412,229	Fitzpatrick WA	0.779	0.158	2	$75,814,376	$4,882,446	$1,267,623,501	NA
	$24,412,229	Mt. Zirkel WA	0.87	0.521	8	$26,165,304	$904,157	$396,132,344	NA
2002									
Baseline - Current Operation with Wet FGD and ESP		Bridger WA	4.381	1.67	30	--	--		
		Fitzpatrick WA	2.051	0.833	13	--	--		
		Mt. Zirkel WA	3.46	1.817	47	--	--		
Scenario 1 - LNB w/OFA, upgraded wet FGD system, FGC for enhanced ESP performance.	$3,387,923	Bridger WA	2.626	0.918	14	$4,505,216	$211,745		
	$3,387,923	Fitzpatrick WA	1.159	0.418	7	$8,163,669	$564,654		
	$3,387,923	Mt. Zirkel WA	1.928	0.969	17	$3,995,192	$112,931		
Scenario 2 - LNB w/OFA, upgraded wet FGD system, and new polishing fabric filter.	$9,726,040	Bridger WA	2.49	0.875	13	$12,234,013	$572,120	$147,398,081	$6,338,118
	$9,726,040	Fitzpatrick WA	1.086	0.406	6	$22,777,611	$1,389,434	$528,176,459	$6,338,118
	$9,726,040	Mt. Zirkel WA	1.862	0.966	18	$11,428,954	$335,381	$2,112,705,834	$6,338,118
Scenario 3 - LNB w/OFA and SCR, upgraded wet FGD system, FGC for enhanced ESP performance	$18,074,111	Bridger WA	1.416	0.596	9	$16,828,782	$860,672	$29,921,403	$2,087,018
	$18,074,111	Fitzpatrick WA	0.595	0.249	1	$30,948,821	$1,506,176	$53,172,429	$1,669,614
	$18,074,111	Mt. Zirkel WA	1.108	0.578	10	$14,587,661	$488,489	$21,515,648	$1,043,509
Scenario 4 - LNB w/OFA and SCR, upgraded wet FGD system, new polishing fabric filter.	$24,412,229	Bridger WA	1.39	0.583	9	$22,458,352	$1,162,487	$487,547,500	NA
	$24,412,229	Fitzpatrick WA	0.585	0.246	1	$41,588,124	$2,034,352	$2,112,705,834	NA
	$24,412,229	Mt. Zirkel WA	1.086	0.57	10	$19,576,767	$659,790	$792,264,688	NA

TABLE 4-4
Costs and Visibility Modeling Results for Baseline Vs. Post-Control Scenarios at Class I Areas
Jim Bridger 3

Scenario	First Year Cost	Class I Area	Highest Delta- (dV)	98th Percentile Delta- (dV)	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 and ESP		Bridger WA	1.995	0.896	17	--	--		
		Fitzpatrick WA	2.095	0.457	7	--	--		
		Mt. Zirkel WA	2.27	1.544	44	--	--		
Scenario 1 - LNB w/OFA, upgraded wet FGD system, FGC for enhanced ESP performance.	$3,387,923	Bridger WA	1.147	0.492	7	$8,385,947	$338,792		
	$3,387,923	Fitzpatrick WA	1.195	0.229	3	$14,859,309	$846,981		
	$3,387,923	Mt. Zirkel WA	1.218	0.937	19	$10,392,400	$135,517		
Scenario 2 - LNB w/OFA, upgraded wet FGD system, and new polishing fabric filter.	$9,726,040	Bridger WA	1.155	0.45	6	$21,807,265	$884,185	$150,907,560	$6,338,118
	$9,726,040	Fitzpatrick WA	1.178	0.232	3	$43,226,845	$2,431,510	$2,112,705,834	NA
	$9,726,040	Mt. Zirkel WA	1.235	0.896	18	$15,009,321	$374,078	$154,588,232	$6,338,118
Scenario 3 - LNB w/OFA and SCR, upgraded wet FGD system, FGC for enhanced ESP performance	$18,074,111	Bridger WA	0.991	0.319	3	$31,324,283	$1,291,008	$63,725,736	$2,782,690
	$18,074,111	Fitzpatrick WA	0.738	0.156	2	$60,046,882	$3,614,822	$109,843,044	$8,348,071
	$18,074,111	Mt. Zirkel WA	0.759	0.544	8	$18,074,111	$502,059	$23,716,112	$834,807
Scenario 4 - LNB w/OFA and SCR, upgraded wet FGD system, new polishing fabric filter.	$24,412,229	Bridger WA	0.949	0.306	3	$41,376,659	$1,743,731	$487,547,500	NA
	$24,412,229	Fitzpatrick WA	0.719	0.152	2	$80,040,095	$4,882,446	$1,584,529,376	NA
	$24,412,229	Mt. Zirkel WA	0.736	0.533	8	$24,146,616	$678,117	$576,192,500	NA
3-year Averages									
Scenario 1		Bridger WA				$7,245,638	$270,382		
		Fitzpatrick WA				$12,926,919	$752,872		
		Mt. Zirkel WA				$6,732,927	$163,481		
Scenario 2		Bridger WA				$19,492,855	$734,821	$240,282,269	$6,338,118
		Fitzpatrick WA				$36,283,482	$2,084,151	$1,056,352,917	$6,338,118
		Mt. Zirkel WA				$13,823,598	$468,059	$788,775,717	$6,338,118
Scenario 3		Bridger WA				$31,112,781	$1,071,621	$1,422,560,942	$2,318,909
		Fitzpatrick WA				$49,337,276	$2,911,940	$85,257,274	$6,121,919
		Mt. Zirkel WA				$17,457,272	$553,320	$25,383,514	$840,158
Scenario 4		Bridger WA				$41,077,387	$1,447,410	$517,095,834	NA
		Fitzpatrick WA				$65,814,198	$3,933,081	$1,654,952,903	NA
		Mt. Zirkel WA				$23,296,229	$747,355	$588,196,511	NA

Sample Calculations: Cost per dV Reduction for Scenario 1 for 2001: = $3,387,923 / (0.896 - 0.492) = $8,845,751

Sample Calculations: Cost per Reduction in No. of Days Above 0.5 dV for 2001: = $3,387,923 / (20 - 7) = $260,609.

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 3, 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 4.0. Visibility improvements for all emission control scenarios were analyzed, and the results are compared below, utilizing a Least-Cost Envelope, as outlined in the draft EPA 1990 *New Source Review Workshop Manual (NSR Manual).* The purpose of this analysis is to use an objective, EPA-approved methodology to evaluate and make the final recommendation of BART control technology.

5.1 Least-Cost Envelope Analysis

For the control scenarios modeled in Section 4, Tables 5-1 through 5-3 list the total annualized cost, cost per dV reduction, and cost per reduction in number of days above 0.5 dV for each of the three Class I areas. . A comparison of the incremental results between selected scenarios is provided in Tables 5-4 through 5-6. Figures 5-1 to 5-6 show the total annualized cost versus number of days above 0.5 dV, and the total annualized cost versus 98th percentile ΔdV reduction, for the three Class I areas.

5.1.1 Analysis Methodology

Page B-41 of the New Source Review (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 3.

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 and 3, represent the least-cost envelope depicted by the curvilinear line connecting them. Scenarios 2 and 4 are inferior options and should not be considered in the derivation of incremental cost effectiveness. Scenarios 2 and 4 represent inferior controls, because Scenario 1 provides approximately same amount of visibility impact reduction for less cost than Scenario 2; and similarly, Scenario 3 will provides approximately the same amount of visibility impact reduction for less cost than Scenario 4. 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 1 Wilderness Area
Jim Bridger 3

Scenario	Controls	98th Percentile 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 FGD, ESP	0.0	0.0	$0.0	$0.0	$0.0
1	LNB w/OFA, upgraded wet FGD system, FGC for enhanced ESP performance.	0.5	13.0	$3.4	$7.3	$0.3
2	LNB w/OFA, upgraded wet FGD system, and new polishing fabric filter.	0.6	13.67	$9.7	$19.5	$0.7
3	LNB w/OFA and SCR, upgraded wet FGD system, FGC for enhanced ESP performance	07	17.3	$18.1	$31.1	$1.07
4	LNB w/OFA and SCR, upgraded wet FGD system, new polishing fabric filter.	0.7	17.3	$24.4	$41.1	$1.45

TABLE 5-2
Control Scenario Results for the Fitzpatrick Class 1 Wilderness Area
Jim Bridger 3

Scenario	Controls	98th Percentile 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 FGD, ESP	0.0	0.0	$0.0	$0.0	$0.0
1	LNB w/OFA, upgraded wet FGD system, FGC for enhanced ESP performance.	0.3	4.7	$3.4	$12.9	$0.8
2	LNB w/OFA, upgraded wet FGD system, and new polishing fabric filter.	0.3	5.0	$9.7	$36.3	$2.1
3	LNB w/OFA and SCR, upgraded wet FGD system, FGC for enhanced ESP performance	0.4	7.3	$18.0	$49.3	$2.9
4	LNB w/OFA and SCR, upgraded wet FGD system, new polishing fabric filter.	0.4	7.3	$24.4	$65.8	$3.9

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

Scenario	Controls	98th Percentile 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 FGD, ESP	0.0	0.0	$0.0	$0.0	$0.0
1	LNB w/OFA, upgraded wet FGD system, FGC for enhanced ESP performance.	0.7	23.0	$3.4	$6.7	$0.2
2	LNB w/OFA, upgraded wet FGD system, and new polishing fabric filter.	0.7	23.0	$9.7	$13.8	$0.5
3	LNB w/OFA and SCR, upgraded wet FGD system, FGC for enhanced ESP performance	1.1	33.3	$18.1	$17.5	$0.6
4	LNB w/OFA and SCR, upgraded wet FGD system, new polishing fabric filter.	1.1	33.3	$24.4	$23.3	$0.8

TABLE 5-4
Bridger Class I Wilderness Area Incremental Analysis Data
Jim Bridger 3

Options Compared	Incremental Reduction in Days Above 0.5 dV (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Baseline and Scenario 1	13.0	0.5	$0.3	$6.6
Scenario 1 and Scenario 3	4.3	0.2	$3.4	$86.1
Scenario 3 and Scenario 4	0.0	0.01	N/A	$514.

TABLE 5-5
Fitzpatrick Class I Wilderness Area Incremental Analysis Data
Jim Bridger 3

Options Compared	Incremental Reduction in Days Above 0.5 dV (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Baseline and Scenario 1	4.7	0.3	$0.7	$12.0
Scenario 1 and Scenario 3	2.7	0.1	$5.5	$128.
Scenario 3 and Scenario 4	0.0	0.004	N/A	$1,585.

TABLE 5-6
Mt. Zirkel Class I Wilderness Area Incremental Analysis Data
Jim Bridger 3

Options Compared	Incremental Reduction in Days Above 0.5 dV (Days)	Incremental dV Reductions (dV)	Incremental Cost Effectiveness (Million$/Days)	Incremental Cost Effectiveness (Million$/dV)
Baseline and Scenario 1	23.0	0.7	$0.2	$5.0
Scenario 1 and Scenario 3	10.3	0.4	$1.4	$39.4
Scenario 3 and Scenario 4	0.0	0.01	N/A	$543.

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

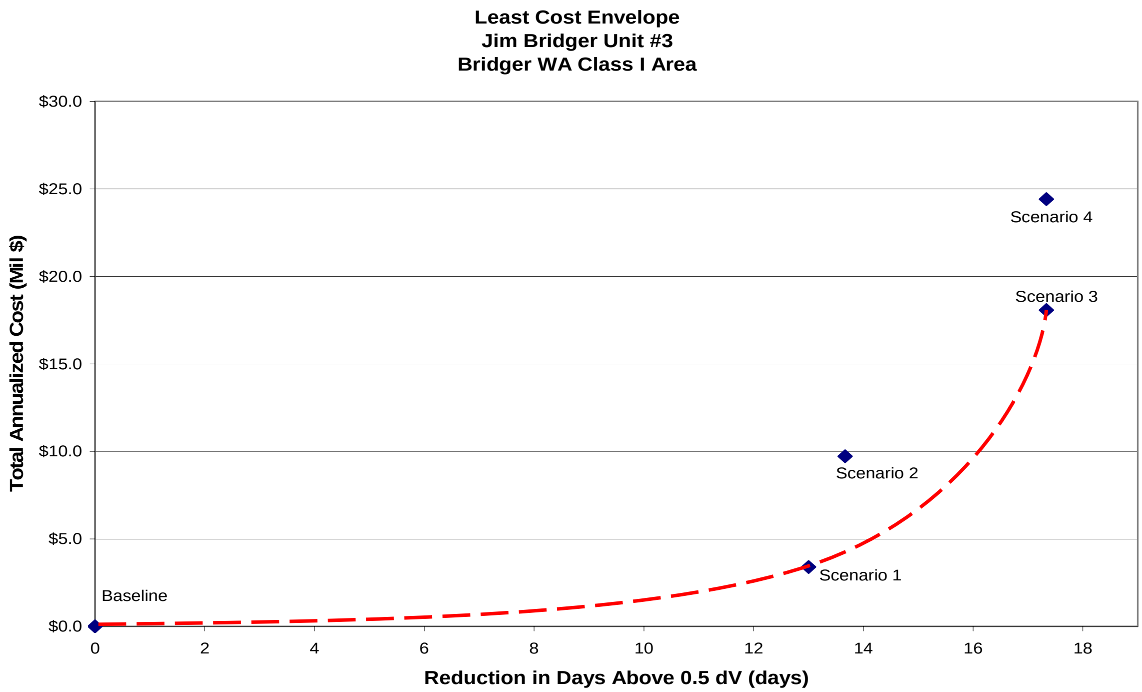


FIGURE 5-2
Least Cost Envelope Bridger Class I WA 98th Percentile Reduction
Jim Bridger 3

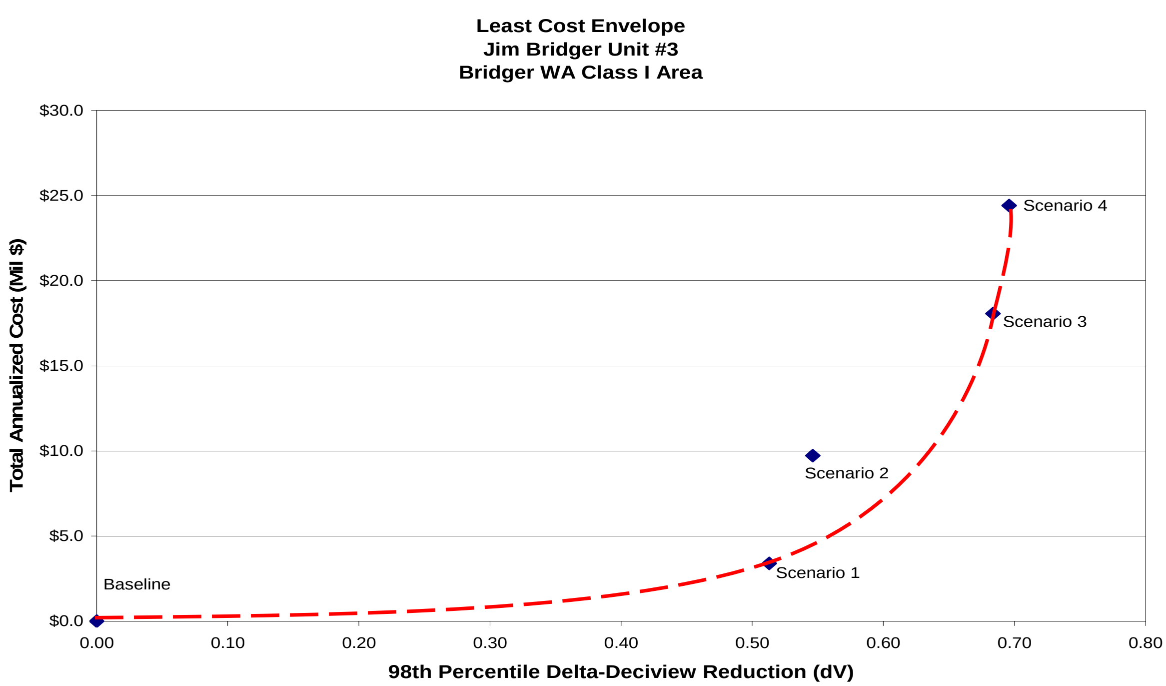


FIGURE 5-3
Least Cost Envelope Fitzpatrick Class I WA Days Reduction
Jim Bridger 3

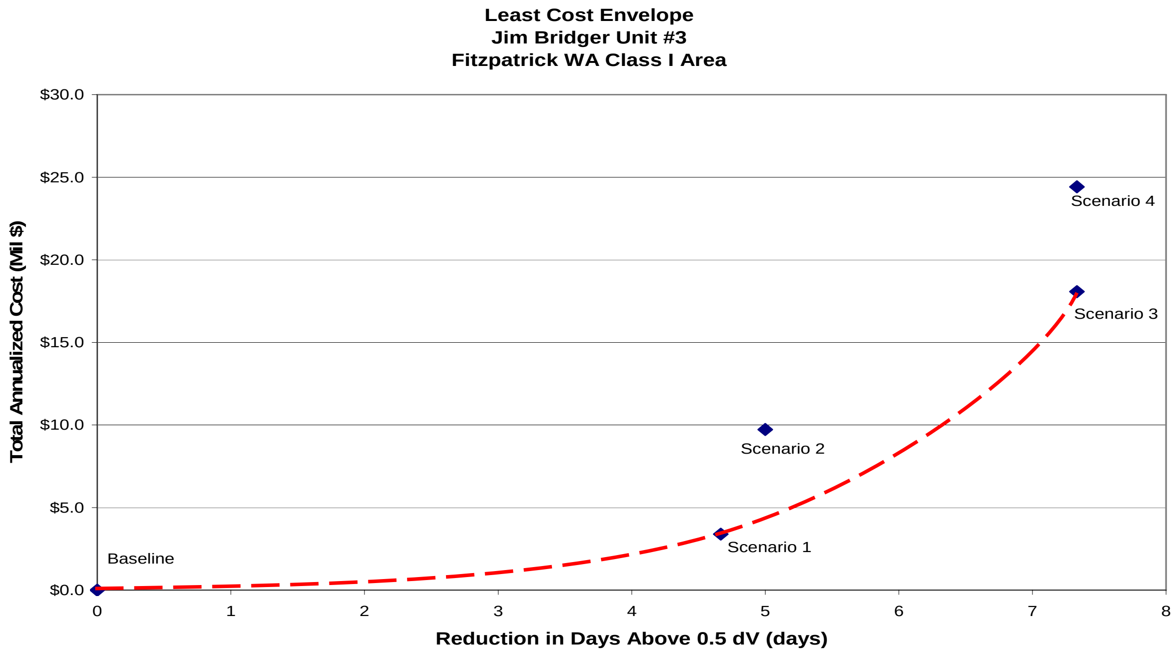


FIGURE 5-4
Least Cost Envelope Fitzpatrick Class I WA 98th Percentile Reduction
Jim Bridger 3

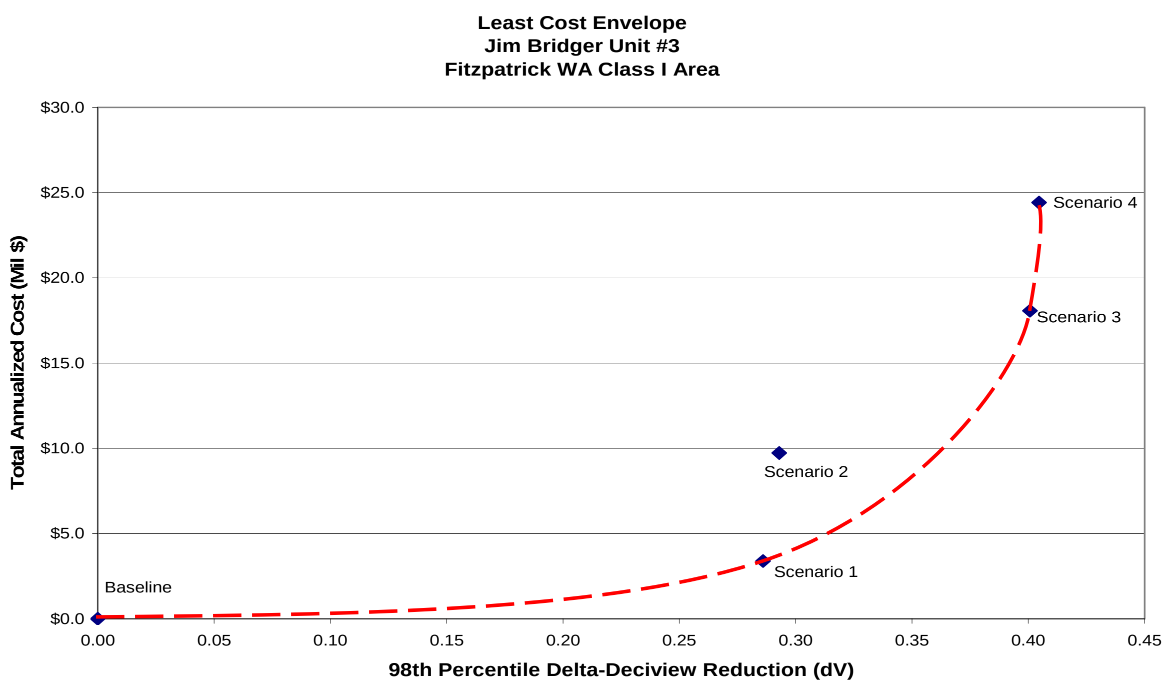


FIGURE 5-5
Least Cost Envelope Mt. Zirkel Class I WA Days Reduction
Jim Bridger 3

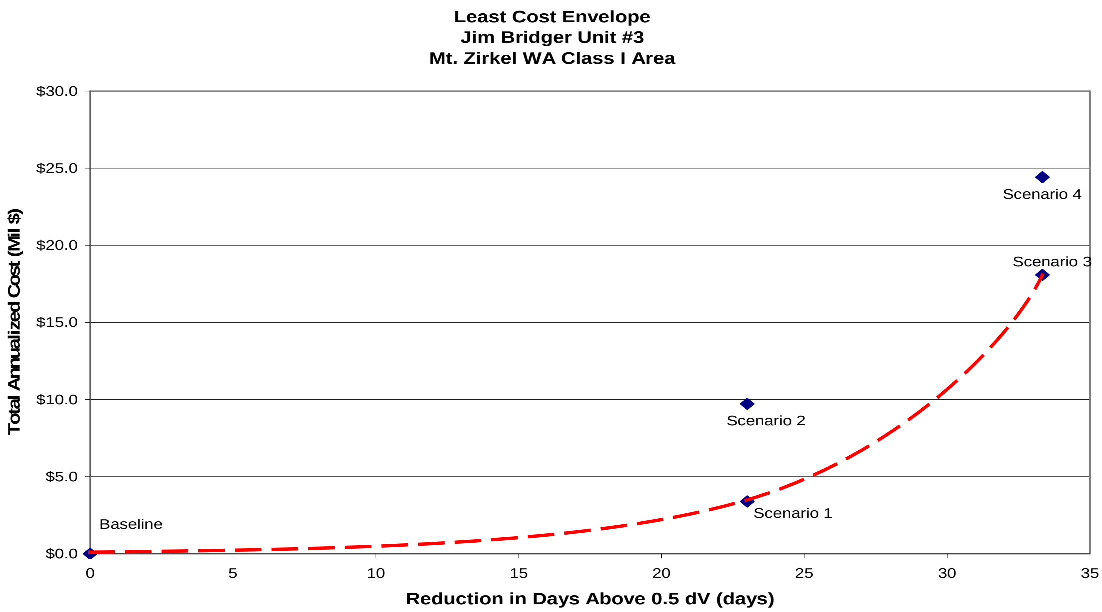
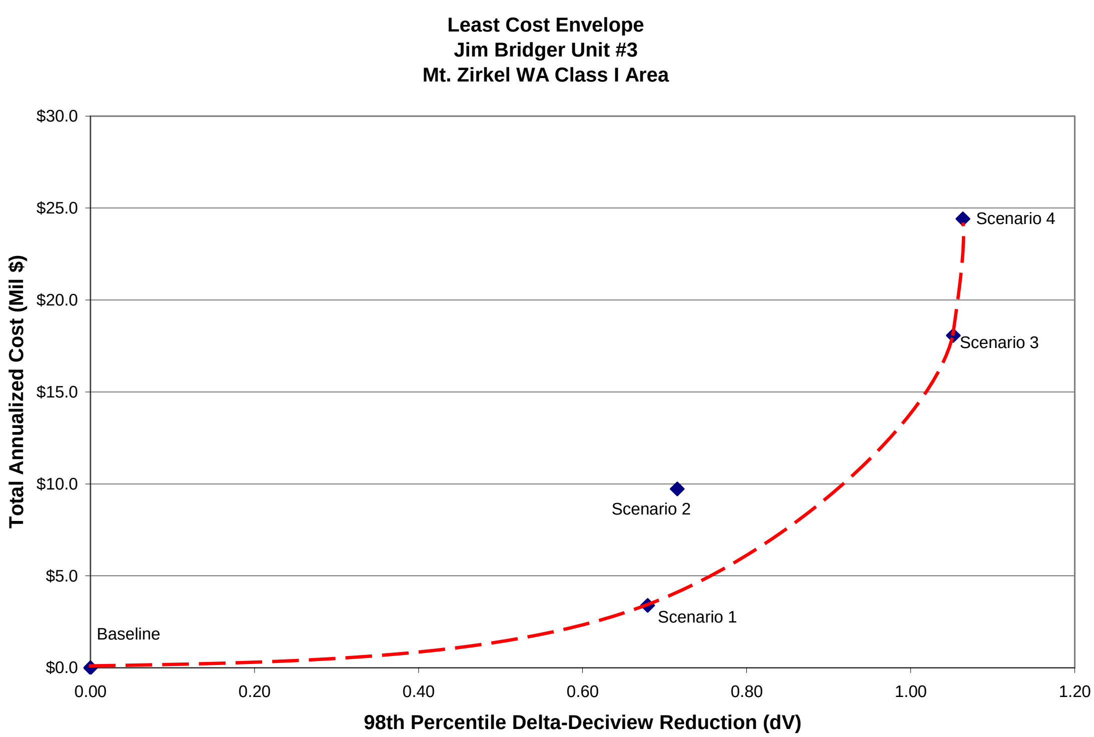


FIGURE 5-6
Least Cost Envelope Mt. Zirkel Class I WA 98th Percentile Reduction
Jim Bridger 3



5.1.2 Analysis Results

Results of the Least Cost Analysis, shown in Tables 5-1 through 5-6 and Figures 5-1 through 5-4 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 for 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 Class 1 WA 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 above 0.5 dV is between the Baseline and Scenario 1. The incremental cost effectiveness for Scenario 1 compared to the Baseline for the Bridger WA, for example, is reasonable at $260,000/day and $6.60 Million/dV. However, the incremental cost effectiveness for Scenario 3 compared to Scenario 1, again for the Bridger WA, is excessive at $3.39 Million/day and $88.05 Million/dV. The same conclusions are reached for each of the three wilderness areas studied. Therefore, Scenario 1 represents BART for Jim Bridger 3.

5.2 Recommendations

5.2.1 NO_x Emission Control

The BART presumptive NO_x limit assigned by EPA for tangentially-fired boilers burning subbituminous coal is 0.15 lb/MMBtu. However, as documented in Section 3.2.1.1, the characteristics of the Jim Bridger coals are more closely aligned with bituminous coals, and have been assigned a presumptive BART NOx limit of 0.28 lb/MMBtu.

CH2M HILL recommends low-NOx burners with over-fire air (LNB w/OFA) as BART for Jim Bridger 3, 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. NO_x 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/MMBtu.

5.2.2 SO_2 Emission Control

CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for Jim Bridger 3, 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/MMBtu.

5.2.3 PM_{10} Emission Control

CH2M HILL recommends finalizing the permitting of the flue gas conditioning system to enhance the performance of the existing electrostatic precipitator (ESP) as BART for Jim Bridger 3, 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 (Appendix C), state that 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 scenarios. Thus the results indicate that even though many millions of dollars will be spent, only minimal if any visibility improvements may result.

Finally, it should be noted that none of the data were corrected for natural obscuration. Water in various forms (fog, clouds, snow, or rain) or other naturally caused aerosols may obscure the atmosphere and reduce visibility. During the period of 2001 through 2003, there were several mega-wildfires that lasted for many days, with a significant impact on background visibility in these Class 1 areas. If natural obscuration lessens the achievable reduction in visibility impacts modeled for BART controls at the Jim Bridger 3 facility, the overall effect would be to increase the costs per dV reduction that are presented in this report

6.0 References

BART Air Modeling Protocol - Individual Source Visibility Assessments for BART Control Analyses. September, 2006.

Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule.

Multi-Pollutant Control Report. October, 2002, updated October 2006

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

Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule (40 CFR Part 51; July 6, 2005, pg 39129)

S&L Study Multi-Pollutant Control Report. October, 2002, updated October 2006

United States Environmental Protection Agency, 1990. *New Source Review Workshop Manual –Prevention of Significant Deterioration and Nonattainment Area Permitting*. October 1990.

Appendices

APPENDIX A

Economic Analysis

PacifiCorp BART Analysis Report Tables

Jim Bridger Unit 3

TABLE 3-1

NO_x Control Technology Emission Rate Ranking

Jim Bridger Unit 3

Technology	Projected Emission Rate (lb/MMBtu)
LNB w/OFA	0.24
ROFA	0.22
LNB w/OFA & SNCR	0.20
LNB w/OFA & SCR	0.07

TABLE 3-2

NO_x Control Cost Comparison

Jim Bridger Unit 3

Factor	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR
Total Installed Capital Costs	$ 8.7 Million	$ 20.5 Million	$ 22.0 Million	$ 129.6 Million
Total First Year Fixed & Variable O&M 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 (MW)	-	6.41	0.52	3.22
Annual Power Usage (Million kW-Hr/Yr)	-	50.6	4.1	25.4
NO_x Design Control Efficiency	46.7%	51.1%	55.6%	84.4%
Tons NO_x Removed per Year	4,967	5,440	5,913	8,987
First Year Average Control Cost ($/Ton of NO_x Removed)	181	843	610	1,734
Incremental Control Cost ($/Ton of NO_x Removed)	181	7,797	2,863	3,896

TABLE 3-3

SO_2 Control Technology Emission Rate Ranking

Jim Bridger Unit 3

Control Technology	Short-Term Expected SO_2 Emission Rate (Lb/MMBtu)
N/A	N/A
N/A	N/A
Upgraded Wet FGD	0.10

PacifiCorp BART Analysis Report Tables

Jim Bridger Unit 3

TABLE 3-4

SO_2 Control Cost Comparison

Jim Bridger Unit 3

Factor	N/A	N/A	Upgraded Wet FGD
Total Installed Capital Costs			$ 13.0 Million
Total First Year Fixed & Variable O&M Costs			$ 1.3 Million
Total First Year Annualized Cost			$ 2.5 Million
Power Consumption (MW)			0.52
Annual Power Usage (Million kW-Hr/Yr)			4.1
SO_2 Design Control Efficiency			62.5%
Tons SO_2 Removed per Year			3,950
First Year Average Control Cost (\$/Ton of SO_2 Removed)			631
Incremental Control Cost (\$/Ton of SO_2 Removed)			631

TABLE 3-5

PM_{10} Control Technology Emission Ranking

Jim Bridger Unit 3

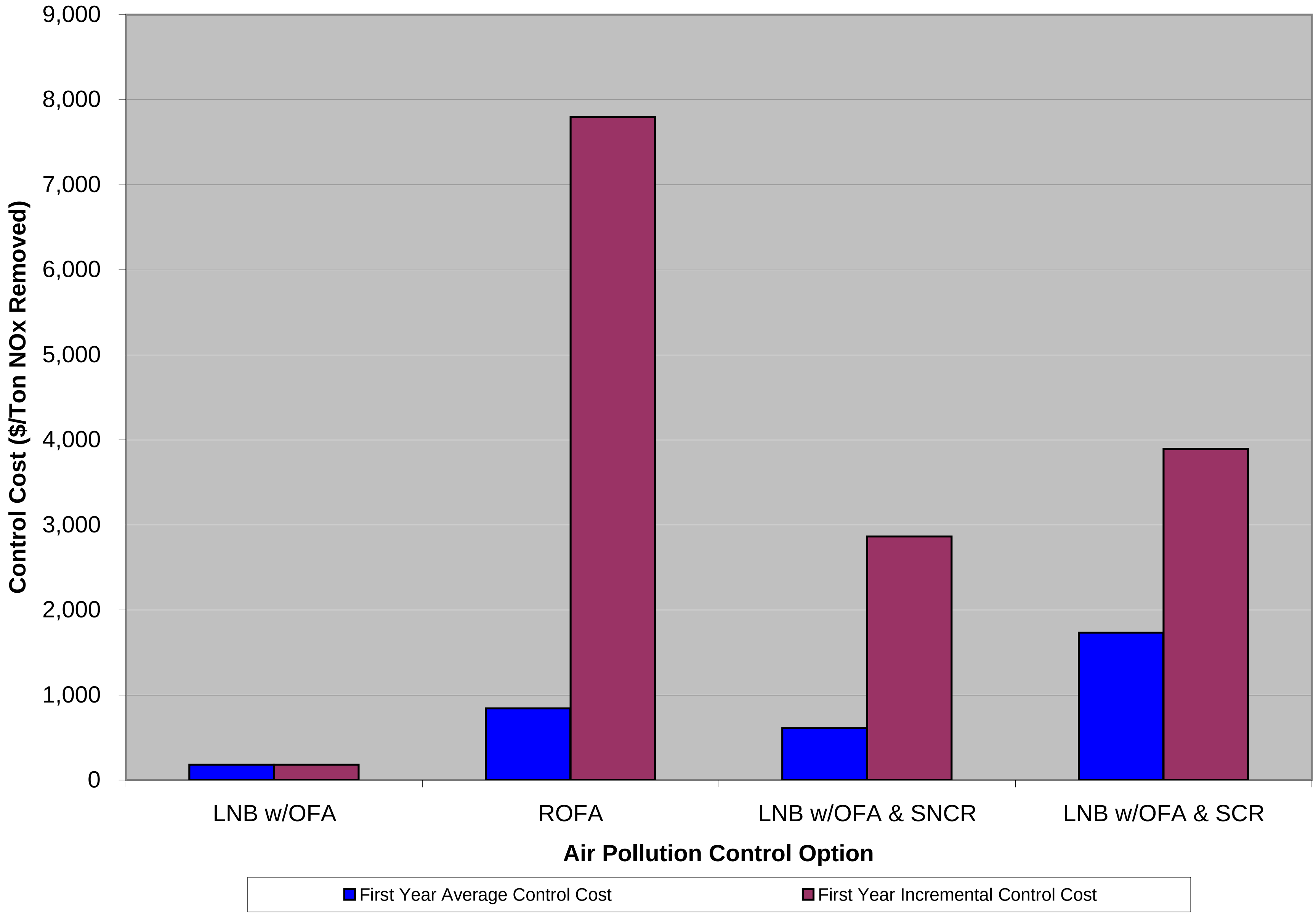
Control Technology	Short-Term Expected PM_{10} Emission Rate (Lb/MMBtu)
Flue Gas Conditioning	0.030
Fabric Filter	0.015

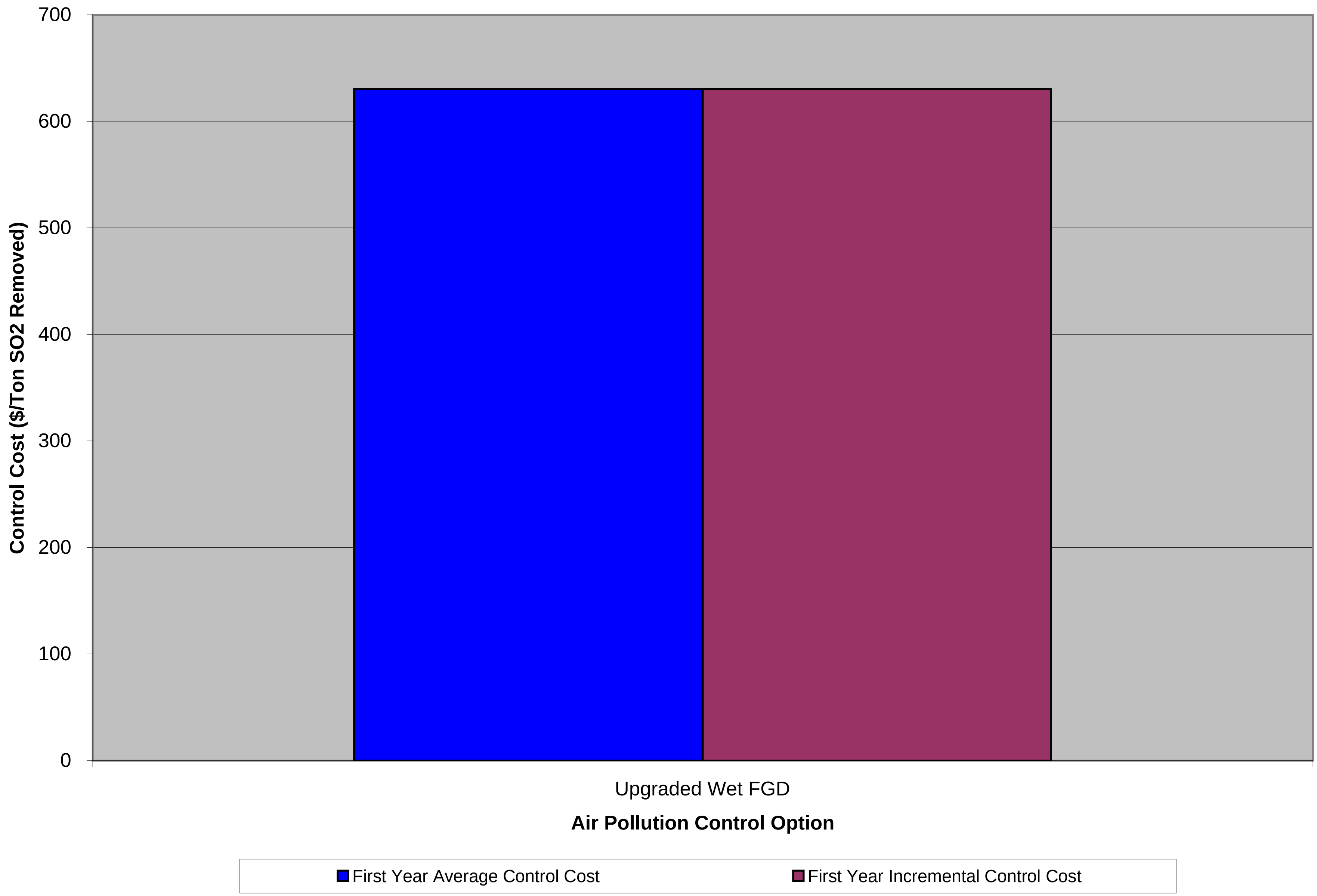
TABLE 3-6

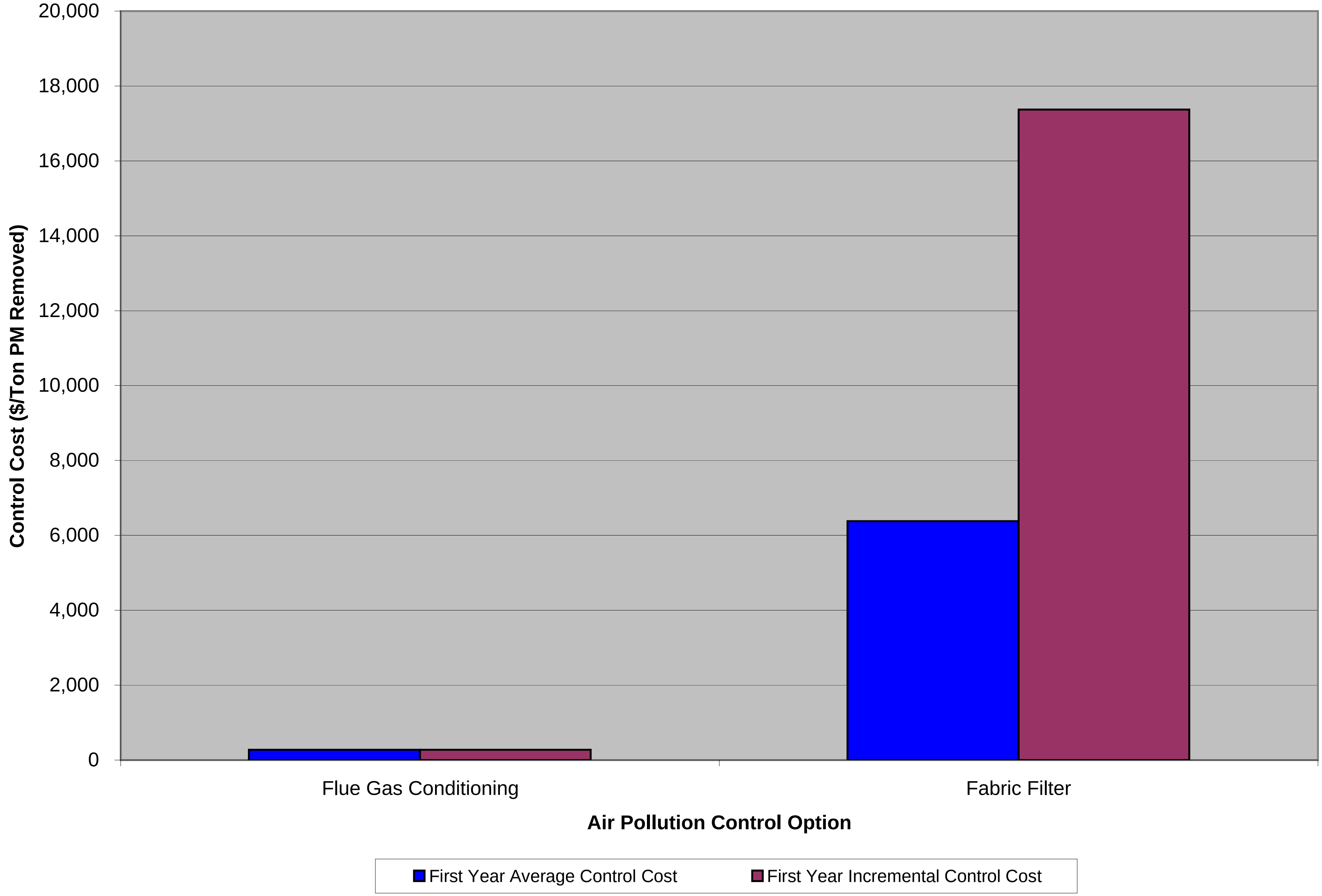
PM_{10} Control Cost

Jim Bridger Unit 3

Factor	Flue Gas Conditioning	Fabric Filter
Total Installed Capital Costs	$ - Million	$ 48.4 Million
Total First Year Fixed & Variable Operations & Maintenance Costs	$ 0.2 Million	$ 1.7 Million
Total First Year Annualized Cost	$ 0.2 Million	$ 6.3 Million
Power Consumption (MW)	0.05	3.33
Annual Power Usage (Million kW-Hr/Yr)	0.4	26.3
PM Design Control Efficiency	47.37%	73.68%
Tons PM Removed per Year	639	993
First Year Average Control Cost (\$/Ton of PM Removed)	275	6,381
Incremental Control Cost (\$/Ton of SO_2 Removed)	275	17,371


9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
0
Control Cost ($/Ton NOx Removed)
LNB w/OFA
ROFA
LNB w/OFA & SNCR
LNB w/OFA & SCR
Air Pollution Control Option
First Year Average Control Cost
First Year Incremental Control Cost


700
600
500
400
300
200
100
0
Control Cost ($/Ton SO2 Removed)
Upgraded Wet FGD
Air Pollution Control Option
First Year Average Control Cost
First Year Incremental Control Cost


20,000
18,000
16,000
14,000
12,000
10,000
8,000
6,000
4,000
2,000
0
Control Cost ($/Ton PM Removed)
Flue Gas Conditioning
Fabric Filter
Air Pollution Control Option
First Year Average Control Cost
First Year Incremental Control Cost

PacifiCorp BART Analysis Scenarios

Select Unit:	5	Jim Bridger Unit 3

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	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	$ 3,387,923 $ 3,387,923 $ 3,387,923	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	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, New Fabric Filter	$ 9,726,040 $ 9,726,040 $ 9,726,040	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	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	$ 18,074,111 $ 18,074,111 $ 18,074,111	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	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	$ 24,412,229 $ 24,412,229 $ 24,412,229	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 3 **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 ($)	**0**	**8,700,001**	**20,528,122**	**21,973,632**	**129,575,495**	**12,999,900**	**0**	**48,386,333**
FIRST YEAR O&M COST ($)								
Operating Labor ($)	0	0	0	0	0	0	0	0
Maintenance Material ($)	0	28,000	42,000	122,000	190,000	25,550	0	51,099
Maintenance Labor ($)	0	42,000	63,000	183,000	285,000	17,033	10,000	76,649
Administrative Labor ($)	0	0	0	0	0	0	0	0
TOTAL FIXED O&M COST	**0**	**70,000**	**105,000**	**305,000**	**475,000**	**42,583**	**10,000**	**127,749**
Makeup Water Cost	0	0	0	0	0	29,927	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	600,000	0	0	294,008
Waste Disposal Cost	0	0	0	0	0	442,958	0	0
Electric Power Cost	0	0	2,528,012	204,984	1,269,718	204,984	19,710	1,313,474
TOTAL VARIABLE O&M COST	**0**	**0**	**2,528,012**	**1,210,795**	**2,782,566**	**1,211,075**	**165,564**	**1,607,482**
TOTAL FIRST YEAR O&M COST	**0**	**70,000**	**2,633,012**	**1,515,795**	**3,257,566**	**1,253,658**	**175,564**	**1,735,231**
FIRST YEAR DEBT SERVICE ($)	0	827,612	1,952,796	2,090,304	12,326,235	1,236,652	0	4,602,887
TOTAL FIRST YEAR COST ($)	**0**	**897,612**	**4,585,808**	**3,606,099**	**15,583,801**	**2,490,310**	**175,564**	**6,338,118**
Power Consumption (MW)	**0.0**	**0.0**	**6.4**	**0.5**	**3.2**	**0.5**	**0.1**	**3.3**
Annual Power Usage (Million kW-Hr/Yr)	**0.0**	**0.0**	**50.6**	**4.1**	**25.4**	**4.1**	**0.4**	**26.3**
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**	**610**	**1,734**	**0**	**0**	**0**
Incremental Control Cost ($/Ton NOx Removed)	**0**	**181**	**7,797**	**2,863**	**3,896**	**0**	**0**	**0**
		2-1	3-2	4-2	5-4			
SO2 Removal Rate (%)	**77.8%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**62.5%**	**0.0%**	**0.0%**
SO2 Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**3,950**	**0**	**0**
First Year Average Control Cost ($/Ton SO2 Rem.)	**0**	**0**	**0**	**0**	**0**	**631**	**0**	**0**
Incremental Control Cost ($/Ton SO2 Removed)	**Base**	**0**	**0**	**0**	**0**	**631**	**0**	**0**
						8-1		
PM Removal Rate (%)	**99.33%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**0.00%**	**47.37%**	**73.68%**
PM Removed (Tons/Yr)	**0**	**0**	**0**	**0**	**0**	**0**	**639**	**993**
First Year Average Control Cost ($/Ton PM Rem.)	**0**	**0**	**0**	**0**	**0**	**0**	**275**	**6,381**
Incremental Control Cost ($/Ton PM Removed)	**Base**	**0**	**0**	**0**	**0**	**0**	**275**	**17,371**
							9-1	10-9
PRESENT WORTH COST ($)	**0**	**9,555,250**	**52,697,883**	**40,493,391**	**169,375,961**	**28,316,912**	**2,145,015**	**69,587,130**

INPUT CALCULATIONS

Jim Bridger Unit 3 **Boiler Design:** **Tangential-Fired PC**

Parameter	Current Operation	NOx Control: LNB w/OFA	NOx Control: ROFA	NOx Control: LNB w/OFA & SNCR	NOx Control: LNB w/OFA & SCR	SO2 Control: Upgraded Wet FGD	PM Control: Flue Gas Conditioning	PM Control: Fabric Filter	Comments
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	342	342	342	342	342	342	342	
(Lb/MMBtu)	8.530	0.057	0.057	0.057	0.057	0.057	0.057	0.057	
(Lb Moles/Hr)	1,705.3	11.4	11.4	11.4	11.4	11.4	11.4	11.4	
(Tons/Yr)	201,739	1,348	1,348	1,348	1,348	1,348	1,348	1,348	
Fly Ash Removal Rate (%)	99.33%	0.00%	0.00%	0.00%	0.00%	0.00%	47.37%	73.68%	
(Lb/Hr)	50,835	0	0	0	0	0	162	252	
(Ton/Yr)	200,391	0	0	0	0	0	639	993	
Fly Ash Emission Rate (Lb/Hr)	342	342	342	342	342	342	180	90	
(Lb/MMBtu)	0.057	0.057	0.057	0.057	0.057	0.057	0.030	0.015	
(Ton/Yr)	1,348	1,348	1,348	1,348	1,348	1,348	710	355	

Parameter	Current Operation	NOx Control: LNB w/OFA	NOx Control: ROFA	NOx Control: LNB w/OFA & SNCR	NOx Control: LNB w/OFA & SCR	SO2 Control: Upgraded Wet FGD	PM Control: Flue Gas Conditioning	PM Control: Fabric Filter	Comments
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	21,973,632	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 ($2006)	0	8,700,001	20,528,122	21,973,632	129,575,495	12,999,900	0	48,386,333	
NOx Emission Control System ($/kW)	0	16	39	41	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 ($/kW)	0	16	39	41	244	25	0	91	
Total Fixed Operating & Maintenance Costs									
Operating Labor ($)	0	0	0	0	0	0	0	0	
Maintenance Material ($)	0	28,000	42,000	122,000	190,000	25,550	0	51,099	
Maintenance Labor ($)	0	42,000	63,000	183,000	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	305,000	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	52	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	29,927	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 ($)	0	0	0	1,005,811	912,848	533,206	145,854	0	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost					SCR Catalyst	Bags		Bags	
Annual SCR Catalyst (m3) / No. FF Bags	0	0	0	0	200	0	0	2,827	
SCR Catalyst ($/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	600,000	0	0	294,008	
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%	0.61%	0.10%	0.01%	0.63%	
(MW)	0.00	0.00	6.41	0.52	3.22	0.52	0.05	3.33	
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	204,984	1,269,718	204,984	19,710	1,313,474	
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

		Current Emission Rates (Lb/MMBtu)			NOx Control Emission Rates (Lb/MMBtu)				SO2 Control Emission Rates (Lb/MMBtu)			PM Emission Rates (Lb/MMBtu)	
Index No.	Name of Unit	Controlled SO2	Controlled NOx	Controlled PM	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	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)

		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	$ -	$ -	$ -	$ -	-	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)

		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	$ -	$ 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)

		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 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)

		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	$ -	$ 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

		NOx Control				SO2 Control			PM Control	
Index No.	Name of Unit | Case --->	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 3

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	$9,419,000	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%	$1,883,800	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%	$526,805	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%	$103,797	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%	$264,391	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%	$1,075,838	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**		**$13,273,632**		**$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 3 — 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 3 — 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 3 — 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	305,000	-	1,005,811	-	-	204,984	1,210,795	2,090,304	3,606,099	610
2	2015	311,100	-	1,025,927	-	-	209,084	1,235,011	2,090,304	3,636,415	615
3	2016	317,322	-	1,046,446	-	-	213,265	1,259,711	2,090,304	3,667,337	620
4	2017	323,668	-	1,067,375	-	-	217,531	1,284,905	2,090,304	3,698,877	626
5	2018	330,142	-	1,088,722	-	-	221,881	1,310,603	2,090,304	3,731,049	631
6	2019	336,745	-	1,110,496	-	-	226,319	1,336,815	2,090,304	3,763,864	637
7	2020	343,480	-	1,132,706	-	-	230,845	1,363,552	2,090,304	3,797,335	642
8	2021	350,349	-	1,155,361	-	-	235,462	1,390,823	2,090,304	3,831,476	648
9	2022	357,356	-	1,178,468	-	-	240,171	1,418,639	2,090,304	3,866,299	654
10	2023	364,503	-	1,202,037	-	-	244,975	1,447,012	2,090,304	3,901,819	660
11	2024	371,793	-	1,226,078	-	-	249,874	1,475,952	2,090,304	3,938,049	666
12	2025	379,229	-	1,250,599	-	-	254,872	1,505,471	2,090,304	3,975,004	672
13	2026	386,814	-	1,275,611	-	-	259,969	1,535,581	2,090,304	4,012,698	679
14	2027	394,550	-	1,301,124	-	-	265,169	1,566,292	2,090,304	4,051,146	685
15	2028	402,441	-	1,327,146	-	-	270,472	1,597,618	2,090,304	4,090,363	692
16	2029	410,490	-	1,353,689	-	-	275,881	1,629,570	2,090,304	4,130,364	699
17	2030	418,700	-	1,380,763	-	-	281,399	1,662,162	2,090,304	4,171,165	705
18	2031	427,074	-	1,408,378	-	-	287,027	1,695,405	2,090,304	4,212,783	713
19	2032	435,615	-	1,436,546	-	-	292,768	1,729,313	2,090,304	4,255,232	720
20	2033	444,327	-	1,465,276	-	-	298,623	1,763,899	2,090,304	4,298,531	727
Present Worth		3,726,445	-	12,288,849	-	-	2,504,464	14,793,314	21,973,632	40,493,391	342
(% of PW)		9.2%	0.0%	30.3%	0.0%	0.0%	6.2%	36.5%	54.3%	100.0%	

Jim Bridger Unit 3 — 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	600,000	-	1,269,718	2,782,566	12,326,235	15,583,801	1,734
2	2015	484,500	-	931,105	612,000	-	1,295,113	2,838,218	12,326,235	15,648,952	1,741
3	2016	494,190	-	949,727	624,240	-	1,321,015	2,894,982	12,326,235	15,715,407	1,749
4	2017	504,074	-	968,722	636,725	-	1,347,435	2,952,882	12,326,235	15,783,190	1,756
5	2018	514,155	-	988,096	649,459	-	1,374,384	3,011,939	12,326,235	15,852,329	1,764
6	2019	524,438	-	1,007,858	662,448	-	1,401,871	3,072,178	12,326,235	15,922,851	1,772
7	2020	534,927	-	1,028,015	675,697	-	1,429,909	3,133,622	12,326,235	15,994,783	1,780
8	2021	545,626	-	1,048,575	689,211	-	1,458,507	3,196,294	12,326,235	16,068,154	1,788
9	2022	556,538	-	1,069,547	702,996	-	1,487,677	3,260,220	12,326,235	16,142,993	1,796
10	2023	567,669	-	1,090,938	717,056	-	1,517,431	3,325,424	12,326,235	16,219,328	1,805
11	2024	579,022	-	1,112,757	731,397	-	1,547,779	3,391,933	12,326,235	16,297,190	1,813
12	2025	590,603	-	1,135,012	746,025	-	1,578,735	3,459,771	12,326,235	16,376,609	1,822
13	2026	602,415	-	1,157,712	760,945	-	1,610,310	3,528,967	12,326,235	16,457,616	1,831
14	2027	614,463	-	1,180,866	776,164	-	1,642,516	3,599,546	12,326,235	16,540,244	1,840
15	2028	626,752	-	1,204,484	791,687	-	1,675,366	3,671,537	12,326,235	16,624,524	1,850
16	2029	639,287	-	1,228,573	807,521	-	1,708,874	3,744,968	12,326,235	16,710,490	1,859
17	2030	652,073	-	1,253,145	823,671	-	1,743,051	3,819,867	12,326,235	16,798,175	1,869
18	2031	665,115	-	1,278,208	840,145	-	1,777,912	3,896,264	12,326,235	16,887,614	1,879
19	2032	678,417	-	1,303,772	856,948	-	1,813,470	3,974,190	12,326,235	16,978,842	1,889
20	2033	691,985	-	1,329,847	874,087	-	1,849,740	4,053,674	12,326,235	17,071,894	1,900
Present Worth		5,803,480	-	11,153,043	7,330,712	-	15,513,231	33,996,986	129,575,495	169,375,961	942
(% of PW)		3.4%	0.0%	6.6%	4.3%	0.0%	9.2%	20.1%	76.5%	100.0%	

Jim Bridger Unit 3 — 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	29,927	533,206	-	442,958	204,984	1,211,075	1,236,652	2,490,310	631
2	2015	43,435	30,526	543,870	-	451,818	209,084	1,235,297	1,236,652	2,515,384	637
3	2016	44,303	31,136	554,747	-	460,854	213,265	1,260,003	1,236,652	2,540,958	643
4	2017	45,189	31,759	565,842	-	470,071	217,531	1,285,203	1,236,652	2,567,044	650
5	2018	46,093	32,394	577,159	-	479,472	221,881	1,310,907	1,236,652	2,593,652	657
6	2019	47,015	33,042	588,702	-	489,062	226,319	1,337,125	1,236,652	2,620,792	664
7	2020	47,955	33,703	600,476	-	498,843	230,845	1,363,868	1,236,652	2,648,475	671
8	2021	48,914	34,377	612,486	-	508,820	235,462	1,391,145	1,236,652	2,676,711	678
9	2022	49,893	35,065	624,735	-	518,996	240,171	1,418,968	1,236,652	2,705,513	685
10	2023	50,890	35,766	637,230	-	529,376	244,975	1,447,347	1,236,652	2,734,890	692
11	2024	51,908	36,481	649,975	-	539,964	249,874	1,476,294	1,236,652	2,764,855	700
12	2025	52,946	37,211	662,974	-	550,763	254,872	1,505,820	1,236,652	2,795,419	708
13	2026	54,005	37,955	676,234	-	561,778	259,969	1,535,936	1,236,652	2,826,594	716
14	2027	55,085	38,714	689,758	-	573,014	265,169	1,566,655	1,236,652	2,858,393	724
15	2028	56,187	39,488	703,554	-	584,474	270,472	1,597,988	1,236,652	2,890,828	732
16	2029	57,311	40,278	717,625	-	596,164	275,881	1,629,948	1,236,652	2,923,911	740
17	2030	58,457	41,084	731,977	-	608,087	281,399	1,662,547	1,236,652	2,957,656	749
18	2031	59,626	41,905	746,617	-	620,249	287,027	1,695,798	1,236,652	2,992,076	758
19	2032	60,819	42,744	761,549	-	632,654	292,768	1,729,714	1,236,652	3,027,185	766
20	2033	62,035	43,598	776,780	-	645,307	298,623	1,764,308	1,236,652	3,062,995	776
Present Worth		520,271	365,648	6,514,628	-	5,412,000	2,504,464	14,796,741	12,999,900	28,316,912	358
(% of PW)		1.8%	1.3%	23.0%	0.0%	19.1%	8.8%	52.3%	45.9%	100.0%	

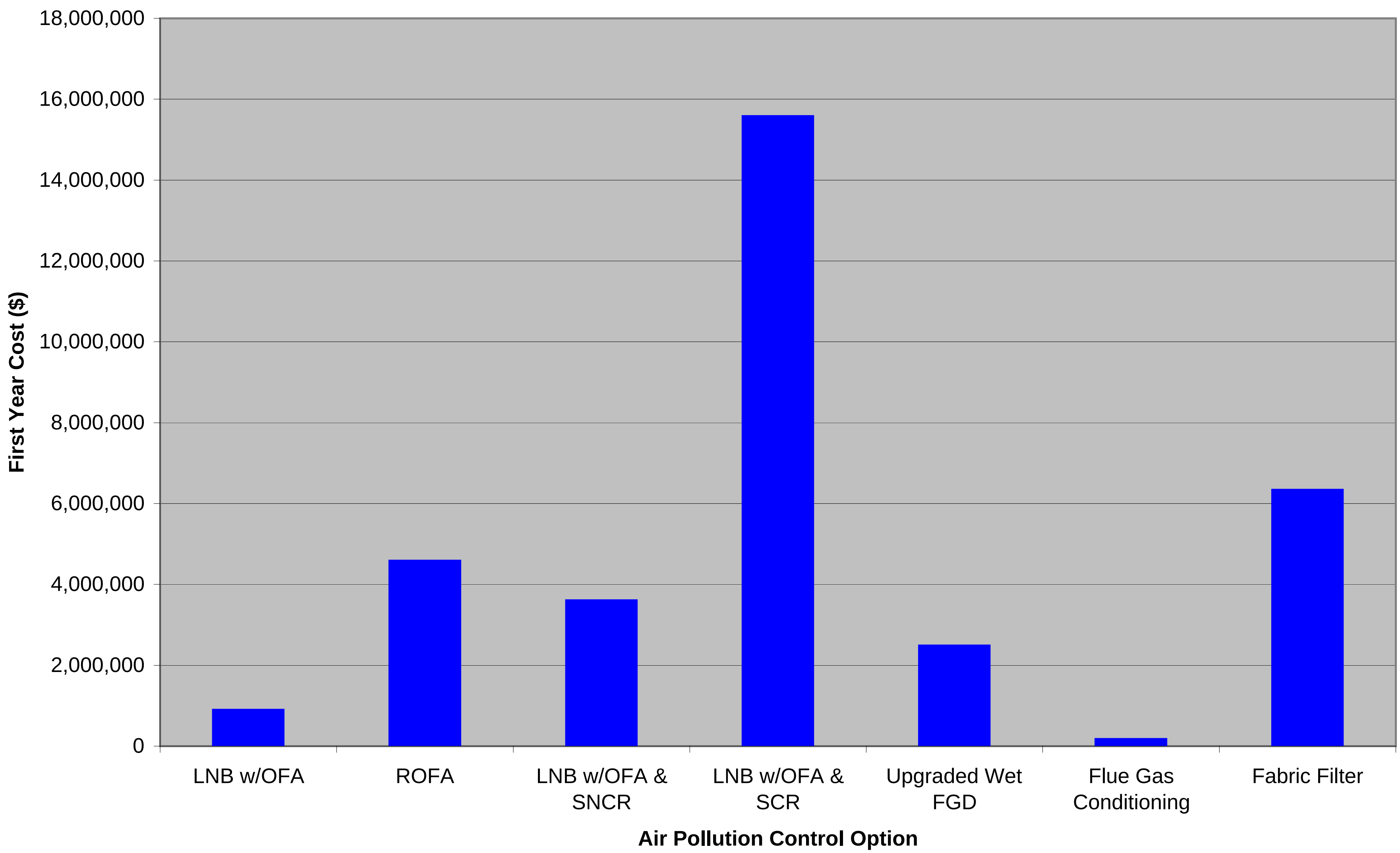
Jim Bridger Unit 3 — Flue Gas Conditioning

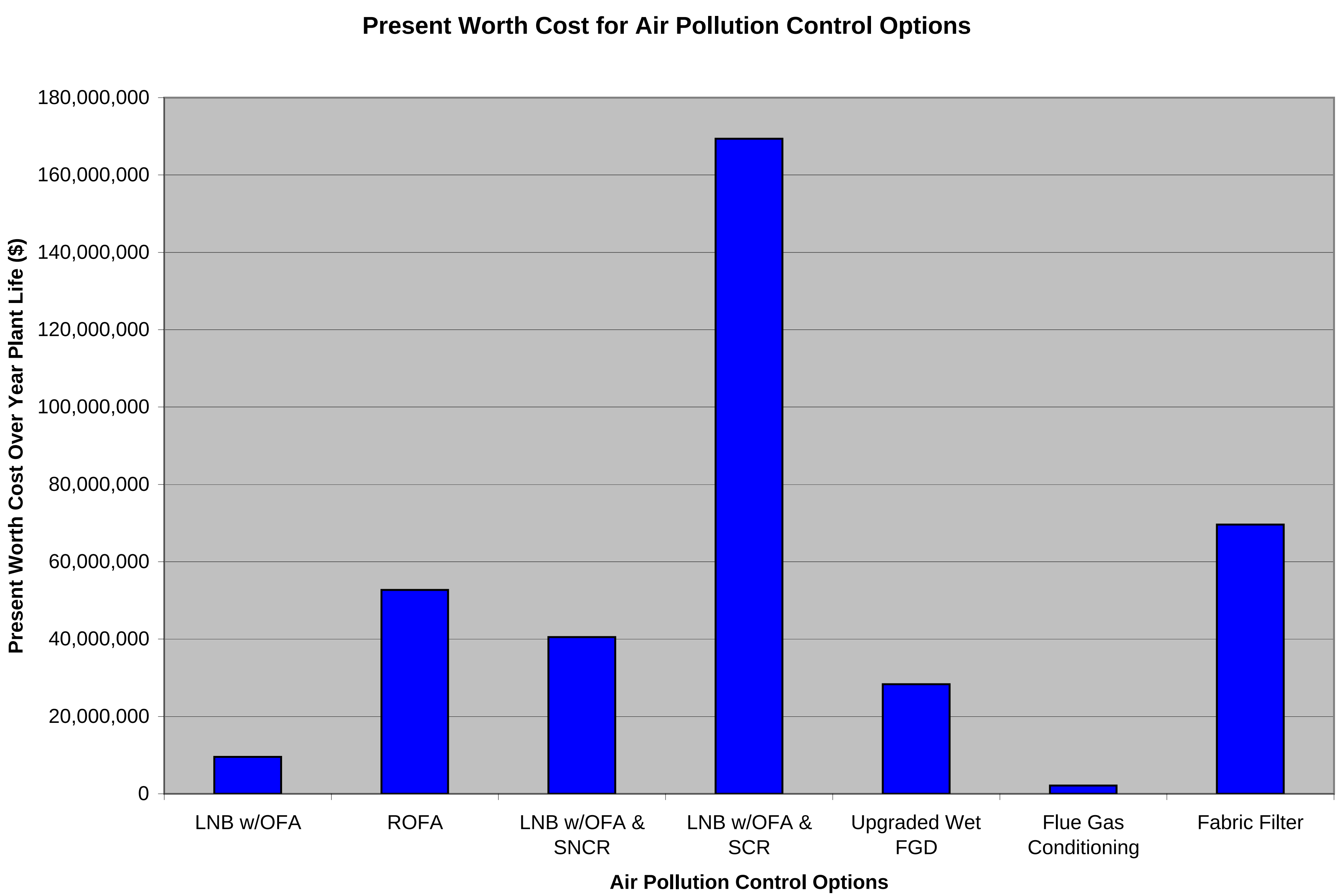
Year	Date	TOTAL FIXED O&M COST	Makeup Water Cost	Reagent Cost	SCR Catalyst / FF Bag Cost	Waste Disposal Cost	Electric Power Cost	TOTAL VARIABLE O&M COST	DEBT SERVICE	TOTAL ANNUAL COST	Control Cost ($/Ton PM Removed)
0	2013										
1	2014	10,000	-	145,854	-	-	19,710	165,564	-	175,564	275
2	2015	10,200	-	148,771	-	-	20,104	168,875	-	179,075	280
3	2016	10,404	-	151,747	-	-	20,506	172,253	-	182,657	286
4	2017	10,612	-	154,781	-	-	20,916	175,698	-	186,310	292
5	2018	10,824	-	157,877	-	-	21,335	179,212	-	190,036	298
6	2019	11,041	-	161,035	-	-	21,761	182,796	-	193,837	304
7	2020	11,262	-	164,255	-	-	22,197	186,452	-	197,714	310
8	2021	11,487	-	167,540	-	-	22,641	190,181	-	201,668	316
9	2022	11,717	-	170,891	-	-	23,093	193,985	-	205,701	322
10	2023	11,951	-	174,309	-	-	23,555	197,864	-	209,815	329
11	2024	12,190	-	177,795	-	-	24,026	201,822	-	214,012	335
12	2025	12,434	-	181,351	-	-	24,507	205,858	-	218,292	342
13	2026	12,682	-	184,978	-	-	24,997	209,975	-	222,658	349
14	2027	12,936	-	188,678	-	-	25,497	214,175	-	227,111	356
15	2028	13,195	-	192,451	-	-	26,007	218,458	-	231,653	363
16	2029	13,459	-	196,300	-	-	26,527	222,827	-	236,286	370
17	2030	13,728	-	200,226	-	-	27,058	227,284	-	241,012	377
18	2031	14,002	-	204,231	-	-	27,599	231,830	-	245,832	385
19	2032	14,282	-	208,315	-	-	28,151	236,466	-	250,749	393
20	2033	14,568	-	212,482	-	-	28,714	241,195	-	255,764	401
Present Worth		122,179	-	1,782,023	-	-	240,814	2,022,837	-	2,145,015	168
(% of PW)		5.7%	0.0%	83.1%	0.0%	0.0%	11.2%	94.3%	0.0%	100.0%	

Jim Bridger Unit 3 — 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	-	-	294,008	-	1,313,474	1,607,482	4,602,887	6,338,118	6,381
2	2015	130,304	-	-	299,888	-	1,339,744	1,639,632	4,602,887	6,372,822	6,416
3	2016	132,910	-	-	305,886	-	1,366,539	1,672,425	4,602,887	6,408,221	6,451
4	2017	135,568	-	-	312,004	-	1,393,870	1,705,873	4,602,887	6,444,328	6,488
5	2018	138,279	-	-	318,244	-	1,421,747	1,739,991	4,602,887	6,481,156	6,525
6	2019	141,045	-	-	324,609	-	1,450,182	1,774,790	4,602,887	6,518,722	6,563
7	2020	143,866	-	-	331,101	-	1,479,186	1,810,286	4,602,887	6,557,038	6,601
8	2021	146,743	-	-	337,723	-	1,508,769	1,846,492	4,602,887	6,596,121	6,640
9	2022	149,678	-	-	344,477	-	1,538,945	1,883,422	4,602,887	6,635,986	6,681
10	2023	152,671	-	-	351,367	-	1,569,723	1,921,090	4,602,887	6,676,648	6,722
11	2024	155,725	-	-	358,394	-	1,601,118	1,959,512	4,602,887	6,718,123	6,763
12	2025	158,839	-	-	365,562	-	1,633,140	1,998,702	4,602,887	6,760,428	6,806
13	2026	162,016	-	-	372,873	-	1,665,803	2,038,676	4,602,887	6,803,579	6,849
14	2027	165,256	-	-	380,331	-	1,699,119	2,079,450	4,602,887	6,847,593	6,894
15	2028	168,562	-	-	387,937	-	1,733,102	2,121,039	4,602,887	6,892,487	6,939
16	2029	171,933	-	-	395,696	-	1,767,764	2,163,460	4,602,887	6,938,279	6,985
17	2030	175,371	-	-	403,610	-	1,803,119	2,206,729	4,602,887	6,984,987	7,032
18	2031	178,879	-	-	411,682	-	1,839,181	2,250,863	4,602,887	7,032,629	7,080
19	2032	182,456	-	-	419,916	-	1,875,965	2,295,881	4,602,887	7,081,224	7,129
20	2033	186,106	-	-	428,314	-	1,913,484	2,341,798	4,602,887	7,130,790	7,179
Present Worth		1,560,813	-	-	3,592,147	-	16,047,838	19,639,984	48,386,333	69,587,130	3,503
(% of PW)		2.2%	0.0%	0.0%	5.2%	0.0%	23.1%	28.2%	69.5%	100.0%	

First Year Cost for Air Pollution Control Options




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 3
2.0 OVERVIEW 4
3.0 EMISSIONS DATA FOR MODELING 7
3.1 Baseline Modeling 7
3.2 Post-Control Modeling 8
4.0 METEOROLOGICAL DATA 9
5.0 CALPUFF MODEL APPLICATION 12
6.0 POST PROCESSING 15
7.0 REPORTING 19

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.

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(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 $PM_{10-2.5}$. 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	
		98^{th} Percentile Value (dv)	No. of days exceeding 0.5 dv	98^{th} Percentile Value (dv)	No. of days exceeding 0.5 dv	98^{th} Percentile Value (dv)	No. of days exceeding 0.5 dv

APPENDIX C

Just-Noticeable Differences in Atmospheric Haze

Dr. Ronald Henry

TECHNICAL PAPER

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Just-Noticeable Differences in Atmospheric Haze

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ABSTRACT

This article examines the only available experimental data taken in the natural environment on the ability of an observer to perceive small, incremental changes in the colorfulness of objects seen through atmospheric haze and estimates an appropriate just-noticeable difference (JND) from these data. This experimentally determined threshold of perception is compared to changes in the deciview scale. Based on these experimental results, the deciview scale is found to not be uniform over a wide range of visibility conditions, as has been previously claimed. In addition, a 1-deciview change never produces a perceptible change in haze, as defined by a 95% probability of producing a measurable change in the colorfulness of an object seen through the haze.

INTRODUCTION

Section 169A of the Clean Air Act sets a national goal of protecting visibility in national parks and other pristine areas. Under regulations promulgated in 1980, the U.S. Environmental Protection Agency (EPA) has taken specific regulatory action to protect visibility in the Grand Canyon National Park by reducing emissions of sulfur dioxide from the Navajo Electric Generating Station near the eastern end of the Grand Canyon and from the Mohave Power Plant at the western end. However, current concerns about visibility degradation stem from regional haze that is difficult or impossible to attribute to individual sources of air pollution. This issue is addressed by regional haze regulations that set a goal of making reasonable progress toward improving regional visibility in five-year increments, leading to the attainment of "natural conditions" by 2064.[1] Progress is to be measured by an innovative visibility metric for regulatory purposes known as the deciview,[2] used instead of visual range or other visibility metrics because it "expresses uniform changes in haziness in terms of common increments across the entire range of visibility conditions, from pristine to extremely hazy conditions."[1] One goal of this article is to assess this and other claims about the deciview scale in light of actual measurements of the perception of haziness. Since the deciview scale is meant to quantify small, just-noticeable differences (JNDs) in visibility, a review of the basic concepts of thresholds and JNDs is given.

IMPLICATIONS

Current regulations use the deciview to quantify a perceptible change in regional haze. Based on the results of this article, changes in atmospheric extinction required to meet regional haze regulations calculated using deciviews would probably be too small, sometimes much too small. In addition, these regulations require that progress be assessed over five-year intervals. In this way, the burden of reducing emissions is spread evenly over many years. However, since deciviews are not uniform in perception, it may be that the actual improvement in visibility will not be uniform.

Perceptual Threshold Concepts

For all the senses, thresholds are necessary—otherwise we would be constantly distracted by small, inconsequential changes in the environment. A background of random noise, some from the environment and some produced inside our own sensory organs, would make it next to impossible to form a stable view of the world. Our vision would be like the grainy, speckled images produced by night vision cameras. On a more basic scientific level, the study of thresholds of the senses has led to a deeper understanding of sensory physiology and how our vision and other senses function. For this reason, virtually all studies of thresholds of vision have been carried out under controlled laboratory conditions.

Since laboratory conditions seldom mimic the natural environment, thresholds so determined are generally not useful in predicting perception in the complex natural world. As an example of the drastic effect that experimental conditions can have on perception, consider an experiment to determine the ability of an observer to perceive the difference in the length of two strings—or to put it another way, to determine the threshold for perception of the difference in the length of two strings, or the JND. If the two strings are widely separated when presented to the observer, the threshold will be much greater than if the two strings are presented side by side. The visual equivalent of this is the use of a split image to determine the ability to distinguish color. If two colors are seen as two halves of a disk, the JND is very small, but if one color is presented as a full disk, followed a few seconds later by the other color, the JND will be much larger. The topic of the background on which the colors are seen is also important (e.g., if it is black or a complex scene). In general, many conditions influence thresholds; for this reason, the results of laboratory experiments should be applied with great caution to the natural environment. Thus, this article will report and analyze data taken in a unique experiment in the natural environment with a goal of determining a JND in atmospheric haze.

In the above discussion, the terms "threshold" and "JND" have been freely used, but not defined. The naïve definition of a threshold or JND is clear: It is the smallest amount, or change in, a physical stimulus that is detectable. Ideally, a 1-JND change in a stimulus such as contrast or color would always result in the observer seeing a change, and anything less would not. Of course, the senses do not work in this simple on-off manner. In actuality, as the change in the physical stimulus increases, the probability that the observer will detect the change increases as well. Thus, thresholds and JNDs have always been defined by a probability of detection. Furthermore, the sensitivity of people's senses varies from person to person and during a person's life. Even if each person had a single, idealized threshold, the response of the general population would be best described by a probability of detection.

Repeated matching by the method of adjustments is one of the oldest methods of determining a JND. Falmagne[3] described this and other methods to quantify perception. Briefly, the observer is shown a target color and a variable test color and is asked to adjust the test color until it matches the target. Taking random starting points, the matching procedure is repeated as often as is practical. Since the observer has judged the matching color to be the same as the target color, the variability in the matches is a measure of a JND around the target. The standard deviation of the matches is one measure of this variability that is often used; another is the difference between the 75th and the 25th percentile of the match distribution. The method of adjustments has been replaced in laboratory studies by methods that give less control to the observer and more to the researcher and therefore improve the reproducibility of the results (unfortunately, these methods are impractical for field studies). However, JNDs are still defined by some measure related to the probability of detection. The final determination of the value of a JND or threshold is really dependent on how the measurements are made and how the data are interpreted. For the experimental data used in this article, the method of adjustments was used and a JND related to the standard deviation of repeated matches was defined.

Atmospheric Visibility Concepts

In the classical theory of atmospheric visibility, the threshold of contrast perception, that is, the threshold for perception of a large, dark object on the horizon, is assumed to be 2%.[4] This number is somewhat arbitrary. The Federal Aviation Administration (FAA) has taken the more conservative value of 5.5% as a contrast threshold for the definition of visual range, presumably because approaching aircraft seen from a cockpit are usually neither large nor dark. The common formula for visual range, using the 2% threshold, is

$$V_R = \frac{-\ln(0.02)}{b_{ext}} = \frac{3.9}{b_{ext}} \tag{1}$$

where b_{ext} is the extinction coefficient of the atmosphere, which is assumed to be homogeneous. The extinction coefficient in the denominator of the formula can be thought of as the fraction of light that is lost as it traverses 1 m of air. For completely clear air, b_{ext} has a value of about 10 x 10^{-6} m^{-1} or 10 Mm^{-1}, or a visual range of about 390 km. More typically, particles in the air usually increase the extinction coefficient to 150–300 Mm^{-1} or more. Typical visual ranges are about 10 km in the eastern United States and 50 km or more in the western United States. Closely related to b_{ext} and visual range is the more general concept of optical depth. For a target at a distance x, this is defined as xb_{ext}. It is dimensionless; if b_{ext} is held constant it represents distance, and if the distance is constant, it represents changes in b_{ext}. From eq 1, the visual range corresponds to an optical depth of 3.9, and a distance of about one quarter of the visual range is equivalent to an optical depth of 1.

Despite lacking a firm psychophysical or experimental basis, the visual range defined by the 2% threshold has stood the test of time. However, while visual range has proven to be a good surrogate for atmospheric visibility for the aviation community, it is of limited value in addressing the concerns of the air quality community. Unlike aviation, where poor visibility is of greatest interest, the air quality community is primarily concerned with relatively small changes in good visibility. Pitchford and Malm[2] have proposed the deciview as a visibility indicator more suited to air quality regulations. If the extinction coefficient is given in Mm^{-1}, then deciview is defined as

$$v = 10 \ln(b_{ext} / 10) \tag{2}$$

Current regional haze visibility regulations state that:

(1) A 1-deciview change in haziness is a small, but noticeable, change in haziness under most circumstances when viewing scenes in Class I areas.

(2) Deciview units are uniform in perception over a wide range of visibility conditions; that is, a 1-deciview change is just perceptible regardless of the visibility conditions.[1]

The next section describes a color matching experiment in the Great Smoky Mountains National Park. The results of this experiment are used to estimate a just-noticeable change in haze based on color perception. The validity of the claims for deciviews will be evaluated by comparison to experimental estimates of JNDs.

EXPERIMENTAL DATA

During summer 1995, a group of researchers from universities, government agencies, and private companies conducted the SouthEast Aerosol and Visibility Study (SEAVS) in the Great Smoky Mountains National Park. The SEAVS focused largely on aerosol composition,[5,6] airborne particle size distribution,[7,8] and the role of water in the aerosol.[9-11] However, the SEAVS had a number of other aspects, including a study of the perception of color through atmospheric haze.[12] The methods and primary results of the color perception study are described below.

The perceived colors of natural targets were quantified by color matching using a specially constructed visual colorimeter.[13] An observer looked at some scene element, such as a barn or green field, with one eye. The observer looked with the other eye in the visual colorimeter at a color spot, which the observer adjusted to match the color of the target. The perceived color was recorded as the amount of red, green, and blue light in the color match. At the same time, the spectrum of the light coming from the target was measured by a telespectroradiometer. A color appearance model was applied to produce measures of the perceived color as recorded by the visual colorimeter and as calculated from the spectrum.[14]

Of most interest here are the hue and colorfulness. The hue is what most people call the color—red, green, blue, yellow, and so on. It is quantified as a mixture of pure red, green, blue, or yellow lights. The colorfulness is the degree to which the hue is expressed; it is similar to the concept of saturation. A deep red color would have a colorfulness of about 100, while a colorfulness of 10 or less is almost achromatic (i.e., white or gray).

Two observers (Mahadev and Urquito) made color matches of a set of natural targets during the SEAVS. These observers were both males in their 20s with normal color vision. Each had received extensive training in color matching using the visual colorimeter. The scattering coefficient of the atmosphere was measured by a nearby nephelometer; particle absorption was small and its contribution to the extinction coefficient ignored. The full details of the experiment are found in Mahadev.[15]

The perception study found that viewing through a semitransparent atmosphere affected the perception of hue and colorfulness in a highly nonlinear way. The eye appeared to split the light coming from the target into two parts, the haze and the target. The result was that as the haze increased, the hue of the target as seen by the observer remained constant. However, because the increasing haze scattered more light into the sight path, the hue calculated from the spectrum became bluer. To the observer, the main effect of haze was to decrease the perceived colorfulness. Furthermore, the decrease in colorfulness seemed to be exponential with optical depth (optical depth is the dimensionless product of the extinction coefficient and distance):

$$M(\tau) = M_0 \exp(-\tau) \tag{3}$$

where $M(\tau)$ is the colorfulness of the object at optical depth τ and M_0 is the colorfulness at zero optical depth (i.e., no haze). M_0 is also known as the inherent colorfulness. The colorfulness of the horizon was assumed to be small enough to be taken as zero—the horizon was perceived to be white. This result implies that a JND in colorfulness can be taken to be a JND in haze.

JND in Colorfulness

Estimates of JNDs in colorfulness were based on sets of repeated color matches made during periods when the observing conditions (cloud cover, haze level, and lighting) were judged to be constant or nearly so. Observer Urquito made six sets of repeated matches.[15] Figure 1 is a plot of all the repeated observations of the colorfulness of the red barn roof made by this observer versus optical depth. The exponential fit given by eq 1 is fairly good ($R^2 = 0.68$). The error bars in the figure are twice the standard deviation given in Table 1. They show that one set

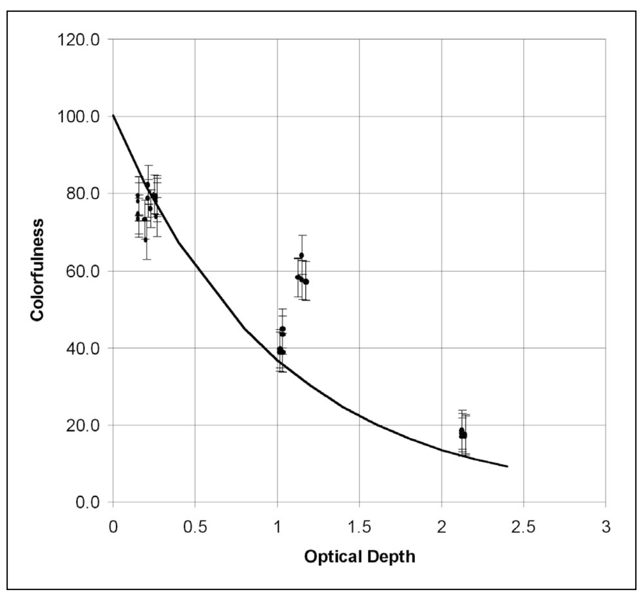

Figure 1. Colorfulness vs. optical depth for observer Urquito for repeated observations of the red barn roof. The line is an exponential fit as in eq 1, and the error bars are two times the standard deviation given in Table 2.

Table 1. Repeated measurements of the red barn roof by observer Mahadev.

Date	Time	Scattering Coefficient $(Mm)^{-1}$	Visual Range (km)	Colorfulness Spectra	Colorfulness Perceived	Spectra Hue % Red	Spectra Hue % Blue	Perceived Hue % Red	Perceived Hue % Blue
7/29/95	10:20 a.m.	37	105.7	38.0	42.2	53	47	97	3
7/29/95	10:46 a.m.	39	100.3	38.9	45.6	40	60	92	8
7/29/95	10:54 a.m.	39	100.3	39.9	45.4	38	62	99	1
7/29/95	11:03 a.m.	42	93.1	35.6	46.3	52	48	92	8
7/29/95	11:12 a.m.	42	93.1	37.5	44.9	53	47	93	7
7/25/95	11:49 a.m.	65	60.2	31.2	41.1	50	50	88	12
7/25/95	12:01 p.m.	65	60.2	30.8	45.1	42	58	84	16
7/25/95	12:12 p.m.	65	60.2	30.4	44.1	53	47	91	9
7/25/95	12:19 p.m.	65	60.2	29.4	43.0	54	46	91	9
7/25/95	12:24 p.m.	65	60.2	29.2	48.4	47	53	93	7
8/11/95	9:46 a.m.	157	24.9	37.6	29.2	19	81	97	3
8/11/95	9:57 a.m.	157	24.9	37.2	28.8	22	78	98	2
8/11/95	10:07 a.m.	157	24.9	37.5	29.2	23	77	98	2
8/11/95	10:16 a.m.	161	24.3	36.3	34.9	24	76	98	2
8/11/95	10:21 a.m.	161	24.3	36.7	29.5	23	77	98	2
8/14/95	10:12 a.m.	311	12.6	44.4	18.2	9	91	91	9
8/14/95	10:18 a.m.	312	12.5	44.0	18.4	8	92	97	3
8/14/95	10:30 a.m.	313	12.5	44.8	17.6	7	93	95	5
8/14/95	10:34 a.m.	313	12.5	44.7	18.1	7	93	94	6
8/14/95	10:38 a.m.	313	12.5	44.3	18.3	8	92	94	6
8/18/95	11:00 a.m.	595	6.6	35.3	9.7	2	98	81	19
8/18/95	10:46 a.m.	616	6.4	35.4	6.8	2	98	98	2
8/18/95	10:50 a.m.	616	6.4	35.2	9.4	2	98	91	9
8/18/95	10:53 a.m.	616	6.4	35.0	7.3	2	98	99	1
8/18/95	10:57 a.m.	616	6.4	35.7	10.0	2	98	97	3

of repeated measurements had colorfulness values that deviated much more than 2 sigma from the exponential line. However, the spread of these values about the mean was about the same as other observations for the same optical depth. This shows that the variability in the colorfulness numbers is not affected by systematic observer bias in the average colorfulness, and that the variability will be used to define the JND. The observations of the same target by the other observer are discussed in detail below.

Table 1 gives the results of five sets of repeated matches by observer Mahadev for the roof of a red barn about 3.5 km distant. Table 1 is sorted by the extinction coefficient so that one can easily see that the perceived hue did not change with increasing haze, but that the hue derived from the spectrum changed from red to blue. Colorfulness had the opposite behavior; the perceived values decreased with increasing haze and the values from the spectrum stayed about the same. Two-way analysis of variance was applied to estimate the random error in the sets of repeated measurements in Table 1. This analysis was repeated for both observers' matches of five additional natural targets. The results are given in Table 2. The standard deviation for both observers was 2.05, as calculated from the average of the variances. Although viewing conditions were chosen to be constant, some of this variability was due to small changes in atmospheric conditions.

Based on these results, one can define the JND in colorfulness in many ways. One appropriate definition for this application is based on the following thought experiment. An observer matches a target with the visual colorimeter and determines the colorfulness to be C_1. The extinction coefficient of the atmosphere is decreased, so the colorfulness of the target is increased by an amount ΔC. The observer matches the target again to get the new colorfulness C_2. A JND is defined as the value of ΔC that gives a 95% probability that $C_2 - C_1 > 0$. Assume that C_1 and C_2 are normal random variables with standard deviation s and means C_0 and $C_0+\Delta C$, respectively (statistical analysis of the SEAVS color matching data confirms that this is a good assumption). Then $C_2 - C_1$ is a normal random variable with mean ΔC and standard deviation $2^{1/2}\sigma$. The value of ΔC needed to ensure a 95% probability that $C_1 - C_2 > 0$ is given by $2^{1/2}\sigma F(0.95)$, where $F(0.95)$ is the inverse of the cumulative standard normal distribution and is equal to 1.645. Thus, the colorfulness JND is taken to be $2^{1/2}\sigma F(0.95) = 2.326\sigma$. From Table 2, using the data for both observers gives $\sigma = 2.05$, and a 1 colorfulness JND is 4.8. This value of σ includes the effects of small random variations in natural illumination, which should be included for this application because they are inevitably present, but makes the value of a colorfulness JND a bit larger than it would be otherwise.

Table 2. Standard deviations of colorfulness for repeated matches of natural targets.

Target	Observer M	Observer U	Distance (km)
White silo	0.91	1.33	3.54
Red roof	1.93	2.41	3.54
Near green meadow	2.93	2.15	3.86
Green hills	2.15	3.46	5.15
Far green meadow	1.45	1.64	10.46
Horizon sky	1.53	1.19	
Average	1.92	2.17	
Number of observations	55	60	

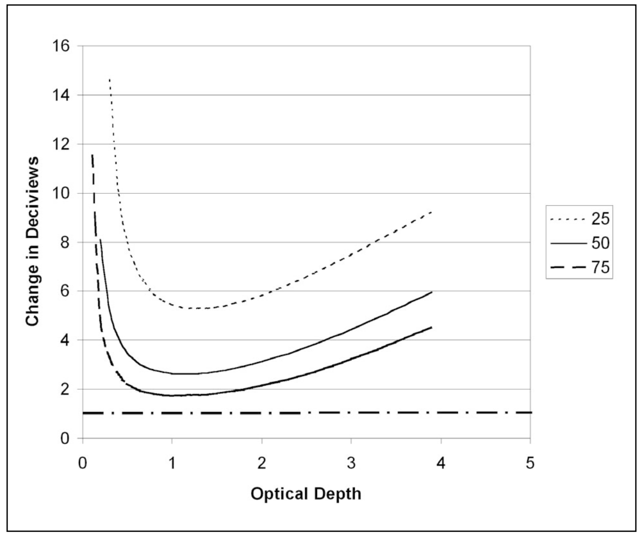

Figure 2. Change in deciviews needed to produce a just-noticeable increase in colorfulness for objects with an inherent colorfulness of 25, 50, and 75. The horizontal dashed dotted line represents what would be expected if a 1-deciview change were actually a uniform measure of haze perception.

Deciviews and Colorfulness JNDs

Relationships between colorfulness, deciviews, and optical depth are derived below; these will be applied to test the validity of the properties of deciviews given in the regional haze regulations.

From eqs 2 and 3, an expression for deciviews v as a function of colorfulness M is derived:

$$v = 10\ln\left(-\frac{1}{10x}\ln\left(\frac{M}{M_0}\right)\right) \quad (4)$$

For a given optical depth and inherent colorfulness, the equations above were used to calculate the change in deciviews needed to give a 1-JND increase in colorfulness, using 4.8 as a JND. Figure 2 is a plot of the results as a function of optical depth for objects with three levels of inherent colorfulness. These levels of inherent colorfulness represent a reasonable range for natural targets.[12] As might be expected, more colorful objects are more sensitive to changes in atmospheric haze. Perhaps unexpectedly, the figure shows that landscape features at a distance corresponding to an optical depth of 1–2 are the most sensitive to changes in extinction as measured by deciviews. This range corresponds to one quarter to one half of the visual range. Landscape features outside this range are much less sensitive to changes in haze. If the deciview scale were perceptually uniform, as claimed in the regional haze rules, then the lines in the figure would be horizontal, or at least approximately so. However, the change in deciviews needed to produce a 1-JND change in colorfulness varied a great deal with optical depth and inherent colorfulness. The figure also shows that a 1-JND change in colorfulness always requires more than a 1-deciview change, sometimes much more.

DISCUSSION AND CONCLUSIONS

Regional atmospheric haze affects visibility by producing a visible haze layer that limits the visual range, reduces contrast, and deceases the colorfulness of objects seen though the haze. Of these three effects of haze, the decrease in colorfulness may be the most important and sensitive visual cue. Visual range is not often useful for judging the effects of small changes in extinction. For example, a change in visual range from 50 to 60 km will not be noticed if the most distant landscape feature is at 25 km. The effect of haze on contrast is a better candidate as an indicator of change in haze; however, perceived contrast, like perceived hue, is affected in a nonlinear fashion by the semitransparent nature of haze and is not a sensitive indicator of changes in atmospheric haze.[16] Experimental data have shown that colorfulness is a sensitive measure of changes in haze, so this article has used it to define just-noticeable changes in atmospheric haze.

A just-noticeable decrease in atmospheric haze is defined as a decrease in extinction that would produce a 95% probability of a measurable increase in colorfulness of an object seen through the haze. From the experimental evidence from the two young male observers, a JND in colorfulness was 4.8. For the population in general, this number is certainly too low, since all visual functions decline with age. Thus, the conclusions below about the deciview scale based on this number are understated for the general population.

Analysis of the experimental data showed that for a JND in atmospheric haze as defined above:

(1) The deciview scale is not uniform in perception over a wide range of visibility conditions. In fact, the change in deciviews needed to be noticeable

varies greatly depending on the optical distance of the landscape feature and its inherent colorfulness.

(2) A 1-deciview change is never noticeable.

What are the implications of these results for measuring progress toward reducing regional haze using the deciview metric? This is difficult to judge because the current proposals are very complex, using particulate measurements and relative humidity to estimate the extinction coefficient and average deciviews for the 20% most-impaired and 20% least-impaired days. The goal is to show no change on the least-impaired days and improvement on the most-impaired days, leading to natural conditions by 2064.[17]

The results of this article highlight a possible flaw in this regulatory scheme based on the deciview metric. An unstated assumption is that the nature of the scenic vista can be ignored—that is, a given deciview change will affect the perception of all landscape features in all scenes in the same way. Figure 2 shows that this is approximately true only if all the important landscape features have nearly the same inherent colorfulness and are at distances that correspond to an optical depth of between 1 and 2, or about one quarter to one half of the visual range. In this limited case, the deciview is indeed a uniform metric. However, most scenic vistas do not fit these restrictions and, by Figure 2, will require greater decreases in extinction as measured by deciviews to show a perceptible change. The result is that the emission reductions required by the proposed regulatory analysis are likely to produce much smaller improvements in perceived effects of regional haze than expected. The EPA guidance documents provide an example of an eastern scenic vista with a baseline of 27 deciviews and natural conditions of 11.[17] The decrease in extinction to reach natural conditions by 2064 is 0.35 deciview/yr, or 1.75 deciviews in five years. This five-year reduction should, according to the regulations, result in a noticeable change in regional haze. However, the results herein predict that there would very likely be no noticeable difference in any actual scenic vista in the region as a result of the required emission reductions.

Regional haze rules also call for a uniform rate of improvement in visibility (measured in deciviews) that is needed to go from current conditions to natural conditions by 2064. Since the deciview scale is not uniform in perception over a wide range of visibility conditions, this requirement is also flawed and will not result in uniform improvement in perceived visibility.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

IDAHO POWER COMPANY

Exhibit Accompanying Testimony of John Carstensen
Addendum to Final Report – BART Analysis for Jim Bridger Unit 3

February 1, 2012

TECHNICAL MEMORANDUM CH2MHILL

Addendum to Jim Bridger Unit 3 BART Report

PREPARED FOR: Wyoming Division of Air Quality

PREPARED BY: CH2M HILL

COPIES: Bill Lawson/PacifiCorp

DATE: March 26, 2008

Introduction

In compliance with the Regional Haze Rule (40 Code of Federal Regulations [CFR] 51), the Wyoming Division of Air Quality (WDAQ) required PacifiCorp Energy to conduct a detailed Best Available Retrofit Technology (BART) review to analyze the effects to visibility in nearby Class I areas from plant emissions, both for baseline and for reasonable control technology scenarios. PacifiCorp submitted these evaluations to WDAQ in January 2007. A revised report was submitted in October 2007.

On January 3, 2008, PacifiCorp Energy personnel met with WDAQ staff to discuss the status of the BART reviews. At that time, the state requested that additional modeling scenarios for several of the PacifiCorp facilities be performed to aid in their BART review. This memorandum presents the economics analysis for two scenarios modeled, referred to as Scenario A and Scenario B and described as follows:

- Scenario A: PacifiCorp committed controls at permitted rates—low nitrogen oxide (NO_x) burners (LNBs) with over-fire air (OFA), sodium based flue gas desulfurization (FGD), SO_3 injection
- Scenario B: PacifiCorp committed controls and selective catalytic reduction (SCR) at permitted rates

The CALPUFF modeling system (v. 5.711a) was used for this analysis. All technical options and model triggers used in CALMET, CALPUFF, and CALPOST are consistent with those used for the previous BART analyses and described in the BART report submitted in October 2007.

Stack Parameters, Emissions Information, and Capital Cost

Table 1 summarizes the control equipment for Scenarios A and B as well as the current equipment installed at the plant. The overall capital cost of installing these options is also shown.

TABLE 1
Control Scenario Summary
Jim Bridger Unit 3

	Equipment Type			Capital Cost
	NO_x	SO_2	PM_{10}	Million dollars
Baseline	LNB	Wet sodium FGD	ESP	—
Scenario A	LNB with OFA	Wet sodium FGD	ESP with SO_3 injection	$40.5
Scenario B	LNB with OFA and SCR	Wet sodium FGD	ESP with SO_3 injection	$207.0

Emissions were modeled for the following pollutants:

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

Table 2 shows stack parameters and emission rates that were used for the Jim Bridger Unit 3 BART modeling and analysis.

TABLE 2
Calpuff Model Inputs
Jim Bridger Unit 3

	BART Comparison[d]		
Model Input Data	Baseline	Scenario A [e]	Scenario B [f]
Hourly Heat Input (mmBtu/hour)	6,000	6,000	6,000
Sulfur Dioxide (SO2) Stack Emissions (lb/hr)	1,602	900	900
Nitrogen Oxide (NOx) Stack Emissions (lb/hr)	2,700	1,560	420
PM_{10} Stack Emissions (lb/hr)	342	180.0	180.0
Coarse Particulate ($PM_{2.5}$ <diameter< PM_{10}) Stack Emissions (lb/hr)[a]	147	77.4	77.4
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[b]	195	102.6	102.6
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	55.2	55.2	94.7
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)	—	—	7.0
$(NH_4)HSO_4$ Stack Emissions (lb/hr)	—	—	12.2

TABLE 2
Calpuff Model Inputs
Jim Bridger Unit 3

	BART Comparison[d]		
Model Input Data	**Baseline**	**Scenario A [e]**	**Scenario B [f]**
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	54.1	54.1	92.8
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	5.1
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	10.2
Total Sulfate (SO_4) (lb/hr)[c]	54.1	54.1	108.1
Stack Conditions			
Stack Height (meters)	152	152	152
Stack Exit Diameter (meters)	7.32	7.32	7.32
Stack Exit Temperature (Kelvin)	333	328	328
Stack Exit Velocity (meters per second)	25.6	24.7	24.7

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% ESP and 57% 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% ESP and 43% Baghouse.
[c] 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)
[d] SO_2, NO_x, and PM rates are expressed in terms of permitted emission rates. Actual emissions will be less than the permitted rates.
[e] PacifiCorp Committed Controls @ permitted rates: LNB with OFA, Wet FGD, ESP with SO_3
[f] PacifiCorp Committed Controls and SCR @ permitted rates

Economic Analysis

In completing this additional analysis to supplement the previous BART study, technology alternatives were investigated and potential reductions in NO_x, SO_2, and PM_{10} emissions rates were identified.

A comparison of Scenarios A and B on the basis of costs, design control efficiencies, and tons of pollutant removed is summarized in Tables 3 through 5. Capital costs were provided by PacifiCorp. The complete economic analyses for these two scenarios are provided as Attachment 1.

TABLE 3
Scenario A Control Cost
Jim Bridger Unit 3

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario A
	LNB with OFA	Wet FGD	ESP with gas conditioning	Control Cost
Total Installed Capital Costs (million dollars)	$11.3	$25.3	$3.90	$40.5
Annualized First-Year Capital Costs	$1.07	$2.41	$0.37	$3.85
First Year Fixed & Variable O&M Costs (million dollars)	$0.07	$0.98	$0.18	$1.22
Total First Year Annualized Costs (million dollars) [a]	$1.15	$3.39	$0.55	$5.08
Power Consumption (MW)	—	0.52	0.05	0.57
Annual Power Usage (Million kWh/Yr)	—	4.10	0.39	4.49
Permitted Emission Rate (lb/mmBtu)	0.26	0.15	0.03	—
Additional Tons of Pollutant Removed per Year over Baseline	4,494	2,838	639	7,971
First Year Average Control Cost ($/Ton of Pollutant Removed)	255	1,193	856	637

NOTE:
[a] First year annualized costs include power consumption costs.

TABLE 4
Scenario B Control Cost
Jim Bridger Unit 3

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario B
	LNB with OFA & SCR	**Wet FGD**	**ESP with gas conditioning**	**Control Cost**
Total Installed Capital Costs (million dollars)	$177.8	$25.3	$3.90	$207.0
Annualized First-Year Capital Costs	$16.91	$2.41	$0.37	$19.69
First Year Fixed & Variable O&M Costs (million dollars)	$3.36	$0.98	$0.18	$4.52
Total First Year Annualized Costs (million dollars) [a]	$20.28	$3.39	$0.55	$24.21
Power Consumption (MW)	3.22	0.52	0.05	3.79
Annual Power Usage (Million kWh/Yr)	25.39	4.10	0.39	29.89
Permitted Emission Rate (lb/mmBtu)	0.07	0.15	0.03	—
Additional Tons of Pollutant Removed per Year over Baseline	8,988	2,838	639	12,465
First Year Average Control Cost ($/Ton of Pollutant Removed)	2,256	1,193	856	1,942

NOTE:
[a] First year annualized costs include power consumption costs.

TABLE 5
Incremental Control Costs, Scenario B compared to Scenario A
Jim Bridger Unit 3

	NO_x Control	SO_2 Control	PM_{10} Control	Total Control Cost
Incremental Installed Capital Costs (million dollars)	$166.5	0	0	$166.5
Incremental Annualized First-Year Capital Costs	$15.84	0	0	$15.84
Incremental First Year Fixed & Variable O&M Costs (million dollars)	$3.30	0	0	$3.30
Incremental First Year Annualized Costs (million dollars) [a]	$19.13	0	0	$19.13
Incremental Power Consumption (MW)	3.22	0	0	3.22
Incremental Annual Power Usage (Million kWh/Yr)	25.39	0	0	25.39
Incremental Improvement in Emission Rate (lb/mmBtu)	0.19	0	0	—
Incremental Tons of Pollutant Removed	4,494	0	0	4,494
Incremental First Year Average Control Cost ($/Ton of Pollutant Removed)	4,258	0	0	4,258

NOTE:
[a] Incremental first year annualized costs include power consumption costs.

Modeling Results and Least-Cost Envelope Analysis

CH2M HILL modeled Jim Bridger Unit 3 for two post-control scenarios. The results determine the change in deciview based on each alternative at the Class I areas specific to the project. The Class I areas potentially affected are Bridger Wilderness, Fitzpatrick Wilderness, and Mount Zirkel Wilderness for this unit.

Modeled Scenarios

Current operations (baseline) and two alternative control scenarios were modeled to cover the range of effectiveness for the combination of the individual NO_x, SO_2, and PM control technologies being evaluated. The modeled scenarios include the following:

- Baseline: Current operations with LNB, Wet sodium FGD, and ESP
- Scenario A: LNB with OFA, Wet sodium FGD, and ESP with SO_3 injection
- Scenario B: Scenario A with SCR

Summary of Visibility Analysis

Tables 6 through 8 present a summary of the modeling period (2001–2003) results for each scenario and Class I area.

TABLE 6
Costs and Visibility Modeling Results as Applicable to Bridger Wilderness
Jim Bridger Unit 3

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and ESP	—	4.381	1.265	30
Scenario A	Scenario A: PacifiCorp Committed Controls	$5,077,127	2.919	0.829	17
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$24,210,545	1.647	0.481	10

TABLE 7
Costs and Visibility Modeling Results as Applicable to Fitzpatrick Wilderness
Jim Bridger Unit 3

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and ESP	—	2.542	0.615	13
Scenario A	Scenario A: PacifiCorp Committed Controls	$5,077,127	1.747	0.379	7
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$24,210,545	0.959	0.232	4

TABLE 8
Costs and Visibility Modeling Results as Applicable to Mount Zirkel Wilderness
Jim Bridger Unit 3

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and ESP	—	3.460	1.642	47
Scenario A	Scenario A: PacifiCorp Committed Controls	$5,077,127	2.168	1.046	22
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$24,210,545	1.298	0.607	12

Results

Tables 9 through 11 present a summary of the costs and modeling results for each scenario and Class I area.

TABLE 9
Incremental Costs and Incremental Visibility Improvements Relative to Bridger Wilderness
Jim Bridger Unit 3

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$5.08	0.436	13	$11.64	$0.39
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$24.21	0.784	20	$30.88	$1.21
Scenario B Compared To Scenario A	Addition of SCR	$19.13	0.348	7	$54.98	$2.73

TABLE 10
Incremental Costs and Incremental Visibility Improvements Relative to Fitzpatrick Wilderness
Jim Bridger Unit 3

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$5.08	0.236	6	$21.51	$0.85
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$24.21	0.383	9	$63.21	$2.69
Scenario B Compared To Scenario A	Addition of SCR	$19.13	0.147	3	$130.16	$6.38

TABLE 11
Incremental Costs and Incremental Visibility Improvements Relative to Mount Zirkel Wilderness
Jim Bridger Unit 3

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$5.08	0.596	25	$8.52	$0.20
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$24.21	1.035	35	$23.39	$0.69
Scenario B Compared To Scenario A	Addition of SCR	$19.13	0.439	10	$43.58	$1.91

Least-Cost Envelope Analysis

The least-cost envelope graphs for Bridger Wilderness are shown in Figures 1 and 2, for Fitzpatrick Wilderness in Figures 3 and 4, and for Mount Zirkel Wilderness in Figures 5 and 6.

FIGURE 1

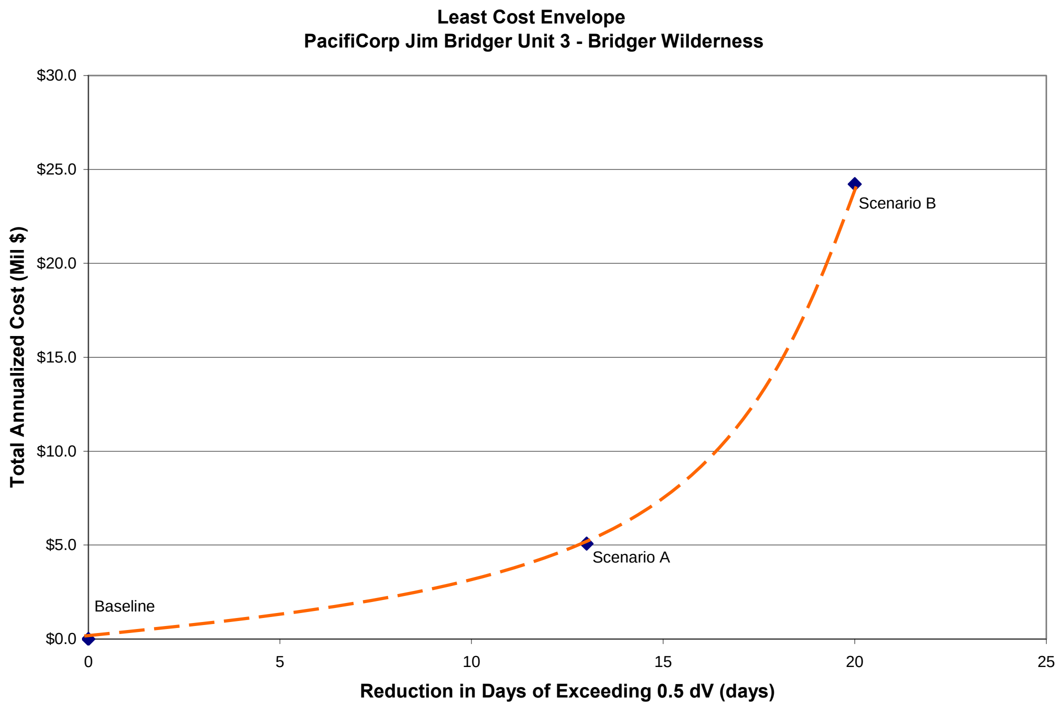


FIGURE 2

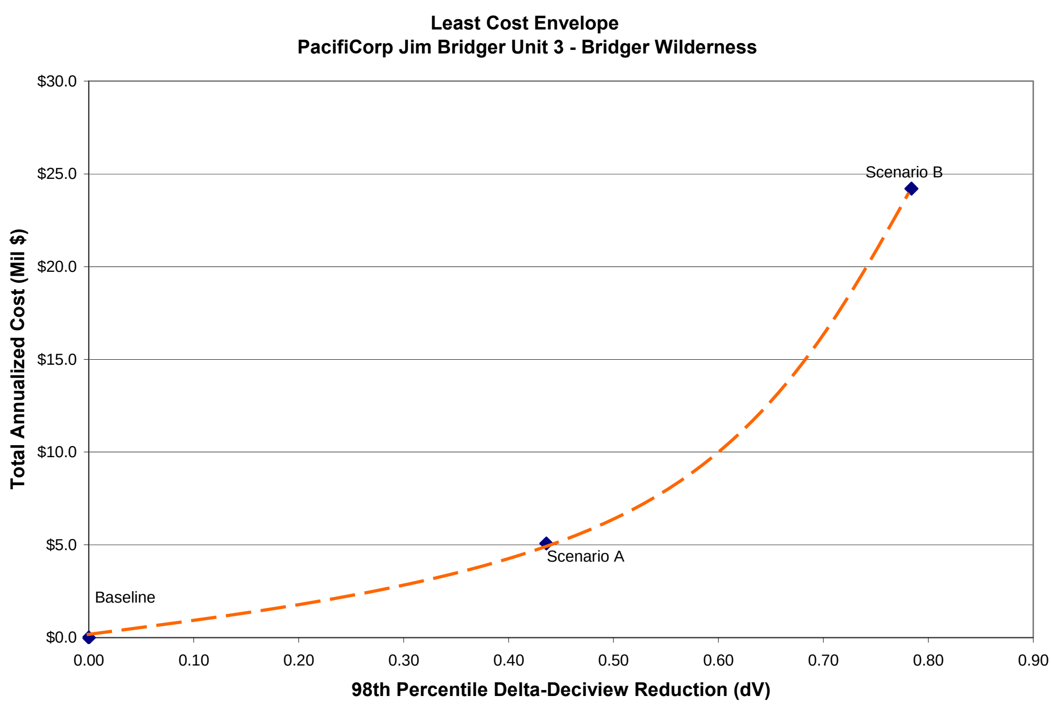


FIGURE 3

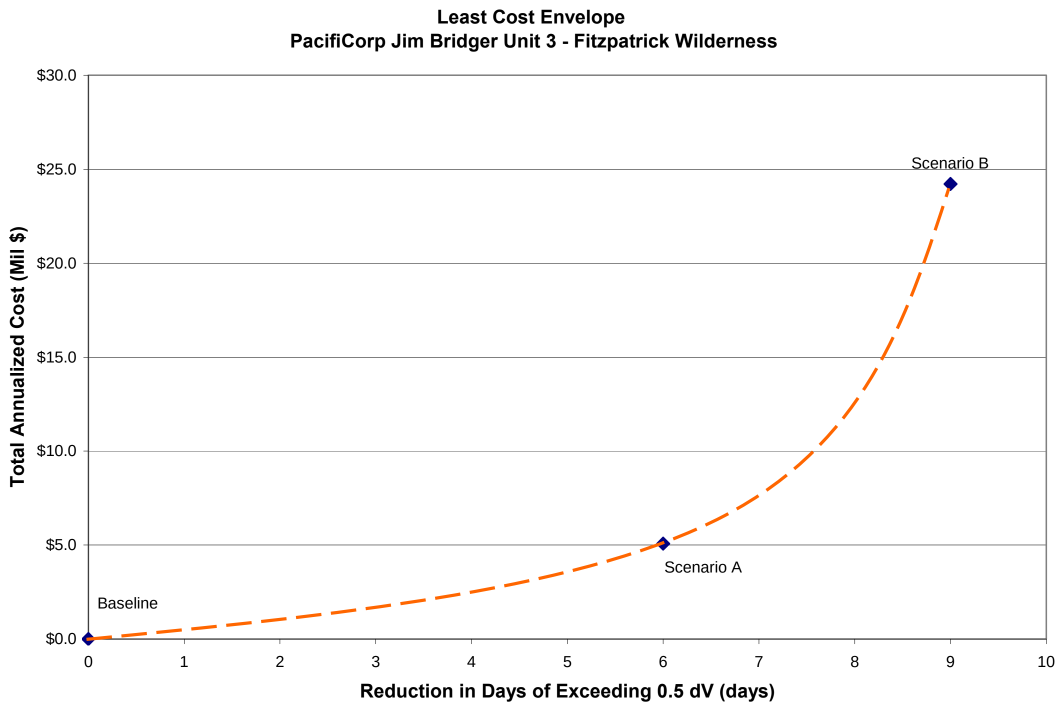


FIGURE 4

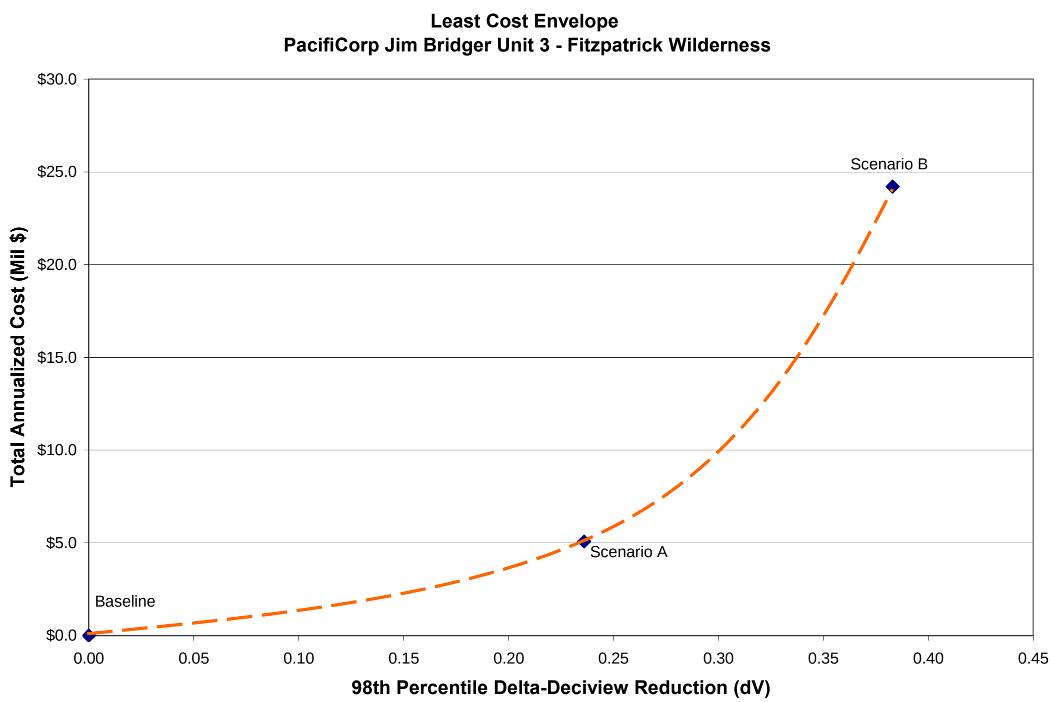


FIGURE 5

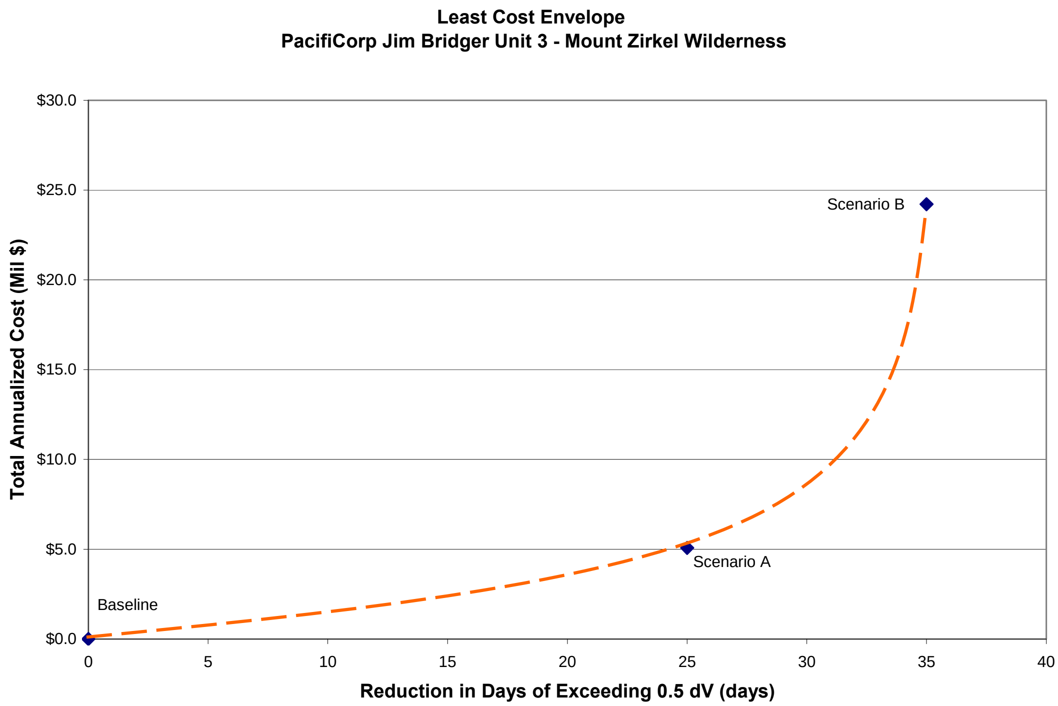
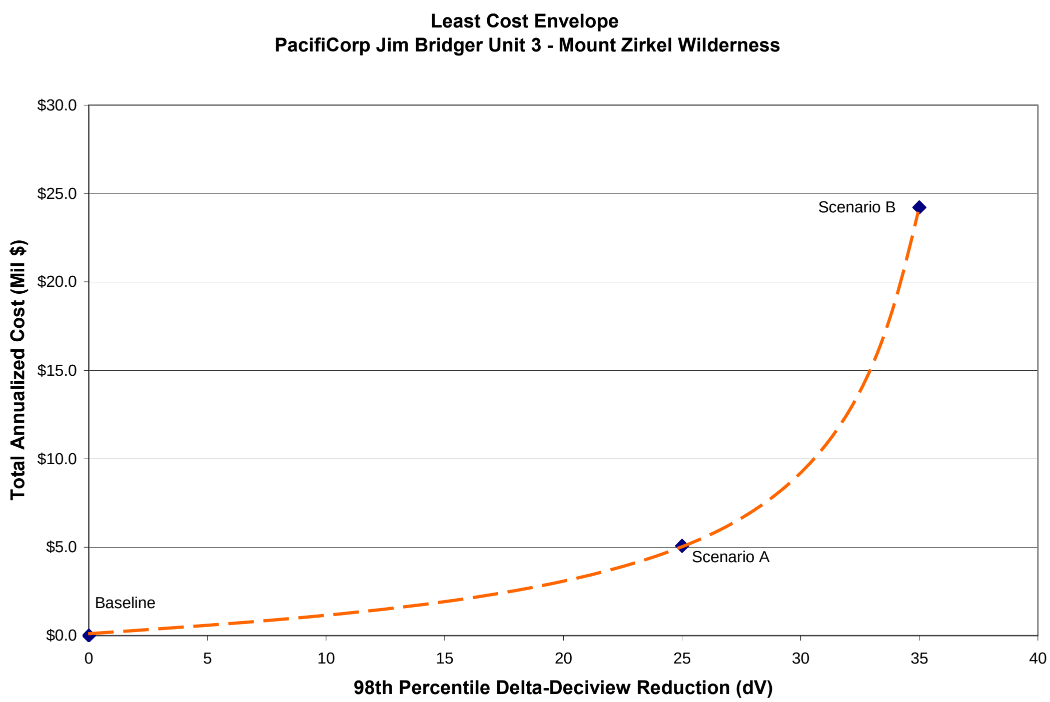


FIGURE 6



ATTACHMENT 1

Complete Economic Analyses for Scenarios A and B

ECONOMIC ANALYSIS SUMMARY - FIRST YEAR COSTS

Jim Bridger 3

Boiler Design: Tangential fired PC

TYPE OF EMISSIONS CONTROLS		NO_x Control				SO_2 Control and PM			Scenario A	Scenario B
Technology Label	**BASE**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**A+F**	**D+F**
	Current Operation	Low NO_x Burners with Overfire Air	Rotating Overfire Air	Low NO_x Burners with Overfire Air and Non-Selective Catalytic Reduction	Low NO_x Burners with Overfire Air and Selective Catalytic Reduction	ESP w/ Gas Conditioning	Fabric Filter	Upgrade Wet FGD	LNB w/OFA, Upgrade Wet FGD and ESP w/gas conditioning	LNB w/OFA, SCR, Upgrade Wet FGD and ESP w/gas conditioning
ECONOMIC FACTORS										
Interest Rate (%)	7.10%	7.10%	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%	7.10%	7.10%
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20
CAPITAL INVESTMENT										
Total Installed Capital Costs ($)	$0	$11,300,000	$20,528,122	$21,973,632	$177,800,000	$3,900,000	$48,386,333	$25,300,000	$40,500,000	$207,000,000
FIRST YEAR DEBT SERVICE ($/Yr)	**$0**	**$1,074,944**	**$1,952,796**	**$2,090,304**	**$16,913,727**	**$370,999**	**$4,602,887**	**$2,406,734**	**$3,852,677**	**$19,691,459**
FIRST YEAR FIXED O&M Costs ($/Yr)										
Operating Labor ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance Material ($/Yr)	$0	$28,000	$42,000	$122,000	$190,000	$0	$51,099	$25,500	$53,500	$215,500
Maintenance Labor ($/Yr)	$0	$42,000	$63,000	$183,000	$285,000	$10,000	$76,649	$17,033	$69,033	$312,033
Administrative Labor ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FIRST YEAR FIXED O&M COST	**$0**	**$70,000**	**$105,000**	**$305,000**	**$475,000**	**$10,000**	**$127,748**	**$42,533**	**$122,533**	**$527,533**
FIRST YEAR VARIABLE O&M Costs ($/Yr)										
Makeup Water Costs ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$29,927	$29,927	$29,927
Reagent Costs ($/Yr)	$0	$0	$0	$89,411	$1,020,310	$145,854	$0	$383,167	$529,021	$1,549,331
SCR Catalyst / FF Bag Costs ($/Yr)	$0	$0	$0	$0	$600,000	$0	$294,008	$0	$0	$600,000
Waste Disposal Costs ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$318,275	$318,275	$318,275
Electric Power Costs ($/Yr)	$0	$0	$2,526,822	$204,984	$1,269,324	$19,710	$1,312,686	$204,984	$224,694	$1,494,018
TOTAL FIRST YEAR VARIABLE O&M Costs ($/Yr)	**$0**	**$0**	**$2,526,822**	**$294,395**	**$2,889,634**	**$165,564**	**$1,606,694**	**$936,353**	**$1,101,917**	**$3,991,551**
SUMMARY OF FIRST YEAR COSTS ($/Yr)										
First Year Debt Service ($/Yr)	$0	$1,074,944	$1,952,796	$2,090,304	$16,913,727	$370,999	$4,602,887	$2,406,734	$3,852,677	$19,691,459
First Year Fixed O&M Costs ($/Yr)	$0	$70,000	$105,000	$305,000	$475,000	$10,000	$127,748	$42,533	$122,533	$527,533
First Year Variable O&M Costs ($/Yr)	$0	$0	$2,526,822	$294,395	$2,889,634	$165,564	$1,606,694	$936,353	$1,101,917	$3,991,551
Total First Year Costs ($/Yr)	**$0**	**$1,144,944**	**$4,584,618**	**$2,689,699**	**$20,278,361**	**$546,563**	**$6,337,329**	**$3,385,620**	**$5,077,127**	**$24,210,544**
CONTROL COST COMPARISONS										
NO_x Technology Comparison										
Additional NO_x Removed From Base Case (Tons/Yr)	0	4,494	5,440	5,440	8,988					
First Year Average Control Cost ($/Ton NO_x Removed)	$0	$255	$843	$494	$2,256					
Technology Case Comparison		A-BASE	B-A	C-A	D-A					
Incremental NO_x Removed (Tons/Yr)	0	4,494	946	946	4,494					
Incremental Control Cost ($/Ton NO_x Removed)	$0	$255	$3,636	$1,633	$4,258					
SO_2 Technology Comparison	77.5%					77.5%	77.5%	87.5%		
Additional SO_2 Removed From Base Case (Tons/Yr)	0					0	0	2,838		
First Year Average Control Cost ($/Ton SO_2 Removed)	$0					#DIV/0!	#DIV/0!	$1,193		
Technology Case Comparison						E-BASE	F-E	G-F		
Incremental SO_2 Removed (Tons/Yr)	0					0	0	2,838		
Incremental Control Cost ($/Ton SO_2 Removed)	$0					#DIV/0!	#DIV/0!	-$1,040		
PM Technology Comparison	0.0%									
Additional PM Removed From Base Case (Tons/Yr)	0					639	993	0		
First Year Average Control Cost ($/Ton PM Removed)	$0					$856	$6,380	#DIV/0!		
Technology Case Comparison						E-BASE	F-E	G-F		
Incremental PM Removed (Tons/Yr)	0					639	355	-993		
Incremental Control Cost ($/Ton PM Removed)	$0					$856	$16,322	$2,971		
SCENARIO A AND B COMPARISONS										
Additional NO_x, SO_2, & PM Removed From Base Case (Tons/Yr)	**0**								**7,971**	**12,465**
First Year Average Control Cost Compared to Base Case ($/Ton Removed)	**$0**								**$637**	**$1,942**
Incremental Tons Removed - Scenario B vs Scenario A (Tons/Yr)	**0**									**4,494**
Incremental Control Costs - Scenario B vs Scenario A ($/Ton Removed)	**$0**									**$4,258**

INPUT CALCULATIONS

Jim Bridger 3 — **Boiler Design:** **Tangential-Fired PC**

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 and PM Control Technologies			Scenario A	Scenario B
Control Technologies										
NO_x Emission Control System	LNCFS-1 & Windbox Mods.	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR				LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System	Wet FGD					N/A	N/A	Upgrade Wet FGD	Upgrade Wet FGD	Upgrade Wet FGD
PM Emission Control System	ESP					ESP w/ Gas Conditioning	Fabric Filter	ESP	ESP w/ Gas Conditioning	ESP w/ Gas Conditioning
General Plant Design and Operating Data										
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC
Annual Power Plant Capacity Factor	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Net Power Output (kW)	530,000	530,000	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	11,320	11,320
Boiler Heat Input, Measured by Fuel Input (MMBtu/Hr)	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Annual Heat Input, Measured by Fuel Input (MMBtu/Year)	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846	47,300,846
Boiler Heat Input, Measured by CEM (MMBtu/Hr)	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Annual Heat Input, Measured by CEM (MMBtu/Year)	47,304,000	47,304,000	47,304,000	47,304,000	47,304,000	47,304,000	47,304,000	47,304,000	47,304,000	47,304,000
Plant Fuel Source										
Boiler Fuel Source	Bridger Mine Underground	Bridger Mine Underground	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	9,660	9,660
Coal Sulfur Content (wt.%)	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.58%	0.580%	0.58%	0.58%
Coal Ash Content (wt.%)	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%	10.30%
Coal Flow Rate (Lb/Hr)	621,077	621,077	621,077	621,077	621,077	621,077	621,077	621,077	621,077	621,077
Coal Consumed (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	2,448,284	2,448,284
Nitrogen Oxide Emissions										
NO_x Emission Rate (Lb/MMBtu)	0.45	0.26	0.22	0.22	0.07				0.26	0.07
NO_x Emission Rate (Lb/Hr)	2,700	1,560	1,320	1,320	420				1,560	420
NO_x Emission Rate (Lb Moles/Hr)	89.97	51.98	43.99	43.99	14.00				51.98	14.00
NO_x Emission Rate (Ton/Yr)	10,643	6,150	5,203	5,203	1,656				6,150	1,656
Add'l NO_x Removed from Current Operations (Lb/Hr)	0	1,140	1,380	1,380	2,280				1,140	2,280
Add'l NO_x Removed from Current Operations (Ton/Yr)	0	4,494	5,440	5,440	8,988				4,494	8,988
Sulfur Dioxide Emissions										
Uncontrolled SO_2 (Lb/MMBtu)	1.20					1.20	1.20	1.20	1.20	1.20
Uncontrolled SO_2 (Lb/Hr)	7,198					7,198	7,198	7,198	7,198	7,198
Uncontrolled SO_2 (Lb Moles/Hr)	112.35					112.35	112.35	112.35	112.35	112.35
Uncontrolled SO_2 (Tons/Yr)	28,374					28,374	28,374	28,374	28,374	28,374
Controlled SO_2 Emission Rate (Lb/MMBtu)	0.27					0.27	0.27	0.15	0.15	0.15
SO_2 Removal Efficiency (%)	77.5%					77.5%	77.5%	87.5%	87.5%	87.5%
Controlled SO_2 Emissions (Lb/Hr)	1,620					1,620	1,620	900	900	900
Controlled SO_2 Emissions (Ton/Yr)	6,386					6,386	6,386	3,548	3,548	3,548
SO_2 Removed (Lb/Hr)	5,578					5,578	5,578	6,298	6,298	6,298
SO_2 Removed (Ton/Yr)	21,988					21,988	21,988	24,826	24,826	24,826
Add'l SO_2 Removed from Current Operations (Lb/Hr)	0					0	0	720	720	720
Add'l SO_2 Removed from Current Operations (Ton/Yr)	0					0	0	2,838	2,838	2,838
Particulate Matter Emissions										
Uncontrolled Fly Ash (Lb/Hr)	51,177					51,177	51,177	51,177	51,177	51,177
Uncontrolled Fly Ash (Lb/MMBtu)	8.529					8.529	8.529	8.529	8.529	8.529
Uncontrolled Fly Ash (Tons/Yr)	201,739					201,739	201,739	201,739	201,739	201,739
Controlled Fly Ash Emission Rate (Lb/MMBtu)	0.057					0.030	0.015	0.057	0.030	0.030
Controlled Fly Ash Removal Efficiency (%)	99.3%					99.6%	99.8%	99.3%	99.6%	99.6%
Controlled Fly Ash Emissions (Lb/Hr)	342					180	90	342	180	180
Controlled Fly Ash Emissions (Ton/Yr)	1,348					710	355	1,348	710	710
Fly Ash Removed (Lb/Hr)	50,835					50,997	51,087	50,835	50,997	50,997
Fly Ash Removed (Ton/Yr)	200,390					201,029	201,384	200,390	201,029	201,029
Add'l Ash Removed from Current Operation (Lb/Hr)	0					162	252	0	162	162
Add'l Ash Removed from Current Operation (Ton/Yr)	0					639	993	0	639	639
Economic Factors										
Interest Rate (%)	7.10%	7.10%	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%	7.10%	7.10%
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20

INPUT CALCULATIONS

Jim Bridger 3 — **Boiler Design:** **Tangential-Fired PC**

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 and PM Control Technologies			Scenario A	Scenario B
Control Technologies										
NO_x Emission Control System	LNCFS-1 & Windbox Mods.	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR				LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System	Wet FGD					N/A	N/A	Upgrade Wet FGD	Upgrade Wet FGD	Upgrade Wet FGD
PM Emission Control System	ESP					ESP w/ Gas Conditioning	Fabric Filter	ESP	ESP w/ Gas Conditioning	ESP w/ Gas Conditioning
Installed Capital Costs										
NO_x Emission Control System ($2012)		$11,300,000	$20,528,122	$21,973,632	$177,800,000				$11,300,000	$177,800,000
SO_2 Emission Control System ($2012)						$0	$0	$25,300,000	$25,300,000	$25,300,000
PM Emission Control System ($2012)						$3,900,000	$48,386,333	$0	$3,900,000	$3,900,000
Total Emission Control System Capital Costs ($2012)		$11,300,000	$20,528,122	$21,973,632	$177,800,000	$3,900,000	$48,386,333	$25,300,000	$40,500,000	$207,000,000
NO_x Emission Control System ($/kW)		$21	$39	$41	$335				$21	$335
SO_2 Emission Control System ($/kW)								$48	$48	$48
PM Emission Control System ($/kW)						$7	$91		$7	$7
Total Emission Control Capital Costs ($/kW)		$21	$39	$41	$335	$7	$91	$48	$76	$391
Fixed Operating & Maintenance Costs										
Operating Labor ($)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Maintenance Material ($)		$28,000	$42,000	$122,000	$190,000	$0	$51,099	$25,500	$53,500	$215,500
Maintenance Labor ($)		$42,000	$63,000	$183,000	$285,000	$10,000	$76,649	$17,033	$69,033	$312,033
Administrative Labor ($)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Total 1st Fixed Year O&M Cost ($)		$70,000	$105,000	$305,000	$475,000	$10,000	$127,748	$42,533	$122,533	$527,533
Annual Fixed O&M Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Fixed O&M Cost ($/Yr)		$82,985	$124,478	$361,578	$563,114	$11,855	$151,446	$50,423	$145,263	$625,392
Variable Operating & Maintenance Costs										
Water Cost										
Makeup Water Usage (gpm)		0	0	0	0	0	0	52	52	52
Unit Price ($/1000 gallons)		$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22
First Year Water Cost ($)		$0	$0	$0	$0	$0	$0	$29,927	$29,927	$29,927
Annual Water Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Water Costs ($/Yr)		$0	$0	$0	$0	$0	$0	$35,479	$35,479	$35,479
Reagent Cost										
Type of Reagent		None	None	Urea	Anhydrous NH3	Elemental Sulfur	Lime	Soda Ash	Soda Ash & Elemental Sulfur	Soda Ash, Elemental Sulfur, Anhydrous NH3
Unit Cost ($/Ton)		$0.00		$370.00	$400.00	$370.00	$91.25	$80.00		
Unit Cost ($/Lb)		$0.000		$0.185	$0.200	$0.185	$0.046	$0.040		
Molar Stoichiometry		0.00		0.45	1.00	0.00	1.15	1.02		
Reagent Purity (Wt.%)		100%		100%	100%	100%	90%	100%		
Reagent Usage (Lb/Hr)				61	647	100	0	1,215		
First Year Reagent Cost ($)		$0		$89,411	$1,020,310	$145,854	$0	$383,167	$529,021	$1,549,331
Annual Reagent Cost Escalation Rate (%)		2.00%		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Reagent Costs ($/Yr)				$105,997	$1,209,580	$172,910	$0	$454,246	$627,156	$1,836,737
SCR Catalyst / Fabric Filter Bag Replacement Cost										
Material Replaced					SCR Catalyst		Bags		0	& SCR Catalyst
Annual SCR Catalyst (m3) / No. FF Bags					200		2,827			
SCR Catalyst ($/m3) / Bag Cost ($/ea.)					$3,000		$104			
First Year SCR Catalyst / Bag Replacement Cost ($)					$600,000		$294,008		$0	$600,000
Annual SCR Catalyst / Bag Cost Escalation Rate (%)					2.00%		2.00%		0%	2.00%
Levelized Catalyst/Fabric Fitler Bag Costs ($/Yr)					$711,302		$348,547		$0	$711,302
FGD Waste Disposal Cost										
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)						0	0	3,319	3,319	3,319
FGD Waste Disposal Unit Cost ($/Dry Ton)						$24.33	$24.33	$24.33	$24.33	$24.33
First Year FGD Waste Disposal Cost ($)						$0	$0	$318,275	$318,275	$318,275
Annual Waste Disposal Cost Esc. Rate (%)						2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Waste Disposal Costs ($/Yr)						$0	$0	$377,316	$377,316	$377,316
Auxiliary Power Cost										
Auxiliary Power Requirement (MW)		0.00	6.41	0.52	3.22	0.05	3.33	0.52	0.57	3.79
Auxiliary Power Requirement (% of Plant Output)		0.00%	1.21%	0.10%	0.61%	0.01%	0.63%	0.10%	0.11%	0.72%
Auxilliary Power Useage (MWh)		0	50,536	4,100	25,386	394	26,254	4,100	4,494	29,880
Unit Cost ($2006/MW-Hr)		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
First Year Auxiliary Power Cost ($)		$0	$2,526,822	$204,984	$1,269,324	$19,710	$1,312,686	$204,984	$224,694	$1,494,018
Annual Power Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Auxilliary Power Costs ($/Yr)		$0	$2,995,555	$243,009	$1,504,787	$23,366	$1,556,193	$243,009	$266,375	$1,771,163