BEFORE THE ENVIRONMENTAL QUALITY COUNCIL
STATE OF WYOMING

In the Matter of the Appeal And Petition for Review of: BART Permit No. MD-6040 (Jim Bridger Power Plant); and BART Permit No. MD-6042 (Naughton Power Plant).	))))))	Docket No. 10-2801

RESPONSE TO PACIFICORP'S MOTION FOR PARTIAL SUMMARY JUDGMENT

DEQ/AQD's Application Analysis, dated 5/28/09

EXHIBIT 10

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6040

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Jim Bridger Power Plant
FACILITY LOCATION:	Section 3, T20N, R101W UTM Zone: 12 Easting: 684,055 m, Northing: 4,622,745 m Sweetwater County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Robert Arambel, Plant Managing Director
MAILING ADDRESS:	P.O. Box 158 Point of Rocks, WY 82942
TELEPHONE NUMBER:	(307) 352-4220
REVIEWERS:	Cole Anderson, Air Quality Engineer Josh Nall, Air Quality Modeler

PURPOSE OF APPLICATION:

Sections 169A and 169B of the 1990 Clean Air Act Amendments require states to improve visibility at Class I areas. On July 1, 1999, EPA first published the Regional Haze Rule, which provided specific details regarding the overall program requirements to improve visibility. The goal of the regional haze program is to achieve natural conditions by 2064.

Section 308 of the Regional Haze Rule (40 CFR part 51) includes discussion on control strategies for improving visibility impairment. One of these strategies is the requirement under 40 CFR 51.308(e) for certain stationary sources to install Best Available Retrofit Technology (BART) to reduce emissions of three (3) visibility impairing pollutants, nitrogen oxides (NO_x), particulate matter (PM), and sulfur dioxide (SO_2). EPA published Appendix Y to part 51 - *Guidelines for BART Determinations Under the Regional Haze Rule* in the July 6, 2005 Federal Register to provide guidance to regulatory authorities for making BART determinations. Chapter 6, Section 9, Best Available Retrofit Technology was adopted into the Wyoming Air Quality Standards and Regulations (WAQSR) and became effective on December 5, 2006. The Wyoming Department of Environmental Quality, Air Quality Division (Division) will determine BART for NO_x and PM_{10} for each source subject to BART and include each determination in the §308 Wyoming Regional Haze State Implementation Plan (SIP).

Section 309 of the Regional Haze Rule (40 CFR part 51), *Requirements related to the Grand Canyon Visibility Transport Commission*, provides states that are included within the Transport Region addressed by the Grand Canyon Visibility Transport Commission (i.e., Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming) an alternative to the requirements established in 40 CFR 51.308. This alternative control strategy for improving visibility contains special provisions for addressing SO_2 emissions, which include a market trading program and a provision for a series of SO_2 milestones. Wyoming submitted a §309 Regional Haze SIP to EPA on December 29, 2003. As of the date of this analysis, EPA has not taken action on the SIP. National litigation issues related to the Regional Haze Rule, including BART, required states to submit revisions. On November 21, 2008, the State of Wyoming submitted revisions to the 2003 §309 Regional Haze SIP submittal. Sources that are subject to BART are required to address SO_2 emissions as part of the BART analysis even though the control strategy has been identified in the Wyoming §309 Regional Haze SIP.

On January 16, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), PacifiCorp submitted four (4) BART applications, one for each existing coal-fired boiler at the Jim Bridger Power Plant. A map showing the location of PacifiCorp's Jim Bridger Power Plant is attached as Appendix A.

October 16, 2007, PacifiCorp submitted updated applications for each of the four (4) Jim Bridger units subject to BART. Additional modeling performed after the January 16, 2007 submittal and revised visibility control effectiveness calculations were included.

December 5, 2007, PacifiCorp submitted revised applications incorporating changes to the post-processing of the visibility model runs for each of the four (4) Jim Bridger units.

March 31, 2008, PacifiCorp submitted addendums to each of the BART applications for Jim Bridger Units 1-4. Revised cost estimates and updated visibility modeling for two (2) NO_x control scenarios were included in the addendums.

February 2, 2009, PacifiCorp submitted additional information addressing presumptive BART emission rates for the four (4) coal-fired boilers at the Jim Bridger Power Plant. The information addresses the type of coal fired in the four boilers and its impact on NO_x emissions.

BART ELIGIBILITY DETERMINATION:

In August of 2005 the Wyoming Air Quality Division began an internal review of sources that could be subject to BART. This initial effort followed the methods prescribed in 40 CFR part 51, Appendix Y: *Guidelines for BART Determinations Under the Regional Haze Rule* to identify sources and facilities. The rule requires that States identify and list BART-eligible sources, which are sources that fall within the 26 source categories, have emission units which were in existence on August 7, 1977 but not in operation before August 7, 1962 and have the potential to emit more than 250 tons per year (tpy) of any visibility impairing pollutant when emissions are aggregated from all eligible emission units at a stationary source. Fifty-one (51) sources at fourteen (14) facilities were identified that could be subject to BART in Wyoming.

The next step for the Division was to identify BART-eligible sources that may emit any air pollutant which may reasonably be anticipated to cause or contribute to impairment of Class I area visibility. Three pollutants are identified by 40 CFR part 51, Appendix Y as visibility impairing pollutants. They are sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). Particulate matter with an aerodynamic diameter of 10 microns or less (PM_{10}) was used as an indicator of PM. In order to determine visibility impairment of each source, a screening analysis was performed using CALPUFF. Sources that emitted over 40 tons of SO_2 or NO_x or 15 tons of PM_{10} were included in the screening analysis. Using three years of meteorological data, the screening analysis calculated visibility impacts from sources at nearby Class I areas. Sources whose modeled 98th percentile 24-hour impact or 8th highest modeled impact, by year, was equal to or greater than 0.5 deciviews (dv) above natural background conditions (Δdv) were determined to be subject to BART. For additional information on the Division's screening analysis see the Visibility Improvement Determination: Screening Modeling section of this analysis. The four existing coal-fired boilers at PacifiCorp's Jim Bridger Power Plant were determined to be subject to BART. PacifiCorp was notified in a letter dated June 14, 2006 of the Division's finding.

DESCRIPTION OF BART ELIGIBLE SOURCES:

PacifiCorp's Jim Bridger Power Plant is comprised of four (4) identically sized nominal 530 Mega Watts (MW) tangentially fired boilers burning pulverized coal for a total net generating capacity of 2,120 MW. Jim Bridger Unit 1 was placed in service in 1974. Unit 2 commenced service in 1975. Unit 3 entered service in 1976 followed by Unit 4, which commenced service in 1979. Each unit was initially equipped with early generation low NO_x burners (LNB) manufactured by Combustion Engineering to control emission of nitrogen oxides (NO_x). They are also equipped with dry Flakt wire frame electrostatic precipitators (ESPs) to control particulate matter emissions (PM), for which particulate matter less than 10 microns (PM_{10}) is used as a surrogate. Finally, to control sulfur dioxide (SO_2) emissions, each unit is equipped with a three absorber tower wet sodium flue gas desulfurization (WFGD) system made by Babcock & Wilcox.

Table 1: Jim Bridger Units 1-4 Pre-2005 Emission Limits

Source	Firing Rate (MMBtu/hour)	Existing Controls	NO_x (lb/MMBtu) [a]	SO_2 (lb/MMBtu) [a]	PM/PM_{10} (lb/MMBtu) [a]
Unit 1	6,000	LNB, ESP, WFGD	0.70 (3-hour block) 0.42 (annual)	0.3 (2-hour block)	0.10 (2-hour block)
Unit 2	6,000	LNB, ESP, WFGD	0.70 (3-hour block) 0.40 (annual)	0.3 (2-hour block)	0.10 (2-hour block)
Unit 3	6,000	LNB, ESP, WFGD	0.70 (3-hour block) 0.41 (annual)	0.3 (2-hour block)	0.10 (2-hour block)
Unit 4	6,000	LNB, ESP, WFGD	0.70 (3-hour block) 0.45 (annual) 3,514 lb/hr	0.2 (2-hour block) 1,004 lb/hr (2-hour block)	0.10 (2-hour block) 502 lb/hr (2-hour block)

[a] Emissions taken from Operating Permit 3-1-120 which does not include the most recent New Source Review construction permit limits.

On April 1, 2005, Air Quality Permit MD-1138 was issued to PacifiCorp to replace the first generation low NO_x burners (LNB) on Jim Bridger Unit 2 with a new ALSTOM TFS 2000™ low NO_x firing system including two elevations of separated overfire air (OFA). The Division received written notification from PacifiCorp on June 13, 2005 that the new LNB were installed and placed into service May 29, 2005. The permitted NO_x emission limit of 0.26 lb/MMBtu, annual average, authorized in MD-1138 for Jim Bridger Unit 2 went into effect in 2005.

On October 6, 2006, after the LNB modification to Unit 2 was completed, PacifiCorp submitted a construction permit application to modify Jim Bridger Units 1, 2, 3 and 4 by replacing the existing first generation low NO_x burners on Units 1, 3 and 4 with Alstom TFS 2000™ LNB with two elevations of separated overfire air, install a flue gas conditioning (FGC) system which injects SO_3 gas into the flue gas to improve the efficiency of the electrostatic precipitator on Units 1-4, and upgrade the existing flue gas desulfurization (FGD) systems on all four units to achieve greater than 90% sulfur dioxide removal. Air Quality Permit MD-1552 was issued April 9, 2007 authorizing the new LNB, FGC, and WFGD modifications to the Jim Bridger Power Plant. PacifiCorp notified the Division that the LNB upgrades to Unit 3 were completed and the unit started up May 30, 2007. June 18, 2008, the Division received notification from PacifiCorp that the new low NO_x burners on Unit 4 were installed during a recent ten week outage and the unit started up June 8, 2008. Modifications to the scrubber vessels on Unit 4 were not necessary in order to meet the SO_2 emission limits permitted in MD-1552. Unit 4 can meet the limits by reducing the amount of flue gas bypassing the scrubber. However, this would increase the moisture content of the gas entering the exhaust stack and modifications to the stack drain system were required to accommodate the increased moisture. Current emission limits for Jim Bridger Units 1-4 are listed in Table 2 below.

Table 2: Jim Bridger Units 1-4 Current Emission Limits [(a)]

Source	Controls	NO_x	SO_2	PM/PM_{10} [(b)]
Unit 1	Existing LNB, ESP with FGC, WFGD	0.45 lb/MMBtu (12-month rolling)	0.3 lb/MMBtu (2-hour block) 1,600 lb/hr (24-hr rolling)	0.03 lb/MMBtu 180 lb/hr
Unit 2	New LNB with OFA, ESP with FGC, WFGD	0.26 lb/MMBtu (12-month rolling)	0.3 lb/MMBtu (2-hour block) 1,600 lb/hr (24-hr rolling)	0.03 lb/MMBtu 180 lb/hr
Unit 3	New LNB with OFA, ESP with FGC, WFGD	0.26 lb/MMBtu (12-month rolling)	0.3 lb/MMBtu (2-hour block) 1,600 lb/hr (24-hr rolling)	0.03 lb/MMBtu 180 lb/hr
Unit 4	New LNB with OFA, ESP with FGC, WFGD	0.26 lb/MMBtu (12-month rolling)	0.2 lb/MMBtu (2-hour block) 0.15 lb/MMBtu (12-month rolling) 1,004 lb/hr (2-hr block) 900 lb/hr (24-hr rolling)	0.03 lb/MMBtu 180 lb/hr

(a) Emissions limits from New Source Review construction permit MD-1552.
(b) Averaging period is 1 hour as determined by 40 CFR 60.46 and EPA Reference Test Methods 1-5.

PacifiCorp is currently evaluating the upgraded stack drain system on the Unit 4 exhaust stack. Upon completion of a wet scrubber upgrades permitted in MD-1552, the SO_2 limits for the corresponding unit becomes 0.15 lb/MMBtu on a 12-month rolling average and 900 lb/hr on a 24-hr rolling average. A construction schedule for the LNB and WFGD upgrades was submitted in the permit application for MD-1552. PacifiCorp provided an update on the proposed construction schedule in a letter received on September 17, 2008. A construction summary is provided in Table 3.

Table 3: MD-1552 Permitted Upgrades to Jim Bridger Units 1-4

Source	New Low NO_x Burners with Separate Overfire Air (status, year)	Upgrades to the Existing Wet Scrubber (status, year)
Unit 1	Planned, 2010	Planned, 2010
Unit 2	Completed, 2005	Planned, 2009
Unit 3	Completed, 2007	Planned, 2011
Unit 4	Completed, 2008	Completed, 2008

CHAPTER 6, SECTION 9 – BEST AVAILABLE RETROFIT TECHNOLOGY (BART)

A BART determination is an emission limit based on the application of a continuous emission reduction technology for each visibility impairing pollutant emitted by a source. It is "...established, on a case-by-case basis, taking into consideration (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology."[1] A BART analysis is a comprehensive evaluation of potential retrofit technologies with respect to the five criteria above. At the conclusion of the BART analysis, a technology and corresponding emission limit is chosen for each pollutant for each unit subject to BART.

Visibility control options presented in the application for each source were reviewed using the methodology prescribed in 40 CFR 51 Appendix Y, as required in WAQSR Chapter 6 Section 9(c)(i). This methodology is comprised of five basic steps:

Step 1: Identify all[2] available retrofit control technologies
Step 2: Eliminate technically infeasible options
Step 3: Evaluate control effectiveness of remaining control technologies
Step 4: Evaluate impacts and document the results
Step 5: Evaluate visibility impacts

The Division acknowledges that BART is intended to identify retrofit technology for existing sources and is not the same as a top down analysis required for new sources under the Prevention of Significant Deterioration (PSD) rules known as Best Available Control Technology (BACT). Although BART is not the same as BACT, it is possible that BART may be equivalent to BACT on a case-by-case basis. The Division applied all five steps to each visibility impairing pollutant emitted from each coal-fired boiler (Units 1-4) at the Jim Bridger Power Plant thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

[1] 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39163).
[2] Footnote 12 of 40 CFR 51 Appendix Y defines the intended use of 'all' by stating "...you must identify the most stringent option and a reasonable set of options for analysis that reflects a comprehensive list of available technologies."

PRESUMPTIVE LIMITS FOR SO_2 AND NO_X FROM UTILITY BOILERS

EPA conducted detailed analyses of available retrofit technology to control NO_x and SO_2 emissions from coal-fired power plants. These analyses considered unit size, fuel type, cost effectiveness, and existing controls to determine reasonable control levels based on the application of an emissions reduction technology.

EPA's presumptive BART SO_2 limits analysis considered coal-fired units with existing SO_2 controls and units without existing control. Four key elements of the analysis were: "...(1) identification of all potentially BART-eligible EGUs [electric generating units], and (2) technical analyses and industry research to determine applicable and appropriate SO_2 control options, (3) economic analysis to determine cost effectiveness for each potentially BART-eligible EGU, and (4) evaluation of historical emissions and forecast emission reduction for each potentially BART-eligible EGU."[3] 491 BART-eligible coal-fired units were identified and included in the presumptive BART analysis for SO_2. Based on removal efficiencies of 90% for spray dry lime dry flue gas desulfurization systems and 95% for limestone forced oxidation wet flue gas desulfurization systems, EPA calculated projected SO_2 emission reductions and cost effectiveness for each unit. Based on the results of this analysis, EPA concluded that the majority of identified BART-eligible units greater than 200 MW without existing SO_2 control can meet the presumptive limits at a cost of $400 to $2,000 per ton of SO_2 removed.

A presumptive BART NO_x limits analysis was performed using the same 491 BART-eligible coal-fired units identified in the SO_2 presumptive BART analysis. EPA considered the same four key elements and established presumptive NO_x limits for EGUs based coal type and boiler configuration. For all boiler types, except cyclone, presumptive limits were based on combustion control technology (e.g., low NO_x burners and overfire air). Presumptive NO_x limits for cyclone boilers are based on the installation of SCR, a post combustion add-on control. EPA acknowledged that approximately 25% of the reviewed units could not meet the proposed limits based on current combustion control technology, but that nearly all the units could meet the presumptive limits using advanced combustion control technology, such as rotating opposed fire air. National average cost effectiveness values for presumptive NO_x limits ranged from $281 to $1,296 per ton removed.

Based on the results of the analyses for presumptive NO_x and SO_2 limits, EPA established presumptive limits for EGUs greater than 200 MW operating without NO_x post combustion controls or existing SO_2 controls located at facilities with a generating capacity greater than 750 MW. 40 CFR part 51 Appendix Y states that the presumptive SO_2 level for an uncontrolled unit is either 95% control or 0.15 lb/MMBtu. Presumptive NO_x levels for uncontrolled units are listed in Table 1 of Appendix Y and classified by the boiler burner configuration (unit type) and coal type. NO_x emission values range from 0.62 lb/MMBtu down to 0.15 lb/MMBtu. While Appendix Y establishes presumptive SO_2 limits and says that states should require presumptive NO_x, it also clearly gives states discretion to "...determine that an alternative [BART] control level is justified based on a careful consideration of the statutory factors."[4] The Division's following BART analysis for NO_x, SO_2, and PM/PM_{10} takes into account each of the five statutory factors.

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[3] 40 CFR Part 51 Appendix Y: Guidelines for BART Determinations under the Regional Haze Rule (70 Federal Register 39133).
[4] Ibid. (70 Federal Register 39171).

PacifiCorp's Jim Bridger Power Plant consists of four units with a total generating capacity of 2,120 MW. Jim Bridger Units 1-4 are identical nominal 530 MW units with tangentially fired pulverized coal boilers. SO_2 emissions from all units are controlled with existing Babcock & Wilcox three absorber tower wet sodium flue gas desulfurization systems that were installed in 1982, 1986, 1988, and 1990 on Units 4, 2, 3, and 1, respectively. NO_x emissions from Units 1-4 were initially controlled using first generations low NO_x burners. In 2005, the existing low NO_x burners were replaced with Alstom TFS 2000™ low NO_x firing system including two elevations of separated overfire air (OFA) on Unit 2. Subsequent to PacifiCorp's filing of the Jim Bridger BART applications for all four units, Air Quality Permit MD-1552 was issued on April 9, 2007 authorizing the upgrade of the remaining LNB with new Alstom TFS 2000™ low NO_x firing systems. As of the date of this analysis, two additional new LNB systems are installed on Units 3 and 4. The final Jim Bridger LNB upgrade is planned for 2010 on Unit 1, as shown in Table 3. Presumptive SO_2 limits of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limits based on unit type and coal type, could apply to all four Jim Bridger units. However, the Division required additional analysis of potential retrofit controls for NO_x, SO_2, and PM/PM_{10}, taking into consideration all five statutory factors, before making a BART determination.

NO_x emissions from coal combustion are affected by the chemical and physical properties of the feed coal. Heat content, carbon content, fuel-bound nitrogen and oxygen, volatile matter content, volatility, and agglomeration of the feed coal significantly affect the design and operation of combustion controls such as LNB and OFA systems. This is evidenced by EPA's decision to classify presumptive NO_x emission levels based on specific controls as applied to different boiler types firing various types of coal. In EPA's analysis for establishing presumptive NO_x limits, three primary coal types were identified: bituminous, sub-bituminous, and lignite. These coal classifications were based on EPA's Mercury Information Collection Request (ICR) for the Electric Utility Steam Generating Unit Mercury Emissions Information Collection Effort, OMB Control Number 2060-0396. In responding to the ICR PacifiCorp reported that Jim Bridger Units 1-4 burned sub-bituminous coal. Subsequent to the ICR PacifiCorp further evaluated the coal classification using ASTM method *D 388 - 05 Standard Classification of Coals by Rank*, an industrial standard for classifying coal. After reviewing method D 388 coal classifications, PacifiCorp noted that high volatile C bituminous coal and sub-bituminous A coals have similar heating values, but different agglomeration characteristics. Table 3 from ASTM method *D 388 - 05 Standard Classification of Coals by Rank* is shown as Figure 1.

Figure 1

Table 3
Classification of Coals by Rank[a] (ASTM D 388)

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis) Equal or Greater Than	Fixed Carbon Limits, % Less Than	Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis) Greater Than	Volatile Matter Limits, % Equal or Less Than	Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis) Equal or Greater Than	Calorific Value Limits, Btu/lb Less Than	Agglomerating Character
I. Anthracitic	1. Meta-anthracite	98	—	—	2	—	—	Nonagglomerating
	2. Anthracite	92	98	2	8	—	—	
	3. Semianthracite[c]	86	92	8	14	—	—	
II. Bituminous	1. Low volatile bituminous coal	78	86	14	22	—	—	Commonly agglomerating[e]
	2. Medium volatile bituminous coal	69	78	22	31	—	—	
	3. High volatile A bituminous coal	—	69	31	—	14,000[d]	—	
	4. High volatile B bituminous coal	—	—	—	—	13,000[d]	14,000	
	5. High volatile C bituminous coal	—	—	—	—	11,500	13,000	
						10,500[e]	11,500	Agglomerating
III. Subbituminous	1. Subbituminous A coal	—	—	—	—	10,500	11,500	Nonagglomerating
	2. Subbituminous B coal	—	—	—	—	9,500	10,500	
	3. Subbituminous C coal	—	—	—	—	8,300	9,500	
IV. Lignitic	1. Lignite A	—	—	—	—	6,300	8,300	
	2. Lignite B	—	—	—	—	—	6,300	

[a]This classification does not include a few coals, principally nonbanded varieties, which have unusual physical and chemical properties and which come within the limits of fixed carbon or calorific value of the high volatile bituminous and subbituminous ranks. All of these coals either contain less than 48% dry, mineral-matter-free Btu/lb.

[b]Moist refers to coal containing its natural inherent moisture but not including visible water on the surface of the coal.

[c]If agglomerating, classify in low volatile group of the bituminous class.

[d]Coals having 69% or more fixed carbon on the dry, mineral-matter-free basis shall be classified according to fixed carbon, regardless of calorific value.

[e]It is recognized that there may be nonagglomerating varieties in these groups of the bituminous class, and there are notable exceptions in high volatile C bituminous group.

PacifiCorp contracted with CH2M Hill and ALSTOM, a boiler manufacturer, to further research the impact of coal characteristics on NO_x emissions. Laboratory tests, including tests using a bench-scale drop tube furnace run by ALSTOM, showed the influence of both fuel type and stoichiometry on NO_x emissions. Additional testing examined the impact of coal volatility on NO_x emissions. Based on the results of the research, PacifiCorp concluded that "[t]he coals used at Bridger and Naughton tend to be higher rank than typical PRB coals. As such, they will have less fuel nitrogen released during the devolatilization phase of combustion, and thus will produce have [*sic*] somewhat higher NO_x than will true PRB coals when fired under low-NO_x staged conditions."

PacifiCorp also examined how fuel-bound NO_x evolves from solid coal char after the volatile component of the coal is combusted. After reviewing laboratory test data on NO_x conversion from fuel-bound nitrogen during volatilization and during char combustion, PacifiCorp concluded: "Typically, lower rank (more reactive) fuels have more fuel NO_x associated with the volatiles than the char, so low-rank coals overall have the lowest NO_x potential. The performance of the Bridger and Naughton coals tends to fall between the PRB coals and eastern bituminous coals shown [Figure 3, CH2M Hill's *Technical Memorandum: Coal Quality and Nitrogen Oxide Formation* submitted by PacifiCorp on February 2, 2009]. This would support the conclusion that the Bridger and Naughton coals have a NO_x reduction potential below eastern bituminous coals, but not as low as true PRB coals."

Coal characteristics affect the design and efficiency of pollution control equipment, as well as boiler design. Based on the information presented by PacifiCorp, it is likely that the Jim Bridger units will not be able to achieve presumptive NO_x levels of 0.15 lb/MMBtu for tangential boilers firing sub-bituminous coal. As mentioned earlier, Air Quality Permit MD-1552 authorized the installation of new ALSTOM TFS 2000™ LNB and separated OFA systems. Jim Bridger Units 2-4 are currently equipped with this combustion control system. Fourth quarter 2008 continuous emissions monitor (CEM) values for NO_x from units equipped with new LNB and OFA systems are shown in Table 4.

Table 4: Latest CEM Data for Units with New ALSTOM LNB and OFA

Jim Bridger Source	Q4 2008 NO_x Emissions (lb/MMBtu, 12-month rolling average)				
	August	September	October	November	December
Unit 2	0.23	0.23	0.23	0.22	0.22
Unit 3	0.20	0.20	0.20	0.20	0.20
Unit 4	0.26	0.25	0.23	0.22	0.21

The Division required additional analysis of potential retrofit controls for NO_x, which included add-on controls in addition to combustion control, taking into consideration all five statutory factors, before making a BART determination. While the Division noted the applicable presumptive NO_x levels for the Jim Bridger units, the effectiveness of the proposed combustion control for removing NO_x was evaluated under Step 2: Eliminate technically infeasible options, Step 3: Evaluate control effectiveness of remaining control technologies, and Step 4: Evaluate impacts and document the results of the BART process.

NO_x: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp identified four control technologies to control NO_x emissions: (1) low NO_x burners with two stages of separated OFA, a form of advanced OFA, (2) rotating opposed fire air (ROFA), (3) selective non-catalytic reduction (SNCR), and (4) selective catalytic reduction (SCR). LNB with separated OFA and ROFA are two combustion control technologies that reduce NO_x emissions by controlling the combustion process within the boiler. These two technologies have been demonstrated to effectively control NO_x emissions by reducing the amount of oxygen directly accessible to the fuel during combustion creating a fuel-rich environment and by enhancing control of air-fuel mixing throughout the boiler's combustion zone. SNCR and SCR are add-on controls that provide a chemical conversion mechanism for NO_x to form molecular nitrogen (N_2) in the flue gas after combustion occurs. These four technologies are proven emissions controls commonly used on coal-fired electric generating units.

1. Low NO_x Burners with Separated Overfire Air – LNB technologies can rely on a combination of fuel staging and combustion air control to suppress the formation of thermal NO_x. Fuel staging occurs in the very beginning of combustion, where the pulverized coal is injected through the burner into the furnace. Careful control of the fuel-air mixture leaving the burner can limit the amount of oxygen available to the fuel during combustion creating a fuel rich zone that reduces the nitrogen to molecular nitrogen (N_2) rather than using oxygen in the combustion air to oxidize the nitrogen to NO_x. The addition of separated overfire air provides additional NO_x control by injecting air into the lower temperature combustion zone when NO_x is less likely to form. This allows complete combustion of the fuel while reducing both thermal and chemical NO_x formation.

2. Rotating Opposed Fire Air – ROFA can be used with LNB technology to control the combustion process inside the boiler. Similar to the separated overfire air technology discussed above, ROFA manipulates the flow of combustion air to enhance fuel-mixing and air-flow characteristics within the boiler. By inducing rotation of the combustion air within the boiler, ROFA can reduce the number of high temperature combustion zones in the boiler and increase the effective heat absorption. Both of which effectively reduce the formation of NO_x caused by fuel combustion within the boiler.

3. Selective Non-Catalytic Reduction – SNCR is similar to SCR in that it involves the injection of a reducing agent such as ammonia or urea into the flue gas stream. The reduction chemistry, however, takes place without the aid of a catalyst. SNCR systems rely on appropriate injection temperatures, proper mixing of the reagent and flue gas, and prolonged retention time in place of the catalyst. SNCR operates at higher temperatures than SCR. The effective temperature range for SNCR is 1,600 to 2,100°F. SNCR systems are very sensitive to temperature changes and typically have lower NO_x emissions reduction (up to fifty or sixty percent) and may emit ammonia out of the exhaust stack when too much ammonia is added to the system.

4. Selective Catalytic Reduction – SCR is a post combustion control technique in which vaporized ammonia or urea is injected into the flue gas upstream of a catalyst. NO_x entrained in the flue gas is reduced to molecular nitrogen (N_2) and water. The use of a catalyst facilitates the reaction at an exhaust temperature range of 300 to 1,100°F, depending on the application and type of catalyst used. When catalyst temperatures are not in the optimal range for the reduction reaction or when too much ammonia is injected into the process, unreacted ammonia can be released to the atmosphere through the stack. This release is commonly referred to as ammonia slip. A well controlled SCR system typically emits less ammonia than a comparable SNCR control system.

In addition to applying these control technologies separately, they can be combined to increase overall NO_x reduction. PacifiCorp evaluated the application of LNB with separated OFA in combination with both SNCR and SCR add-on controls.

NO_x: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

None of the four control technologies proposed to control NO_x emissions were deemed technically infeasible by PacifiCorp.

NO_x: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as LNB with separated OFA, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

PacifiCorp contracted with Sargent and Lundy (S&L) to conduct a study of applicable NO_x control technologies for the Jim Bridger units and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with separated OFA on the Jim Bridger units would result in a NO_x emission rate as low as 0.24 lb/MMBtu. On pages 3-9 of the December 2007 submittals for Jim Bridger Units 1 and 3 and on pages 3-10 of the December 2007 submittals for Jim Bridger Units 2 and 4 PacifiCorp states: "PacifiCorp has indicated that this rate [0.24 lb/MMBtu] corresponds to a vendor guarantee, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls." However, due to unforeseen operational issues associated with retrofitting the boilers, including site specific challenges, PacifiCorp proposes an additional NO_x increase of 0.02 lb/MMBtu to total 0.26 lb/MMBtu.

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boilers at the Jim Bridger Power Plant with Mobotec's ROFA. Mobotec analyzed the operation of existing LNB and OFA ports. Typically the existing LNB system does not require modification and the existing OFA ports are not used by a new ROFA system. Instead, computational fluid modeling is performed to determine the location of the new ROFA ports. Mobotec concluded that a NO_x emission rate of 0.18 lb/MMBtu was achievable using ROFA technology. PacifiCorp added an additional operating margin of 0.04 lb/MMBtu to account for site specific issues, including the type of coal burned in the boilers, to total 0.22 lb/MMBtu.

S&L evaluated emission reductions associated with installing SNCR in addition to retrofitting the boilers with LNB with OFA. Based on installing LNB with separated OFA capable of achieving a NO_x emission rate of 0.24 lb/MMBtu, S&L concluded that SNCR can reduce emissions another 15 % resulting in a projected emission rate of 0.20 lb/MMBtu. PacifiCorp noted in the analysis that the economics of SNCR are greatly impacted by reagent utilization. When SNCR is used to achieve high levels of NO_x reduction, lower reagent utilization can result in significantly higher operating cost.

S&L prepared the design conditions and cost estimates for installing SCR in each of the Jim Bridger units. A high-dust SCR configuration, where the catalyst is located downstream from the boiler economizer before the air heater and any particulate control equipment, was used in the analysis. The flue gas ducts would be routed to a separate large reactor containing the catalyst to increase the removal rate. Additional catalyst would be added to accommodate the coal feedstock. Based on the S&L design, which included installing both LNB with separated OFA and SCR, PacifiCorp concluded the Jim Bridger units could achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 5: NO_x Emission Rates Per Boiler

Control Technology	Resulting NO_x Emission Rate (lb/MMBtu)
Existing LNB	0.45 [(a)]
New LNB with separated OFA	0.26 [(b)]
Existing LNB with ROFA	0.22
New LNB with separated OFA and SNCR	0.20
New LNB with separated OFA and SCR	0.07

(a) Annual averaged NO_x emissions established through 40 CFR part 76 which vary among the four Jim Bridger units from 0.40-0.45 lb/MMBtu.

(b) Jim Bridger Units 2-4 have installed new LNB with separated OFA and are subject to a new NO_x emission limit of 0.26 lb/MMBtu, annual average, established in MD-1552.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts associated with installing each of the proposed control technologies. Replacing the existing LNB with new LNB including separated OFA will not significantly impact the boiler efficiency or forced draft fan power usage, two common potential areas for adverse energy impact often affected by changes in boiler combustion. Installing the Mobotec ROFA system has the highest energy impact on Jim Bridger. Two (2) 4,000 to 4,300 horsepower ROFA fans (6,410 kilo Watts [kW] total) are required to induct a sufficient volume of air into each boiler to cause rotation of the combustion air throughout the boiler. PacifiCorp determined the SNCR system would require approximately 530 kW of additional power to operate pretreatment and injection equipment, pumps, compressors, and control systems. In addition to energy costs associated with the reagent handling and injection, installation of the SCR catalyst will require additional power from the existing flue gas fan systems to overcome the pressure drop across the catalyst. Based on the S&L study, PacifiCorp estimated the additional power requirements for SCR installation on each unit at the Jim Bridger Power Plant ranged from approximately 3.22 MW to 3.36 MW.

PacifiCorp evaluated the environmental impacts of the proposed NO_x control technologies. Installing LNB with separated OFA may increase carbon monoxide (CO) emissions and unburned carbon in the ash, commonly referred to as loss on ignition (LOI). Mobotec has predicted CO emissions and LOI would be the same or lower than prior levels for the ROFA system. The installation of SNCR and SCR could impact the saleability and disposal of fly ash due to higher ammonia levels, and could potentially create a visible stack plume sometimes referred to as a blue plume, if the ammonia injection rate is not well controlled. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and transportation of the ammonia to the power plant site.

PacifiCorp anticipates operating Jim Bridger Units 1-4 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. EPA did not use the dollars per deciview metric to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of anticipated visibility improvement gained by the application of additional emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed NO_x emission control. Economic and environmental costs for additional NO_x controls on Units 1-4 are summarized in the following tables.

Table 6: Jim Bridger Units 1, 3, & 4 Economic Costs Per Boiler

Cost	Existing LNB	New LNB with separated OFA	Existing LNB with ROFA	New LNB with separated OFA and SNCR	New LNB with separated OFA and SCR
Control Equipment Capital Cost	$0	$11,300,000	$20,528,122	$22,127,239	$177,800,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,074,969	$1,952,840	$2,104,964	$16,914,114
Annual O&M Costs	$0	$70,000	$2,633,012	$605,837	$3,382,286
Annual Cost of Control	$0	$1,144,969	$4,585,852	$2,710,801	$20,296,400

Table 7: Jim Bridger Units 1, 3, & 4 Environmental Costs Per Boiler

	Existing LNB	New LNB with separated OFA	Existing LNB with ROFA	New LNB with separated OFA and SNCR	New LNB with separated OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.45 [a]	0.26	0.22	0.20	0.07
Annual NO_x Emission (tpy) [b]	10,643	6,150	5,203	4,730	1,656
Annual NO_x Reduction (tpy)	N/A	4,493	5,440	5,913	8,987
Annual Cost of Control	$0	$1,144,969	$4,585,852	$2,710,801	$20,296,400
Cost per ton of Reduction	N/A	$255	$843	$459	$2,258
Incremental Cost per ton of Reduction	N/A	$255	$3,634	$1,103 [c]	$5,721

[a] Annual averaged emissions established by 40 CFR Part 76 vary from 0.40-0.45 lb/MMBtu and using 0.45 lb/MMBtu is conservative.
[b] Annual emissions based on individual heat input rate of 6,000 MMBtu/hr for 7,884 hours of operation per year.
[c] Incremental cost from installing new LNB with separated OFA since the incremental cost using existing LNB with ROFA is negative as a result of the higher annual cost of control.

Table 8: Jim Bridger Unit 2 Economic Costs

Cost	Existing LNB with separated OFA	Existing LNB with ROFA	Existing LNB with separated OFA and SNCR	Existing LNB with separated OFA and SCR
Control Equipment Capital Cost	$0	$20,528,122	$13,427,239	$166,500,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,952,840	$1,277,333	$15,839,145
Annual O&M Costs	$0	$2,631,822	$605,837	$3,370,460
Annual Cost of Control	$0	$4,584,662	$1,883,170	$19,209,605

Table 9: Jim Bridger Unit 2 Environmental Costs

	Existing LNB with separated OFA	Existing LNB with ROFA	Existing LNB with separated OFA and SNCR	Existing LNB with separated OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.26	0.22	0.20	0.07
Annual NO_x Emission (tpy) [a]	6,150	5,203	4,730	1,656
Annual NO_x Reduction (tpy)	N/A	947	1,420	4,494
Annual Cost of Control	$0	$4,584,662	$1,883,170	$19,209,605
Cost per ton of Reduction	N/A	$4,841	$1,326	$4,275
Incremental Cost per ton of Reduction	N/A	$4,841	$1,326 [b]	$5,636

[a] Annual emissions based on individual heat input rate of 6,000 MMBtu/hr for 7,884 hours of operation per year.
[b] Incremental cost from existing LNB with separated OFA since the incremental cost using existing LNB with ROFA is negative as a result of the higher annual cost of control.

The cost effectiveness and incremental cost effectiveness of the four proposed BART technologies for NO_x are all reasonable. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls by modeling LNB with separated OFA and LNB with separated OFA and SCR. While new LNB with OFA and SNCR and existing LNB with ROFA were not individually evaluated in Step 5: Evaluate visibility impact, the anticipated degree of visibility improvement from applying either control lies within the modeled range of visibility impacts.

The final step in the NO_x BART determination process for Jim Bridger Units 1-4, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants. The visibility analysis follows Steps 1-4 for SO_2 emissions in this application analysis. Tables 27-30, on pages 36-39, list the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Jim Bridger Units 1-4 are currently equipped with electrostatic precipitators to control PM emissions from the boilers. As discussed in more detail below, ESPs control PM/PM_{10} from the flue gas stream by creating a strong electro-magnetic field in which fly ash particles gain electric charge. PacifiCorp states the existing ESPs are able to control PM/PM_{10} emissions to 0.045 lb/MMBtu, 0.074 lb/MMBtu, 0.057 lb/MMBtu, and 0.030 lb/MMBtu from Units 1, 2, 3, and 4, respectively. Three PM control technologies were analyzed for application on the four Jim Bridger units: fabric filters or baghouses, ESPs, and flue gas conditioning.

1. Fabric filters (FF) – FF are woven pieces of material that collect particles with sizes ranging from submicron to several hundred microns in diameter at efficiencies generally in excess of 99%. The layer of dust trapped on the surface of the fabric, commonly referred to as dust cake, is primarily responsible for such high efficiency. Joined pores within the cake act as barriers to trap particulate matter too large to flow through the pores as it travels through the cake. Limitations are imposed by the temperature and corrosivity of the gas and by adhesive properties of the particles. Most of the energy used to operate the system results from pressure drop across the bags and associated hardware and ducting.

2. Electrostatic precipitators – ESPs use electrical forces (charge) to move particulate matter out the gas stream onto collection plates. The particles are given an electrical charge by directing the gas stream through a corona, or region of gaseous ion flow. The charged particles are acted upon by an induced electrical field from high voltage electrodes in the gas flow that forces them to the walls or collection plates. Once the particles couple with the collection plates, they must be removed without re-entraining them into the gas stream. In dry ESP applications, this is usually accomplished by physically knocking them loose from the plates and into a hopper for disposal. Wet ESPs use water to wash the particles from the collector plates into a sump. The efficiency of an ESP is primarily determined by the resistivity of the particle, which is dependent on chemical composition, and also by the ability to clean the collector plates without reintroducing the particles back into the flue gas stream.

3. Flue Gas Conditioning (FGC) – Injecting a conditioning medium, typically SO_3, into the flue gas can lower the resistivity of the fly ash, improving the particles' ability to gain an electric charge. If the material is injected upstream of an ESP the flue gas particles more readily accept charge from the corona and are drawn to the collection plates. Adding FGC can account for large improvements in PM collection efficiency for existing ESPs that are constrained by space and flue gas residence time.

PM_{10}: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

PacifiCorp did not eliminate any of the three control technologies listed above as technically infeasible. PacifiCorp analyzed the impact of installing FGC using the existing ESPs and installing a polishing fabric filter downstream of the existing ESPs on Jim Bridger Units 1-4.

PM_{10}: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as dry electrostatic precipitators, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

Jim Bridger Units 1-4 have existing ESPs and rather than evaluate costs of replacing them, PacifiCorp evaluated additional controls to improve the PM_{10} removal efficiency. An ESP is an effective PM control device, as the existing units are already capable of controlling PM_{10} emissions to 0.045 lb/MMBtu, 0.074 lb/MMBtu, 0.057 lb/MMBtu, and 0.030 lb/MMBtu for Units 1, 2, 3, and 4, respectively. The technology continually improves and is commonly proposed for consideration in BACT analyses to control particulate emissions from new PC boilers. Rather than demolishing the existing ESP and constructing an entirely new PM control device, PacifiCorp recognized the cost benefit of keeping the existing unit and augmenting the control. Installing FGC on Units 1-4 can improve the PM removal efficiencies on the existing ESPs down to 0.030 lb/MMBtu. In addition to maintaining the existing ESPs, a polishing fabric filter can be installed downstream of the existing ESPs. PacifiCorp proposed the use of Compact Hybrid Particulate Collector (COHPAC) licensed by Electric Power Research Institute (EPRI). The COHPAC unit is smaller than a full-scale fabric filter and 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). COHPAC is effective at controlling particulates not captured by the primary PM control device, but is not designed to treat high PM concentrations in the entire flue gas stream immediately downstream of the boiler. The existing ESP must remain in service for the COHPAC fabric filter to effectively reduce PM/PM_{10} emissions. PacifiCorp estimates the application of the COHPAC unit in addition to using FGC with the existing ESPs can reduce emissions an additional 50% resulting in a PM_{10} emission rate of 0.015 lb/MMBtu. PacifiCorp's proposed emission rates for each technology as applied to Units 1-4 are shown in Table 10 below.

Table 10: PM_{10} Emission Rates Per Boiler

Control Technology	Resulting PM_{10} Emission Rate (lb/MMBtu)
Existing ESPs	0.030-0.074 [a]
Existing ESPs with FGC	0.030
Existing ESP and New Polishing Fabric Filter	0.015

[a] Achievable baseline emission rates using existing ESPs on Jim Bridger Units 1-4.

PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impact of installing COHPAC on each of the four units. The pressure drop created by the fabric filter and associated ductwork requires additional energy from the existing draft fan, which will have to be upgraded. PacifiCorp calculated the additional energy costs based on a 90 percent annual plant capacity factor. The installation of a COHPAC fabric filter would require approximately 3.4 MW of power, equating to an annual power usage of approximately 26.7 million kW-hr for Unit 1. Installing a COHPAC on Unit 2 would require approximately 3.4 MW of power, equating to an annual power usage of approximately 26.5 million kW-hr. Unit 3 would require approximately 3.3 MW of power, equating to an annual power usage of approximately 26.3 million kW-hr and Unit 4 would require approximately 3.4 MW of power, equating to an annual power usage of approximately 26.7 million kW-hr.

Installing FGC on each of the four units will require a minimal amount of additional power. PacifiCorp estimates that FGC will require an additional 50 kW per unit.

PacifiCorp evaluated the environmental impacts associated with the proposed installation of FGC and COHPAC on Units 1-4 and did not anticipate negative environmental impacts from the addition of either of these PM control technologies.

PacifiCorp anticipates operating Jim Bridger Units 1-4 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. The dollars per deciview metric was not used to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. As discussed in the comprehensive visibility analysis presented later in this analysis as Step 5: Evaluate visibility impacts, the Division evaluated the amount of visibility improvement gained in relation to each proposed emission control technology. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed PM emission control. Economic and environmental costs for additional PM control on Jim Bridger Units 1-4 are summarized in the following tables.

Table 11: Jim Bridger Units 1 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$3,900,000	$48,386,333
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$371,007	$4,602,992
Annual O&M Costs	$0	$175,564	$1,764,126
Annual Cost of Control	$0	$546,571	$6,367,118

Table 12: Jim Bridger Unit 1 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.045	0.030	0.015
Annual PM_{10} Emission (tpy) [(a)]	1,064	710	355
Annual PM_{10} Reduction (tpy)	N/A	354	709
Annual Cost of Control	$0	$546,571	$6,367,118
Cost per ton of Reduction	N/A	$1,544	$8,980
Incremental Cost per ton of Reduction	N/A	$1,544	$16,396

[(a)] Annual emissions based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.

Table 13: Jim Bridger Unit 2 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$3,900,000	$48,386,333
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$371,007	$4,602,992
Annual O&M Costs	$0	$175,564	$1,754,666
Annual Cost of Control	$0	$546,571	$6,357,658

Table 14: Jim Bridger Unit 2 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.074	0.030	0.015
Annual PM_{10} Emission (tpy) [(a)]	1,750	710	355
Annual PM_{10} Reduction (tpy)	N/A	1,040	1,395
Annual Cost of Control	$0	$546,571	$6,357,658
Cost per ton of Reduction	N/A	$526	$4,557
Incremental Cost per ton of Reduction	N/A	$526	$16,369

[(a)] Annual emissions based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.

Table 15: Jim Bridger Unit 3 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$3,900,000	$48,386,333
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$371,007	$4,602,992
Annual O&M Costs	$0	$175,564	$1,734,442
Annual Cost of Control	$0	$546,571	$6,337,434

Table 16: Jim Bridger Unit 3 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.057	0.030	0.015
Annual PM_{10} Emission (tpy) [a]	1,348	710	355
Annual PM_{10} Reduction (tpy)	N/A	638	993
Annual Cost of Control	$0	$546,571	$6,337,434
Cost per ton of Reduction	N/A	$857	$6,382
Incremental Cost per ton of Reduction	N/A	$857	$16,312

[a] Annual emissions based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.

Table 17: Jim Bridger Unit 4 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	N/A	$48,386,333
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	N/A	$4,602,992
Annual O&M Costs	$0	$175,564	$1,764,126
Annual Cost of Control	$0	$175,564	$6,367,118

Table 18: Jim Bridger Unit 4 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.030	0.030	0.015
Annual PM_{10} Emission (tpy) [(a)]	710	710	355
Annual PM_{10} Reduction (tpy)	N/A	0	355
Annual Cost of Control	$0	$175,564	$6,367,118
Cost per ton of Reduction	N/A	N/A	$17,936
Incremental Cost per ton of Reduction	N/A	N/A	$17,936

[(a)] Annual emissions based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter are not reasonable. However, the control was included in the final step in the PM/PM_{10} BART determination process for Jim Bridger Units 1-4, Step 5: Evaluate visibility impacts, which is addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The visibility analysis follows Steps 1-4 for SO_2 emissions in this application analysis. Tables 27-30, on pages 36-39, list the modeled control scenarios and associated emission rates.

SO_2: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp reviewed a broad range of informative sources, including EPA's RACT/BACT/LAER clearinghouse, in an effort to identify applicable SO_2 emission control technologies for Jim Bridger Units 1-4. Based on the results of this review, PacifiCorp proposed wet flue gas desulfurization (WFGD) and dry flue gas desulfurization (DFGD) as potential retrofit technologies to reduced SO_2 emissions.

1. Wet FGD – SO_2 is removed through absorption by mass transfer as soluble SO_2 in the exhaust gas mixture is dissolved in an alkaline water solvent that has low volatility under process conditions. SO_2 diffuses from the gas into the scrubber water when the liquid contains less than the equilibrium concentration of the gaseous SO_2. The rate of SO_2 mass transfer between the two phases is largely dependent on the surface area exposed and the time of contact. A properly designed wet scrubber or gas absorber will provide sufficient contact between the gas and the liquid solvent to allow diffusion of SO_2. Once the SO_2 enters the alkaline water phase, it will form a weak acid and react with the alkaline component dissolved in the scrubber water to form a sulfate (SO_4) or sulfite (SO_3). The acid/alkali chemical reaction prevents the SO_2 from diffusing back into the flue gas stream. When the alkaline scrubber water is saturated with sulfur compounds, it can be converted to a wet gypsum by-product that may be sold. SO_2 removal efficiencies for wet scrubbers can be as high as 99%.

2. Dry FGD – Dry scrubbers are similar to sorbent injection systems in that both systems introduce media directly into the flue gas stream, however the addition of the dry scrubber vessel provides greater contact area for adsorption and enhances chemical reactivity. A spray dryer dry scrubber sprays an atomized alkaline slurry into the flue gas upstream of particulate control system, often a fabric filter. Water in the slurry evaporates, hydrolizing the SO_2 into a weak acid, which reacts

with the alkali to form a sulfate or sulfite. The resulting dry product is captured in the particulate control and physically moved from the exhaust gas into a storage bin. The dry by-product may be dissolved back into the lime slurry or dried and sold as a gypsum by-product. Spray dryer dry scrubbers typically require lower capital cost than a wet scrubber. They also require less flue gas after-treatment. When exhaust gas leaves the wet scrubber, it is at or near saturation. A wet scrubber can lower exhaust gas temperatures down into a temperature range of 110 to 140°F, which may lead to corrosive condensation in the exhaust stack. A spray dryer dry scrubber does not enhance stack corrosion like a wet scrubber because it will not saturate the exhaust gas or significantly lower the gas temperature. Removal efficiencies for spray dryer dry scrubbers can range from 70% to 95%.

SO_2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

PacifiCorp did not eliminate either of the two control technologies listed above as technically infeasible. PacifiCorp analyzed the impact of installing dry FGD on each of the units using the existing ESPs, optimizing the existing wet FGDs, and upgrading the existing wet FGDs.

SO_2: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES

The Division considers the control effectiveness of a proposed control technology to be equivalent to the BART-determined permit limit. The limit is based on continuous compliance when the control equipment is well maintained and operated in a manner consistent with good air pollution control practices for minimizing emissions. In order to demonstrate continuous compliance with the permit limit it is important to consider that even well maintained and operated equipment will have some emissions variability. Complex emission control equipment, such as wet FGD, generally have inherent variability that must be considered when establishing the limit. Otherwise, the source will be out of compliance even though the equipment is operated and maintained as well as possible.

PacifiCorp determined that Jim Bridger Units 1-4 have an uncontrolled SO_2 emission rate, per unit, of 1.2 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight. The existing three column Babcock & Wilcox wet FGD systems on Jim Bridger Units 1-3 currently reduce SO_2 emissions by approximately 78% to achieve a SO_2 emission limit of 0.27 lb per MMBtu. The Babcock & Wilcox wet FGD system on Jim Bridger Unit 4 currently reduces emission by 86% resulting in a SO_2 emission rate of 0.17 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight.

Installing a new dry FGD system and utilizing the existing ESP on each of the Jim Bridger units may reduce uncontrolled SO_2 emissions by 82.5% resulting in an emission rate of 0.21 lb/MMBtu of SO_2, based on an average coal sulfur content of 0.58% by weight. Presumptive SO_2 levels for uncontrolled units are 95% emissions reduction or 0.15 lb/MMBtu. PacifiCorp does not anticipate achieving presumptive SO_2 emission levels using dry FGD. Additionally, PacifiCorp's experience evaluating the application of dry FGD to coal-fired boilers indicates there will be a substantial capital cost involved in removing the existing wet FGD units and replacing them with the new dry FGD. For these reasons and the fact that wet FGD is an effective, modern SO_2 emissions control technology capable of reducing emissions lower than 0.21 lb/MMBtu, PacifiCorp did not further evaluate and document the costs associated with installing dry FGD on Jim Bridger Units 1-4 or quantify the resulting visibility improvement.

PacifiCorp evaluated potential changes to the existing wet FGD systems on Jim Bridger Units 1-4 to improve the SO_2 removal efficiencies. The first option was to optimize the existing equipment. Partially closing the bypass damper will reduce the amount of flue gas that is not treated by the wet FGD system and is instead used to reheat the treated flue gas exiting the scrubber. Relocating the opacity monitor and modifying the system to minimize scaling problems will also help reduce SO_2 emissions. PacifiCorp anticipates the reduction in SO_2 emissions from applying the above optimization changes on Units 1-3 will be an additional 0.07 lb/MMBtu emission reduction, resulting in a 0.20 lb/MMBtu emission rate. The wet FGD system on Unit 4 is achieving an emission rate of 0.17 lb/MMBtu and any minor optimization changes to the system are not expected to significantly reduce emissions. PacifiCorp did not further evaluate optimizing the existing wet FGD systems on Units 1-4 because the anticipated emission rates, 0.20 lb/MMBtu for Units 1-3 and 0.17 lb/MMBtu for Unit 4, are above the presumptive SO_2 limit of 0.15 lb/MMBtu and do not achieve a 95% SO_2 removal efficiency.

The final proposed option is upgrading the wet FGD systems. This would involve completely closing the bypass damper to eliminate bypass flue gas flow, relocating the opacity monitor, adding new induction fans, adding a liner and drains to the existing exhaust stack for wet operation, and using a refined soda ash reagent in place of the existing sodium reagent. Applying the proposed upgrades is anticipated to reduce total SO_2 emissions by approximately 92% resulting in an emission rate of 0.10 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight. PacifiCorp considers it to be technically infeasible for the present wet FGD systems to achieve a 95% SO_2 removal efficiency, which equates to 0.06 lb/MMBtu for the Jim Bridger units, on a continuous basis. PacifiCorp's proposed emission rates for each SO_2 emission reduction technology applied to Jim Bridger Units 1-4 are shown in Table 19.

Table 19: SO_2 Emission Rates Per Boiler

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Existing Wet FGD	0.27 [a]
New Dry FGD with Existing ESP	0.21
Optimized Wet FGD	0.20 [b]
Upgraded Wet FGD	0.10

[a] Unit 4 currently achieves a 0.17 lb/MMBtu SO_2 emission rate.
[b] Unit 4 is already well controlled and any additional optimization changes are not expected to significantly reduce emissions.

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of upgrading the existing wet FGD systems on all four units. The upgrades require 530 kW on Units 1 and 2, and 520 kW of additional power on Units 3 and 4. Using a 90% annual plant capacity factor, the additional power amounts to approximately 4.2 million kW-hr per unit.

PacifiCorp's environmental evaluation of installing additional SO_2 controls noted that upgrading the existing wet FGD systems on the four units results in additional scrubber waste disposal and makeup water requirements. Eliminating the scrubber bypass will reduce the stack gas temperature from 140°F to 120°F, which in turn reduces the buoyancy of the exiting flue gas.

PacifiCorp anticipates operating Jim Bridger Units 1-4 indefinitely and did not include life extension costs in the economic analysis. A standard control life of 20 years was used to calculate the capital recovery factor. The annual cost to control was determined using a capital recovery factor based on a 7.1% interest rate. PacifiCorp labor and service costs were used to calculate the annual operating and maintenance costs. Annual power costs, including a cost escalation factor, associated with the operation of pollution controls were included.

Several different metrics can be considered when evaluating the cost-benefit relationships of different emission control technologies. In 40 CFR part 51 Appendix Y two metrics are specifically mentioned: cost effectiveness and incremental cost effectiveness. Through the application of BACT, the Division has extensive experience using cost effectiveness (i.e., dollars per ton of pollutant removed) to evaluate different control technologies. Incremental cost effectiveness is also used extensively by the Division when comparing emission controls under the BACT process. While the BART and the BACT processes are not necessarily equivalent, control determinations from either process are based on cost effectiveness and incremental cost effectiveness and are indicative of the economic costs to control emissions. In addition to providing cost effectiveness and incremental cost effectiveness results, PacifiCorp provided cost information in terms of cost of applying emission controls and the level of visibility improvement achieved (i.e., dollars per deciviews). While this metric can illustrate the control cost and visibility improvement differences between control options, it is not commonly used to assess the overall effectiveness of pollution control equipment. When performing the presumptive BART limits analyses for NO_x and SO_2, EPA addressed cost effectiveness and incremental cost effectiveness separate from visibility improvement. The dollars per deciview metric was not used to compare control options. Visibility improvements from the application of the analyzed control measures used to establish presumptive levels were addressed in a separate visibility analysis. The Division considered capital cost, annual cost, cost effectiveness, and incremental cost effectiveness in the evaluation of each proposed SO_2 emission control. Economic and environmental costs for additional controls on Jim Bridger Units 1-4 are summarized in the following tables.

Table 20: Jim Bridger Units 1-3 Economic Costs

Cost	Existing Wet FGD	Upgraded Wet FGD
Control Equipment Capital Cost	$0	$12,999,990
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$1,236,681
Annual O&M Costs	$0	$1,258,176 [a]
Annual Cost of Control	$0	$2,494,857

[a] Annual maintenance costs for Unit 3 are $4,518 less per year than Units 1 and 2.

Table 21: Jim Bridger Units 1-3 Environmental Costs

	Existing Wet FGD	Upgraded Wet FGD
SO_2 Emission Rate (lb/MMBtu)	0.27	0.10
Annual SO_2 Emission (tpy) [(a)]	6,386	2,365
Annual SO_2 Reduction (tpy)	N/A	4,021
Annual Cost of Control	$0	$2,494,857
Cost per ton of Reduction	N/A	$620 [(b)]
Incremental Cost per ton of Reduction	N/A	$620 [(b)]

[(a)] Annual emissions based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.
[(b)] Cost per ton of SO_2 reduction on Unit 3 is $619 because annual maintenance costs are $4,518 less.

Table 22: Jim Bridger Unit 4 Economic Costs

Cost	Existing Wet FGD	Upgraded Wet FGD
Control Equipment Capital Cost	$0	$5,759,814
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$547,931
Annual O&M Costs	$0	$658,683
Annual Cost of Control	$0	$1,206,614

Table 23: Jim Bridger Unit 4 Environmental Costs

	Existing Wet FGD	Upgraded Wet FGD
SO_2 Emission Rate (lb/MMBtu)	0.17	0.10
Annual SO_2 Emission (tpy) [(a)]	4,021	2,365
Annual SO_2 Reduction (tpy)	N/A	1,656
Annual Cost of Control	$0	$1,206,614
Cost per ton of Reduction	N/A	$729
Incremental Cost per ton of Reduction	N/A	$729

[(a)] Annual emissions based on unit heat input rate of 6,000 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of upgrading the existing wet FGD on all four units is reasonable. The final step in the SO_2 BART determination process for Jim Bridger Units 1-4, Step 5: Evaluate visibility impacts, is addressed in a comprehensive visibility analysis presented in the next section of this BART application analysis. The Division evaluated the amount of visibility improvement gained from the application of additional NO_x, PM/PM_{10}, and SO_2 emission control technology in relation to all three visibility impairing pollutants. Tables 27-30, on pages 36-39, list the modeled control scenarios and associated emission rates.

VISIBILITY IMPROVEMENT DETERMINATION:

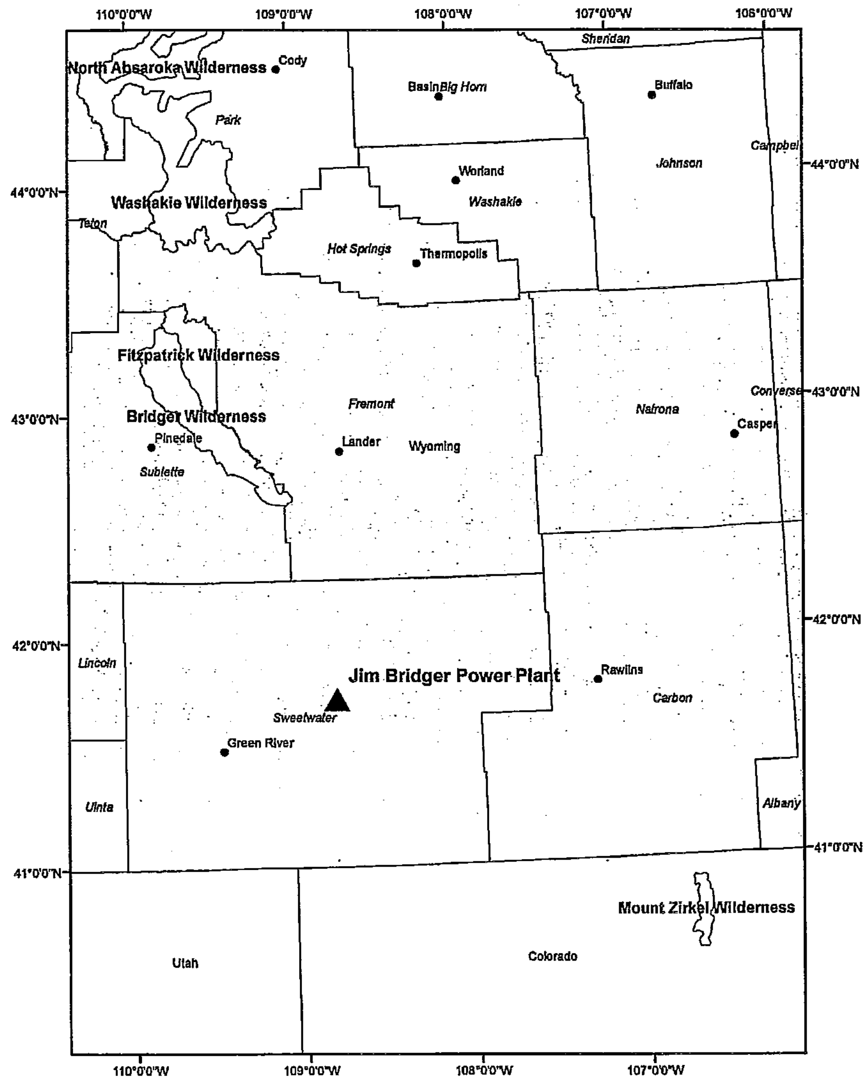
The fifth of five steps in a BART determination analysis, as required by 40 CFR part 51 Appendix Y, is the determination of the degree of Class I area visibility improvement that would result from installation of the various options for control technology. This factor was evaluated for the PacifiCorp Jim Bridger facility by using an EPA-approved dispersion modeling system (CALPUFF) to predict the change in Class I area visibility. The Division had previously determined that the facility was subject to BART based on the results of initial screening modeling that was conducted using current (baseline) emissions from the facility. The screening modeling, as well as more refined modeling conducted by the applicant, is described in detail below.

Bridger Wilderness Area (WA) and Fitzpatrick WA in Wyoming and Mount Zirkel WA in Colorado are the closest Class I areas to the PacifiCorp Jim Bridger facility, as shown in Figure 2 below. Bridger WA is located approximately 98 kilometers (km) northwest of the facility and Fitzpatrick WA is located approximately 151 km northwest of the facility. Mount Zirkel WA is located approximately 185 km southeast of the facility.

Only those Class I areas most likely to be impacted by the Jim Bridger Power Plant sources were modeled, as determined by source/Class I area locations, distances to each Class I area, and professional judgment considering meteorological and terrain factors. It can be reasonably assumed that areas at greater distances and in directions of less frequent plume transport will experience lower impacts than those predicted for the three modeled areas. All source-Class I area distances from Jim Bridger Power Plant to Bridger WA, Fitzpatrick WA, and Mount Zirkel WA exceed 50 km and are less than 300 km, thus falling within the range recommended for CALPUFF application.

Screening modeling that was conducted to determine if the Jim Bridger plant sources would be subject to BART, as described below, included receptors for the two closest Class I areas only (Bridger WA and Fitzpatrick WA). Subsequent refined modeling, as described later in this document, was conducted for all three of the closest Class I areas (Bridger WA, Fitzpatrick WA, and Mount Zirkel WA).

Figure 2
Jim Bridger Power Plant and Class I Areas



SCREENING MODELING

To determine if the PacifiCorp Jim Bridger facility would be subject to BART, the Division conducted CALPUFF modeling using three years of meteorological data. These data, from 1995-1996 and 2001, consisted of surface and upper-air observations and gridded output from the Mesoscale Model (MM5). Resolution of the MM5 data was 36-km for all three of the modeled years. Sources input to the modeling included the potential emissions for current operation from the four coal-fired boilers at the Jim Bridger facility.

Results of the modeling showed that the 98th percentile value for the change in visibility (in units of delta deciview [Δdv]) was above 0.5 Δdv for Bridger WA and Fitzpatrick WA for all three years of meteorology. As defined in EPA's final BART rule, a predicted 98th percentile impact equal to or greater than 0.5 Δdv from a given source indicates that the source contributes to visibility impairment, and therefore is subject to BART. The results of the screening modeling are shown in the table below.

Table 24: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
1995		
Bridger WA	9.7	3.1
Fitzpatrick WA	3.3	1.5
1996		
Bridger WA	8.7	2.0
Fitzpatrick WA	3.8	1.1
2001		
Bridger WA	4.6	2.8
Fitzpatrick WA	4.3	1.5

Δdv = delta deciview
WA = wilderness area

REFINED MODELING

Because of the results of the Division's screening modeling, PacifiCorp was required to conduct a refined BART analysis that included CALPUFF visibility modeling for the facility. The modeling approach followed the requirements described in the Division's BART modeling protocol, *BART Air Modeling Protocol - Individual Source Visibility Assessments for BART Control Analyses* (WDEQ-AQD, September 2006).

CALPUFF System

Predicted visibility impacts from the PacifiCorp Jim Bridger sources were determined with the EPA CALPUFF modeling system, which is the EPA-preferred modeling system for long-range transport. As described in the EPA Guideline on Air Quality Models (Appendix W of 40 CFR part 51), long-range transport is defined as modeling with source-receptor distances greater than 50 km. Because all modeled areas are located more than 50 km from the facility, the CALPUFF system was appropriate for use.

The CALPUFF modeling system consists of a meteorological data pre-processor (CALMET), an air dispersion model (CALPUFF), and post-processor programs (POSTUTIL, CALSUM, CALPOST). The CALPUFF model was developed as a non-steady-state air quality modeling system for assessing the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal.

CALMET is a diagnostic wind model that develops hourly wind and temperature fields in a three-dimensional, gridded modeling domain. Meteorological inputs to CALMET can include surface and upper-air observations from multiple meteorological monitoring stations. Additionally, the CALMET model can utilize gridded analysis fields from various mesoscale models such as MM5 to better represent regional wind flows and complex terrain circulations. Associated two-dimensional fields such as mixing height, land use, and surface roughness are included in the input to CALMET. The CALMET model allows the user to "weight" various terrain influence parameters in the vertical and horizontal directions by defining the radius of influence for surface and upper-air stations.

CALPUFF is a multi-layer, Lagrangian puff dispersion model. CALPUFF can be driven by the three-dimensional wind fields developed by the CALMET model (refined mode), or by data from a single surface and upper-air station in a format consistent with the meteorological files used to drive steady-state dispersion models. All far-field modeling assessments described here were completed using the CALPUFF model in a refined mode.

CALSUM is a post-processing program that can operate on multiple CALPUFF output files to combine the results for further post-processing. POSTUTIL is a post-processing program that processes CALPUFF concentrations and wet/dry flux files. The POSTUTIL model operates on one or more output data files from CALPUFF to sum, scale, and/or compute species derived from those that are modeled, and outputs selected species to a file for further post-processing. CALPOST is a post-processing program that can read the CALPUFF (or POSTUTIL or CALSUM) output files and calculate the impacts to visibility.

All of the refined CALPUFF modeling was conducted with the version of the CALPUFF system that was recognized as the EPA-approved release at the time of the development of the Division's modeling protocol. Version designations of the key programs are listed in the table below.

Table 25: Key Programs in CALPUFF System

Program	Version	Level
CALMET	5.53a	040716
CALPUFF	5.711a	040716
CALPOST	5.51	030709

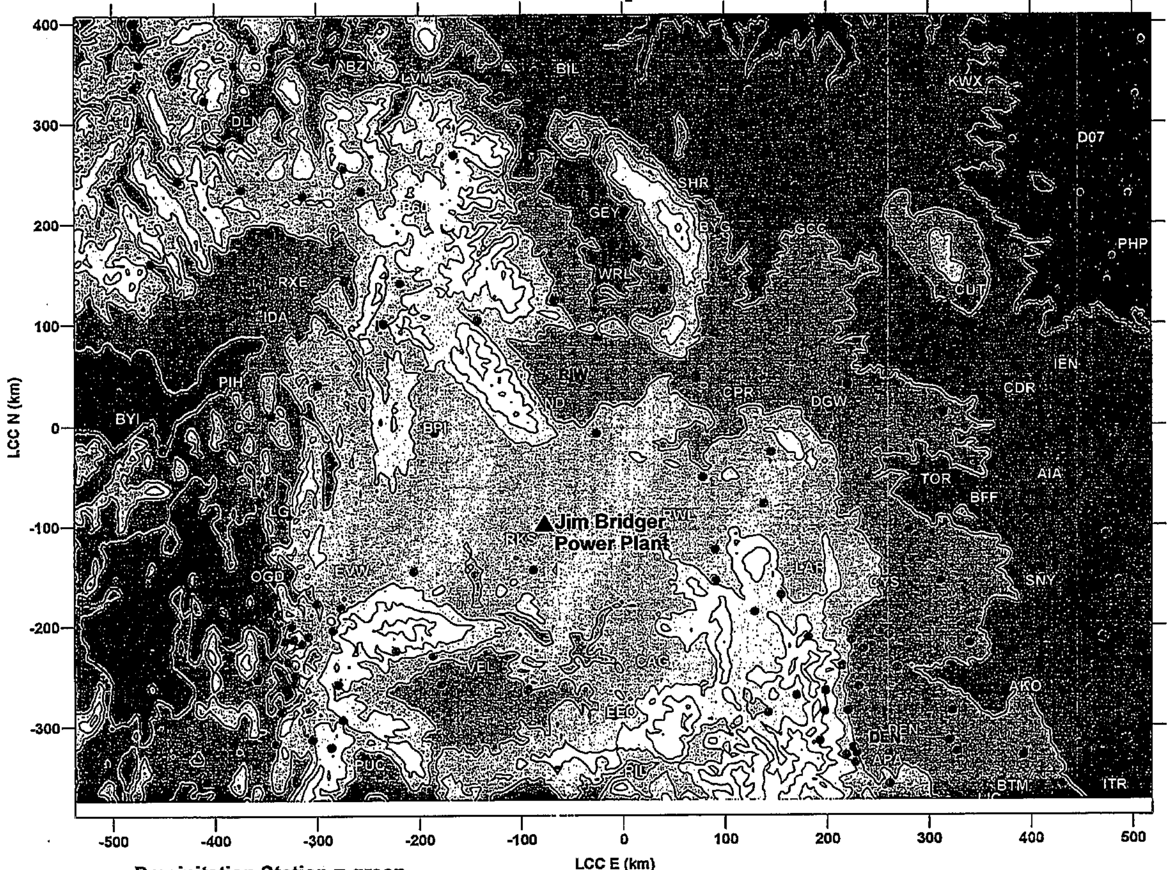
Meteorological Data Processing (CALMET)

As required by the Division's modeling protocol, the CALMET model was used to construct an initial three-dimensional windfield using data from the MM5 model. Surface and upper-air data were input to CALMET to adjust the initial windfield, but because of the relative scarcity of wind observations in the modeling domain, the influence of the observations on the initial windfield was minimized. Because the MM5 data were afforded a high degree of influence on the CALMET windfields, the Division obtained MM5 data at 12-km resolution that spanned the years 2001-2003. Locations of the observations that were input to CALMET, including surface, upper-air, and precipitation stations, are shown in Figure 3. Default settings were used in the CALMET input files for most of the technical options. The following table lists the key user-defined CALMET settings that were selected.

Table 26: Key User-Defined CALMET Settings

Variable	Description	Value
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, 3400
RMIN2	Minimum distance for extrapolation	-1
IPROG	Use gridded prognostic model output	14
RMAX 1	Maximum radius of influence (surface layer, km)	30
RMAX 2	Maximum radius of influence (layers aloft, km)	50
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

Figure 3
Observations Input to CALMET



Precipitation Station = green
Surface Station = white 3-letter
Upper-Air (+ surface) = red 3-letter

CALPUFF Modeling Setup

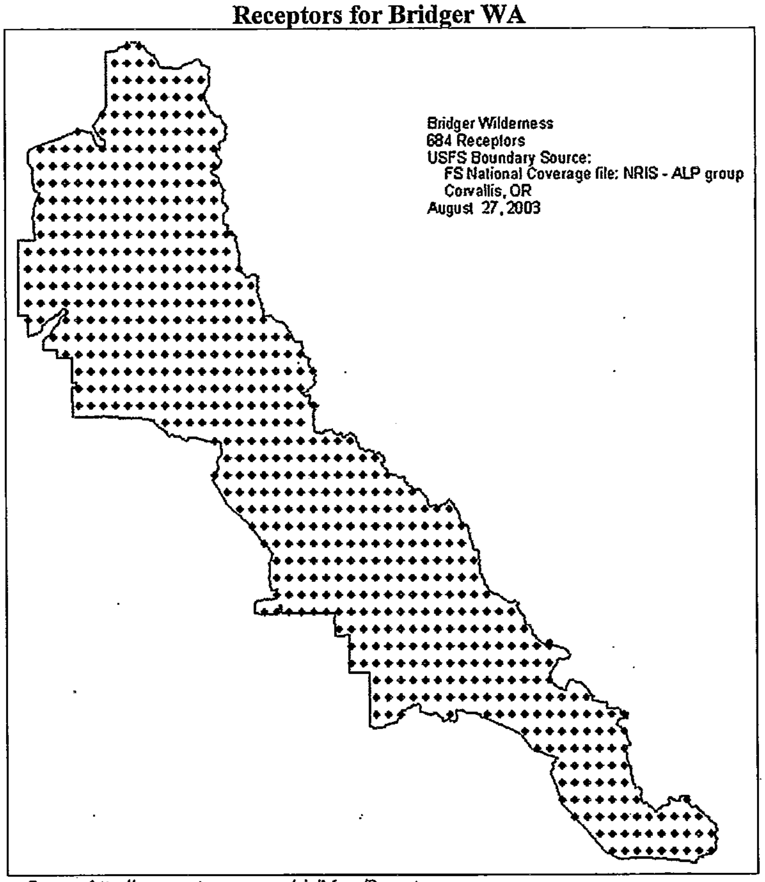
To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia concentrations. For ozone, hourly data collected from the following stations were used:

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

For any hour that was missing ozone data from all stations, a default value of 44 parts per billion (ppb) was used by the model as a substitute. For ammonia, a domain-wide background value of 2 ppb was used.

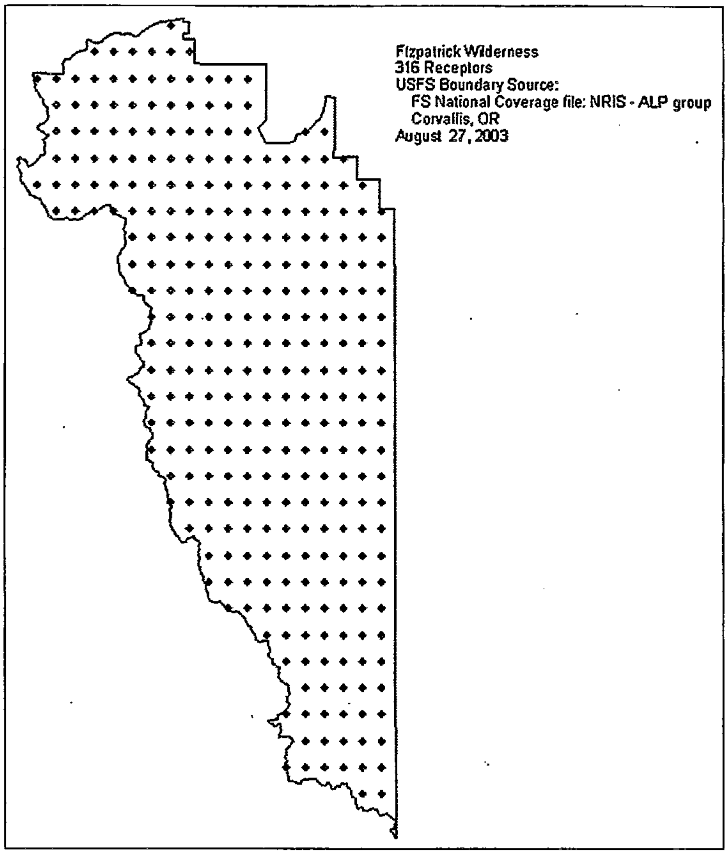
Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate Lambert Conformal Conic coordinates. Figures 4-6 show the receptor configurations that were used for Bridger WA, Fitzpatrick WA, and Mount Zirkel WA. Receptor spacing for the three modeled areas is approximately 1.3 km in the east-west direction and approximately 1.8 km in the north-south direction.

Figure 4
Receptors for Bridger WA



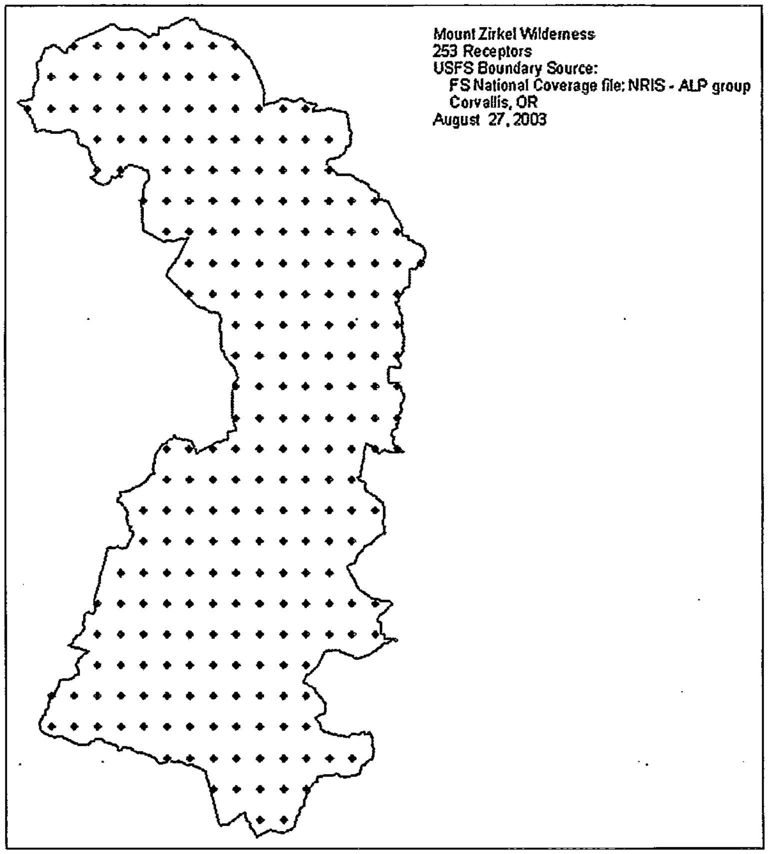
Source: http://www.nature.nps.gov/air/Maps/Receptors

Figure 5
Receptors for Fitzpatrick WA



Source: http://www.nature.nps.gov/air/Maps/Receptors/index.cfm

Figure 6
Receptors for Mount Zirkel WA



Source: http://www.nature.nps.gov/air/Maps/Receptors/index.cfm

CALPUFF Inputs – Baseline and Control Options

Source release parameters and emissions for baseline and control options for each unit at the Jim Bridger Plant are shown in the tables below.

Table 27: CALPUFF Inputs for Jim Bridger Unit 1

JIM BRIDGER 1	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operation with Wet FGD and ESP	LNB with separated OFA, Upgrade Wet FGD, Enhanced ESP	LNB with separated OFA, Upgrade Wet FGD, New Fabric Filter	LNB with separated OFA and SCR, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter	Committed Controls: LNB with separated OFA, Upgrade FGD, Enhanced ESP	Committed Controls with SCR
Hourly Heat Input (mmBtu/hour)	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.27	0.10	0.10	0.10	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	1,602	600	600	600	600	900	900
Nitrogen Oxide (NOx) (lb/mmBtu)	0.45	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	2,700	1,440	1,440	420	420	1,560	420
PM_{10} (lb/mmBtu)	0.045	0.030	0.015	0.030	0.015	0.030	0.030
PM_{10} (lb/hr)	270.0	180.0	90.0	180.0	90.0	180.0	180.0
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[a]	116.1	77.4	51.3	77.4	51.3	77.4	77.4
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[b]	153.9	102.6	38.7	102.6	38.7	102.6	102.6
Sulfuric Acid (H_2SO_4) (lb/hr)	55.2	55.2	55.2	94.8	94.8	55.2	94.7
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	7.0	7.0	--	7.0
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	--	12.2	12.2	--	12.2
H_2SO_4 as Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	92.9	92.9	54.1	92.8
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	5.1	5.1	--	5.1
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	10.2	10.2	--	10.2
Total Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	108.2	108.2	54.1	108.1
Stack Conditions							
Stack Height (meters)	152	152	152	152	152	152	152
Stack Exit Diameter (meters)	7.32	7.32	7.32	7.32	7.32	7.32	7.32
Stack Exit Temperature (Kelvin)	333	322	333	333	333	328	328
Stack Exit Velocity (meters per second)	25.6	24.7	27.4	27.4	27.4	24.7	24.7

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Table 28: CALPUFF Inputs for Jim Bridger Unit 2

JIM BRIDGER 2	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operations with LNB with separated OFA, Wet FGD, and ESP	LNB with separated OFA, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA, Upgrade Wet FGD, New Fabric Filter	LNB with separated OFA and SCR, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter	Committed Controls: LNB with separated OFA, Upgrade FGD, Enhanced ESP	Committed Controls with SCR
Hourly Heat Input (mmBtu/hour)	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.27	0.10	0.10	0.10	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	1,602	600	600	600	600	900	900
Nitrogen Oxide (NOx) (lb/mmBtu)	0.24	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,440	1,440	1,440	420	420	1,560	420
PM_{10} (lb/mmBtu)	0.074	0.030	0.015	0.030	0.015	0.030	0.030
PM_{10} (lb/hr)	444.0	180.0	90.0	180.0	90.0	180.0	180.0
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[(a)]	190.9	77.4	51.3	77.4	51.3	77.4	77.4
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[(b)]	253.1	102.6	38.7	102.6	38.7	102.6	102.6
Sulfuric Acid (H_2SO_4) (lb/hr)	55.2	55.2	55.2	94.8	94.8	55.2	94.7
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	7.0	7.0	--	7.0
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	--	12.2	12.2	--	12.2
H_2SO_4 as Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	92.9	92.9	54.1	92.8
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	5.1	5.1	--	5.1
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	10.2	10.2	--	10.2
Total Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	108.2	108.2	54.1	108.1
Stack Conditions							
Stack Height (meters)	152	152	152	152	152	152	152
Stack Exit Diameter (meters)	7.32	7.32	7.32	7.32	7.32	7.32	7.32
Stack Exit Temperature (Kelvin)	333	322	333	333	333	328	328
Stack Exit Velocity (meters per second)	27.4	24.7	27.4	27.4	27.4	24.7	24.7

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Table 29: CALPUFF Inputs for Jim Bridger Unit 3

JIM BRIDGER 3	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operations with Wet FGD and ESP	LNB with separated OFA, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA, Upgrade Wet FGD, New Fabric Filter	LNB with separated OFA and SCR, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter	Committed Controls: LNB with separated OFA, Upgrade FGD, Enhanced ESP	Committed Controls with SCR
Hourly Heat Input (mmBtu/hour)	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.27	0.10	0.10	0.10	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	1,602	600	600	600	600	900	900
Nitrogen Oxide (NOx) (lb/mmBtu)	0.45	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	2,700	1,440	1,440	420	420	1,560	420
PM_{10} (lb/mmBtu)	0.057	0.030	0.015	0.030	0.015	0.030	0.030
PM_{10} (lb/hr)	342.0	180.0	90.0	180.0	90.0	180.0	180.0
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[a]	147.1	77.4	51.3	77.4	51.3	77.4	77.4
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[b]	194.9	102.6	38.7	102.6	38.7	102.6	102.6
Sulfuric Acid (H_2SO_4) (lb/hr)	55.2	55.2	55.2	94.8	94.8	55.2	94.7
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	7.0	7.0	--	7.0
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	--	12.2	12.2	--	12.2
H_2SO_4 as Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	92.9	92.9	54.1	92.8
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	5.1	5.1	--	5.1
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	10.2	10.2	--	10.2
Total Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	108.2	108.2	54.1	108.1
Stack Conditions							
Stack Height (meters)	152	152	152	152	152	152	152
Stack Exit Diameter (meters)	7.32	7.32	7.32	7.32	7.32	7.32	7.32
Stack Exit Temperature (Kelvin)	333	322	333	333	333	328	328
Stack Exit Velocity (meters per second)	25.6	24.8	27.4	27.4	27.4	24.7	24.7

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Table 30: CALPUFF Inputs for Jim Bridger Unit 4

JIM BRIDGER 4	Baseline	Post-Control Scenario 1	Post-Control Scenario 2	Post-Control Scenario 3	Post-Control Scenario 4	Post-Control Scenario A	Post-Control Scenario B
Model Input Data	Current Operations with Wet FGD and ESP	LNB with separated OFA, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA, Upgrade Wet FGD, New Fabric Filter	LNB with separated OFA and SCR, Upgrade Wet FGD, and Enhanced ESP	LNB with separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter	Committed Controls: LNB with separated OFA, Upgrade FGD, Enhanced ESP	Committed Controls with SCR
Hourly Heat Input (mmBtu/hour)	6,000	6,000	6,000	6,000	6,000	6,000	6,000
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.17	0.10	0.10	0.10	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	1,002	600	600	600	600	900	900
Nitrogen Oxide (NOx) (lb/mmBtu)	0.45	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	2,700	1,440	1,440	420	420	1,560	420
PM_{10} (lb/mmBtu)	0.030	0.030	0.015	0.030	0.015	0.030	0.030
PM_{10} (lb/hr)	180.0	180.0	90.0	180.0	90.0	180.0	180.0
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[(a)]	77.4	77.4	51.3	77.4	51.3	77.4	77.4
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[(b)]	102.6	102.6	38.7	102.6	38.7	102.6	102.6
Sulfuric Acid (H_2SO_4) (lb/hr)	55.2	55.2	55.2	94.8	94.8	55.2	94.7
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)				7.0	7.0		7.0
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)				12.2	12.2		12.2
H_2SO_4 as Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	92.9	92.9	54.1	92.8
$(NH_4)_2SO_4$ as SO_4 (lb/hr)				5.1	5.1		5.1
$(NH_4)HSO_4$ as SO_4 (lb/hr)				10.2	10.2		10.2
Total Sulfate (SO_4) (lb/hr)	54.1	54.1	54.1	108.2	108.2	54.1	108.1
Stack Conditions							
Stack Height (meters)	152	152	152	152	152	152	152
Stack Exit Diameter (meters)	9.45	9.45	9.45	9.45	9.45	9.45	9.45
Stack Exit Temperature (Kelvin)	322	322	322	322	322	322	322
Stack Exit Velocity (meters per second)	12.9	12.9	12.9	12.9	12.9	12.9	12.9

Notes:

(a) AP-42, Table 1.1-6: coarse PM counted as a percentage of PM_{10}. This equates to 43 percent for ESP and 57 percent for Baghouse.

(b) AP-42, Table 1.1-6: fine PM counted as a percentage of PM_{10}. This equates to 57 percent for ESP and 43 percent for Baghouse.

Visibility Post-Processing (CALPOST)

The changes in visibility were modeled using Method 6 within the CALPOST post-processor. Method 6 requires input of monthly relative humidity factors [f(RH)] for each Class I area. Monthly f(RH) factors that were used for Bridger WA, Fitzpatrick WA, and Mount Zirkel WA are shown in the table below.

Table 31: Relative Humidity Factors for CALPOST

Month	Mount Zirkel WA	Bridger WA & Fitzpatrick WA
January	2.20	2.50
February	2.20	2.30
March	2.00	2.30
April	2.10	2.10
May	2.20	2.10
June	1.80	1.80
July	1.70	1.50
August	1.80	1.50
September	2.00	1.80
October	1.90	2.00
November	2.10	2.50
December	2.10	2.40

According to the final BART rule, natural background conditions as a reference for determination of the modeled Δdv change should be representative of the 20 percent best natural visibility days in a given Class I area. EPA BART guidance provides the 20 percent best days deciview values for each Class I area on an annual basis, but does not provide the individual species concentration data required for input to CALPOST.

Species concentrations corresponding to the 20 percent best days were calculated for each Class I area by scaling back the annual average (natural background) concentrations given in Table 2-1 of the EPA document *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 deciview values for that particular Class I area would be calculated.

The scaling procedure is illustrated here for Bridger WA. From Appendix B in the EPA natural visibility guidance document, the deciview value for the 20 percent best days at Bridger WA is 1.96 dv. To obtain the speciated background concentrations representative of the 20 percent best days, the deciview value (1.96 dv) was first converted to light extinction. The relationship between deciviews and light extinction is expressed as follows:

$dv = 10 \ln (b_{ext}/10)$ or $b_{ext} = 10 \exp (dv/10)$

where: b_{ext} = light extinction expressed in inverse megameters (Mm^{-1}).

Using this relationship with the known deciview value of 1.96, one obtains an equivalent light extinction value of 12.17 Mm^{-1}. Next, the annual average natural visibility concentrations were set equal to a total extinction value of 12.17 Mm^{-1}. The relationship between total light extinction and the individual components of the light extinction is as follows:

b_{ext} = (3)f(RH)[ammonium sulfate] + (3)f(RH)[ammonium nitrate] + (0.6)[coarse mass] + (4)[organic carbon] + (1)[soil] + (10)[elemental carbon] + b_{ray}

where:

- bracketed quantities represent background concentrations in $\mu g/m^3$
- values in parenthesis represent scattering efficiencies
- f(RH) is the relative humidity adjustment factor (applied to hygroscopic species only)
- b_{ray} is light extinction due to Rayleigh scattering (10 Mm^{-1} used for all Class I areas)

Substituting the annual average natural background concentrations, the average f(RH) for Bridger WA, and including a coefficient for scaling, one obtains:

12.17 = (3)(2.1)[0.12]X + (3)(2.1)[0.1]X + (0.6)[3.0]X + (4)[0.47]X + (1)[0.5]X + (10)[0.02]X + 10

In the equation above, X represents a scaling factor needed to convert the annual average natural background concentrations to values representative of the 20 percent best days. Solving for X provides a value of 0.376. Table 32 presents the annual average natural background concentrations, the calculated scaling factor, and the calculated background concentrations for the 20 percent best days for Bridger WA.

Table 32: Calculated Background Components for Bridger WA

Component	Annual Average for West Region ($\mu g/m^3$)	Calculated Scaling Factor	20% Best Days for Bridger WA ($\mu g/m^3$)
Ammonium Sulfate	0.12	0.376	0.045
Ammonium Nitrate	0.10	0.376	0.038
Organic Carbon	0.47	0.376	0.176
Elemental Carbon	0.02	0.376	0.008
Soil	0.50	0.376	0.188
Coarse Mass	3.00	0.376	1.127

The scaled aerosol concentrations were averaged for Bridger WA and Fitzpatrick WA because of their geographical proximity and similar annual background visibility. The 20 percent best days aerosol concentrations for all three Class I areas in question are listed in the table below.

Table 33: Natural Background Aerosol Concentrations (μg/m^3)

Aerosol Component	Mount Zirkel WA	Fitzpatrick WA & Bridger WA
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

Visibility Post-Processing Results

The results of the visibility modeling for each of the four units for the baseline and control scenarios are shown in the tables below. For each scenario, the 98th percentile Δdv results are reported along with the total number of days for which the predicted impacts exceeded 0.5 dv. Following the tables are figures that present the results graphically for baseline, the BART configuration proposed by PacifiCorp, and for the proposed BART configuration with the addition of SCR.

Table 34: CALPUFF Visibility Modeling Results: Unit 1

Class I Area	2001 98th Percentile Value (Δdv)	2001 No. of Days > 0.5 Δdv	2002 98th Percentile Value (Δdv)	2002 No. of Days > 0.5 Δdv	2003 98th Percentile Value (Δdv)	2003 No. of Days > 0.5 Δdv	3-Year Average 98th Percentile Value (Δdv)	3-Year Average No. of Days > 0.5 Δdv
Baseline – Wet FGD, ESP								
Bridger WA	0.746	14	1.448	26	0.761	16	0.985	19
Fitzpatrick WA	0.418	7	0.704	11	0.373	7	0.498	8
Mt Zirkel WA	1.236	27	1.496	34	1.232	35	1.321	32
Post-Control Scenario 1 – LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.384	7	0.845	14	0.411	5	0.547	9
Fitzpatrick WA	0.221	3	0.378	5	0.199	2	0.266	3
Mt Zirkel WA	0.736	16	0.816	13	0.736	16	0.763	15
Post-Control Scenario 2 – LNB w/ separated OFA, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.372	6	0.780	13	0.408	5	0.520	8
Fitzpatrick WA	0.211	3	0.347	6	0.186	2	0.248	4
Mt Zirkel WA	0.676	15	0.777	13	0.686	15	0.713	14
Post-Control Scenario 3 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, Enhanced ESP								
Bridger WA	0.279	3	0.519	9	0.258	3	0.352	5
Fitzpatrick WA	0.127	1	0.226	1	0.118	2	0.157	1
Mt Zirkel WA	0.453	5	0.473	4	0.433	5	0.453	5
Post-Control Scenario 4 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.268	3	0.500	8	0.248	3	0.339	5
Fitzpatrick WA	0.125	1	0.223	1	0.114	2	0.154	1
Mt Zirkel WA	0.436	2	0.465	4	0.422	5	0.441	4
Post-Control Scenario A – Committed Controls: LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.442	7	0.930	14	0.466	6	0.613	9
Fitzpatrick WA	0.256	3	0.417	6	0.222	3	0.298	4
Mt Zirkel WA	0.797	18	0.917	14	0.755	18	0.823	17
Post-Control Scenario B – Committed Controls + SCR								
Bridger WA	0.342	3	0.619	9	0.285	4	0.415	5
Fitzpatrick WA	0.155	3	0.284	2	0.138	2	0.192	2
Mt Zirkel WA	0.477	7	0.562	9	0.461	6	0.500	7

Table 35: CALPUFF Visibility Modeling Results: Unit 2

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Wet FGD, LNB w/ separated OFA, ESP								
Bridger WA	0.530	10	0.990	20	0.533	9	0.684	13
Fitzpatrick WA	0.298	4	0.534	8	0.263	3	0.365	5
Mt Zirkel WA	0.842	23	1.008	18	0.803	20	0.884	20
Post-Control Scenario 1 – LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.385	7	0.847	14	0.416	5	0.549	9
Fitzpatrick WA	0.223	3	0.377	5	0.200	2	0.267	3
Mt Zirkel WA	0.733	16	0.815	13	0.735	16	0.761	15
Post-Control Scenario 2 – LNB w/ separated OFA, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.375	6	0.784	13	0.409	5	0.523	8
Fitzpatrick WA	0.210	3	0.348	6	0.188	2	0.249	4
Mt Zirkel WA	0.681	15	0.777	13	0.688	15	0.715	14
Post-Control Scenario 3 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, Enhanced ESP								
Bridger WA	0.279	3	0.516	9	0.258	3	0.351	5
Fitzpatrick WA	0.127	1	0.226	1	0.118	2	0.157	1
Mt Zirkel WA	0.455	5	0.474	5	0.435	5	0.455	5
Post-Control Scenario 4 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.268	3	0.499	7	0.248	3	0.338	4
Fitzpatrick WA	0.125	1	0.222	1	0.115	2	0.154	1
Mt Zirkel WA	0.439	2	0.465	4	0.423	5	0.442	4
Post-Control Scenario A – Committed Controls: LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.442	7	0.930	14	0.466	6	0.613	9
Fitzpatrick WA	0.256	3	0.417	6	0.222	3	0.298	4
Mt Zirkel WA	0.797	18	0.917	14	0.755	18	0.823	17
Post-Control Scenario B – Committed Controls + SCR								
Bridger WA	0.342	3	0.619	9	0.285	4	0.415	5
Fitzpatrick WA	0.155	3	0.284	2	0.138	2	0.192	2
Mt Zirkel WA	0.477	7	0.562	9	0.461	6	0.500	7

Table 36: CALPUFF Visibility Modeling Results: Unit 3

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Wet FGD, ESP								
Bridger WA	0.741	15	1.447	27	0.759	16	0.982	19
Fitzpatrick WA	0.418	7	0.713	11	0.378	7	0.503	8
Mt Zirkel WA	1.226	27	1.498	34	1.228	35	1.317	32
Post-Control Scenario 1 – LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.386	7	0.854	14	0.414	5	0.551	9
Fitzpatrick WA	0.223	3	0.377	4	0.192	2	0.264	3
Mt Zirkel WA	0.733	16	0.815	13	0.734	16	0.761	15
Post-Control Scenario 2 – LNB w/ separated OFA, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.376	6	0.782	13	0.410	5	0.523	8
Fitzpatrick WA	0.214	3	0.349	6	0.188	2	0.250	4
Mt Zirkel WA	0.677	15	0.778	13	0.686	15	0.714	14
Post-Control Scenario 3 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, Enhanced ESP								
Bridger WA	0.279	3	0.509	9	0.258	3	0.349	5
Fitzpatrick WA	0.128	1	0.226	1	0.118	2	0.157	1
Mt Zirkel WA	0.451	5	0.473	4	0.432	5	0.452	5
Post-Control Scenario 4 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.268	3	0.498	7	0.248	3	0.338	4
Fitzpatrick WA	0.126	1	0.222	1	0.115	2	0.154	1
Mt Zirkel WA	0.437	2	0.464	4	0.420	5	0.440	4
Post-Control Scenario A – Committed Controls: LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.442	7	0.930	14	0.466	6	0.613	9
Fitzpatrick WA	0.256	3	0.417	6	0.222	3	0.298	4
Mt Zirkel WA	0.797	18	0.917	14	0.755	18	0.823	17
Post-Control Scenario B – Committed Controls + SCR								
Bridger WA	0.342	3	0.619	9	0.285	4	0.415	5
Fitzpatrick WA	0.155	3	0.284	2	0.138	2	0.192	2
Mt Zirkel WA	0.477	7	0.562	9	0.461	6	0.500	7

Table 37: CALPUFF Visibility Modeling Results: Unit 4

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Wet FGD, ESP								
Bridger WA	0.695	12	1.330	23	0.736	13	0.920	16
Fitzpatrick WA	0.406	5	0.615	11	0.346	7	0.456	8
Mt Zirkel WA	1.129	24	1.380	25	1.201	33	1.237	27
Post-Control Scenario 1 – LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.386	7	0.821	14	0.429	5	0.545	9
Fitzpatrick WA	0.223	3	0.379	3	0.207	2	0.270	3
Mt Zirkel WA	0.688	16	0.800	14	0.688	17	0.725	16
Post-Control Scenario 2 – LNB w/ separated OFA, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.383	7	0.802	14	0.425	5	0.537	9
Fitzpatrick WA	0.232	3	0.361	3	0.202	2	0.265	3
Mt Zirkel WA	0.671	15	0.790	13	0.678	17	0.713	15
Post-Control Scenario 3 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, Enhanced ESP								
Bridger WA	0.285	3	0.472	7	0.275	2	0.344	4
Fitzpatrick WA	0.143	2	0.233	1	0.129	2	0.168	2
Mt Zirkel WA	0.426	4	0.442	5	0.409	5	0.426	5
Post-Control Scenario 4 – LNB w/ separated OFA and SCR, Upgrade Wet FGD, New Fabric Filter								
Bridger WA	0.273	3	0.466	7	0.263	2	0.334	4
Fitzpatrick WA	0.136	1	0.230	1	0.124	1	0.163	1
Mt Zirkel WA	0.410	3	0.434	5	0.399	4	0.414	4
Post-Control Scenario A – Committed Controls: LNB w/ separated OFA, Upgrade Wet FGD, FGC for Enhanced ESP								
Bridger WA	0.448	7	0.893	14	0.489	6	0.610	9
Fitzpatrick WA	0.273	3	0.428	6	0.226	2	0.309	4
Mt Zirkel WA	0.743	17	0.892	15	0.770	19	0.802	17
Post-Control Scenario B – Committed Controls + SCR								
Bridger WA	0.343	4	0.579	8	0.301	4	0.408	5
Fitzpatrick WA	0.164	3	0.288	1	0.139	2	0.197	2
Mt Zirkel WA	0.444	5	0.538	8	0.460	6	0.481	6

Figure 7
Modeled BART Impacts: 98th Percentile (delta-dv)

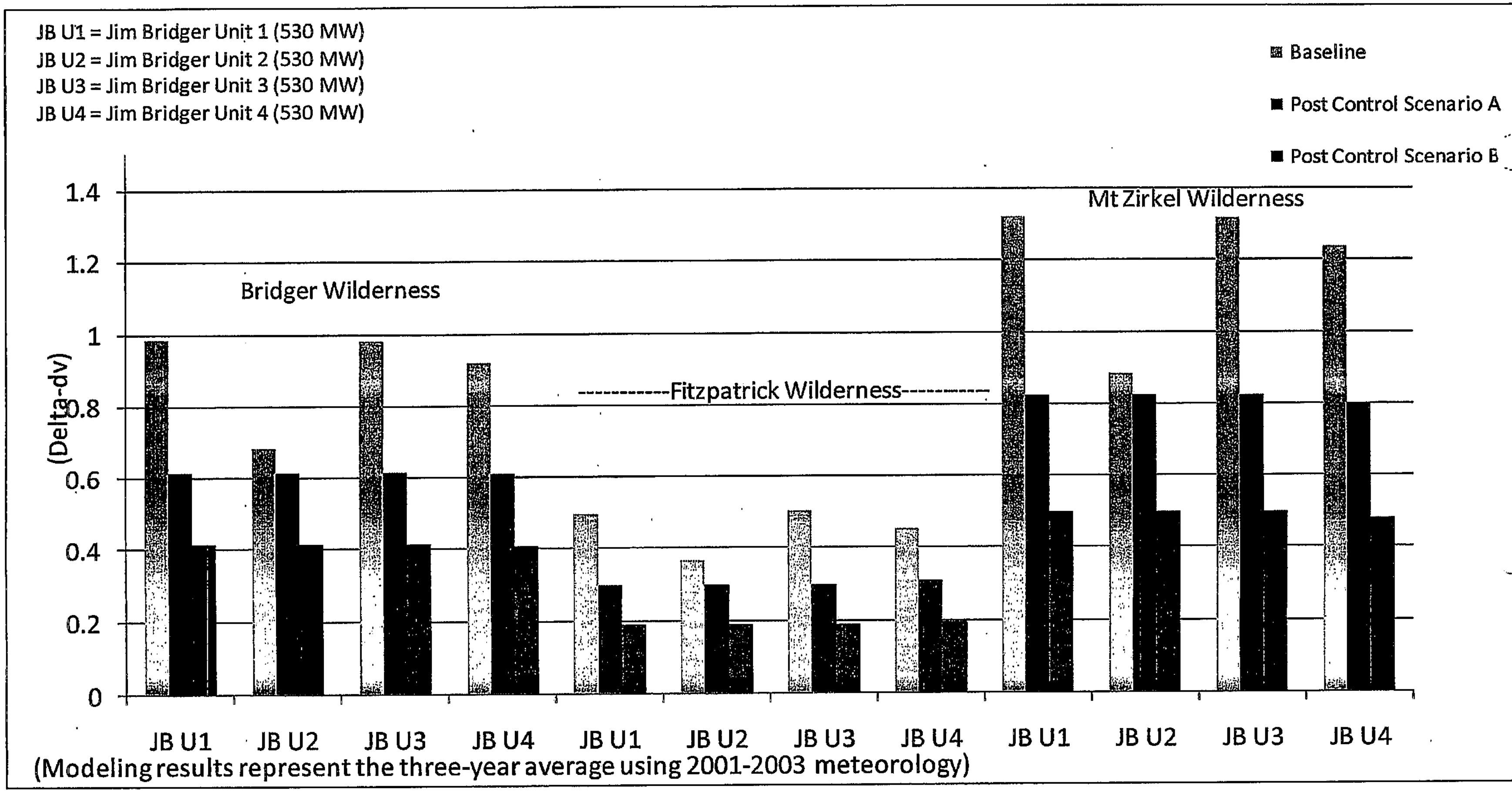
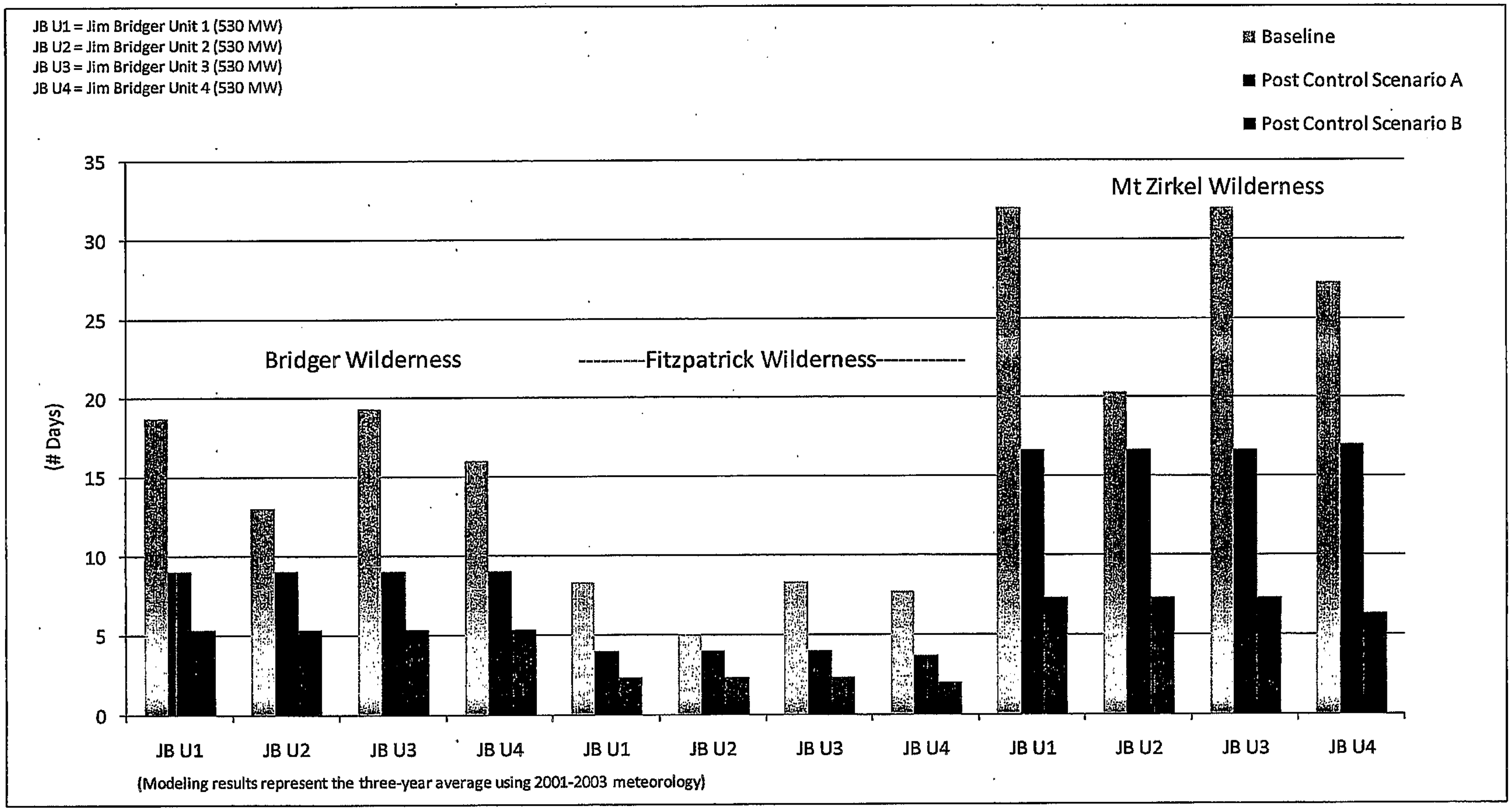


Figure 8
Modeled BART Impacts: Number of Days > 0.5 delta-dv



BART CONCLUSIONS:

After considering (1) the costs of compliance, (2) the energy and non-air quality environmental impacts of compliance, (3) any pollution equipment in use or in existence at the source, (4) the remaining useful life of the source, and (5) the degree of improvement in visibility (all five statutory factors) from each proposed control technology, the Division determined BART for each visibility impairing pollutant emitted from the four units subject to BART at the Jim Bridger Power Plant.

NO_x

LNB with separated OFA is determined to be BART for Units 1-4 for NO_x based, in part, on the following conclusions:

1. LNB with separated OFA on Units 1, 3, and 4 was cost effective with a capital cost of $11,300,000 per unit and a $255 per ton of NO_x removed average cost effectiveness for each unit over a twenty year operational life. LNB with separated OFA on Unit 2 did not require any additional capital cost or annual O&M cost.

2. Combustion control using LNB with separated OFA does not require non-air quality environmental mitigation for the use of chemical reagents (i.e., ammonia or urea) and there is a minimal energy impact.

3. After careful consideration of the five statutory factors, especially the costs of compliance and the existing pollution control equipment, a NO_x control level of 0.26 lb/MMBtu on a 30-day rolling average, above EPA's established presumptive limit of 0.15 lb/MMBtu for tangential-fired boilers burning sub-bituminous coal, is justified.

4. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged visibility improvement from the baseline summed across the three Class I areas achieved with LNB with separated OFA, upgraded wet FGD, and FGC for enhanced ESP (Post-Control Scenario A) was 1.070 Δdv from Unit 1, 0.199 Δdv from Unit 2, 1.068 Δdv from Unit 3, and 0.892 Δdv from Unit 4.

5. Annual NO_x emission reductions from LNB with separated OFA on Unit 1, 3, and 4 are 4,493 tons per unit for a total annual reduction at the Jim Bridger Power Plant of 13,479 tons. There are no NO_x reductions from Unit 2 as LNB with separated OFA is baseline for the unit.

LNB with separated OFA and SCR was not determined to be BART for Units 1-4 for NO_x based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on each unit is significantly higher than LNB with separated OFA. Capital costs for SCR on Units 1-4 are $166,500,000 per unit. Annual operating costs for Units 1, 3, and 4 are $3,382,286 per unit and Unit 2 is $3,370,466.

2. Additional non-air quality environmental mitigation is required for the use of chemical reagents.

3. Operation of LNB with separated OFA and SCR is parasitic and requires an estimated 3.22 MW to 3.36 MW of power from each unit.

4. While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control A as the only difference is directly attributable to the installation of SCR. Subtracting the modeled values from each other yield the incremental visibility improvement from SCR. The cumulative 3-year averaged visibility improvement from Post-Control Scenario A across the three Class I areas achieved with Post-Control Scenario B was 0.627 Δdv per unit from Units 1-3 and 0.635 Δdv from Unit 4.

The Division considers the installation and operation of the BART-determined NO_x controls, LNB with separated OFA, to meet the corresponding emission limits of 0.26 lb/MMBtu, 30-day rolling average, 1,560 lb/hr, 30-day rolling average, and 6,833 tpy on a continuous basis to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

Jim Bridger Unit 1:	LNB with separated OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 1,560 lb/hr (30-day rolling average) and 6,833 tpy as BART for NO_x.
Jim Bridger Unit 2:	LNB with separated OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 1,560 lb/hr (30-day rolling average) and 6,833 tpy as BART for NO_x.
Jim Bridger Unit 3:	LNB with separated OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 1,560 lb/hr (30-day rolling average) and 6,833 tpy as BART for NO_x.
Jim Bridger Unit 4:	LNB with separated OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 1,560 lb/hr (30-day rolling average) and 6,833 tpy as BART for NO_x.

PM/PM_{10}

Existing ESP with FGC is determined to be BART for Units 1-4 for PM/PM_{10} based, in part, on the following conclusions:

1. Recognizing the cost benefit associated with using the existing ESPs and the minimal energy impact of installing FGC, the cost of compliance for the control technology is cost effective for each unit, over a twenty year operational life, for reducing PM emissions. The cost effectiveness for existing ESP with FGC is $1,544 for Unit 1, $526 for Unit 2, $857 for Unit 3. Unit 4 did not require additional capital cost.

2. No negative non-air environmental impacts are anticipated from existing ESPs with FGC.

3. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged visibility improvement from the baseline across the three Class I areas achieved with LNB with separated OFA, upgraded wet FGD, and FGC for enhanced ESP (Post-Control Scenario A) was 1.070 Δdv from Unit 1, 0.199 Δdv from Unit 2, 1.068 Δdv from Unit 3, and 0.892 Δdv from Unit 4. While the visibility improvement attributable to the installation of FGC on existing ESPs can't be directly determined from the visibility modeling, the Division does not anticipate the PM contribution to be significant when compared to NO_x and SO_2 contributions.

Existing ESP with a polishing fabric filter was not determined to be BART for Units 1-4 for PM/PM_{10} based, in part, on the following conclusions:

1. The cost of compliance for a polishing fabric filter on each unit is not reasonable over a twenty year operational life. The cost effectiveness for installing a new polishing fabric filter on the existing ESP is $8,980 for Unit 1, $4,557 for Unit 2, $6,382 for Unit 3, and $17,936 for Unit 4. Incremental cost effectiveness is $16,396, $16,369, $16,312, and $17,936 for Units 1, 2, 3, and 4, respectively.

2. The cumulative 3-year averaged visibility improvement from new LNB with separated OFA, upgraded wet FGD, and FGC for enhanced ESP with FGC (Post-Control Scenario 1) across the three Class I areas achieved with LNB and separated OFA, upgraded wet FGD, and adding a polishing fabric filter (Post-Control Scenario 2) was 0.095 Δdv from Unit 1, 0.090 Δdv from Unit 2, 0.089 Δdv from Unit 3 and 0.025 Δdv from Unit 4.

The Division considers the installation and operation of the BART-determined PM/PM_{10} controls, existing ESP with FGC, to meet the corresponding emission limits of 0.030 lb/MMBtu, 180 lb/hr, and 788 tpy on a continuous basis to meet the statutory requirements of BART.

Unit-by-unit PM/PM_{10} BART determinations:

<u>Jim Bridger Unit 1</u>: Continuing to use the existing ESP and adding FGC to meet an established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 180 lb/hr, and 788 tpy as BART for PM/PM_{10}.

<u>Jim Bridger Unit 2</u>: Continuing to use the existing ESP and adding FGC to meet an established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 180 lb/hr, and 788 tpy as BART for PM/PM_{10}.

<u>Jim Bridger Unit 3</u>: Continuing to use the existing ESP and adding FGC to meet an established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 180 lb/hr, and 788 tpy as BART for PM/PM_{10}.

<u>Jim Bridger Unit 4</u>: Continuing to use the existing ESP and adding FGC to meet an established PM/PM_{10} emission limits of 0.030 lb/MMBtu, 180 lb/hr, and 788 tpy as BART for PM/PM_{10}.

SO_2: REGIONAL SO_2 MILESTONE AND BACKSTOP TRADING PROGRAM

PacifiCorp evaluated control SO_2 control technologies that can achieve a SO_2 emission rate of 0.15 lb/MMBtu or lower from the coal-fired boilers. PacifiCorp's proposed BART controls are upgrading the existing wet FGD on each of the units.

Wyoming is a §309 state participating in the Regional SO_2 Milestone and Backstop Trading Program. §308(e)(2) provides States with the option to implement or require participation in an emissions trading program or other alternative measure rather than to require sources subject to BART to install, operate, and maintain additional control technology to meet an established emission limit on a continuous basis. However, the alternate program must achieve greater reasonable progress than would be accomplished by installing BART. A demonstration that the alternate program can achieve greater reasonable progress is prescribed by §308(e)(2)(i). Since the pollutant of concern is SO_2, this demonstration has been performed under §309 as part of the state implementation plan. §309(d)(4)(i) requires that the SO_2 milestones established under the plan "...must be shown to provide for greater reasonable progress than would be achieved by application of BART pursuant to §51.308(e)(2)."

Wyoming participated in creating a detailed report entitled **Demonstration that the SO_2 Milestones Provide Greater Reasonable Progress than BART** covering SO_2 emissions from all states participating in the Regional SO_2 Milestone and Backstop Trading Program. The document was submitted to EPA in support of the §309 Wyoming Regional Haze SIP in November of 2008.

As part of the §309 program, participating states, including Wyoming, must submit an annual Regional Sulfur Dioxide Emissions and Milestone Report that compares actual emissions to pre-established milestones. Participating states have been filing these reports since 2003. Each year, states have been able to demonstrate that actual SO_2 emissions are well below the milestones. The actual emissions and their respective milestones are shown below:

Table 38: Regional Sulfur Dioxide Emissions and Milestone Report Summary

Year	Reported SO_2 Emissions (tons)	3-year Milestone Average (tons)
2003	330,679	447,383
2004	337,970	448,259
2005	304,591	446,903
2006	279,134	420,194
2007	273,663	420,637

In addition to demonstrating successful SO_2 emission reductions, §309 states have also relied on visibility modeling conducted by the WRAP to demonstrate improvement at Class I areas. The complete modeling demonstration showing deciview values was included as part of the visibility improvement section of the §309 SIP, but the SO_2 portion of the demonstration has been included as Table 39 to underscore the improvements associated with SO_2 reductions.

Table 39: Visibility - Sulfate Extinction Only

Class I Area Monitor (Class I Areas Represented)	20% Worst Visibility Days (Monthly Average, Mm^{-1})		20% Best Visibility Days (Monthly Average, Mm^{-1})	
	2018 [1] Base Case (Base 18b)	2018 [2] Preliminary Reasonable Progress Case (PRP18a)	2018 [1] Base Case (Base 18b)	2018 [2] Preliminary Reasonable Progress Case (PRP18a)
Bridger, WY (Bridger WA and Fitzpatrick WA)	5.2	4.3	1.6	1.3
North Absaroka, WY (North Absaroka WA and Washakie WA)	4.8	4.5	1.1	1.1
Yellowstone, WY (Yellowstone NP, Grand Teton NP and Teton WA)	4.3	3.9	1.6	1.4
Badlands, SD	17.8	16.0	3.5	3.1
Wind Cave, SD	13.0	12.1	2.7	2.5
Mount Zirkel, CO (Mt. Zirkel WA and Rawah WA)	4.6	4.1	1.4	1.3
Rocky Mountain, CO	6.8	6.2	1.3	1.1
Gates of the Mountains, MT	5.3	5.1	1.0	1.0
UL Bend, MT	9.7	9.6	1.8	1.7
Craters of the Moon, ID	5.8	5.5	1.5	1.5
Sawtooth, ID	3.0	2.8	1.2	1.1
Canyonlands, UT (Canyonlands NP and Arches NP)	5.4	4.8	2.1	1.9
Capitol Reef, UT	5.7	5.4	1.9	1.8

[1] Represents 2018 Base Case growth plus all established controls as of Dec. 2004. No BART or SO_2 Milestone assumptions were included.
[2] Represents 2018 Preliminary Reasonable Progress growth estimates and established SO_2 limits.

All Class I areas in the surrounding states show a projected visibility improvement for 2018 with respect to SO_2 on the worst days and no degradation on the best days. More discussion on the visibility improvement of the §309 program can be found in the Wyoming §309 Regional Haze SIP revision submitted to EPA in November 2008.

Therefore, in accordance with §308(e)(2), Wyoming's §309 Regional Haze SIP, and WAQSR Chapter 6, Section 9, PacifiCorp will not be required to install the company-proposed BART technology and meet the corresponding achievable emission limit. Instead, PacifiCorp is required to participate in the Regional SO_2 Milestone and Backstop Trading Program authorized under Chapter 14 of the WAQSR.

LONG-TERM STRATEGY FOR REGIONAL HAZE:

In this BART analysis, the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology were taken into consideration when determining BART. When evaluating the costs of compliance the Division recognized a time limitation to install BART-determined controls imposed by the Regional Haze Rule. In addressing the required elements, including documentation for all required analyses, to be submitted in the state implementation plan, 40 CFR

51.308(e)(1)(iv) states: "A requirement that each source subject to BART be required to install and operate BART as expeditiously as practicable, but in no event later than 5 years after approval of the implementation plan revision." As a practical measure, the Division anticipates the requirement to install the BART-determined controls to occur as early as 2015.

PacifiCorp used the **EPA Air Pollution Control Cost Manual**, which is identified in 40 CFR part 51 Appendix Y(IV)(D)(4)(a)(5) as a reference source, to estimate capital costs and calculate cost effectiveness. Section 1 Chapter 2 of the **EPA Air Pollution Control Cost Manual - Sixth Edition** (EPA 452/B-02-001) describes the concepts and methodology of cost estimation used in the manual. Beginning on page 2-28 of Chapter 2.5.4.2, the manual discusses retrofit cost consideration including the practice of developing a retrofit factor to account for unanticipated additional costs of installation not directly related to the capital cost of the controls themselves. However, PacifiCorp did not present a retrofit factor in their cost analyses. PacifiCorp estimated that the installation of SCR requires a minimum of 6 years of advanced planning and engineering before the control can be successfully installed and operated. This planning horizon would necessarily be considered in the scheduled maintenance turnarounds for existing units to minimize installation costs of the pollution control systems.

PacifiCorp's BART-eligible or subject-to-BART power plant fleet is shown in Table 40. While the majority of affected units are in Wyoming, there are four units in Utah and one in Arizona. Since the 5-year control installation requirement is stated in the federal rule it applies to all of PacifiCorp's units requiring additional BART-determined controls. Although BART is determined on a unit-by-unit basis taking into consideration the statutory factors, consideration for additional installation costs related to the logistics of managing more than one control installation, which are indirect retrofit costs, was afforded under the statutory factor: costs of compliance.

Table 40: PacifiCorp's BART-Eligible/Subject Units

Source	State
Hunter Unit 1 [(a)]	Utah
Hunter Unit 2 [(a)]	Utah
Huntington Unit 1 [(a)]	Utah
Huntington Unit 2 [(a)]	Utah
Cholla Unit 4 [(b)]	Arizona
Dave Johnston Unit 3	Wyoming
Dave Johnston Unit 4	Wyoming
Jim Bridger Unit 1	Wyoming
Jim Bridger Unit 2	Wyoming
Jim Bridger Unit 3	Wyoming
Jim Bridger Unit 4	Wyoming
Naughton Unit 1	Wyoming
Naughton Unit 2	Wyoming
Naughton Unit 3	Wyoming
Wyodak	Wyoming

[(a)] Units identified in Utah's §308 Regional Haze SIP.
[(b)] Unit identified on the Western Regional Air Partnership's BART Clearinghouse.

Therefore, based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Jim Bridger Units 1-4 and taking into consideration the logistical challenge of managing multiple pollution control installations within the regulatory time allotted for installation of BART by the Regional Haze Rule, the Division is requiring the installation of SCR on Jim Bridger Unit 3 in 2015 and on Jim Bridger Unit 4 in 2016 for the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan. The Division is also requiring PacifiCorp to submit a permit application to install additional add-on NO_x control on Units 1 and 2 that includes an analysis of: (1) the costs of compliance; (2) the time necessary for compliance; (3) the energy and non-air quality environmental impacts of compliance; and (4) the remaining useful life of existing sources that contribute to visibility impairment (i.e., the four statutory factors taken into consideration when establishing reasonable progress goals[5]) and the associated visibility impacts from the application of each proposed NO_x control. Each proposed add-on NO_x control shall achieve an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average. The permit application shall be submitted by January 1, 2015. Additional add-on NO_x control shall be installed and operational no later than the end of 2023 calendar year on Jim Bridger Units 1 and 2.

CHAPTER 6, SECTION 4 – PREVENTION OF SIGNIFICANT DETERIORATION (PSD):

PacifiCorp's Jim Bridger Power Plant is a "major emitting facility" under Chapter 6, Section 4, of the Wyoming Air Quality Standards and Regulations because emissions of a criteria pollutant are greater than 100 tpy for a listed categorical source. PacifiCorp should comply with the permitting requirements of Chapter 6, Section 4 as they apply to the installation of controls determined to meet BART.

CHAPTER 5, SECTION 2 – NEW SOURCE PERFORMANCE STANDARDS (NSPS):

The installation of controls determined to meet BART will not change New Source Performance Standard applicability for Jim Bridger Units 1-4.

CHAPTER 5, SECTION 3 – NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS (NESHAPs) AND CHAPTER 6, SECTION 6 – HAZARDOUS AIR POLLUTANT (HAP) EMISSIONS AND MAXIMUM AVAILABLE CONTROL TECHNOLOGY (MACT):

The installation of controls determined to meet BART will not change Nation Emission Standards For Hazardous Air Pollutants applicability for Jim Bridger Units 1-4.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Jim Bridger Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-1-120-2, was issued for the facility on September 6, 2005. In accordance with Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations (WAQSR), PacifiCorp will need to modify their operating permit to include changes authorized in this permitting action.

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[5] 40 CFR 51.308(d)(1)(i)(A).

CONCLUSION:

The Division is satisfied that PacifiCorp's Jim Bridger Power Plant will comply with all applicable Wyoming Air Quality Standards and Regulations. The Division proposes to issue a BART Air Quality Permit for modification of the Jim Bridger Power Plant to install new LNB with separated OFA and install FGC in combination with the existing ESP on Units 1-4 to meet the statutory requirements of BART. Jim Bridger Units 3 and 4 shall be equipped with SCR before December 31, 2015 and December 31, 2016, respectively, for the Long-Term Strategy of the Wyoming §308 Regional Haze State Implementation Plan.

In accordance with Long-Term Strategy, PacifiCorp shall submit an application to install additional add-on NO_x control on Jim Bridger Units 1 and 2 that achieves an emission rate, on an individual unit basis, at or below 0.07 lb/MMBtu on a 30-day rolling average by January 1, 2015. It shall include an analysis of the four statutory factors and the associated visibility impacts from the application of each proposed NO_x control. Additional add-on NO_x control shall be installed and operational no later than the end of 2023 calendar year on Units 1 and 2.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Jim Bridger Power Plant with the following conditions:

1. Authorized representatives of the Division of Air Quality be given permission to enter and inspect any property, premise or place on or at which an air pollution source is located or is being constructed or installed for the purpose of investigating actual or potential sources of air pollution, and for determining compliance or non-compliance with any rules, standards, permits or orders.

2. All substantive commitments and descriptions set forth in the application for this permit, unless superseded by a specific condition of this permit, are incorporated herein by this reference and are enforceable as conditions of this permit.

3. That PacifiCorp shall modify their Operating Permit in accordance with Chapter 6, Section 9(e)(iv) and Chapter 6, Section 3 of the WAQSR.

4. All notifications, reports and correspondence associated with this permit shall be submitted to the Stationary Source Compliance Program Manager, Air Quality Division, 122 West 25th Street, Cheyenne, WY 82002 and a copy shall be submitted to the District Engineer, Air Quality Division, 510 Meadowview Drive, Lander, WY 82520.

5. Effective upon completion of the performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Jim Bridger Units 1 through 4 shall not exceed the levels below. The NO_x limits shall apply during all operating periods. PM/PM_{10} lb/hr and tpy limits shall apply during all operating periods. PM/PM_{10} lb/MMBtu limits shall apply during all operating periods except startup. Startup begins with the introduction of fuel into the boiler and ends no later than the point in time when two (2) pulverizers (coal mills) have been placed into service and the flue gas temperature at the inlet ducts to the electrostatic precipitator reaches a temperature of 220 °F, as defined as the average flue gas outlet temperature from the air preheaters.

Units	Pollutant	lb/MMBtu	lb/hr	tpy
2, 3, & 4	NO_x	0.26 (30-day rolling)	1,560 (30-day rolling)	6,833
1, 2, 3,& 4	PM/PM_{10} [(a)]	0.030	180	788

[(a)] Filterable portion only

6. That no later than 90 days after permit issuance NO_x performance tests shall be conducted on Units 2-4 and PM/PM_{10} performance tests shall be conducted on Units 1-4 and a written report of the results be submitted. If a maximum design rate is not achieved within 90 days of permit issuance, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

7. Effective upon completion of the initial performance tests to verify the emission levels below, as required by Condition 8 of this permit, emissions from Jim Bridger Unit 1 shall not exceed the levels below. The limits shall apply during all operating periods.

Pollutant	lb/MMBtu	lb/hr	tpy
NO_x	0.26 (30-day rolling)	1,560 (30-day rolling)	6,833

8. That initial NO_x performance tests shall be conducted on Unit 1after the installation of low NO_x burners and separated overfire air in accordance with Chapter 6, Section 2(j) of the WAQSR, within 30 days of achieving a maximum design rate but not later than 90 days following initial start-up, and a written report of the results be submitted. If a maximum design rate is not achieved within 90 days of start-up, the Administrator may require testing be done at the rate achieved and again when a maximum rate is achieved.

9. Performance tests shall consist of the following:

Coal-fired Boilers (Units 1 through 4):

NO_x Emissions – Compliance with the NO_x 30-day rolling average shall be determined using a continuous emissions monitoring system (CEMS) certified in accordance with 40 CFR part 60.

PM/PM_{10} Emissions – Testing shall follow 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5.

Testing required by the Chapter 6, Section 3, Operating Permit may be submitted to satisfy the testing required by this condition.

10. Prior to any testing required by this permit, a test protocol shall be submitted to the Division for approval, at least 30 days prior to testing. Notification should be provided to the Division at least 15 days prior to any testing. Results of the tests shall be submitted to this office within 45 days of completing the tests.

11. PacifiCorp shall 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 WAQSR.

12. Compliance with the NO_x limits set forth in this permit for the coal-fired boilers (Jim Bridger Units 1-4) shall be determined with data from the continuous monitoring systems required by 40 CFR Part 75 as follows:

a. Exceedances of the NO_x limits shall be defined as follows:

i. Any 30-day rolling average of NO_x emissions which exceeds the lb/MMBtu limits calculated in accordance with the compliance provisions and monitoring requirements of §60.48Da and §60.49Da. The definition of "boiler operating day" shall be consistent with the definition as specified in 40 CFR part 60, subpart Da.

ii. Any 30-day rolling average calculated using valid data (output concentration and average hourly volumetric flowrate) from the existing CEM equipment which exceeds the lb/hr NO_x limit established in this permit. Valid data shall meet the requirements of WAQSR, Chapter 5, Section 2(j) and follow the compliance provisions and monitoring requirements of §60.48Da and §60.49Da. The 30-day average emission rate shall be calculated as the arithmetic average of hourly emissions with valid data during the previous 30-day period. The definition of "boiler operating day" shall be consistent with the definition as specified in 40 CFR part 60, subpart Da.

b. PacifiCorp shall comply with all reporting and record keeping requirements as specified in WAQSR, Chapter 5, Section 2(g) and 40 CFR part 60, subpart D. All excess emissions shall be reported using the procedures and reporting format specified in WAQSR, Chapter 5, Section 2(g).

13. PacifiCorp shall use EPA's Clean Air Markets reporting program to convert the monitoring system data to annual emissions. PacifiCorp shall provide substituted data according to the missing data procedures of 40 CFR, Part 75 during any period of time that there is not monitoring data. All monitoring data must meet the requirements of WAQSR, Chapter 5, Section 2(j).

14. Compliance with the PM/PM_{10} limits set forth in this permit for the coal-fired boilers (Jim Bridger Units 1-4) shall be determined with data from testing for PM conducted annually, or more frequently as specified by the Administrator, following 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5. Testing required by the Chapter 6, Section 3, Operating Permit may be submitted to satisfy the testing required by this condition.

15. Records required by this permit shall be maintained for a period of at least five (5) years and shall be made available to the Division upon request.

16. PacifiCorp shall install new low NO_x burners with separated overfire air on Unit 1, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 8 no later than December 31, 2010.

17. PacifiCorp shall submit a permit application for the installation of selective catalytic reduction (SCR) on Jim Bridger Units 3 and 4 to the Division under the Long-Term Strategy of the Wyoming §308 Regional Haze State Implementation Plan. This application shall address SCR as a system of continuous emissions reduction achieving 0.07 lb/MMBtu on a 30-day rolling average as measured by a certified CEM. SCR shall be installed and operational on Jim Bridger Unit 3 by December 31, 2015 and on Jim Bridger Unit 4 by December 31, 2016.

18. PacifiCorp shall submit a permit application for the installation of additional add-on NO_x control on Jim Bridger Units 1 and 2 to the Division no later than January 1, 2015, under the Long-Term Strategy of the Wyoming §308 Regional Haze State Implementation Plan. It shall include an analysis of the four statutory factors and the associated visibility impacts from the application of each proposed NO_x control and resulting emission levels. This application shall address each add-on NO_x control as a system of continuous emissions reduction achieving the lowest viable NO_x emission, not to exceed a maximum of 0.07 lb/MMBtu on a 30-day rolling average as measured by a certified CEM. Additional add-on NO_x control shall be installed and operational on both Jim Bridger Unit 1 and Unit 2 no later than December 31, 2023.

Appendix A
Facility Location

N
W E
S

0 2 4 8 Miles

PacifiCorp
Jim Bridger Power Plant
Section 3, T20N, R101W
Sweetwater County, Wyoming

Department of Environmental Quality
WYOMING

AQD Jim Bridger BART
002633

Department of Environmental Quality

To protect, conserve and enhance the quality of Wyoming's environment for the benefit of current and future generations.

Dave Freudenthal, Governor

John Corra, Director

May 28, 2009

Mr. William K. Lawson
Environmental Manager
PacifiCorp
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

CERTIFIED – RETURN RECEIPT REQUESTED
Notice of Publication
Permit Application AP-6040

Dear Mr. Lawson:

The Division of Air Quality has completed its initial evaluation of your permit application to address Best Available Retrofit Technology (BART) for four units, under the Regional Haze Rule.

A copy of the public notice and of our evaluation is enclosed for your information. I would recommend that you review the proposed permit conditions associated with the Division's proposed approval. The Public Notice will appear in the June 3, 2009 issue of the Daily Rocket Miner, Rock Springs, Wyoming.

A copy of our evaluation and of your permit application will be kept on file for a sixty (60) day public inspection and comment period. At the end of this period, we will consider all comments made concerning your application and a final decision will be made on your application.

Per Chapter 6, Section 2(o) of the Wyoming Air Quality Standards & Regulations an initial billing is attached for the costs incurred by the Department in reviewing the application. Payment of the initial fee is required prior to permit issuance. An additional fee and any adjustments required to the initial fee shall be made upon permit issuance to cover any additional costs associated with final permit issuance, including costs of public notice, holding public hearings, reviewing public comments and final issuance of permit.

If you should have any questions concerning this matter, please feel free to contact me.

Sincerely,

Andrew Keyfauver
Andrew Keyfauver
NSR Permit Engineer
Air Quality Division

cc: Tony Hoyt
Bob Gill

Herschler Building • 122 West 25th Street • Cheyenne, WY 82002 • http://deq.state.wy.us

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Mr. William K. Lawson
Evironmental Manager
PacifiCorp
1407 W. North Temple, Suite 330
Salt Lake City, UT 84116

BART

2. Article Number (Transfer from service label) 7008 0500 0000 5531 1270

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