UAE Exhibit RR 2.1

HOWARD GEBHART RESUME

D. HOWARD GEBHART

Résumé

Environmental Compliance Section Manager

Summary of Qualifications

Mr. Gebhart has over 25 years' experience in air quality permitting and compliance specializing in issues affecting regulated industries. His expertise lies with permitting and support of the ethanol industry. He manages the environmental compliance section at Air Resource Specialists, Inc., and provides technical studies and evaluations; and prepares models, client permit applications, and air emission calculations. He is well experienced in working with the federal Clean Water Act, Clean Air Act, Recourse Conservation and Recovery Act (RCRA), and many similar programs enacted in many states throughout the U.S.

Professional Experience

- Provides technical studies and evaluations, prepares models, and prepares permit applications for a wide variety of clients.
- Provides emissions inventories, dispersion modeling, regulatory analysis and interpretation, and air compliance auditing.
- Prepares applications for new source permits under federal Prevention of Significant Deterioration (PSD) and state construction and operating permit programs.
- Provides technical studies supporting Environmental Impact Statements (EISs) and Environmental Assessments (EAs) under the National Environmental Policy Act (NEPA).
- Manages the Environmental Compliance Section team.
- Performs permitting and air quality studies for bio-fuel (ethanol), oil & gas /petroleum, mining and minerals, semiconductor, and National Park Service projects, with experience representing both government and private clients.
- Performs air pathway evaluations for releases of hazardous air pollutants from Superfund sites, hazardous waste sites, and incinerators.
- Models the potential consequences of accidental releases of hazardous materials.

Work History

1997-Present	Environmental Compliance Section Manager, Air Resource Specialists, Inc., Fort Collins, CO
1993-1996	District Manager, Trinity Consultants, Inc., Fort Collins, CO
1981-1993	Senior Air Quality Scientist, ENSR Consulting & Engineering, Inc., Fort Collins, CO
1979-1981	Utah Department of Health, Bureau of Air Quality, Salt Lake City, UT

Educational Background

M.S., Meteorology, University of Utah, 1979
B.S., Professional Meteorology, Saint Louis University, 1976

Memberships

Air & Waste Management Association
National Weather Association
Colorado Mining Association
Nevada Mining Association
Nebraska Industrial Council on Environment

UAE Exhibit RR 2.3

WDEQ BART ANALYSIS - NAUGHTON

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6042

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Naughton Power Plant
FACILITY LOCATION:	Sections 32 and 33, T21N, R116W UTM Zone: 12 Easting: 533,450 m, Northing: 4,622,700 m Lincoln County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Angie Skinner, Plant Managing Director
MAILING ADDRESS:	P.O. Box 191 Kemmerer, WY 83101
TELEPHONE NUMBER:	(307) 828-4211
REVIEWERS:	Cole Anderson, Air Quality Engineer James (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 February 12, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), PacifiCorp submitted three (3) BART applications, one for each existing coal-fired boiler at the Naughton Power Plant. A map showing the location of PacifiCorp's Naughton Power Plant is attached as Appendix A.

October 16, 2007, PacifiCorp submitted updated applications for each of the three (3) Naughton units subject to BART. Additional modeling performed after the February 12, 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 three (3) Naughton units.

March 31, 2008, PacifiCorp submitted addendums to each of the BART applications for Naughton Units 1-3. 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 three (3) coal-fired boilers at the Naughton Power Plant. The information addresses the type of coal fired in the three 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 three existing coal-fired boilers at PacifiCorp's Naughton 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 Naughton Power Plant is comprised of three (3) pulverized coal-fired units with a total net generating capacity of 700 megawatts (MW). Naughton Unit 1 generates a nominal 160 MW and commenced operation in 1963. The boiler on Unit 1 is tangential fired and was manufactured by Combustion Engineering (now ALSTOM). The unit uses good combustion practices (GCP) to control NO_x emissions. It was originally constructed with a Research Cottrell mechanical dust collector to control particulate matter emissions, and in 1974 a Lodge Cottrell electrostatic precipitator (ESP) was added to further reduce particulate emissions. SO_2 emissions are controlled using low sulfur coal to maintain emissions below 1.2 lb per million British thermal units (MMBtu). Naughton Unit 2 generates a nominal 210 MW and commenced operation in 1968. The boiler on Unit 2 is also tangential fired and was manufactured by ALSTOM. The unit uses GCP to control NO_x emissions. It was originally constructed with a United Conveyor mechanical dust collector to control particulate matter emissions and in 1976 a Lodge Cottrell ESP was added to further reduce particulate emissions. SO_2 emissions are controlled using low sulfur coal to maintain emissions below 1.2 lb/MMBtu. Naughton Unit 3 generates a nominal 330 MW and commenced operation in 1971. The boiler on Unit 3 is tangential fired and was manufactured by ALSTOM. The unit was retrofitted with ALSTOM LCCFS II low NO_x burners (LNB) in 1999. Particulate emissions are controlled using a Buell weighted wire ESP and flue gas conditioning (FGC). SO_2 emissions are controlled using low sulfur coal and a UOP LLC two-tower sodium based wet flue gas desulfurization (WFGD) system that was installed in 1997.

Table 1: Naughton Units 1-3 Pre-2005 Emission Limits [(a)]

Source	Firing Rate (MMBtu/hour)	Existing Controls	NO_x (lb/MMBtu)	SO_2 (lb/MMBtu)	PM/PM_{10} (lb/MMBtu) [(c)(d)]
Unit 1	1,850	GCP, ESP	0.75 (3-hour block) 0.58 (annual) [(b)]	1.2 (2-hour block)	0.24
Unit 2	2,400	GCP, ESP	0.75 (3-hour block) 0.54 (annual) [(b)]	1.2 (2-hour block)	0.23
Unit 3	3,700	LNB, ESP, FGC, WFGD	0.75 (3-hour block) 0.49 (annual) [(b)]	0.5 (2-hour block)	0.21

[(a)] Emissions taken from Operating Permit 31-121.
[(b)] Limit established through the 40 CFR part 76 (Acid Rain Program).
[(c)] Based on the equation: $0.8963/I^{0.1743}$ lb/MMBtu of heat input where I=boiler heat input in MMBtu/hr.
[(d)] Averaging period is 1 hour as determined by the appropriate test method.

PacifiCorp recently received an Air Quality permit to modify the three Naughton units. Units 1 and 2 will be equipped with new state-of-the-art low NO_x systems with advanced overfire air (OFA) and flue gas conditioning systems to help improve the particulate removal efficiency of the existing ESPs on each of the units. New wet flue gas desulfurization systems will be installed on Naughton Units 1 and 2. The existing ESP on Naughton Unit 3 will be replaced with a new full-scale fabric filter (FF) at which time the existing FGC system will be removed. Table 2 lists the new emission limits for the Naughton units. They become effective after the corresponding controls are installed and the applicable initial performance tests are completed.

Table 2: Naughton Units 1-3 Proposed Emission Limits [(a)]

Source	Permitted Controls	NO_x	SO_2	PM/PM_{10}
Unit 1	New LNB with advanced OFA, FGC, ESP, WFGD	0.75 lb/MMBtu (3-hr rolling) 0.26 lb/MMBtu (12-month rolling) 481 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 1.2 lb/MMBtu (2-hr rolling) 833 lb/hr (3-hr block)	0.042 lb/MMBtu [(b)] 78 lb/hr [(b)] 340 tpy [(b)]
Unit 2	New LNB with advanced OFA, FGC, ESP, WFGD	0.75 lb/MMBtu (3-hr rolling) 0.26 lb/MMBtu (12-month rolling) 624 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 1.2 lb/MMBtu (2-hr rolling) 1,080 lb/hr (3-hr block)	0.054 lb/MMBtu [(b)] 130 lb/hr [(b)] 568 tpy [(b)]
Unit 3	Existing LNB with OFA, FF, WFGD	0.75 lb/MMBtu (3-hr rolling) 0.45 lb/MMBtu (12-month rolling) 1,665 lb/hr (12-month rolling)	0.5 lb/MMBtu (2-hour rolling) 1,850 lb/hr (3-hr block)	0.015 lb/MMBtu (24-hour block) 56 lb/hr (24-hour block) 243 tpy

[(a)] Emissions limits taken from recent New Source Review construction permit for Naughton Units 1-3.
[(b)] Averaging period is 1 hour as determined by 40 CFR 60.46 and EPA Reference Test Methods 1-4 and 5.

A construction schedule for installing new LNB with advanced OFA, FGC, and WFGD on Naughton Units 1 and 2, and a full-scale FF on Unit 3 was submitted in the permit application. The installation of FGC on Units 1 and 2 was originally proposed to occur in 2008, however since the authorization to install the controls is dependent on the issuance of the pending Air Quality permit, installation will be delayed until permit issuance. A construction summary is provided in Table 3.

Table 3: Upgrades to Naughton Units 1-3

Source	NO_x Control Equipment, Installation year	SO_2 Control Equipment, Installation year	PM/PM_{10} Control Equipment, Installation year
Unit 1	New LNB with OFA, 2012	WFGD, 2012	FGC, 2009 [(a)]
Unit 2	New LNB with OFA, 2011	WFGD, 2011	FGC, 2009 [(a)]
Unit 3	LNB with OFA, Existing	WFGD, Existing	FF, 2014

[(a)] PacifiCorp originally proposed installing FGC on Units 1 and 2 in 2008, however the installation date has been moved to the date of permit issuance.

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

[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."

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 1-3) at the Naughton Power Plant thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

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

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

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.

PacifiCorp's Naughton Power Plant consists of three units with a total generating capacity of 700 MW. Naughton Unit 1, generating nominal 160 MW, Unit 2, generating a nominal 210 MW, and Unit 3, generating a nominal 330 MW, are tangentially fired pulverized coal boilers. SO_2 emissions from Units 1 and 2 are controlled by burning low sulfur coal without the use of add-on controls. Unit 3 SO_2 emissions are control using an existing UOP LLC two-tower sodium based WFGD system that was installed in 1997. NO_x emissions from Units 1 and 2 are not controlled using either NO_x combustion controls (LNB) or add-on controls. ALSTOM LCCFS II LNB were installed on Unit 3 in 1999. Presumptive SO_2 limits of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limits based on unit type and coal type, do not apply to the three Naughton units because the total generating capacity of the facility is below 750 MW. 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 Naughton Units 1-3 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.

[4] Ibid. (70 Federal Register 39171).

Figure 1

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

Class	Group	Fixed Carbon Limits, % (Dry, Mineral-Matter-Free Basis)		Volatile Matter Limits, % (Dry, Mineral-Matter-Free Basis)		Calorific Value Limits, Btu/lb (Moist,[b] Mineral-Matter-Free Basis)		Agglomerating Character
		Equal or Greater Than	Less Than	Greater Than	Equal or Less Than	Equal or Greater Than	Less Than	
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 Naughton units will not be able to meet presumptive NO_x levels of 0.15 lb/MMBtu for tangential boilers firing sub-bituminous coal. Air Quality Permit MD-1552 authorized the installation of new ALSTOM TFS 2000™ LNB with separated OFA systems on all four units at PacifiCorp's Jim Bridger Power Plant. Units 2-4 are currently equipped with this combustion control system. Recent monitoring data supplied by the continuous emissions monitoring systems on the three units indicate that a NO_x emission rate of 0.15 lb/MMBtu is not achievable on a continuous basis. Fuel characteristics of the coal burned at the Naughton Power Plant are similar to the coal fed to the Jim Bridger units, which are also tangentially-fired boilers. In the absence of site-specific operational data, it is reasonable to anticipate NO_x reductions from the application of new state-of-the-art LNB on the Naughton units will be comparable to the Jim Bridger units.

Naughton was included in EPA's presumptive limits analyses for NO_x and SO_2. As a result of the final publication of 40 CFR part 51, Appendix Y establishing BART presumptive limits for facilities with a generating capacity greater than 750 MW, Naughton is not subject to presumptive limits. 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. And while PacifiCorp addressed applicability of presumptive NO_x limits for the Naughton units in their BART applications, the effectiveness of the proposed combustion control for removing NO_x was evaluated in this analysis 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 advanced OFA, (2) rotating opposed fire air (ROFA), (3) selective non-catalytic reduction (SNCR), and (4) selective catalytic reduction (SCR). LNB with advanced 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 Advanced 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 advanced 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 advanced 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 advanced 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 advanced 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 Naughton units and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with advanced OFA on Naughton Units 1 and 2 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 Naughton Units 1 and 2 PacifiCorp states: "PacifiCorp has indicated that this rate [0.24 lb/MMBtu] corresponds to a vendor guarantee plus an added operating margin, 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. Naughton Unit 3 is equipped with LNB and has demonstrated compliance with a 0.40 lb/MMBtu NO_x emission rate. PacifiCorp reviewed the option of tuning the existing LNB to further reduce NO_x emissions and indicates that lowering emissions to 0.35 lb/MMBtu is possible. In the March 26, 2008 Addendum for Unit 3, PacifiCorp proposed a permitted rate of 0.37 lb/MMBtu to account for unforeseen operational issues and site specific challenges.

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boilers at the Naughton Power Plant with Mobotec's ROFA. Mobotec analyzed the operation of existing burners and OFA ports. Typically the existing burner 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 0.24 lb/MMBtu was achievable on Units 1 and 2 using ROFA technology. Unit 3 may achieve 0.26 lb/MMBtu. PacifiCorp added an additional operating margin to each anticipated emission rate of 0.02 lb/MMBtu to account for site specific issues, including the type of coal burned in the boilers, for total proposed emission rates of 0.26 lb/MMBtu for Units 1 and 2, and 0.28 lb/MMBtu for Unit 3.

S&L evaluated emission reductions associated with installing SNCR in addition to retrofitting the boilers with LNB with advanced OFA. Based on installing LNB with OFA capable of achieving a NO_x emission rate of 0.26 lb/MMBtu on Units 1 and 2, S&L concluded that SNCR can reduce emissions by 20% resulting in a projected emission rate of 0.21 lb/MMBtu. Installing SNCR on Unit 3 can reduce the anticipated rate of 0.37 lb/MMBtu by 20% resulting in a NO_x emission rate of 0.30 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 Naughton 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 new LNB with advanced OFA and SCR, PacifiCorp concluded the Naughton units could achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 4: NO_x Emission Rates Per Boiler

Control Technology	Unit 1 Resulting NO_x Emission Rate (lb/MMBtu)	Unit 2 Resulting NO_x Emission Rate (lb/MMBtu)	Unit 3 Resulting NO_x Emission Rate (lb/MMBtu)
Existing Burners	0.58 [(a)]	0.54 [(a)]	0.45 [(b)]
Tune Existing LNB	--	--	0.37
New LNB with advanced OFA	0.26	0.26	--
Existing Burners with ROFA	0.26	0.26	0.28
New LNB with advanced OFA and SNCR	0.21	0.21	0.30
New LNB with advanced OFA and SCR	0.07	0.07	0.07

[(a)] Annual averaged NO_x emissions listed in Operating Permit 31-121.
[(b)] Annual averaged NO_x emission listed in Operating Permit 3-2-121.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts associated with installing each of the proposed control technologies. Installing new LNB with advanced OFA on Naughton Units 1 and 2 and tuning the existing LNB on Unit 3 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 a significant energy impact on Naughton. One (1) 1,900 horsepower (hp) ROFA fan on Unit 1, one (1) 3,500 hp ROFA fan on Unit 2, and one (1) 6,000 hp ROFA fan on Unit 3 are required to induct a sufficient volume of air into each boiler to cause rotation of the combustion air throughout the boiler. The annual energy impact from operating the proposed ROFA fans is 11,200 Mega Watt-hour (MW-hr), 20,600 MW-hr, and 35,300 MW-hr for Units 1, 2, and 3, respectively.

PacifiCorp determined the SNCR system would require between 200 kilo Watt (kW) and 300 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 Naughton Power Plant ranged from approximately 1.0 MW to 2.0 MW.

PacifiCorp evaluated the environmental impacts from the proposed NO_x control technologies. Installing LNB with advanced 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 Naughton Units 1-3 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 Naughton Units 1-3 are summarized in the following tables.

Table 5: Naughton Unit 1 Economic Costs

Cost	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$9,600,000	$9,068,746	$17,526,855	$94,600,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$913,248	$862,710	$1,667,330	$8,999,298
Annual O&M Costs	$0	$80,000	$679,764	$305,033	$1,231,912
Annual Cost of Control	$0	$993,248	$1,542,474	$1,972,363	$10,231,210

Table 6: Naughton Unit 1 Environmental Costs

	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.58	0.26	0.26	0.21	0.07
Annual NO_x Emission (tpy) [(a)]	4,230	1,896	1,896	1,531	510
Annual NO_x Reduction (tpy)	N/A	2,334	2,334	2,699	3,720
Annual Cost of Control	$0	$993,248	$1,542,474	$1,972,363	$10,231,210
Cost per ton of Reduction	N/A	$426	$661	$731	$2,750
Incremental Cost per ton of Reduction	N/A	$426	$661 [(b)]	$1,178	$8,089

[(a)] Annual emissions based on individual heat input rate of 1,850 MMBtu/hr for 7,884 hours of operation per year.
[(b)] Incremental cost cannot be calculated as the reduced tons of NO_x are anticipated to be the same as installing new LNB with advanced OFA.

Table 7: Naughton Unit 2 Economic Costs

Cost	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$9,100,000	$10,586,222	$19,878,765	$115,900,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$865,683	$1,007,067	$1,891,067	$11,025,567
Annual O&M Costs	$0	$80,000	$1,148,862	$369,890	$1,639,352
Annual Cost of Control	$0	$945,683	$2,155,929	$2,260,957	$12,664,919

Table 8: Naughton Unit 2 Environmental Costs

	Existing Burners	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.54	0.26	0.26	0.21	0.07
Annual NO_x Emission (tpy) [(a)]	5,109	2,460	2,460	1,987	662
Annual NO_x Reduction (tpy)	N/A	2,649	2,649	3,122	4,447
Annual Cost of Control	$0	$945,683	$2,155,929	$2,260,957	$12,664,919
Cost per ton of Reduction	N/A	$357	$814	$724	$2,848
Incremental Cost per ton of Reduction	N/A	$357	$814 [(b)]	$222	$7,852

[(a)] Annual emissions based on individual heat input rate of 2,400 MMBtu/hr for 7,884 hours of operation per year.
[(b)] Incremental cost cannot be calculated as the reduced tons of NO_x are anticipated to be the same as installing new LNB with advanced OFA.

Table 9: Naughton Unit 3 Economic Costs

Cost	Existing LNB	Tuning Existing LNB	Existing LNB and SNCR	Existing LNB with ROFA	Existing LNB and SCR
Control Equipment Capital Cost	$0	$1,000,000	$15,788,530	$14,747,608	$136,800,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$95,130	$1,501,963	$1,402,940	$13,013,784
Annual O&M Costs	$0	$0	$414,076	$1,882,074	$2,668,918
Annual Cost of Control	$0	$95,130	$1,916,039	$3,285,014	$15,682,702

Table 10: Naughton Unit 3 Environmental Costs

	Existing LNB	Tuning Existing LNB	Existing LNB and SNCR	Existing LNB with ROFA	Existing LNB and SCR
NO_x Emission Rate (lb/MMBtu)	0.45	0.37	0.30	0.28	0.07
Annual NO_x Emission (tpy) [(a)]	6,563	5,397	4,376	4,084	1,021
Annual NO_x Reduction (tpy)[)]	N/A	1,167	2,188	2,480	5,542
Annual Cost of Control	$0	$95,130	$1,916,039	$3,285,014	$15,682,702
Cost per ton of Reduction	N/A	$82	$876	$1,325	$2,830
Incremental Cost per ton of Reduction	N/A	$1,783	$4,688	$4,049	$1,783

[(a)] Annual emissions based on individual heat input rate of 3,700 MMBtu/hr for 7,884 hours of operation per year.

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 for Units 1 and 2 by modeling LNB with advanced OFA and LNB with advanced OFA and SCR. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Unit 3 by modeling tuning the existing LNB and OFA and tuning the existing LNB and OFA and installing SCR. While the installation of SNCR and 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 Naughton Units 1-3, 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 28-30, on pages 37-39, list the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Naughton Units 1 and 2 are currently equipped with mechanical dust collectors and electrostatic precipitators to control PM emissions from the boilers to 0.056 lb/MMBtu and 0.064 lb/MMBtu, respectively. Unit 3 is equipped with an ESP using FGC to control PM emission to 0.094 lb/MMBtu. As discussed below in more detail, 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. Three PM control technologies were analyzed for application on the three Naughton 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 Naughton Units 1 and 2. PacifiCorp analyzed the impact of installing a full-scale fabric filter on Unit 3.

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 hot-side 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.

Naughton Units 1 and 2 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 0.056 lb/MMBtu, 0.064 lb/MMBtu, and 0.094 lb/MMBtu for Units 1, 2, and 3, 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 ESP and augmenting the control. Installing FGC on Units 1 and 2 can improve the PM removal efficiencies on the existing ESPs down to 0.040 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 63% resulting in a PM emission rate of 0.015 lb/MMBtu. Demolishing the existing ESPs and installing a new full-scale fabric filter on Units 1 and 2 is anticipated to control emissions down to the same PM emission level, 0.015 lb/MMBtu, as installing a polishing fabric filter downstream of the existing ESP.

Naughton Unit 3 is currently equipped with an ESP and FGC system. PacifiCorp analyzed the impact of upgrading the existing FGC and resulting impact of installing a new full-scale fabric filter. PacifiCorp's proposed emission rates for each technology as applied to Naughton Units 1-3 are shown in Table 11.

Table 11: PM_{10} Emission Rates Per Boiler

Control Technology	Resulting PM_{10} Emission Rate (lb/MMBtu)
Existing ESP	0.056, 0.064, 0.094 [a]
Existing ESP with FGC	0.040
Existing ESP and New Polishing Fabric Filter [b]	0.015
Full-scale Fabric Filter [c]	0.015

[a] Current achievable PM_{10} emissions from Unit 1, 2, and 3, respectively.
[b] Applied to Naughton Units 1 and 2.
[c] Applied to Naughton Unit 3.

<u>PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS</u>

PacifiCorp evaluated the energy impact of installing COHPAC on Units 1 and 2. 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 1.0 MW of power, equating to an annual power usage of approximately 8,000 MW-hr for Unit 1 and 1.4 MW of power, equal to an annual power usage of approximately 10,900 MW-hr for Unit 2. Installing a full-scale fabric filter on Unit 3 would require approximately 2.1 MW of power, equating to an annual power usage of approximately 16,240 MW-hr.

Installing FGC on Units 1 and 2 will require a minimal amount of additional power, about 100 kW which equates to an annual power consumption of 400 kW-hr. Upgrading the existing ESP on Unit 3 is not anticipated to require additional power.

PacifiCorp evaluated the environmental impacts associated with the proposed installation of FGC and COHPAC on Units 1and 2, and did not anticipate negative environmental impacts from the addition of either of these PM control technologies. Upgrading the existing FGC and installing a new full-scale fabric filter on Unit 3 are not anticipated to have significant negative environmental impacts.

PacifiCorp anticipates operating Naughton Units 1-3 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 Naughton Units 1-3 are summarized in the following tables

Table 12: Naughton Unit 1 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	Existing ESP With New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$1,298,352	$29,798,898
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$123,512	$2,834,769
Annual O&M Costs	$0	$77,319	$601,825
Annual Cost of Control	$0	$200,831	$3,436,594

Table 13: Naughton 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)	0.056	0.040	0.015
Annual PM_{10} Emission (tpy) [(a)]	408	292	109
Annual PM_{10} Reduction (tpy)	N/A	117	299
Annual Cost of Control	$0	$200,831	$3,436,594
Cost per ton of Reduction	N/A	$1,721	$11,494
Incremental Cost per ton of Reduction	N/A	$1,721	$17,748

[(a)] Annual emissions based on unit heat input rate of 1,850 MMBtu/hr and 7,884 hours of operation per year.

Table 14: Naughton 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	$1,298,352	$34,898,710
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$123,512	$3,319,914
Annual O&M Costs	$0	$91,904	$781,791
Annual Cost of Control	$0	$215,416	$4,101,705

Table 15: Naughton 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)	0.064	0.040	0.015
Annual PM_{10} Emission (tpy) [(a)]	605	378	142
Annual PM_{10} Reduction (tpy)	N/A	227	464
Annual Cost of Control	$0	$215,416	$4,101,705
Cost per ton of Reduction	N/A	$949	$8,848
Incremental Cost per ton of Reduction	N/A	$949	$16,431

[(a)] Annual emissions based on unit heat input rate of 2,400 MMBtu/hr and 7,884 hours of operation per year.

Table 16: Naughton Unit 3 Economic Costs

Cost	Existing ESP	Existing ESP With Flue Gas Conditioning	New Full-scale Fabric Filter
Control Equipment Capital Cost	$0	$13,299,508	$121,000,000
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,265,182	$11,510,730
Annual O&M Costs	$0	$0	$1,120,813
Annual Cost of Control	$0	$1,265,182	$12,631,543

Table 17: Naughton Unit 3 Environmental Costs

	Existing ESP	Existing ESP With Flue Gas Conditioning	New Full-scale Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.094	0.040	0.015
Annual PM_{10} Emission (tpy) [a]	1,371	583	219
Annual PM_{10} Reduction (tpy)	N/A	788	1,152
Annual Cost of Control	$0	$1,265,182	$12,631,543
Cost per ton of Reduction	N/A	$1,606	$10,963
Incremental Cost per ton of Reduction	N/A	$1,606	$31,172

[a] Annual emissions based on unit heat input rate of 3,700 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Units 1 and 2 are not reasonable. The cost effectiveness and incremental cost effectiveness of applying a new full-scale fabric filter to Unit 3 are also not reasonable. However, the control was included in the final step in the PM/PM_{10} BART determination process for Naughton Units 1-3, 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 28-30, on pages 37-39, 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 Naughton Units 1-3. 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 using the existing ESP, installing dry FGD using a polishing fabric filter, and installing wet FGD using the existing ESP on Units 1 and 2. Upgrading the existing wet waste sodium liquor FGD system with the existing ESP and upgrading the existing wet FGD including switching to a soda ash reagent with the existing ESP were two SO_2 control options analyzed by PacifiCorp for Unit 3.

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.

Naughton Units 1 and 2 currently achieve emission rates of 1.20 lb/MMBtu. Both low sulfur coal, 0.58% sulfur by weight, and high sulfur coal, 1.02% by weight, are used to fuel the boilers in the Naughton units. Installing a new dry FGD system and utilizing the existing ESP on Naughton Units 1 and 2 may reduce uncontrolled SO_2 emissions from each unit by 85%. Resulting SO_2 emission rates for Units 1 and 2 would be 0.18 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and 0.41 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight. Replacing the existing ESP with a new full-scale fabric filter will increase the SO_2 removal efficiency to 87.5%. SO_2 emission rates for Units 1 and 2 from the new fabric filter would be 0.15 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and 0.21 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight.

As mentioned earlier in this analysis, BART presumptive SO_2 levels do not apply to Naughton. However, PacifiCorp used the presumptive SO_2 levels for uncontrolled units, 95% emissions reduction or 0.15 lb/MMBtu, as a reference for comparison. PacifiCorp does not anticipate achieving presumptive SO_2 emission levels using dry FGD. The application of wet FGD on Units 1 and 2 is anticipated to lower SO_2 emissions to 0.10 lb/MMBtu, based on an average coal sulfur content of 0.58% by weight, and 0.15 lb/MMBtu, based on an average coal sulfur content of 1.02% by weight, which meet presumptive SO_2 levels.

The existing wet FGD system on Naughton Unit 3 reduces emissions by 83% to achieve a SO_2 emissions rate of 0.50 lb/MMBtu when burning high sulfur coal, 1.02% by weight. Wet FGD is a state-of-the-art SO_2 emissions control technology and continually improves over time. PacifiCorp evaluated potential changes to the existing wet FGD systems to improve the SO_2 removal efficiencies. Improving inlet gas distribution, adding a second tray to improve gas/liquid contact, and upgrading the reagent and waste solids systems are projected to reduce emissions by 90% to achieve an emission rate of approximately 0.21 lb/MMBtu. Switching to a refined soda ash reagent in the upgraded wet FGD system is anticipated to reduce uncontrolled emissions by 95%, resulting in a SO_2 emission rate of 0.10 lb/MMBtu. PacifiCorp's proposed emission rates for each SO_2 emission reduction technology applied to Naughton Units 1-3 are shown in Table 18.

Table 18: SO_2 Emission Rates Per Boiler [a]

Control Technology	Unit 1 SO_2 Emission Rate (lb/MMBtu)	Unit 2 SO_2 Emission Rate (lb/MMBtu)	Unit 3 SO_2 Emission Rate (lb/MMBtu)
Existing Uncontrolled	1.2	1.2	--
Existing Wet FGD	--	--	0.50
New Dry FGD with Existing ESP	0.41	0.41	--
New Dry FGD with Polishing Fabric Filter	0.21	0.21	--
New Wet FGD with Existing ESP	0.15	0.15	--
Upgraded Wet FGD with Waste Liquor	--	--	0.21
Upgraded Wet FGD with Soda Ash Reagent	--	--	0.10

[a] SO_2 emissions based on an average coal sulfur content of 1.02% by weight.

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of installing both dry FGD and wet FGD systems on Units 1 and 2. PacifiCorp noted that dry FGD systems using the existing ESP require the least amount of power. A dry FGD system using the existing ESP installed on Naughton Units 1 and 2 would require approximately 1.6 MW and 2.2 MW of power, respectively. Wet FGD would require approximately 2.4 MW and 3.3 MW of power for Units 1 and 2, respectively. Based on an annual operating factor of 90%, the cost savings of using dry FGD on Units 1 and 2 would equate to approximately 5,900 MW-hr and 8,300 MW-hr, respectively.

PacifiCorp estimates that upgrading the existing wet sodium FGD system on Naughton Unit 3 would require approximately 330 kW of additional power. Using a 90% annual operating factor, the annual power cost is 2,602 MW-hr.

There are no anticipated environmental impacts from upgrading the existing wet sodium FGD system on Naughton Unit 3 except for an incremental addition to scrubber waste disposal and makeup water requirement. Recycling the waste liquor into the scrubber would save on disposal of these materials and conserve resources.

PacifiCorp compared the environmental impacts of dry FGD versus wet FGD technology. PacifiCorp concluded that dry FGD has five significant environmental advantages over wet FGD. These advantages are taken directly from PacifiCorp's environmental analyses for SO_2 controls on Naughton Units 1 and 2 and listed below.

- <u>Sulfuric Acid Mist</u> Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet electrostatic precipitator (ESP) or hydrated lime injection when medium to high sulfur coal is burned in a unit to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.

- <u>Plume Buoyancy</u> Flue gas following a dry FGD system is not saturated with water (gas temperature 30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Because of the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.

- <u>Liquid Waste Disposal</u> There is no liquid waste from a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste, which may be contaminated with toxic metals (including mercury), requiring proper disposal.

- Solid Waste Disposal The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge must be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant to be disposed.

- Makeup Water Requirements Dry FGD has advantages over a wet scrubber, producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for dry FGD is major advantage for this technology.

PacifiCorp anticipates operating Naughton Units 1-3 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 Naughton Units 1-3 are summarized in the following tables.

Table 19: Naughton Unit 1 Economic Costs

Cost	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
Control Equipment Capital Cost	$0	$64,297,623	$108,995,970	$89,400,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$6,116,633	$10,368,787	$8,504,622
Annual O&M Costs	$0	$3,226,295	$4,006,095	$4,563,874
Annual Cost of Control	$0	$9,342,928	$14,374,882	$13,068,496

Table 20: Naughton Unit 1 Environmental Costs

	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
SO_2 Emission Rate (lb/MMBtu)	1.20	0.41	0.15	0.15
Annual SO_2 Emission (tpy) [(a)]	8,7516	2,990	1,094	1,094
Annual SO_2 Reduction (tpy)	N/A	5,761	7,657	7,657
Annual Cost of Control	$0	$9,342,928	$14,374,882	$13,068,496
Cost per ton of Reduction	N/A	$1,622	$1,877	$1,707
Incremental Cost per ton of Reduction	N/A	$1,622	$2,654	$1,965 [(b)]

[(a)] Annual emissions based on an average coal sulfur content of 1.02%, a heat input rate of 1,850 MMBtu/hr, and 7,884 hours of operation per year.
[(b)] Incremental cost from installing dry FGD with a polishing fabric filter cannot be calculated since the reduced tons of SO_2 are anticipated to be the same. Therefore, the incremental cost from installing dry FGD with the existing ESP was calculated.

Table 21: Naughton Unit 2 Economic Costs

Cost	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
Control Equipment Capital Cost	$0	$88,896,713	$141,244,778	$117,400,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$8,456,744	$13,436,616	$11,168,262
Annual O&M Costs	$0	$4,251,261	$5,259,175	$5,721,158
Annual Cost of Control	$0	$12,708,005	$18,695,791	$16,889,420

Table 22: Naughton Unit 2 Environmental Costs

	Existing	Dry FGD with Existing ESP	Dry FGD with Polishing Fabric Filter	Wet FGD with Existing ESP
SO_2 Emission Rate (lb/MMBtu)	1.20	0.41	0.15	0.15
Annual SO_2 Emission (tpy) [a]	11,353	3,879	1,419	1,419
Annual SO_2 Reduction (tpy)	N/A	7,474	9,934	9,934
Annual Cost of Control	$0	$12,708,005	$18,695,791	$16,889,420
Cost per ton of Reduction	N/A	$1,700	$1,882	$1,700
Incremental Cost per ton of Reduction	N/A	$1,700	$2,434	$1,700 [b]

[a] Annual emissions based on an average coal sulfur content of 1.02%, a heat input rate of 2,400 MMBtu/hr, and 7,884 hours of operation per year.
[b] Incremental cost from installing dry FGD with a polishing fabric filter cannot be calculated since the reduced tons of SO_2 are anticipated to be the same. Therefore, the incremental cost from installing dry FGD with the existing ESP was calculated.

Table 23: Naughton Unit 3 Economic Costs

Cost	Existing Wet FGD	Upgraded Wet FGD with Waste Liquor	Upgraded Wet FGD with Soda Ash Reagent
Control Equipment Capital Cost	$0	$6,000,000	$27,798,972
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$570,780	$2,644,516
Annual O&M Costs	$0	$615,513	$1,656,269
Annual Cost of Control	$0	$1,186,293	$4,300,785

Table 24: Naughton Unit 3 Environmental Costs

	Existing Wet FGD	Upgrade Wet FGD Using Waste Liquor	Upgrading Wet FGD Using Soda Ash Reagent
SO_2 Emission Rate (lb/MMBtu)	0.50	0.21	0.15
Annual SO_2 Emission (tpy) [a]	7,293	3,063	2,188
Annual SO_2 Reduction (tpy)	N/A	4,230	5,105
Annual Cost of Control	$0	$1,186,293	$4,300,785
Cost per ton of Reduction	N/A	$280	$842
Incremental Cost per ton of Reduction	N/A	$280	$3,559

[a] Annual emissions based on an average coal sulfur content of 1.02%, a heat input rate of 3,700 MMBtu/hr, and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the proposed wet FGD and dry FGD controls for Units 1 – 3 are reasonable. The final step in the SO_2 BART determination process for Naughton Units 1-3, 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 28-30, on pages 37-39, list the modeled control scenarios and associated emission rates.

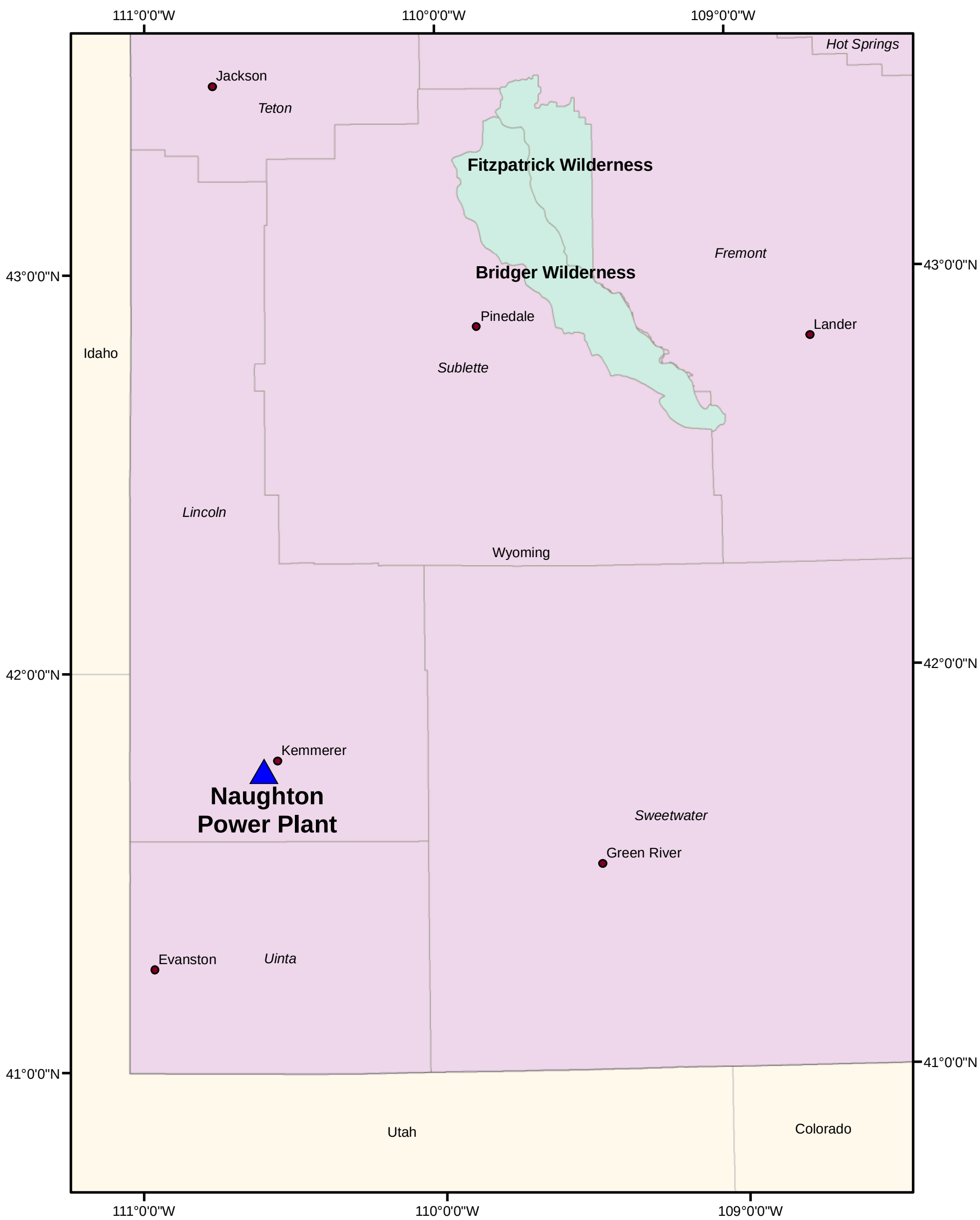
VISIBILITY IMPROVEMENT DETERMINATION:

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 Naughton 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 are the closest Class I areas to the PacifiCorp Naughton facility, as shown in Figure 2 below. Bridger WA is located approximately 140 kilometers (km) northeast of the facility and Fitzpatrick WA is located approximately 165 km northeast of the facility.

Only those Class I areas most likely to be impacted by the Naughton 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 modeled areas.

Figure 2
Naughton Power Plant and Class I Areas



SCREENING MODELING

To determine if the PacifiCorp Naughton 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. Potential emissions for current operation from the three coal-fired boilers at the Naughton plant were input to the model.

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 25: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
1995		
Bridger WA	5.984	3.119
Fitzpatrick WA	3.305	1.632
1996		
Bridger WA	6.185	4.364
Fitzpatrick WA	5.253	2.378
2001		
Bridger WA	7.331	4.277
Fitzpatrick WA	4.789	2.428

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 Naughton 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 26: Key Programs in CALPUFF System

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

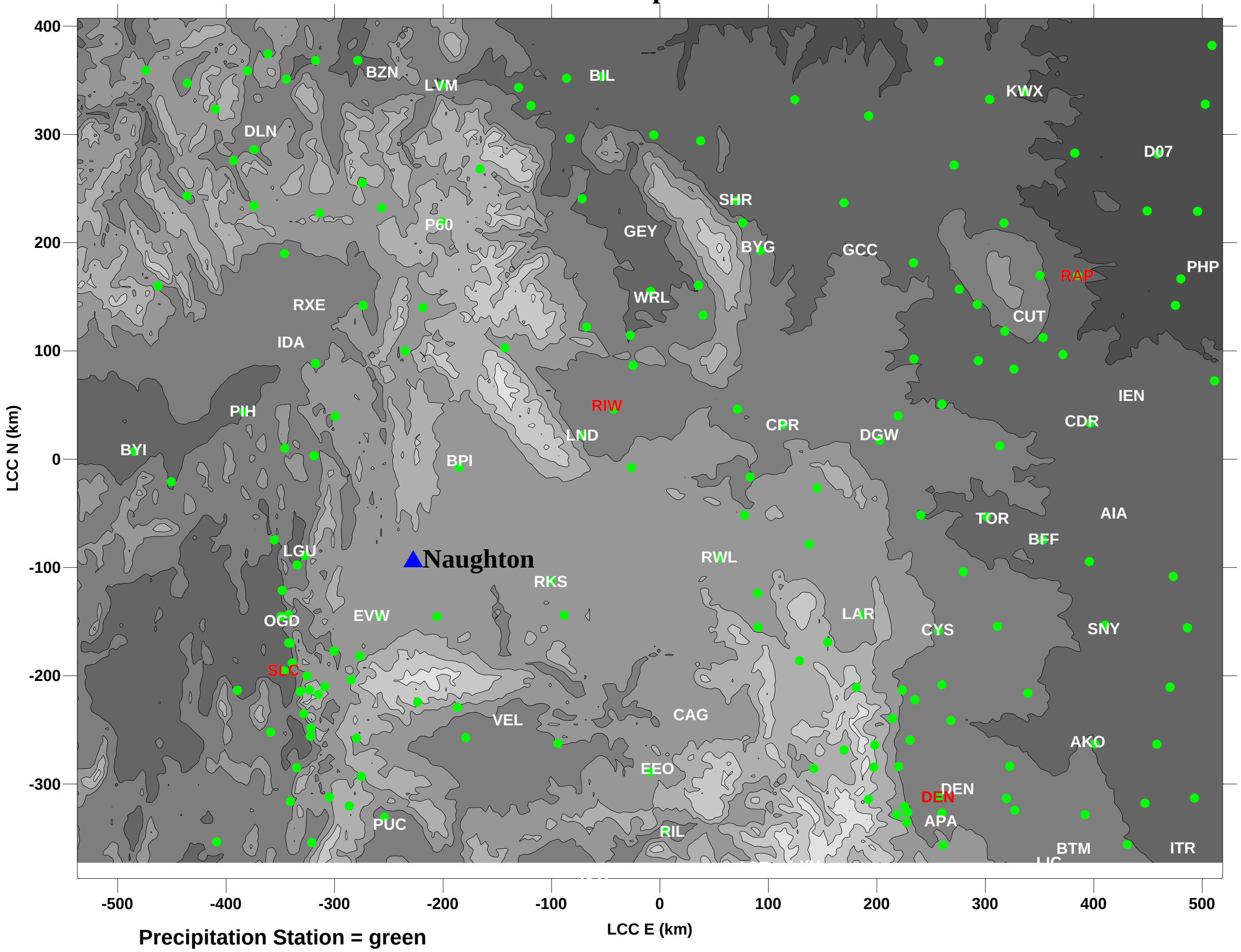
Meteorological Data Processing (CALMET)

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 the figure below. 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 27: 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

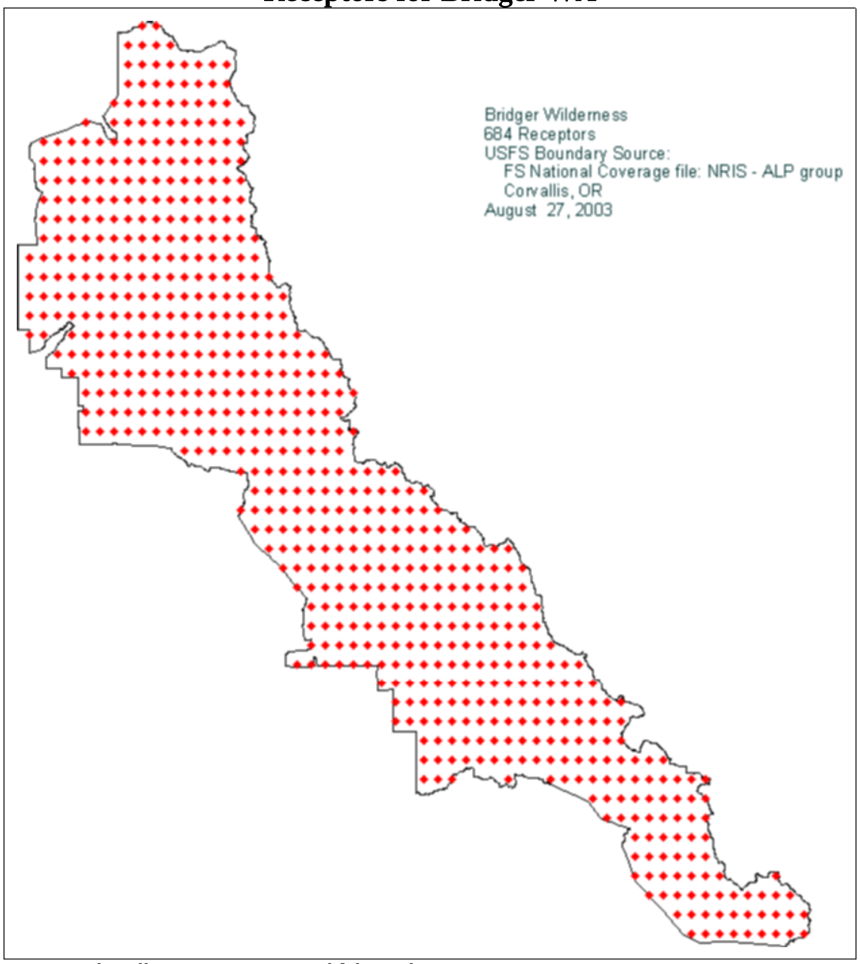
To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia concentrations. For ozone, hourly data collected from the following stations were used:

- 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.

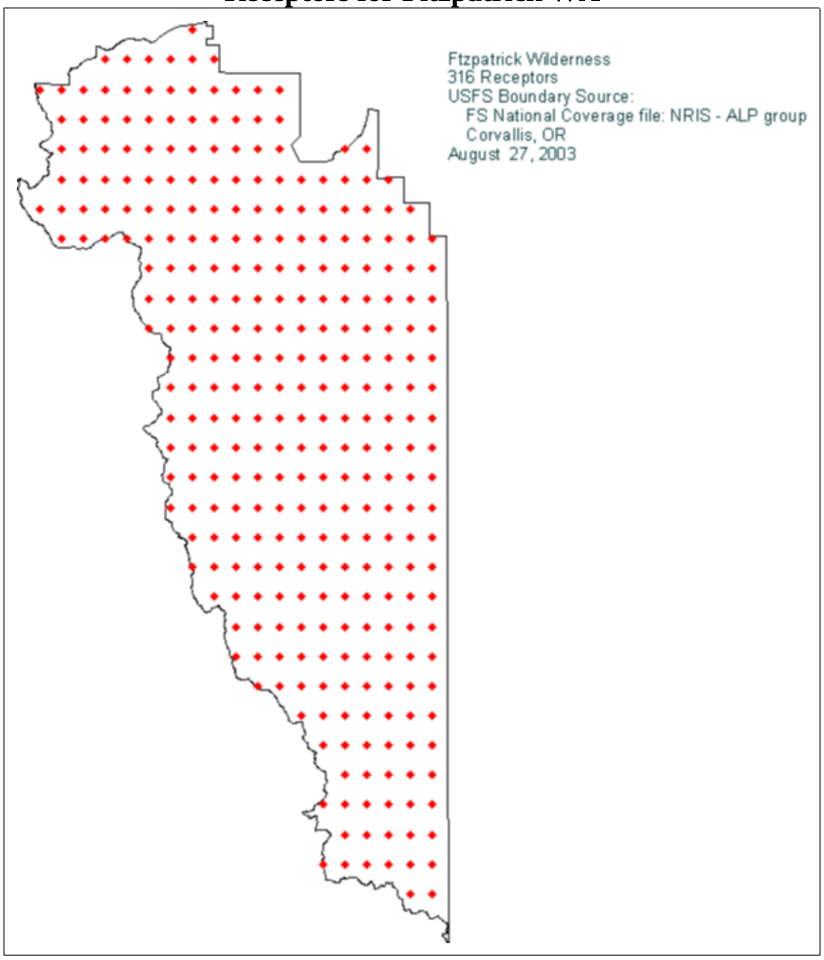
Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate Lambert Conformal Conic coordinates. Figures 4 and 5 show the receptor configurations that were used for Bridger WA and Fitzpatrick WA. Receptor spacing for the modeled areas was 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

<u>CALPUFF Inputs – Baseline and Control Options</u>

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

Table 28: CALPUFF Inputs for Naughton Unit 1

Naughton Unit 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 ESP	LNB with advanced OFA, Dry FGD, ESP with Flue Gas Conditioning	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, ESP with Sulfur Trioxide Injection, New Stack	PacifiCorp Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning, New Stack	PacifiCorp Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	1,850	1,850	1,850	1,850	1,850	1,850	1,850
Sulfur Dioxide (SO_2) (lb/mmBtu)	1.20	0.41	0.15	0.15	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	2,220	759	278	278	185	278	278
Nitrogen Oxide (NOx) (lb/mmBtu)	0.58	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,073	444	444	130	130	481	130
PM_{10} (lb/mmBtu)	0.056	0.040	0.015	0.015	0.040	0.040	0.040
PM_{10} (lb/hr)	103.6	74.0	27.8	27.8	74.0	77.7	77.7
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)(a)	44.5	31.8	15.8	15.8	31.8	33.4	33.4
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)(b)	59.1	42.2	11.9	11.9	42.2	44.3	44.3
Sulfuric Acid (H_2SO_4) (lb/hr)	34.0	1.7	1.7	2.4	29.2	17.0	29.3
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	0.4	2.1	--	2.1
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	--	0.7	3.7	--	3.7
H_2SO_4 as Sulfate (SO_4) (lb/hr)	33.3	1.6	1.6	2.4	28.6	16.7	28.7
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.3	1.6	--	1.5
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	0.6	3.1	--	3.1
Total Sulfate (SO_4) (lb/hr)	33.3	1.6	1.6	3.3	33.2	16.7	33.3
Stack Conditions							
Stack Height (meters)	61	61	61	61	152	145	145
Stack Exit Diameter (meters)	4.27	4.27	4.27	4.27	4.88	4.88	4.88
Stack Exit Temperature (Kelvin)	411	350	342.6	342.6	323	323	323
Stack Exit Velocity (meters per second)	28.1	19.7	24.6	24.6	18.1	18.1	18.1

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 Naughton Unit 2

Naughton Unit 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 ESP	LNB with advanced OFA, Dry FGD, ESP with Flue Gas Conditioning	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Dry FGD, Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, ESP, New Stack	PacifiCorp Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning, New Stack	PacifiCorp Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	2,400	2,400	2,400	2,400	2,400	2,400	2,400
Sulfur Dioxide (SO_2) (lb/mmBtu)	1.20	0.41	0.15	0.15	0.10	0.15	0.15
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	2,868	984	360	360	240	360	360
Nitrogen Oxide (NOx) (lb/mmBtu)	0.54	0.24	0.24	0.07	0.07	0.26	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,291	576	576	168	168	624	168
PM_{10} (lb/mmBtu)	0.064	0.040	0.015	0.015	0.040	0.050	0.040
PM_{10} (lb/hr)	153.6	96.0	36.0	36.0	96.0	129.6	129.6
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[(a)]	65.8	41.3	20.5	20.5	41.3	55.7	55.7
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[(b)]	87.2	54.7	15.5	15.5	54.7	73.9	73.9
Sulfuric Acid (H_2SO_4) (lb/hr)	44.2	2.2	2.2	3.1	37.9	22.1	38.0
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	0.6	2.8	--	2.8
Ammonium Bisulfate $(NH_4)HSO_4$ (lb/hr)	--	--	--	1.0	4.8	--	4.8
H_2SO_4 as Sulfate (SO_4) (lb/hr)	--	--	--	0.4	2.0	--	2.0
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	43.3	2.1	2.1	3.1	37.2	21.6	37.2
$(NH_4)HSO_4$ as SO_4 (lb/hr)				0.8	4.0		4.0
Total Sulfate (SO_4) (lb/hr)	43.3	2.1	2.1	4.3	43.2	21.6	43.2
Stack Conditions							
Stack Height (meters)	68	68	68	68	152	145	145
Stack Exit Diameter (meters)	4.88	4.88	4.88	4.88	5.49	5.49	5.49
Stack Exit Temperature (Kelvin)	411	350	343	343	323	323	323
Stack Exit Velocity (meters per second)	27.8	20.2	24.3	24.3	18.5	18.5	18.5

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 Naughton Unit 3

Naughton Unit 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	Tuning Existing LNB with OFA, Wet FGD with Waste Liquor, Existing ESP	Tuning Existing LNB with OFA & SCR, Wet FGD with Waste Liquor, Enhanced ESP	Tuning Existing LNB with OFA and SCR, Wet FGD with Waste Liquor, Fabric Filter	Tuning Existing LNB with OFA and SCR, Wet FGD with Soda Ash, Fabric Filter	PacifiCorp Committed Controls: Tuning Existing LNB with OFA, Wet Sodium FGD, New Fabric Filter	PacifiCorp Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	3,700	3,700	3,700	3,700	3,700	3,700	3,700
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.50	0.21	0.21	0.21	0.10	0.22	0.22
Sulfur Dioxide (SO_2) pounds per hour (lb/hr)	1,840	777	777	777	370	814	814
Nitrogen Oxide (NOx) (lb/mmBtu)	0.45	0.35	0.07	0.07	0.07	0.37	0.07
Nitrogen Oxide (NOx) (lb/hr)	1,656	1,295	259	259	259	1,369	259
PM_{10} (lb/mmBtu)	0.094	0.040	0.040	0.015	0.015	0.015	0.015
PM_{10} (lb/hr)	348.0	148.0	148.0	55.5	55.5	55.5	55.5
Coarse Particulate ($PM_{2.5}$<diameter< PM_{10}) (lb/hr)[a]	149.6	63.6	63.6	31.6	31.6	23.9	23.9
Fine Particulate (diameter<$PM_{2.5}$) (lb/hr)[b]	198.4	84.4	84.4	23.9	23.9	31.6	31.6
Sulfuric Acid (H_2SO_4) (lb/hr)	34.0	34.0	58.7	58.7	58.7	34.0	58.5
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	4.3	4.3	4.3	--	4.3
Ammonium Bisulfate ($(NH_4)HSO_4$) (lb/hr)	--	--	7.4	7.4	7.4	--	7.4
H_2SO_4 as Sulfate (SO_4) (lb/hr)	33.4	33.4	57.3	57.3	57.3	33.3	57.3
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	3.1	3.1	3.1	--	3.1
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	6.2	6.2	6.2	--	6.2
Total Sulfate (SO_4) (lb/hr)	33.2	33.4	66.6	66.6	66.6	33.3	66.6
Stack Conditions							
Stack Height (meters)	145	145	145	145	145	145	145
Stack Exit Diameter (meters)	8.08	8.08	8.08	8.08	8.08	8.08	8.08
Stack Exit Temperature (Kelvin)	323	322	322	322	323	322	322
Stack Exit Velocity (meters per second)	23.8	20.2	20.2	20.2	18.6	20.2	20.2

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 and Fitzpatrick WA are shown in the table below.

Table 31: Relative Humidity Factors for CALPOST

Month	Bridger WA & Fitzpatrick WA
January	2.50
February	2.30
March	2.30
April	2.10
May	2.10
June	1.80
July	1.50
August	1.50
September	1.80
October	2.00
November	2.50
December	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% 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 μg/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 (μg/m^3)	Calculated Scaling Factor	20% Best Days for Bridger WA (μg/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 the two Class I areas in question are listed in the table below.

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

Aerosol Component	Fitzpatrick WA & Bridger WA
Ammonium Sulfate	0.045
Ammonium Nitrate	0.038
Organic Carbon	0.178
Elemental Carbon	0.008
Soil	0.189
Coarse Mass	1.136

Visibility Post-Processing Results

The results of the visibility modeling for each of the three 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		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Current Operations with ESP								
Bridger WA	1.777	48	1.763	41	1.797	45	1.779	45
Fitzpatrick WA	0.966	23	0.881	18	0.840	20	0.896	20
Post-Control Scenario 1 – LNB with advanced OFA, Dry FGD, ESP with Flue Gas Conditioning								
Bridger WA	0.644	14	0.741	14	0.694	16	0.693	15
Fitzpatrick WA	0.357	3	0.314	5	0.361	5	0.344	4
Post-Control Scenario 2 – LNB with advanced OFA, Dry FGD, New Fabric Filter								
Bridger WA	0.479	7	0.635	9	0.493	7	0.536	8
Fitzpatrick WA	0.235	2	0.205	2	0.266	3	0.235	2
Post-Control Scenario 3 – LNB with advanced OFA and SCR, Dry FGD, New Fabric Filter								
Bridger WA	0.217	1	0.274	1	0.234	3	0.242	2
Fitzpatrick WA	0.119	0	0.105	0	0.123	0	0.116	0
Post-Control Scenario 4 – LNB with advanced OFA and SCR, Wet FGD, ESP with Sulfur Trioxide Injection, New Stack								
Bridger WA	0.387	4	0.288	3	0.397	4	0.357	4
Fitzpatrick WA	0.153	1	0.108	1	0.135	0	0.132	1
Post-Control Scenario A – Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning								
Bridger WA	0.733	14	0.623	9	0.698	12	0.685	12
Fitzpatrick WA	0.320	3	0.221	2	0.280	2	0.274	2
Post-Control Scenario B – Committed Controls and SCR								
Bridger WA	0.406	5	0.370	4	0.413	5	0.396	5
Fitzpatrick WA	0.175	1	0.131	1	0.168	0	0.158	1

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)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Current Operations with ESP								
Bridger WA	2.127	61	1.860	56	2.087	55	2.025	57
Fitzpatrick WA	1.158	26	1.099	24	1.110	22	1.122	24
Post-Control Scenario 1 – LNB with advanced OFA, Dry FGD, ESP with flue gas conditioning								
Bridger WA	0.838	28	0.926	18	0.882	19	0.882	22
Fitzpatrick WA	0.462	6	0.413	5	0.448	6	0.441	6
Post-Control Scenario 2 – LNB with advanced OFA, Dry FGD, New Fabric Filter								
Bridger WA	0.642	14	0.745	11	0.614	12	0.667	12
Fitzpatrick WA	0.312	3	0.286	4	0.313	4	0.304	4
Post-Control Scenario 3 – LNB with advanced OFA and SCR, Dry FGD, Fabric Filter								
Bridger WA	0.284	2	0.321	3	0.291	3	0.299	3
Fitzpatrick WA	0.158	1	0.141	1	0.148	0	0.149	1
Post-Control Scenario 4 – LNB with advanced OFA and SCR, Wet FGD, ESP, New Stack								
Bridger WA	0.482	7	0.354	4	0.526	8	0.454	6
Fitzpatrick WA	0.208	2	0.138	1	0.162	0	0.169	1
Post-Control Scenario A – Committed Controls: LNB with advanced OFA, Wet FGD, ESP with Flue Gas Conditioning								
Bridger WA	0.944	20	0.757	14	0.921	15	0.874	16
Fitzpatrick WA	0.404	4	0.288	4	0.326	2	0.339	3
Post-Control Scenario B – Committed Controls and SCR								
Bridger WA	0.544	10	0.450	7	0.555	9	0.516	9
Fitzpatrick WA	0.221	2	0.167	1	0.186	0	0.191	1

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)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Current Operations with Wet FGD and ESP								
Bridger WA	1.978	66	1.618	56	2.171	53	1.922	58
Fitzpatrick WA	1.126	24	0.893	21	0.871	21	0.963	22
Post-Control Scenario 1 – Tuning Existing LNB with OFA, Wet FGD with Waste Liquor, Existing ESP								
Bridger WA	1.413	12	1.175	32	1.555	39	1.381	28
Fitzpatrick WA	0.735	16	0.564	11	0.549	9	0.616	12
Post-Control Scenario 2 – Tuning Existing LNB with OFA & SCR, Wet FGD with Waste Liquor, Enhanced ESP								
Bridger WA	0.716	19	0.650	10	0.828	14	0.731	14
Fitzpatrick WA	0.371	4	0.290	3	0.260	1	0.307	3
Post-Control Scenario 3 – Tuning Existing LNB with OFA and SCR, Wet FGD with Waste Liquor, Fabric Filter								
Bridger WA	0.697	16	0.635	10	0.810	14	0.714	13
Fitzpatrick WA	0.363	4	0.279	3	0.253	1	0.298	3
Post-Control Scenario 4 – Tuning Existing LNB with OFA and SCR, Wet FGD with Soda Ash, Fabric Filter								
Bridger WA	0.553	12	0.494	7	0.662	11	0.570	10
Fitzpatrick WA	0.265	2	0.203	3	0.214	0	0.227	2
Post-Control Scenario A – Committed Controls: Tuning Existing LNB with OFA, Wet FGD, New Fabric Filter								
Bridger WA	1.460	45	1.21	34	1.583	40	1.418	40
Fitzpatrick WA	0.766	17	0.586	11	0.572	11	0.641	13
Post-Control Scenario B – Committed Controls and SCR								
Bridger WA	0.710	17	0.650	10	0.830	14	0.730	14
Fitzpatrick WA	0.372	4	0.287	3	0.259	1	0.306	3

Figure 6
Modeled BART Impacts: 98th Percentile (delta-dv)

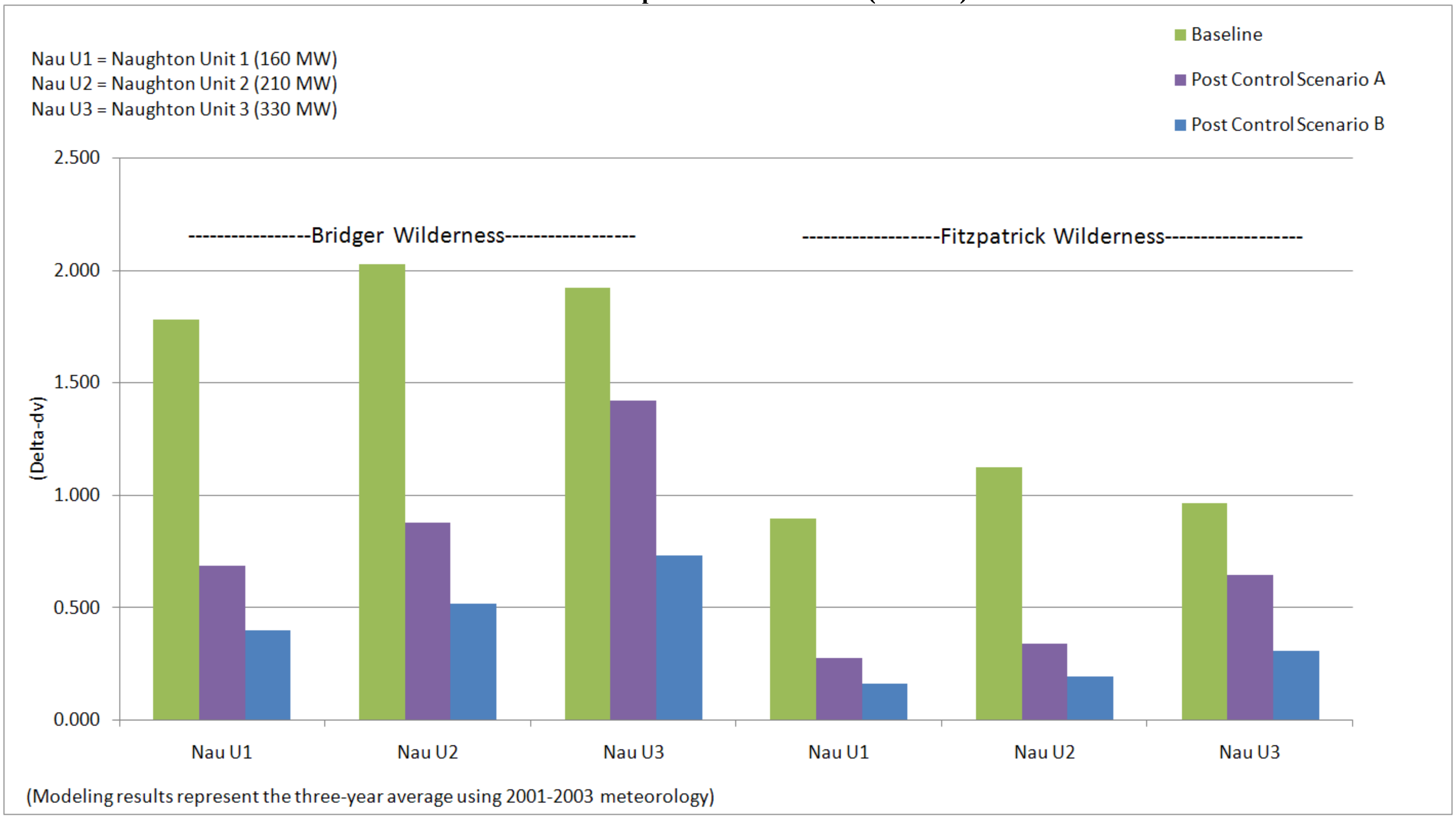
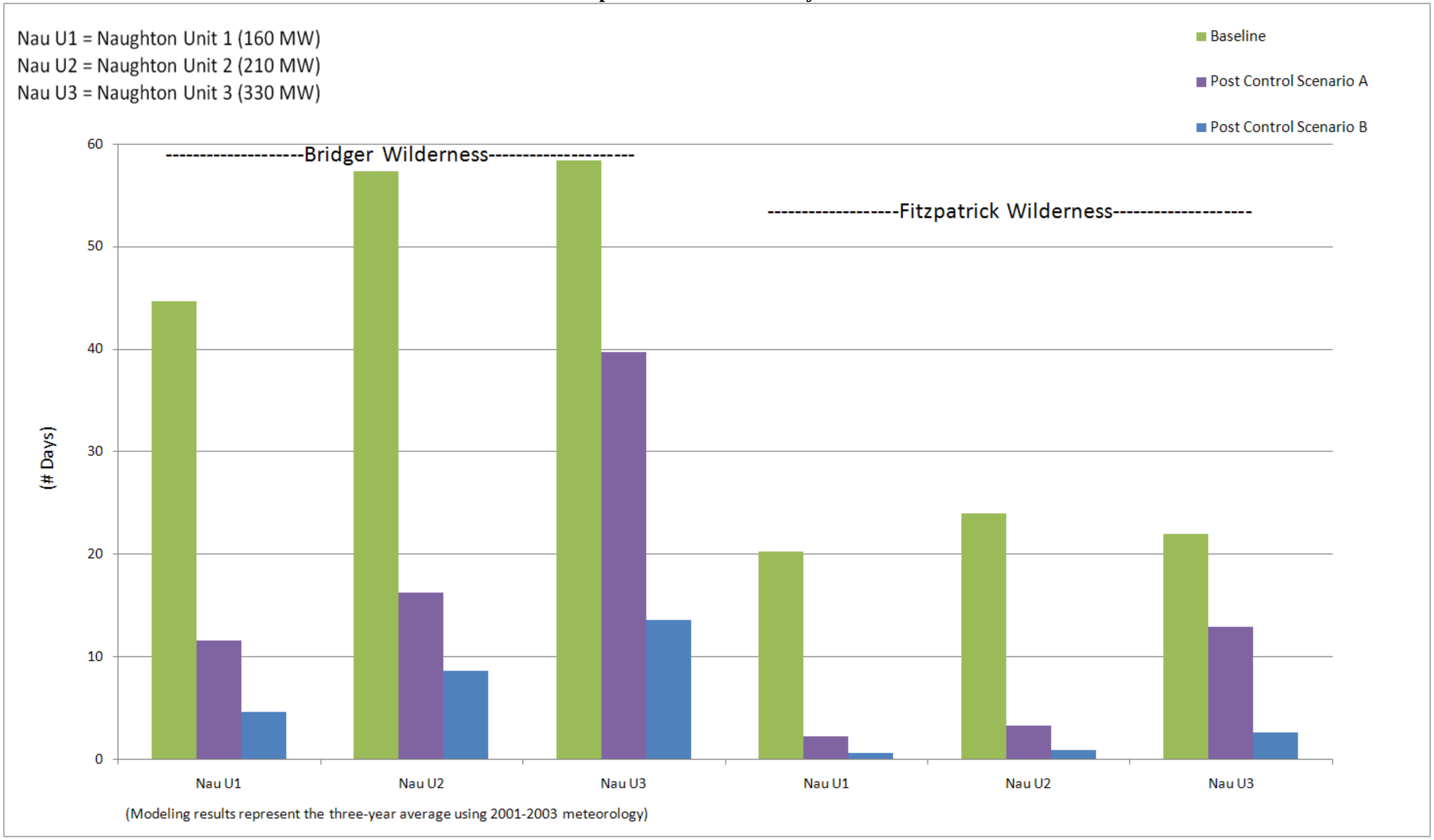


Figure 7
Modeled BART Impacts: Number of Days > 0.5 delta-dv



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 three units subject to BART at the Naughton Power Plant.

<u>NO_x</u>

LNB with advanced OFA is determined to be BART for Units 1 and 2 for NO_x based, in part, on the following conclusions:

1. LNB with advanced OFA on Units 1and 2 was cost effective with a capital cost of $9,600,000 and $9,100,000 per unit, respectively. The average cost effectiveness, over a twenty year operational life, is $426 per ton of NO_x removed for Unit 1 and $357 per ton for Unit 2.

2. Combustion control using LNB with advanced 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, though not applicable, 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 98^{th} percentile visibility improvement from the baseline summed across both Class I areas achieved with LNB with advanced OFA, wet FGD, and existing ESP with FGC (Post-Control Scenario A) was 1.716 Δdv from Unit 1 and 1.934 Δdv from Unit 2.

5. Annual NO_x emission reductions from baseline achieved by applying LNB with advanced OFA on Units 1 and 2 are 2,334 tons and 2,649 tons, respectively.

LNB with advanced OFA and SCR was not determined to be BART for Units 1and 2 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 advanced OFA. Capital cost for SCR on Unit 1 is $94,600,000 and $115,900,000 for Unit 2. Annual SCR O&M costs for Unit 1 are $1,231,912 and $1,639,352 for Unit 2.

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

3. Operation of LNB with advanced OFA and SCR is parasitic and requires an estimated 1.0 MW from Unit 1 and 1.3 MW from Unit 2.

4. While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of SCR. Subtracting the modeled 98th percentile values from each other yield the incremental 98th percentile visibility improvement from SCR. The cumulative 3-year averaged 98th percentile visibility improvement from Post-Control Scenario A across both Class I areas achieved with Post-Control Scenario B was 0.405 Δdv from Unit 1 and 0.506 Δdv from Unit 2.

Tuning the existing LNB with OFA and installing SCR is determined to be BART for Unit 3 for NO_x based, in part, on the following conclusions:

1. The cost effectiveness of tuning the existing LNB with OFA and installing SCR on Unit 3 was reasonable at $2,830 per ton of NO_x removed. The incremental cost effectiveness when compared to existing LNB with ROFA was $1,783 per ton of NO_x and reasonable as well. Both the cost effectiveness and average cost effectiveness were based on a twenty year operational life for the proposed controls.

2. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across both Class I areas achieved by tuning the existing LNB with OFA, wet FGD and installing a new full-scale fabric filter, Post-Control Scenario A, was 0.826 Δdv from Unit 3. Units 1 and 2 yielded notably higher visibility improvements from baseline, 1.716 Δdv and 1.934 Δdv, respectively, using Post-Control Scenario A which included new LNB with advanced OFA, but not SCR.

3. Modeled 98th percentile visibility results from Unit 3 Post-Control Scenario B are directly comparable to those from Post-Control Scenario A, as the only difference is directly attributable to the installation of SCR. The cumulative 3-year averaged 98th percentile visibility improvement across the two Class I areas achieved by installing SCR on Unit 3 was 1.023 Δdv, approximately twice the 98th percentile visibility improvements, 0.405 Δdv from Unit 1 and 0.506 Δdv from Unit 2, using Post-Control Scenario B which included installing SCR.

4. The cumulative 3-year averaged 98th percentile visibility improvement from the baseline summed across both Class I areas achieved by tuning the existing LNB with OFA, SCR, wet FGD, and installing a new full-scale fabric filter, Post-Control Scenario B, was 1.849 Δdv. This visibility improvement is less than the improvement achieved by Post-Control Scenario A using new LNB and advanced OFA on Unit 2, 1.934 Δdv, but higher than Post-Control Scenario A using new LNB and advanced OFA on Unit 1, 1.716 Δdv.

5. Annual NO_x emission reductions from baseline achieved by tuning existing LNB with OFA and installing SCR are 5,542 tons as compared to only 1,167 tons from tuning existing LNB with OFA.

6. 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 0.37 lb/MMBtu on a 30-day rolling average for Unit 3, above EPA's established presumptive limit of 0.15 lb/MMBtu for tangential-fired boilers burning sub-bituminous coal, though not applicable, is not justified.

The Division considers the installation and operation of the BART-determined NO_x controls, new LNB with advanced OFA on Units 1 and 2 and tuning existing LNB with OFA and installing SCR on Unit 3 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

<u>Naughton Unit 1</u>: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 481 lb/hr (30-day rolling average), and 2,107 tpy as BART for NO_x.

<u>Naughton Unit 2</u>: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.26 lb/MMBtu (30-day rolling average), 624 /hr (30-day rolling average), and 2,733 tpy as BART for NO_x.

<u>Naughton Unit 3</u>: Tuning existing LNB with OFA and installing SCR meeting NO_x emission limits of 0.07 lb/MMBtu (30-day rolling average), 259 lb/hr (30-day rolling average), and 1,134 tpy as BART for NO_x.

<u>PM/PM_{10}</u>

Existing ESP with FGC is determined to be BART for Units 1 and 2 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 $1,721 for Unit 1 and $949 for Unit 2.

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 98^{th} percentile visibility improvement from the baseline summed across both Class I areas achieved with LNB with advanced OFA, wet FGD, and existing ESP with FGC (Post-Control Scenario A) was 1.716 Δdv from Unit 1 and 1.934 Δdv from Unit 2. 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 FGC and a polishing fabric filter was not determined to be BART for Units 1 and 2 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 $8,848 for Unit 1 and, $11,494 for Unit 2. Incremental cost effectiveness is $17,748 for Unit 1 and $16,431 for Unit 2.

2. The cumulative 3-year averaged 98th percentile visibility improvement from applying a polishing fabric filter can be calculated by subtracting Post-Control Scenario 2 results from Post-Control Scenario 1 results and summing across both Class I areas. The achieved 98th percentile visibility improvement was 0.266 Δdv from Unit 1 and 0.352 Δdv from Unit 2.

A new full-scale fabric filter is determined to be BART for Unit 3 for PM/PM_{10} based, in part, on the following conclusions:

1. While the Division considers the cost of compliance for a full-scale fabric filter on Unit 3 not reasonable, PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter on Unit 3 in a recently issued New Source Review construction permit. A full-scale fabric filter is the most stringent PM/PM_{10} control technology and therefore the Division will accept it as BART.

The Division considers the installation and operation of the BART-determined PM/PM_{10} controls, existing ESP with FGC on Units 1 and 2 and a new full-scale fabric filter on Unit 3 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

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

Naughton Unit 1:	Installing FGC on the existing ESP and meeting PM/PM_{10} emission limits of 0.040 lb/MMBtu, 74 lb/hr, and 324 tpy as BART for PM/PM_{10}.
Naughton Unit 2:	Installing FGC on the existing ESP and meeting PM/PM_{10} emission limits of 0.040 lb/MMBtu, 96 lb/hr, and 421 tpy as BART for PM/PM_{10}.
Naughton Unit 3:	Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 56 lb/hr, and 243 tpy as BART for PM/PM_{10}.

SO_2: WESTERN BACKSTOP SULFUR DIOXIDE 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 proposed SO_2 BART controls are installing wet FGD with FGC using the existing ESPs on Units 1 and 2, and upgrading the existing wet FGD using waste liquor and removing the existing ESP and installing a new full-scale fabric filter on Unit 3.

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 in Table 37.

Table 37: 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 38 to underscore the improvements associated with SO_2 reductions.

Table 38: 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 the installation costs of the pollution control systems.

PacifiCorp's BART-eligible or subject-to-BART power plant fleet is shown in Table 39. 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 39: 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.

Based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Naughton Units 1-3 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 not requiring additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan in this permitting action. Additional controls may be required in future actions related to the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan.

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

PacifiCorp's Naughton 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 Naughton Units 1-3.

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 Naughton Units 1-3.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Naughton Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-2-121, was issued for the facility on March 19, 2008. 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 the changes authorized in this permitting action.

CONCLUSION:

The Division is satisfied that PacifiCorp's Naughton 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 to install new LNB with advanced OFA on Naughton Units 1 and 2, and install FGC in combination with the existing ESPs to meet the statutory requirements of BART. Before December 31, 2014, PacifiCorp shall tune the existing LNB and OFA on Naughton Unit 3 and install SCR and a new full-scale fabric filter to meet the statutory requirements of BART.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Naughton 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 Naughton Units 1 and 2 shall not exceed the levels below. The lb/hr and tpy limits shall apply during all operating periods. The lb/MMBtu limits shall apply during all operating periods, except startup. Startup begins with the introduction of natural gas into the boiler and ends no later than the point in time when the ESP reaches a temperature of 225°F.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
1	PM/PM_{10} [a]	0.040	74	324
2	PM/PM_{10} [a]	0.040	96	421

[a] Filterable portion only.

6. That no later than 90 days after the installation of new low NO_x burners with advanced overfire air PM/PM_{10} performance tests shall be conducted and a written report of the results shall be submitted. If a maximum design rate is not achieved within 90 days of installing new low NO_x burners with advanced overfire air, 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 Naughton Units 1-3 shall not exceed the levels below. The NO_x limits shall apply during all operating periods. Unit 3 PM/PM_{10} lb/hr and tpy limits shall apply during all operating periods. Unit 3 PM/PM_{10} lb/MMBtu limit shall apply during all operating periods except startup. Startup begins with the introduction of natural gas into the boiler and ends when the boiler is switched over to coal as fuel.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
1	NO_x	0.26 (30-day rolling)	481 (30-day rolling)	2,107
2	NO_x	0.26 (30-day rolling)	624 (30-day rolling)	2,733
3	NO_x	0.07 (30-day rolling)	259 (30-day rolling)	1,134
3	PM/PM_{10} [a]	0.015 [b]	56 [b]	243

[a] Filterable portion only.
[b] Upon installation of a PM continuous emissions monitoring system, the averaging period shall become a 24-hour block average.

8. That initial performance tests be conducted, 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 (Naughton Units 1 through 3):

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. If a PM CEMS is installed on Unit 3, PM CEMS monitoring data collected in accordance with 40 CFR part 60, subpart Da may be submitted to satisfy the testing required by this condition for Unit 3.

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 (Naughton Units 1-3) 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 Naughton Units 1-3 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. If a PM CEMS is installed on Unit 3, PM CEMS monitoring data collected in accordance with 40 CFR part 60, subpart Da may be submitted to satisfy the testing required by this condition for Unit 3.

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 advanced overfire air on Units 1 and 2, in accordance with the Division's BART determination, and conduct the performance tests required in Conditions 6 and 8 no later than December 31, 2012 and June 1, 2012, respectively.

17. PacifiCorp shall, for Units 1 and 2, install flue gas conditioning on the existing ESPs, in accordance with the Division's BART determination, within 90 days of permit issuance.

18. PacifiCorp shall tune the existing low NO_x burners with overfire air and install selective catalytic reduction and a full-scale fabric filter on Unit 3, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 8 no later than December 31, 2014.

Appendix A
Facility Location

UAE Exhibit RR 2.4

WRAP REGIONAL EMISSION REDUCTION ESTIMATES

Regional Emission Reduction Estimates

Note: These estimates have not yet factored in the visibility improvement from the application of Achievable Technologies

	2018 Emissions (Current Controls)	2018 Emissions (Achievable Controls)	Emission Reductions due to Achievable Controls
Arizona	54,654	19,434	35,220
California	-	-	-
Colorado	49,722	11,866	37,856
Idaho	-	-	-
Nevada	3,614	3,614	-
New Mexico	66,887	59,689	7,198
Oregon	21,909	4,940	16,969
Utah	20,466	10,108	10,358
Wyoming	104,092	52,174	51,918
Tribes	48,477	39,820	8,657
TOTAL	369,821	201,645	168,176

Variables that can be changed in the spreadsheet

Control efficiency for uncontrolled utility or industrial boiler	85%
Incremental control efficiency improvement for undercontrolled utility or industrial boiler	5%

Emission Reductions from Source Categories

Utilities	152,095
Industrial Boilers	13,905
Smelters	0
Refineries	2,176
Lime Plants	0
Cement Plants	0
Pulp and Paper	0

Arizona - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities[1], Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls	Comments
AEPCO Apache - Unit 2		2,976	72.5%	85.0%	42.5%	85.0%	3489.1	910.2	2578.9	
AEPCO Apache - Unit 3		2,992	80.6%	85.0%	42.5%	85.0%	3155.3	823.1	2332.2	
Arizona Public Service, Cholla - Unit 2		1,254	62.1%	85.0%	90.0%	90.0%	1716.4	1716.4	0.0	
Arizona Public Service, Cholla - Unit 3		8,912	77.0%	85.0%	0.0%	85.0%	9837.9	1475.7	8362.2	
Arizona Public Service, Cholla - Unit 4		7,987	66.2%	85.0%	34.0%	85.0%	10255.2	2330.7	7924.5	
Chemical Lime - Nelson: Kiln 1		181	100.0%	100.0%	80.0%	80.0%	181.3	181.3	0.0	Current SO2 control eff is an estimate. Theoretical max control eff is not known
Chemical Lime - Nelson: Kiln 2		275	100.0%	100.0%	80.0%	80.0%	274.9	274.9	0.0	Theoretical max control efficiency = 50%-92%.
Chemical Lime - Douglas: Kiln 4		37	100.0%	100.0%	80.0%	80.0%	36.7	36.7	0.0	Current SO2 control eff is an estimate. Theoretical max control eff not known.
Chemical Lime - Douglas: Kiln 5		634	100.0%	100.0%	61.0%	61.0%	633.6	633.6	0.0	Current SO2 control eff is an estimate. Theoretical max control eff not known.
Chemical Lime - Douglas: Kiln 6		0	100.0%	100.0%	0.0%	0.0%	0.1	0.1	0.0	Natural gas fired, so SO2 emissions are not applicable.
SRP - Coronado UB1		10,475	78.4%	85.0%	66.0%	85.0%	11356.8	5010.4	6346.5	
SRP - Coronado UB2		9,522	71.0%	85.0%	66.0%	85.0%	11399.6	5029.2	6370.4	
Abitibi Consolidated Sales Corporation, Snowflake Division; #1 power boiler	040170424	0	100.0%	100.0%	0.0%	85.0%	0.0	0.0	0.0	Boiler is in service as a standby unit at this time. Permitted to operate full time. PTE = 1.2 tpy (natural gas) and 98.6 tpy (#2 oil)
Abitibi Consolidated Sales Corporation, Snowflake Division; #2 power boiler	040170424	1,959	100.0%	100.0%	55.0%	85.0%	1958.7	652.9	1305.8	The pollution control device is a slip stream SO2 wet scrubber, it was not designed to scrub the entire flue gas flow. Current SO2 control efficiency is based on % flue gas stream scrubbed, S content in coal, & physical condition of scrubber.Theoretical max. control eff. is based on a design for 62.1% flue gas flow being scrubbed with 90% max. control eff. and 37.9% of the flue gas being bypasssed.
Abitibi Consolidated Sales Corporation, Snowflake Division; #2 recovery boiler	040170424	359	100.0%	100.0%	0.0%	0.0%	358.7	358.7	0.0	PTE reduced due to the source changing from a Kraft black liquor and natural gas fired boiler to a natural gas only fired boiler. No SO2 controls are required on this source. Boiler is not in service at this time; permitted to operate full time.
						Total	54654.4	19433.9	35220.4	

These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources.
The application of regional achievable control technology estimates to individual sources has only undergone preliminary review by the states. There may be changes due to a more detailed review

[1] Capacity factors are from ICF's data reconciliation spreadsheet that was distributed on July 23, 2000

Emission Reductions by Category

Utilities	33914.6
Industrial Boilers	1305.8

California - Regional Emission Reduction Estimates - DRAFT
Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities, Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
No BART-eligible Units									
						Total	0.0	0.0	0.0

These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources.
The application of regional achievable control technology estimates to individual sources has only undergone preliminary review by the states. There may be changes due to a more detailed review

Emission reductions by source category

Utilities
Industrial Boilers
Refineries

Colorado - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit[1]	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities[2], Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
Conoco Inc. - Denver; FCC Unit Regenerator	0010003	912	100%	100.0%	0.0%	90.0%	912.0	91.2	820.8
Conoco Inc. - Denver; Sulfur Recovery Unit	0010003	1,037	100%	100.0%	90.0%	98.0%	1036.7	207.3	829.3
**Southwestern Portland Cement - Raw Material Dryer	0130003	32	100%	100.0%	0.0%	0.0%	32.0	32.0	0.0
**Southwestern Portland Cement - Kiln	0130003	128	100%	100.0%	0.0%	0.0%	128.0	128.0	0.0
Colorado Springs Utilities - Drake #5	0410004	1,155	49.0%	85.0%	0.0%	85.0%	2003.6	300.5	1703.0
Colorado Springs Utilities - Drake #6	0410004	2,395	67.9%	85.0%	0.0%	85.0%	2998.2	449.7	2548.4
Colorado Springs Utilities - Drake #7	0410004	3,047	51.5%	85.0%	0.0%	85.0%	5029.0	754.4	4274.7
Colorado Springs Utilities - Nixon #1	0410030	4,601	56.3%	85.0%	0.0%	85.0%	6946.4	1042.0	5904.5
Holnam Portland Cement #3	0430001	1,693	100%	100.0%	0.0%	0.0%	1692.7	1692.7	0.0
Tristate Generation - Craig #1	0810018	4,730	80.4%	85.0%	66.0%	85.0%	5000.6	2206.2	2794.5
Tristate Generation - Craig #2	0810018	4,486	81.0%	85.0%	66.0%	85.0%	4707.5	2076.9	2630.7
Public Service CO - Comanche #1	1010003	6,492	74.5%	85.0%	0.0%	85.0%	7407.0	1111.0	6295.9
Public Service CO - Comanche #2	1010003	7,208	74.1%	85.0%	0.0%	85.0%	8268.3	1240.2	7028.0
Tri-Gen Energy - #4	0590820	877	100%	100.0%	0.0%	85.0%	877.0	131.6	745.5
Tri-Gen Energy - #5	0590820	2,683	100%	100.0%	0.0%	85.0%	2683.3	402.5	2280.8
						Total	49722.3	11866.1	37856.2

These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources.
The application of regional achievable control technology estimates to individual sources has only undergone preliminary review by the states. There may be changes due to a more detailed review

[1] For the purposes of this analysis, 4 BART-Eligible Units (Hayden #1 and #2, Cherokee #4, and Valmont #5) were assumed to be in the baseline due to legally-committed controls.
[2] Capacity factors are from ICF's data reconciliation spreadsheet that was distributed on July 23, 2000

Emission Reductions by category

Utilities	33179.7
Industrial Boilers	3026.3
Refineries	1650.1

Idaho - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

*Unit	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities, Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
No BART-eligible units									
						Total	0.0	0.0	0.0

These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources.
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Emission Reductions by source category
Utilities
Industrial Boilers
Refineries

Nevada - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit[1,2]	**AIRS ID**	**1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities**	**1999 Capacity Factor for Utilities[3], Assume 100% Capacity (no change in future) for others**	**2018 Capacity Factor**	**Current Control Efficiency (%)**	**Appropriate Retrofit Technology (%)**	**2018 Emissions (Current Controls)**	**2018 Emissions (Appropriate Retrofit Controls)**	**Emission Reductions due to Appropriate Retrofit Controls**
Nevada Cement Co., Fernley Plant, Kiln #1		167.3	100.0%	100.0%	0.0%	0.0%	167.3	167.3	0.0
Nevada Cement Co., Fernley Plant, Kiln #2		171.0	100.0%	100.0%	0.0%	0.0%	171.0	171.0	0.0
Nevada Power Co., Reid Gardner Station, Unit #1		800.0	60.9%	85.0%	93.0%	93.0%	1116.6	1116.6	0.0
Nevada Power Co., Reid Gardner Station, Unit #2		863.0	65.2%	85.0%	93.0%	93.0%	1125.1	1125.1	0.0
Nevada Power Co., Reid Gardner Station, Unit #3		1,007.0	82.8%	85.0%	93.0%	93.0%	1033.8	1033.8	0.0
						Total	3613.7	3613.7	0.0

These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources.
The application of regional achievable control technology estimates to individual sources has only undergone preliminary review by the states. There may be changes due to a more detailed review

[1] The following sources were identified as potential BART-eligible sources by the state of Nevada, but have been removed from this spreadsheet because of low SO2 emissions.
These are most likely natural-gas-fired.

Sierra Pacific Power, Fort Churchill, Units #1 and #2
Sierra Pacific Power, Tracy Station, Units #2 and #3
Nevada Power Co, Clark Station, Unit #4
Nevada Power Co., Sunrise Station, Unit #2

[2] The Mojave Generating Station was assumed to be in the baseline calculations
[3] Capacity factors are from ICF's data reconciliation spreadsheet that was distributed on July 23, 2000

Emission reductions by source category

Utilities	0.0
Industrial Boilers	
Refineries	

New Mexico - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities, Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
PNM, San Juan, Boiler #1	350450902	5,745	70.60%	85.0%	75.0%	80.0%	6916.8	5533.4	1383.4
PNM, San Juan, Boiler #2	350450902	5,023	71.80%	85.0%	75.0%	80.0%	5946.4	4757.2	1189.3
PNM, San Juan, Boiler #3	350450902	9,885	81.70%	85.0%	75.0%	80.0%	10284.3	8227.4	2056.9
PNM, San Juan, Boiler #4	350450902	8,772	72.40%	85.0%	75.0%	80.0%	10298.6	8238.9	2059.7
Phelps Dodge, Hidalgo Smelter	350230003	31,833	100.00%	100.0%	96.0%	96.0%	31832.5	31832.5	0.0
Giant Industries, Bloomfield Refinery, 1 FCCP ESP stack	350450023	323	100.00%	100.0%	0.0%	90.0%	322.5	32.3	290.3
Giant Refining, Ciniza Refinery, 4 B&W CO boiler	350310008	1,029	100.00%	100.0%	0.0%	0.0%	1028.5	1028.5	0.0
Raton Public Service, Raton Pwr. Plt., 1 Erie	350070001	159	54.10%	85.0%	0.0%	85.0%	249.8	37.5	212.3
El Paso Electric, Rio Grande Gen. Sta., 3	350130002	7	100.00%	100.0%	0.0%	85.0%	7.2	1.1	6.1
						Total	66886.7	59688.7	7198.0

These estimates are only valid as part of the regional estimate and are not intended to establish BART estimates for individual sources.
The application of regional achievable control technology estimates to individual sources has only undergone preliminary review by the states. There may be changes due to a more detailed review

NOTES:
New Mexico inventories emissions on odd-numbered years. 1995 emissions are used for 1996 and 1997 emissions are used for 1998.
Sources are included in the list based on allowable emissions. Actual emissions are used to calculate the 1996-8 Average Emissions.

Emission Reductions by source category

Utilities	6907.7
Industrial Boilers	
Refineries	290.3

Oregon - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit (ODEQ Source Name, #, Emission Unit Name, Emission Unit #)	**AIRS ID**	**1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities**	**1999 Capacity Factor for Utilities[1], Assume 100% Capacity (no change in future) for others**	**2018 Capacity Factor**	**Current Control Efficiency (%)**	**Appropriate Retrofit Technology (%)**	**2018 Emissions (Current Controls)**	**2018 Emissions (Appropriate Retrofit Controls)**	**Emission Reductions due to Appropriate Retrofit Controls**	**Comments**
Fort James Operating Company, PR808 Recovery Furnace, ESP Outlet	410070004	389.7	100%	100.0%	0.0%	0.0%	389.7	389.7	0.0	The Recovery Furnace is controlled with an electrostatic precipitator installed in 1986. The control efficiency is stated in terms of "To yield outlet grain loading of .023 Gr/dscf" The Design inlet gas flow rate is 280,000 ASCF @ 370 deg. F.
Fort James Operating Company, PR831 Power Boiler, Conventional - 6 Burner	410070004	30.5	100%	100.0%	0.0%	0.0%	30.5	30.5	0.0	The Power Boiler does not have a pollution control device.
Boise Cascade Corporation, No. 2 Recovery Furnace	410091849	387.5	100%	100.0%	0.0%	0.0%	387.5	387.5	0.0	Electrostatic Precipitator installed 1990; 99.75% rated efficiency. (TV application page 1 of control device descriptions.)
Boise Cascade Corporation, No. 3 Recovery Furnace	410091849	243.0	100%	100.0%	0.0%	0.0%	243.0	243.0	0.0	Electrostatic Precipitator installed in 1974; 99.4% rated efficiency.
Boise Cascade Corporation, Power Boiler 6-9	410091849	6.6	100%	100.0%	100.0%	100.0%	6.6	6.6	0.0	Power Boilers 6-9 installed 1976, 1966, 1967, and 1987 respectively. The 2008 age determination is based upon the age of the oldest boiler. The detail sheet indicates that this EU contributes 4125 tons to the PSEL. For this report this value was substituted over the value returned by the ACSIS database. No control devices indicated.
Portland General Electric - Beaver, Six combustion turbines for electric power generation	410092520	17.4	100%	100.0%	100.0%	100.0%	17.4	17.4	0.0	Simple cycle installed 1974; combined cycle install 1977. The 1977 date was used in the 2008 age determination. Emission control consists of water injection for NOx and Sulfur limit of 0.3% by weight for fuel.
International Paper - Gardner, PRB 047 Power Boiler Stack	410190036	581.6	100%	100.0%	0.0%	85.0%	581.6	87.2	494.3	Installed in 1962. Tangentially fired. No pollution control device.
International Paper - Gardner, PRB 048 Combined Recovery Boilers Stack	410190036	439.8	100%	100.0%	0.0%	0.0%	439.8	439.8	0.0	Installed in 1962. Modified in 1985. For the 2008 age determination the 1962 date was used. Particulate emissions are controlled in the recovery boilers with a dry bottom electrostatic precipitators. Recovery boiler No. 1 and No. 3 share a common stack. TV permit review report lists the ESP as 99.5% efficiency; 480 V (1), 55Kv (2); 150 amps; 415,000 afcm.
Collins Products LLC, Boiler 7	410350013	0.5	100%	100.0%	100.0%	100.0%	0.5	0.5	0.0	Installed in 1970. Sanderdust and diesel oil fired and also capable of burning natural gas equipped with an economizer. These are baseline limits. The current PSEL for the plant is 51 tons. Both boilers are scheduled to be taken off line in the near future. No reference to any control equipment in either case.
Collins Products LLC, Boiler 8	410350013	0.5	100%	100.0%	100.0%	100.0%	0.5	0.5	0.0	Installed in 1974. Natural gas and diesel back-up.
Willamette Industries, Inc. - Albany, Recovery Boiler #4 Black Liquor Solids	410430471	230.7	100%	100.0%	0.0%	0.0%	230.7	230.7	0.0	Installed in 1971. ESP installed in 1974 described as 99.5% efficient.

Wah Chang, Boilers 1-3	410430547	1.0	100%	100.0%	100.0%	100.0%	1.0	1.0	0.0	The largest single source is a limit for Boilers 1-3 natural gas with oil backup. 176.4 tons attributed to the boilers in the review report based on oil use. However the remaining portion of the limit is based on the Baseline. as a result it appears the source could exceed 250 tons SO2 emissions by the boilers and not exceed the PSEL. Boilers 46-6-A and 46-6-B 48.5 and 29.29 MMBtu, the third boiler is natural gas only. No pollution control equipment. Boiler 1 installed 1978; boiler 2 installed 1973. The 1973 date was used in the 2008 age calculation. 1997 emissions from Accessible Emissions form.
Pope & Talbot, Inc., Power Boiler 1 Oil Use	410433501	14.0	100%	100.0%	100.0%	100.0%	14.0	14.0	0.0	Installed 1968. No controls. Rated capacity is 229 MMBtu/hr. 1996 - 1998 emissions from Accessable Emissions forms.
Amalgamated Sugar Co. -Nyssa, S-B3, Foster - Wheeler Boiler (coal-fired)	410450002	454.8	100%	100.0%	0.0%	85.0%	454.8	68.2	386.6	Coal-fired Foster-Wheeler (stoker) boiler, installed in 1973. Rated Design capacity is 313 MMBtu/hr. Heat input is 273 MMBtu/hr (@ 80% efficiency and 1090 Btu/lb steam). Control equipment is a baghouse installed in 1973. Rated efficiency of the baghouse is unknown. 1998 emissions from the R1001B form.
Amalgamated Sugar Co. -Nyssa, S-B2, Foster Riley Boiler (coal-fired)	410450002	214.6	100%	100.0%	0.0%	85.0%	214.6	32.2	182.4	Coal-fired Foster Riley Boiler, installed in 1966. The unit has a common stack with S-B3. Included here under the "fossil fuel boiler combination" criteria in combination with S-B3. Rated design capacity is 136 MMBtu/hr. This device is controlled by a baghouse only installed in 1975. 1998 emissions from R1001B.
Portland General Electric Company - Boardman, Main Boiler	410490016	16,577.0	75.3%	85.0%	0.0%	85.0%	18712.4	2806.9	15905.6	Construction started 3/24/75. The TV application indicates a date installed of 8/1/80. ESP listed with same dates and 99.7% efficiency.
Reynolds Metals Co., Potrooms Rimary Collection System	410511851	184.5	100%	100.0%	0.0%	0.0%	184.5	184.5	0.0	One of the five potlines was installed in 1970. The 1970 date was used for the 2008 age determination. The rest were installed in 1941. A carbon block is used as an anode in the reduction of alumina. The TV permit notes that sulfur dioxide emission originate from the sulfur content left in the carbon blocks after baking. The process is controlled by baghouses installed in 1977.
						Total	21909.0	4940.1	16968.8	

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[1] Capacity factors are from ICF's data reconciliation spreadsheet that was distributed on July 23, 2000

Emission Reductions by source category

Utilities	15905.6
Industrial Boilers	1063.3
Refineries	

Utah - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities, Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
PacifiCorp-Huntington Plant Unit#1	1501001	2,030	80.5%	85.0%	83.5%	83.5%	2143.5	2143.5	0.0
PacifiCorp-Huntington Unit #2	1501001	11,870	82.8%	85.0%	0.0%	85.0%	12185.4	1827.8	10357.6
PacifiCorp-Hunter Unit #1	1500101	2,636	73.7%	85.0%	80.0%	80.0%	3040.2	3040.2	0.0
PacifiCorp-Hunter Unit #2	1500101	2,962	81.3%	85.0%	80.0%	80.0%	3096.8	3096.8	0.0
						Total	20465.8	10108.3	10357.6

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Emission reductions by source category

Utilities	10357.6
Industrial Boilers	
Refineries	

Wyoming - Regional Emission Reduction Estimates - DRAFT

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities[1], Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
Pacificorp Wyodak Coal Power Plant (U1)	56 005 0046	9,082	88.9%	88.9%	65.0%	85.0%	9082.0	3892.3	5189.7
Black Hills Neil Simpson Coal Power Plant (U1)	56 005 0002	559	78.8%	85.0%	0.0%	85.0%	603.0	90.4	512.5
Pacificorp Naughton Coal Power Plant (U1)	56 023 0004	7,112	82.7%	85.0%	0.0%	85.0%	7309.8	1096.5	6213.3
Pacificorp Naughton Coal Power Plant (U2)	56 023 0004	9,576	81.6%	85.0%	0.0%	85.0%	9975.0	1496.3	8478.8
Pacificorp Naughton Coal Power Plant (U3)	56 023 0004	5,156	68.2%	85.0%	77.0%	82.0%	6426.1	5029.1	1397.0
Pacificorp Dave Johnston Coal Power Plant (U3)	56 009 0001	8,477	61.8%	85.0%	0.0%	85.0%	11659.3	1748.9	9910.4
Pacificorp Dave Johnston Coal Power Plant (U4)	56 009 0001	8,507	77.4%	85.0%	54.0%	85.0%	9342.3	3046.4	6295.9
Pacificorp Jim Bridger Coal Power Plant (U1)	56 037 1002	7,673	82.3%	85.0%	77.0%	82.0%	7924.7	6202.0	1722.8
Pacificorp Jim Bridger Coal Power Plant (U2)	56 037 1002	7,920	85.2%	85.2%	77.0%	82.0%	7920.0	6198.3	1721.7
Pacificorp Jim Bridger Coal Power Plant (U3)	56 037 1002	6,484	69.2%	85.0%	77.0%	82.0%	7964.5	6233.0	1731.4
Pacificorp Jim Bridger Coal Power Plant (U4)	56 037 1002	3,703	79.8%	85.0%	82.0%	82.0%	3944.3	3944.3	0.0
Basin Electric Laramie River Coal Power Plant (U1)	56 031 0001	3,748	82.7%	85.0%	80.5%	80.5%	3852.2	3852.2	0.0
Basin Electric Laramie River Coal Power Plant (U2)	56 031 0001	3,615	83.1%	85.0%	80.5%	80.5%	3697.7	3697.7	0.0
Basin Electric Laramie River Coal Power Plant (U3)	56 031 0001	3,706	79.9%	85.0%	80.5%	80.5%	3942.6	3942.6	0.0
Wyoming Refining TCC Feed Heater (H-03)	56 045 0001	182	100%	100.0%	0.0%	98.0%	181.7	3.6	178.0
Wyoming Refining TCC Plume Burner (H-05)	56 045 0001	58	100%	100.0%	0.0%	98.0%	58.3	1.2	57.2
Little America Oil Refinery #7 Boiler (BL-1415)	56 025 0005	0	100%	100.0%	0.0%	98.0%	0.3	0.0	0.3
FMC Corp. Trona Plant NS-1A Coal Boiler	56 037 0048	2,379	100%	100.0%	0.0%	85.0%	2379.0	356.9	2022.2
FMC Corp. Trona Plant NS-1B Coal Boiler	56 037 0048	2,846	100%	100.0%	0.0%	85.0%	2846.3	427.0	2419.4
General Chemical Trona Plant GR-2-L Coal Boiler	56 037 0002	1,814	100%	100.0%	0.0%	85.0%	1813.7	272.1	1541.6
General Chemical Trona Plant GR-3-W Coal Boiler	56 037 0002	2,972	100%	100.0%	0.0%	85.0%	2972.0	445.8	2526.2
FMC - Granger (Tg) Trona Plant #1 Coal Boiler (14)	56 037 0010	94	100%	100.0%	85.0%	85.0%	94.0	94.0	0.0
FMC - Granger (Tg) Trona Plant #2 Coal Boiler (15)	56 037 0010	103	100%	100.0%	85.0%	85.0%	103.3	103.3	0.0
						Total	104092.0	52173.7	51918.3

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[1] Capacity factors are from ICF's data reconciliation spreadsheet that was distributed on July 23, 2000

Emission reductions by source category

Utilities	43173.5
Industrial Boilers	8509.4
Refineries	235.5

Tribes - Regional Emission Reduction Estimates - BART

Note: These estimates have not yet factored in the visibility improvement from the application of Appropriate Retrofit Technology

Yellow Cells indicate regional estimates from the Regional Haze BART Methodology
Green Cells indicate the average 1996-1998 inventory data, by unit, that was prepared by the states in the Allstat5.xls spreadsheet
Blue Cells indicate 1999 Acid Rain Data

Unit	Tribe	AIRS ID	1996-1998 Average Emissions for Non-Utilities, 1999 Emissions for Utilities	1999 Capacity Factor for Utilities, Assume 100% Capacity (no change in future) for others	2018 Capacity Factor	Current Control Efficiency (%)	Appropriate Retrofit Technology (%)	2018 Emissions (Current Controls)	2018 Emissions (Appropriate Retrofit Controls)	Emission Reductions due to Appropriate Retrofit Controls
Arizona Public Service, 4-Corners, Unit #1	Navajo	350450002	3,352	75.1%	85.0%	72.0%	77.0%	3793.9	3116.4	677.5
Arizona Public Service, 4-Corners, Unit #2	Navajo	350450002	3,254	70.5%	85.0%	72.0%	77.0%	3923.3	3222.7	700.6
Arizona Public Service, 4-Corners, Unit #3	Navajo	350450002	4,989	76.4%	85.0%	72.0%	77.0%	5550.6	4559.4	991.2
Arizona Public Service, 4-Corners, Unit #4	Navajo	350450002	15,046	73.3%	85.0%	72.0%	77.0%	17447.6	14332.0	3115.6
Arizona Public Service, 4-Corners, Unit #5	Navajo	350450002	15,881	76.0%	85.0%	72.0%	77.0%	17761.6	14589.9	3171.7
							Total	48477.0	39820.4	8656.6

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Emission reductions by source category

Utilities	8656.6
Industrial Boilers	
Refineries	

UAE Exhibit RR 2.6

WDEQ BART ANALYSIS - WYODAK

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6043

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Wyodak Plant
FACILITY LOCATION:	Section 27, T50N, R71W UTM Zone: 13, NAD 27 Easting: 469,410 m, Northing: 4,903,708 m Campbell County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Gary L. Harris
MAILING ADDRESS:	48 Wyodak Road - Garner Lake Route Gillette, WY 82718
TELEPHONE NUMBER:	(307) 687-4230
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 February 5, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), the Division received a BART application for the existing coal-fired boiler at the PacifiCorp Wyodak Power Plant. A map showing Wyodak's location is attached as Appendix A.

On June 5, 2007, PacifiCorp submitted additional copies of the February application for the existing unit at Wyodak subject to BART.

On October 16, 2007, PacifiCorp submitted an updated application for the single unit subject to BART at Wyodak. Additional modeling performed after the February 5, 2007 submittal and revised visibility control effectiveness calculations were included.

On December 5, 2007, PacifiCorp submitted a revised application incorporating changes to the post-processing of the visibility model runs for Wyodak Unit 1.

On March 31, 2008, PacifiCorp submitted an addendum to the BART application for Wyodak Unit 1. Revised cost estimates and updated visibility modeling for two (2) NO_x control scenarios were included in the addendum.

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 single existing coal-fired boiler at PacifiCorp's Wyodak Power Plant, Unit 1, was 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 Wyodak Power Plant is comprised of one (1) coal-fired boiler burning pulverized sub-bituminous Powder River Basin coal for a total net generating capacity of a nominal 335 megawatts (MW). Wyodak's pulverized coal-fired boiler commenced service in 1978. It was manufactured by Babcock & Wilcox and equipped with wall-fired burners. NO_x emissions from the boiler are currently controlled with first generation low NO_x burners. Particulate matter (PM) emissions from the unit are controlled using a Babcock & Wilcox Rothemuhle weighted wire electrostatic precipitator (ESP). SO_2 emissions from Wyodak Unit 1 are controlled using a Joy Niro, three-tower lime-based spray dryer installed in 1986.

Table 1: Wyodak Unit 1 Pre-2005 Emission Limits [a]

Source	Firing Rate (MMBtu/hour)	Existing Controls	NO_x (lb/MMBtu)	SO_2 (lb/MMBtu)	PM/PM_{10} (lb/MMBtu)
Unit 1	4,100 [b]	LNB, ESP, & dry FGD	0.70 (3-hour fixed) 0.31 (annual) [c]	0.5 (3-hour fixed)	0.10

[a] Emissions taken from Operating Permit 3-1-101-1.
[b] Boiler heat input reported based on historical monthly coal data.
[c] Annual emission limit established under 40 CFR part 76.

On April 24, 2007, WAQSR Chapter 6, Section 3 Operating Permit 3-1-101-1, was issued to PacifiCorp for Wyodak Unit 1. NO_x and PM emission limits did not change from the previous Operating Permit 30-101-1. SO_2 emission limit established under the Acid Rain Program (40 CFR 76.11) for the baseline period were 0.31 lb/MMBtu, annual average.

The reported maximum firing rate of the boiler stated in Operating Permit 3-1-101-1 is based on monthly coal data. The maximum firing rate of the boiler, as measured by the existing continuous emission monitoring system (CEM), is 4,700 MMBtu/hr. PacifiCorp based emissions calculations for the BART analysis on the highest firing rate of 4,700 MMBtu/hr.

PacifiCorp recently received an Air Quality permit to modify Wyodak Unit 1. The first generation LNB on Unit 1 will be replaced with Alstom TFS 2000™ LNB with overfire air. The existing ESP will be replaced with a new full-scale fabric filter baghouse. Table 2 lists the new emission limits for Unit 1. They become effective after the corresponding controls are installed and the applicable initial performance tests are completed.

Table 2: New Emission Limits for Wyodak Unit 1 [(a)]

Source	Permitted Controls	NO_x	SO_2	PM/PM_{10} [(b)]
Unit 1	New LNB with advanced OFA, Dry FGD, Fabric Filter Baghouse	0.23 lb/MMBtu (30-day rolling) 1,081.0 lb/hr (30-day rolling)	0.16 lb/MMBtu (30-day rolling) 0.5 lb/MMBtu (3-hr block) 2,115.0 lb/hr (3-hr block)	0.015 lb/MMBtu 71.0 lb/hr 308.8 tpy

[(a)] Emissions limits taken from recent New Source Review construction permit for Wyodak Unit 1.
[(b)] Averaging period is determined by the appropriate test method.

PacifiCorp provided a construction schedule for the installation of the new LNB with advanced OFA and a new full-scale fabric filter baghouse in the permit application. Construction activities for the pollution control upgrades on Unit 1 are anticipated to begin March 5, 2011 during the scheduled outage and end approximately April 16, 2011.

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

[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."

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 Wyodak Unit 1 thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

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.

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

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.

PacifiCorp's Wyodak Power Plant generates nominal 335 MW from the single unit. A three-tower lime-based spray dryer currently controls SO_2 emissions. The unit does not have NO_x post-combustion controls. Presumptive SO_2 limit of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limit of 0.23 lb/MMBtu, based on unit type and coal type, do not apply to Unit 1 since the cumulative generating capacity of the facility is less than 750 MW. Before making a BART determination for Unit 1, the Division analyzed potential retrofit controls for NO_x, SO_2, and PM/PM_{10}, taking into consideration all five statutory factors. The analysis is presented below.

NO_x: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp identified four control technologies to control NO_x emissions: (1) low NO_x burners with advanced overfire air, (2) rotating opposed fire air (ROFA), (3) selective non-catalytic reduction (SNCR), and (4) selective catalytic reduction (SCR). LNB with advanced 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 Advanced 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 advanced 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.

[4] Ibid. (70 Federal Register 39171).

2. Rotating Opposed Fire Air – ROFA can be used with LNB technology to control the combustion process inside the boiler. Similar to the advanced 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 advanced 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 advanced 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 Wyodak unit and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with advanced OFA on Wyodak Unit 1 would result in a NO_x emission rate of 0.23 lb/MMBtu. On page 3-4 of the December 2007 submittal PacifiCorp states: "PacifiCorp has indicated that this rate [0.23 lb/MMBtu] corresponds to a vendor guarantee plus an added operating margin, not a vendor prediction, and they believe that this emission rate can be sustained as an average between overhauls."

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boiler at the Wyodak Power Plant with Mobotec's ROFA. Mobotec analyzed the operation of existing burners and OFA ports. Typically the existing burner 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 on Unit 1 using ROFA technology. PacifiCorp added an additional operating margin of 0.02 lb/MMBtu to Unit 1 to account for site specific issues, such as feed coal variance, for total proposed emission rate of 0.20 lb/MMBtu.

S&L evaluated emission reductions associated with installing SNCR in addition to retrofitting the boilers with LNB with advanced OFA. Based on installing LNB with advanced OFA capable of achieving a NO_x emission rate of 0.23 lb/MMBtu on Unit 1, S&L concluded that SNCR can reduce emissions by 20% resulting in projected NO_x emission rate of 0.18 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. PacifiCorp did not model visibility improvement from installing SNCR on Unit 1 on account of the expected marginal emission rate improvement, the burden of significant ongoing parasitic costs, the operating difficulties, and the potential ammonia slip.

S&L prepared the design conditions and cost estimates for installing SCR on Wyodak Unit 1. 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 reactor containing the catalyst to increase physical space occupied by the catalyst to improve the NO_x removal rate. Additional catalyst would be added to accommodate nitrogen levels in the coal feedstock. Based on the S&L design, which included installing both LNB with advanced OFA and SCR, PacifiCorp concluded Unit 1 can achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 3: Wyodak Unit 1 Boiler NO_x Emission Rates

Control Technology	Resulting NO_x Emission Rate (lb/MMBtu)
Existing LNB	0.31 [a]
New LNB with advanced OFA	0.23
Existing burners with ROFA	0.20
New LNB with advanced OFA and SNCR	0.18
New LNB with advanced OFA and SCR	0.07

[a] Operating Permit 3-1-101-1 annual averaged NO_x emissions established through 40 CFR part 76.

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 with advanced OFA will not significantly impact the boiler efficiency or forced draft fan power usage, two common boiler features for adverse energy impact often affected by changes in boiler combustion.

Installing the Mobotec ROFA system has a significant energy impact on Wyodak. One 7,000 horsepower (hp) ROFA fan on Unit 1 is required to induct a sufficient volume of air into the boiler to cause rotation of the combustion air throughout the boiler. The annual energy impact from operating the proposed ROFA fan is 41,200 Mega Watt-hour (MW-hr).

PacifiCorp determined the SNCR system would require 340 kilo Watt (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 requirement for SCR installation on Unit 1 would be approximately 2.4 MW.

PacifiCorp evaluated the environmental impacts from the proposed NO_x control technologies. Installing LNB with advanced 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 Wyodak Unit 1 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 Wyodak Unit 1 are summarized in the following tables.

Table 4: Wyodak Unit 1 Economic Costs

Cost	Existing LNB	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$13,100,000	$15,252,149	$19,495,654	$171,900,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,246,203	$1,450,937	$1,854,622	$16,352,847
Annual O&M Costs	$0	$60,000	$2,147,685	$452,106	$2,557,934
Annual Cost of Control	$0	$1,306,203	$3,598,622	$2,306,728	$18,910,781

Table 5: Wyodak Unit 1 Environmental Costs

	Existing LNB	New LNB with advanced OFA	Existing Burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.31	0.23	0.20	0.18	0.07
Annual NO_x Emission (tpy) [(a)]	5,744	4,261	3,706	3,335	1,297
Annual NO_x Reduction (tpy)	N/A	1,483	2,038	2,409	4,447
Annual Cost of Control	$0	$1,306,203	$3,598,622	$2,306,728	$18,910,781
Cost per ton of Reduction	N/A	$881	$1,766	$958	$4,252
Incremental Cost per ton of Reduction	N/A	$881	$4,130	-$3,482 [(b)]	$8,147

[(a)] Annual emissions based on unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year.
[(b)] Incremental cost is negative because the annual cost of control for existing burners with ROFA is significantly higher than new LNB with advanced OFA and SNCR.

The cost effectiveness of the four proposed BART technologies for NO_x are all reasonable. The incremental cost effectiveness is reasonable for all NO_x control technologies. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Unit 1 by modeling LNB with advanced OFA and LNB with advanced OFA and SCR. While the installation of SNCR and 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 Wyodak Unit 1, 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. Table 15 on page 28 lists the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Wyodak Unit 1 is currently equipped with an electrostatic precipitator (ESP) to control PM emissions from the boiler. As discussed below 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. While the current PM_{10} emission limit for Unit 1 is 0.10 lb/MMBtu, PacifiCorp states that the existing ESP is achieving controlled PM/PM_{10} emissions of 0.030 lb/MMBtu. PacifiCorp analyzed three technologies for additional PM control: 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 the use of the existing ESP with a polishing fabric filter or installing a new full-scale fabric filter to control PM/PM_{10} emissions as technically infeasible. However, PacifiCorp did not further analyze the use of FGC or installing a new full-scale fabric filter. According to PacifiCorp, the existing ESP on Unit 1 is well designed and provides adequate space and residence time for the flue gas particles to gain an electric charge and migrate to the collection plate. The application of FGC is not expected to significantly improve PM/PM_{10} removal efficiency. Installing a new full-scale fabric filter is cost-prohibitive in comparison to installing a polishing fabric filter on the existing ESP, which can achieve the same PM/PM_{10} emission rate.

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 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.

Unit 1 has an existing ESP and rather than evaluate costs of replacing the unit, PacifiCorp evaluated additional controls to improve the PM removal efficiency. An ESP is an effective PM control device, as the existing unit is already capable of controlling PM_{10} emissions from Unit 1 to 0.030 lb/MMBtu. The technology continually improves and is commonly proposed for consideration in BACT analyses to control particulate emissions from new PC boilers. In addition to maintaining the existing ESP, 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 the existing ESP on Unit 1 can reduce emissions an additional 50% resulting in a PM_{10} emission rate of 0.015 lb/MMBtu. PacifiCorp did not further evaluate the installation on a new full-scale fabric filter on Unit 1 since there is a substantial capital cost associated with the control and no anticipated benefit when compared to COHPAC.

Table 6: Wyodak Unit 1 Boiler PM_{10} Emission Rates

Source	Existing ESP PM_{10} Emission (lb/MMBtu)	Existing ESP With Polishing Fabric Filter PM_{10} Emission (lb/MMBtu)
Unit 1	0.030	0.015

PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impact of installing COHPAC on Unit 1. 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 2.1 MW of power, equating to an annual power usage of approximately 16,200 MW-hr.

PacifiCorp evaluated the environmental impacts from the proposed installation of COHPAC on Unit 1 and did not anticipate negative environmental impacts from the addition of this PM control technology.

PacifiCorp anticipates operating Wyodak Unit 1 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 the proposed PM/PM_{10} emission control. Economic and environmental costs for additional PM/PM_{10} control on Wyodak Unit 1 are summarized in the following tables.

Table 7: Wyodak Unit 1 Economic Costs

Cost	Existing ESP	Existing ESP with New Polishing Fabric Filter
Control Equipment Capital Cost	$0	$32,630,832
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$3,104,171
Annual O&M Costs	$0	$1,120,709
Annual Cost of Control	$0	$4,224,880

Table 8: Wyodak Unit 1 Environmental Costs

	Existing ESP	Exiting ESP with New Polishing Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.030	0.015
Annual PM_{10} Emission (tpy) [a]	556	278
Annual PM_{10} Reduction (tpy)	N/A	278
Annual Cost of Control	$0	$4,224,880
Cost per ton of Reduction	N/A	$15,197
Incremental Cost per ton of Reduction	N/A	$15,197

[a] Annual emissions based on unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Unit 1 are not reasonable. However, the control was included in the final step in the PM/PM_{10} BART determination process for Wyodak Unit 1, Step 5: Evaluate visibility impacts, which 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. Table 15 on page 28 lists 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 Wyodak Unit 1. 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 control technology listed above as technically infeasible. Both dry FGD and wet FGD are proven SO_2 control technologies. PacifiCorp analyzed the impact of both SO_2 emission reduction technologies on Wyodak Unit 1.

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 dry 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 Wyodak Unit 1 has an uncontrolled SO_2 emission rate of 1.61 lb/MMBtu, based on an average coal sulfur content of 0.65% by weight. The existing three column dry scrubber currently reduces SO_2 emissions by approximately 69% to achieve the SO_2 emission limit of 0.50 lb/MMBtu. Upgrading the existing dry FGD system by eliminating bypass flue gas flow, placing new static mixers to redistribute the flue gas flow prior to the ESP, increasing the reagent feed ratio, and increasing the recycle ratio is projected to reduce SO_2 emissions by 80% from uncontrolled levels, based on an average sulfur content in the feed coal of 0.65% by weight. The resulting SO_2 emission rate would be 0.32 lb/MMBtu.

If the existing ESP is replaced with a new full-scale fabric filter downstream of the lime spray dryer, the dry FGD system is projected to achieve 90% SO_2 removal after the aforementioned upgrades are applied to the dry scrubber. Based on an average sulfur content of 0.65% by weight, the resulting SO_2 emission rate is 0.16 lb/MMBtu.

PacifiCorp evaluated the application of wet FGD on Wyodak Unit 1. A new wet FGD would likely use lime/limestone forced oxidation scrubbing, which is available in several variations from vendors. Wet lime/limestone scrubbing is projected to achieve a SO_2 removal rate of 95% resulting in an outlet SO_2 emission rate of 0.08 lb/MMBtu, based on a sulfur content of 0.65% by weight in the feed coal. PacifiCorp's proposed emission rates for each SO_2 emission reduction technology applied to Wyodak Unit 1 are shown in Table 9.

Table 9: Wyodak Unit 1 SO_2 Emission Rates

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Existing Dry FGD	0.50
Upgraded Dry FGD with existing ESP	0.32
Upgraded Dry FGD with full-scale Fabric Filter	0.16
Wet Lime FGD with existing ESP	0.08

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of upgrading the existing dry FGD system with the existing ESP on Wyodak Unit 1. Dry FGD requires less electric power than a wet FGD system. Upgrading the current dry FGD system with the existing ESP at Wyodak would require approximately 0.1 MW of additional power. Upgrading the existing dry FGD and installing a new polishing fabric filter would require 0.2 MW, while a new wet FGD would require approximately 1.8 MW. Using a 90% annual plant capacity factor, upgrading the existing dry FGD and installing a full-scale fabric filter equates to an annual power savings of approximately 12,600 MW-hr as opposed to installing and operating a new wet FGD system.

PacifiCorp compared the environmental impacts of dry FGD versus wet FGD technology. PacifiCorp concluded that dry FGD has five significant environmental advantages over wet FGD. These advantages are taken directly from PacifiCorp's environmental analysis for SO_2 controls on Wyodak Unit 1 and listed below.

- Sulfuric Acid Mist Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet electrostatic precipitator (ESP) or hydrated lime injection when medium to high sulfur coal is burned in a unit to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.

- Plume Buoyancy Flue gas following a dry FGD system is not saturated with water (gas temperature 30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Because of the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.

- Liquid Waste Disposal There is no liquid waste from a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste, which may be contaminated with toxic metals (including mercury), requiring proper disposal.

- Solid Waste Disposal The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge must be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant to be disposed.

- Makeup Water Requirements Dry FGD has advantages over a wet scrubber, producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for dry FGD is major advantage for this technology.

PacifiCorp anticipates operating Wyodak Unit 1 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 SO_2 emission control. Economic and environmental costs for additional SO_2 controls on Wyodak Unit 1 are summarized in the following tables.

Table 10: Wyodak Unit 1 Economic Costs

Cost	Existing Dry FGD with existing ESP	Upgraded Dry FGD with existing ESP	Upgraded Dry FGD with new full-scale Fabric Filter	New Wet FGD
Control Equipment Capital Cost	$0	$26,759,011	$66,777,531	$95,136,483
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$2,545,585	$6,352,547	$9,050,334
Annual O&M Costs	$0	$1,346,423	$1,471,432	$2,798,979
Annual Cost of Control	$0	$3,892,008	$7,823,979	$11,849,313

Table 11: Wyodak Unit 1 Environmental Costs

	Existing Dry FGD with existing ESP	Upgraded Dry FGD with existing ESP	Upgraded Dry FGD with new full-scale Fabric Filter	New Wet FGD
SO_2 Emission Rate (lb/MMBtu)	0.5	0.32	0.16	0.08
Annual SO_2 Emission (tpy) [a]	9,264	5,929	2,964	1,482
Annual SO_2 Reduction (tpy)	N/A	3,335	6,300	7,782
Annual Cost of Control	$0	$3,892,008	$7,823,979	$11,849,313
Cost per ton of Reduction	N/A	$1,167	$1,242	$1,523
Incremental Cost per ton of Reduction	N/A	$1,167	$1,326	$2,716

[a] Annual emissions based on unit heat input rate of 4,700 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the proposed wet FGD and dry FGD controls for Unit 1 are reasonable. The final step in the SO_2 BART determination process for Wyodak Unit 1, 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. Table 15 on page 28 lists 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 Wyodak plant with an EPA-approved dispersion modeling system (CALPUFF) to predict the changes 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.

Wind Cave and Badlands National Parks (NP) in South Dakota are the closest Class I areas to the Wyodak plant, as shown in Figure 1 below. Wind Cave NP is located approximately 168 kilometers (km) east-southeast of the plant and Badlands NP is located approximately 240 km east-southeast of the plant.

Only those Class I areas most likely to be impacted by the Wyodak 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 two modeled areas.

SCREENING MODELING

To determine if the Wyodak plant would be subject to BART, the Division conducted CALPUFF visibility modeling using three years of meteorological data. These data, from 2001-2003, consisted of surface and upper-air observations from individual weather stations and gridded output from the Mesoscale Model (MM5). Resolution of the MM5 data was 36-km for all three of the modeled years. Potential emissions for current operation from the coal-fired boiler at the Wyodak plant were input to the model.

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 Badlands NP and Wind Cave NP. 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 Table 12.

Figure 1
Wyodak Power Plant and Class I Areas

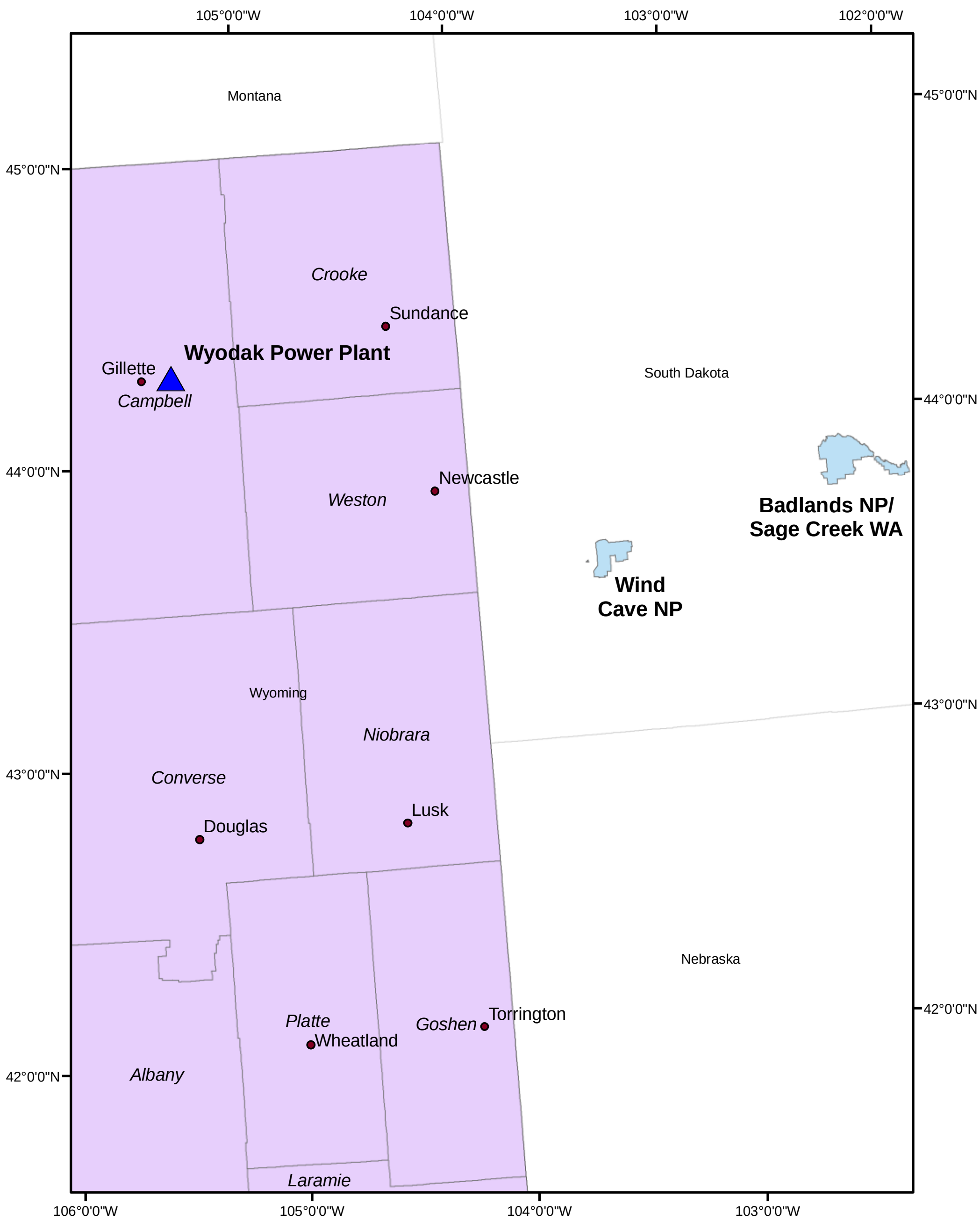


Table 12: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
2001		
Badlands NP	1.155	0.842
Wind Cave NP	1.671	1.007
2002		
Badlands NP	2.160	1.246
Wind Cave NP	2.490	1.213
2003		
Badlands NP	2.484	1.097
Wind Cave NP	3.685	1.657

Δdv = delta deciview
NP = national park

REFINED MODELING

Because of the results of the Division's screening modeling, PacifiCorp was required to conduct a BART analysis that included refined 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 Wyodak plant 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 13: Key Programs in CALPUFF System

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

<u>Meteorological Data Processing (CALMET)</u>

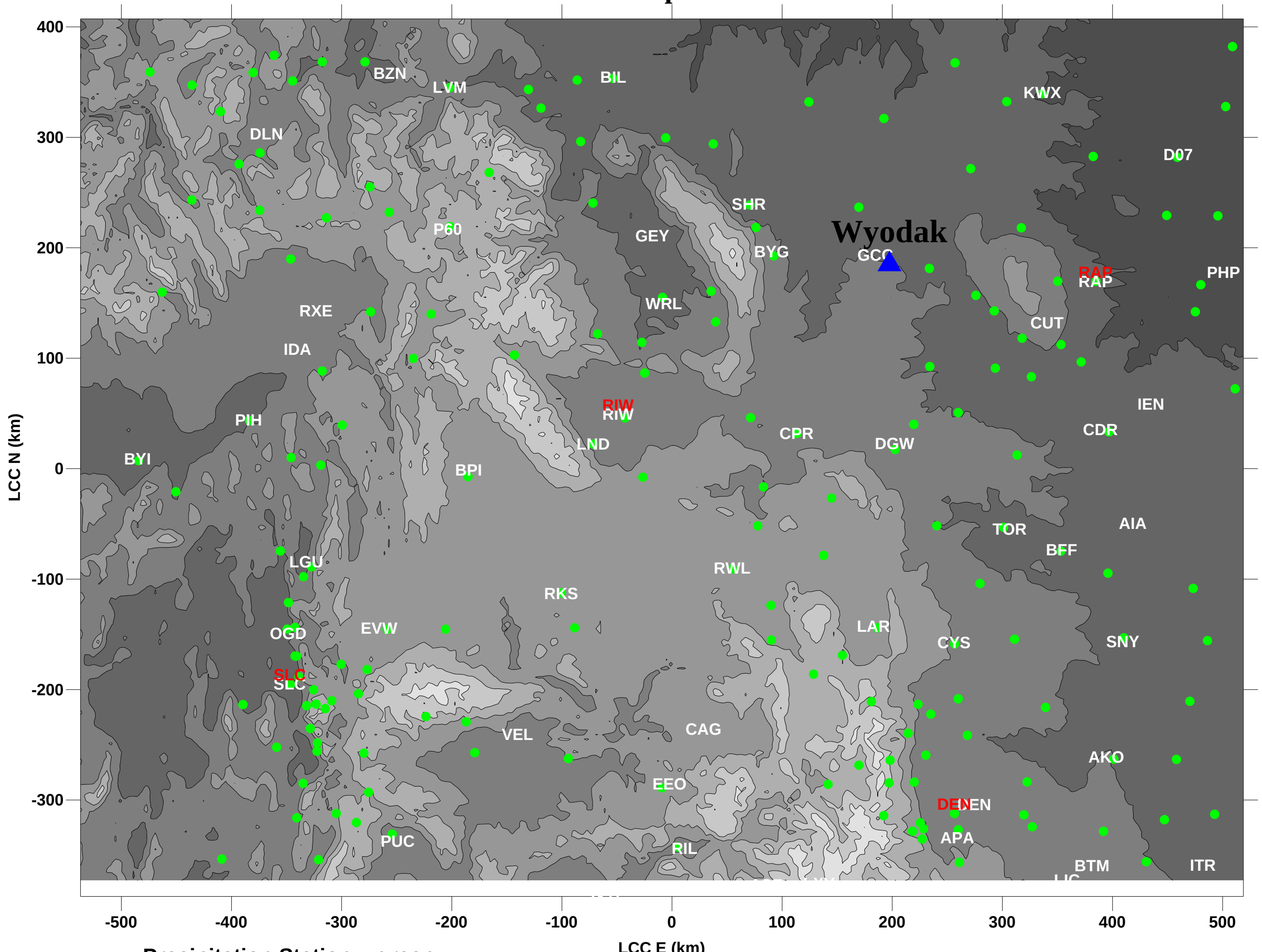
As required by the Division's modeling protocol, the CALMET model was used to construct an initial three-dimensional windfield using data from the MM5 model. Surface and upper-air observations were input to CALMET to adjust the initial windfield, but because of the relative scarcity of wind observations 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 the figure below. 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 14: 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 2
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 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 3 through 4 show the receptor configurations that were used for Badlands NP and Wind Cave NP. Receptor spacing within Wind Cave NP is approximately 0.7 km in the east-west direction and approximately 0.9 km in the north-south direction. For Badlands NP, the receptor spacing is approximately 1.3 km in the east-west direction and approximately 1.8 km in the north-south direction.

Figure 3
Receptors for Wind Cave NP

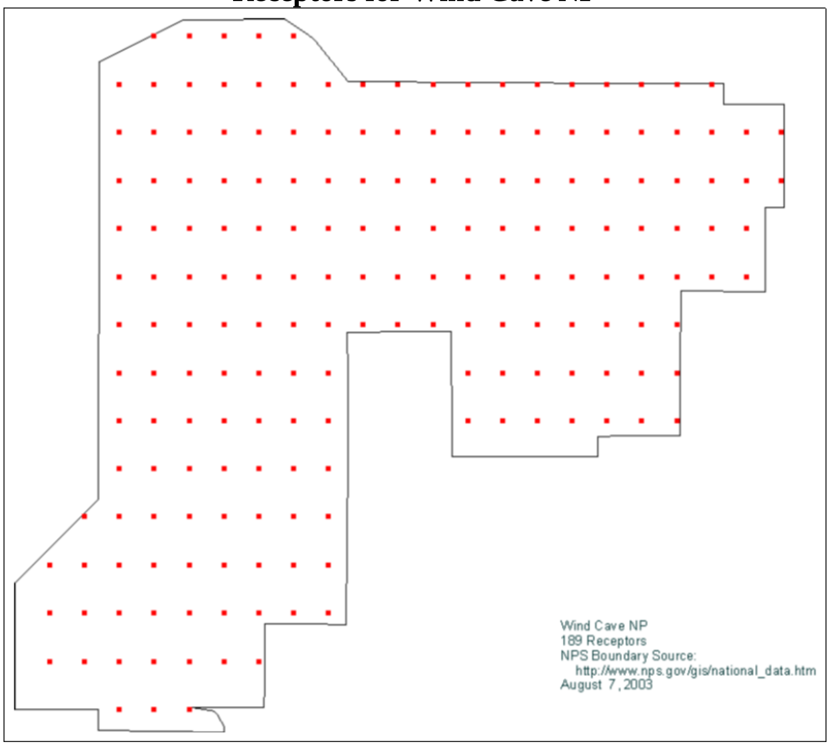
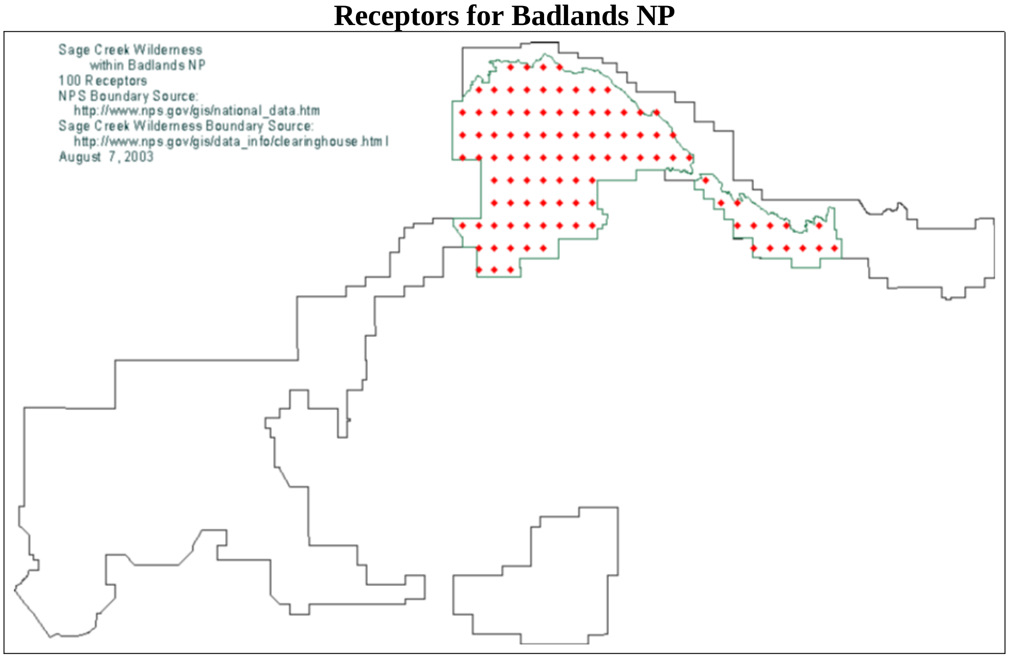


Figure 4
Receptors for Badlands NP



CALPUFF Inputs – Baseline and Control Options

Source release parameters and emissions for baseline and control options for the Wyodak plant are shown in the table below.

Table 15: CALPUFF Inputs for Wyodak Unit 1

Wyodak Unit 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 Dry FGD and ESP	LNB with advanced OFA, Dry FGD, ESP	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, ESP	Committed Controls: LNB with advanced OFA, Dry FGD, New Fabric Filter	Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	4,700	4,700	4,700	4,700	4,700	4,700	4,700
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.50	0.32	0.16	0.16	0.08	0.16	0.16
Sulfur Dioxide (SO_2) (lb/hr)	2,350	1,518	759	759	380	759	759
Nitrogen Oxide (NO_x) (lb/mmBtu)	0.31	0.23	0.23	0.07	0.07	0.23	0.07
Nitrogen Oxide (NO_x) (lb/hr)	1,457	1,081	1,081	329	329	1,081	329
PM_{10} (lb/mmBtu)	0.030	0.030	0.015	0.015	0.030	0.015	0.015
PM_{10} (lb/hr)	141.0	141.0	70.5	70.5	141.0	70.5	70.5
Coarse Particulate ($PM_{2.5}$ <diameter < PM_{10}) (lb/hr)[(a)]	60.6	60.6	40.2	40.2	60.6	40.2	40.2
Fine Particulate (diameter < $PM_{2.5}$) (lb/hr)[(b)]	80.4	80.4	30.3	30.3	80.4	30.3	30.3
Sulfuric Acid (H_2SO_4) (lb/hr)	5.6	5.6	5.6	9.4	105.0	5.6	9.4
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	1.1	5.5	--	1.1
$(NH_4)HSO_4$ (lb/hr)	--	--	--	1.9	9.5	--	1.9
H_2SO_4 as Sulfate (SO_4) (lb/hr)	5.5	5.5	5.5	9.2	103.0	5.5	9.2
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.8	4.0	--	0.8
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	1.6	8.0	--	1.6
Total Sulfate (SO_4) (lb/hr)[(c)]	5.5	5.5	5.5	11.6	114.9	5.5	11.6
Stack Conditions							
Stack Height (meters)	122	122	122	122	122	122	122
Stack Exit Diameter (meters)	6.1	6.1	6.1	6.1	6.1	6.1	6.1
Stack Exit Temperature (Kelvin)	358	353	350	350	322	350	350
Stack Exit Velocity (meters per second)	23.5	23.5	23.5	23.5	23.5	23.5	23.5

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.

<u>Visibility Post-Processing (CALPOST)</u>

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 Badlands NP and Wind Cave NP are shown in the table below.

Table 16: Relative Humidity Factors for CALPOST

Month	**Badlands NP & Wind Cave NP**
January	2.65
February	2.65
March	2.65
April	2.55
May	2.70
June	2.60
July	2.30
August	2.30
September	2.20
October	2.25
November	2.75
December	2.65

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 Badlands NP. From Appendix B in the EPA natural visibility guidance document, the deciview value for the 20 percent best days at Badlands NP is 2.18 dv. To obtain the speciated background concentrations representative of the 20 percent best days, the deciview value (2.18 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 2.18, one obtains an equivalent light extinction value of 12.44 Mm^{-1}. Next, the annual average natural visibility concentrations were set equal to a total extinction value of 12.44 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 Badlands NP, and including a coefficient for scaling, one obtains:

12.44 = (3)(2.55)[0.12]X + (3)(2.55)[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 0.402. Table 17 presents the annual average natural background concentrations, the calculated scaling factor, and the calculated background concentrations for the 20 percent best days for Badlands NP.

Table 17: Calculated Background Components for Badlands NP

Component	Annual Average for West Region ($\mu g/m^3$)	Calculated Scaling Factor	20% Best Days for Badlands NP ($\mu g/m^3$)
Ammonium Sulfate	0.12	0.402	0.048
Ammonium Nitrate	0.10	0.402	0.040
Organic Carbon	0.47	0.402	0.189
Elemental Carbon	0.02	0.402	0.008
Soil	0.50	0.402	0.201
Coarse Mass	3.00	0.402	1.205

The scaled aerosol concentrations were averaged for Badlands NP and Wind Cave NP because of their geographical proximity and similar annual background visibility. The 20 percent best days aerosol concentrations for the two Class I areas in question are listed in the table below.

Table 18: Natural Background Aerosol Concentrations (μg/m^3)

Aerosol Component	Wind Cave NP & Badlands NP
Ammonium Sulfate	0.047
Ammonium Nitrate	0.040
Organic Carbon	0.186
Elemental Carbon	0.008
Soil	0.198
Coarse Mass	1.191

Visibility Post-Processing Results

The results of the visibility modeling for the Wyodak facility 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 19: CALPUFF Visibility Modeling Results for Wyodak Unit 1

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Dry FGD, ESP								
Badlands NP	0.841	27	1.140	34	1.070	31	1.017	31
Wind Cave NP	1.153	41	1.323	38	1.530	37	1.335	39
Post-Control Scenario 1 – LNB w/ advanced OFA, Dry FGD, ESP								
Badlands NP	0.595	12	0.829	18	0.739	20	0.721	17
Wind Cave NP	0.817	19	0.940	26	1.114	28	0.957	24
Post-Control Scenario 2 – LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.472	6	0.624	14	0.583	13	0.560	11
Wind Cave NP	0.671	11	0.788	17	0.929	17	0.796	15
Post-Control Scenario 3 – LNB w/ advanced OFA and SCR, Dry FGD, Fabric Filter								
Badlands NP	0.254	1	0.331	2	0.314	2	0.300	2
Wind Cave NP	0.333	2	0.383	5	0.457	6	0.391	4
Post-Control Scenario 4 – LNB w/ advanced OFA and SCR, Wet FGD, ESP								
Badlands NP	0.294	1	0.405	3	0.340	3	0.346	2
Wind Cave NP	0.396	2	0.519	9	0.684	10	0.533	7
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.473	6	0.624	14	0.583	13	0.560	11
Wind Cave NP	0.671	11	0.788	17	0.929	17	0.796	15
Post-Control Scenario B – Committed Controls + SCR								
Badlands NP	0.254	1	0.331	2	0.314	2	0.300	2
Wind Cave NP	0.333	2	0.383	5	0.457	6	0.391	4

Figure 5
Modeled BART Impacts: 98th Percentile (delta-dv)

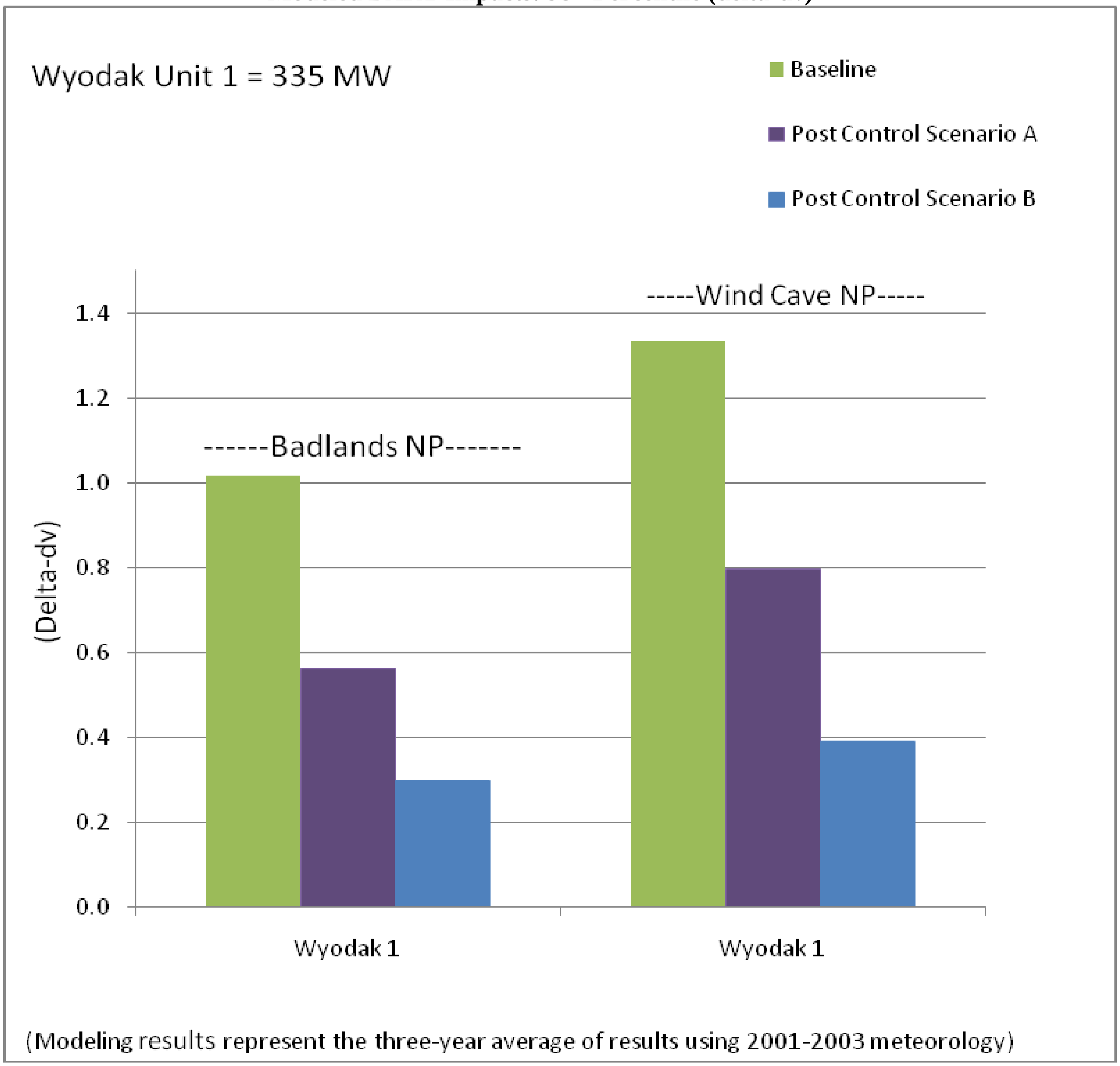
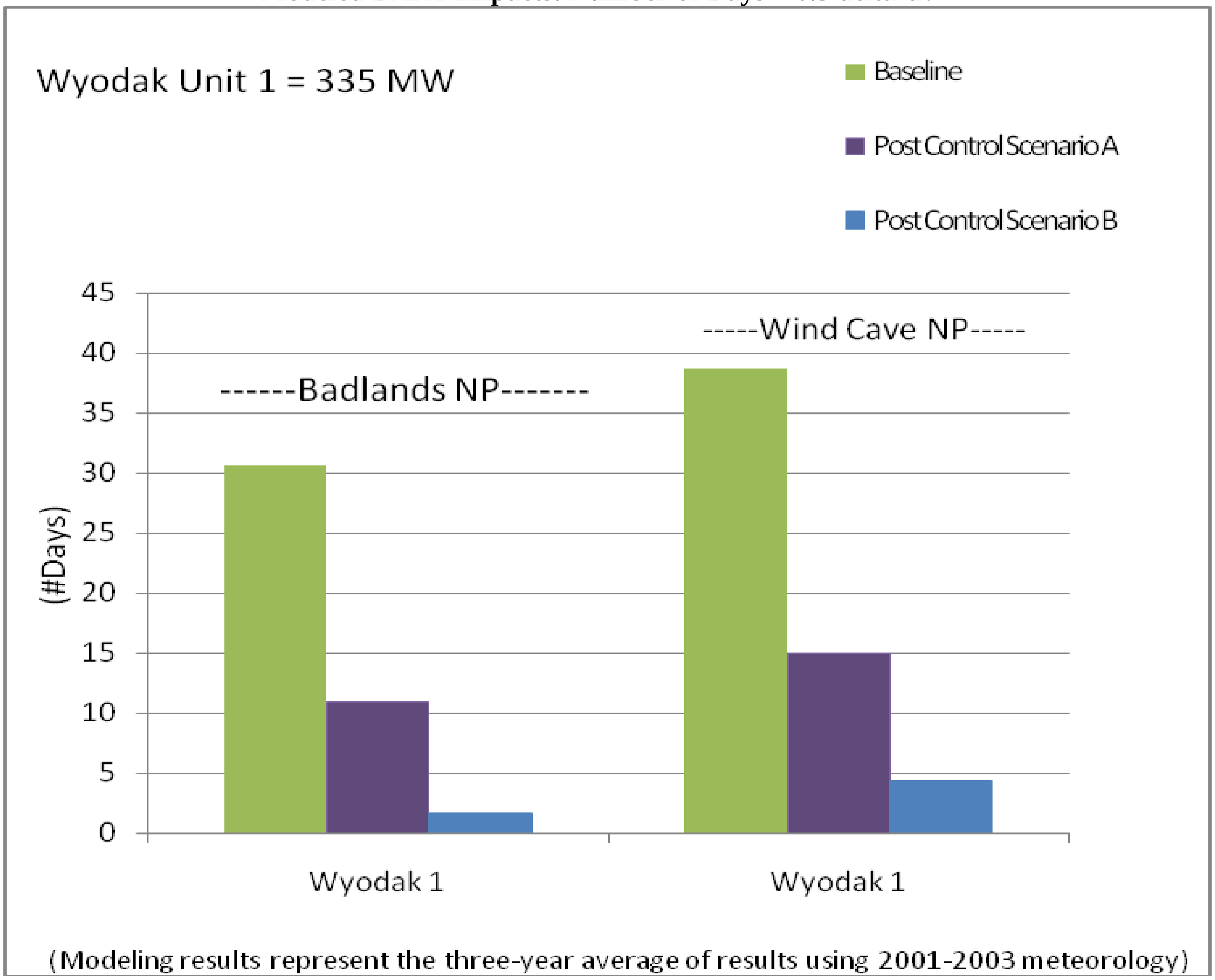


Figure 6
Modeled BART Impacts: Number of Days > 0.5 delta-dv



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 single unit subject to BART at the Wyodak Power Plant.

NO_x

LNB with advanced OFA is determined to be BART for Unit 1 for NO_x based, in part, on the following conclusions:

1. LNB with advanced OFA on Unit 1 was cost effective with a capital cost of $13,100,000. The average cost effectiveness, over a twenty year operational life, is $881 per ton of NO_x removed.

2. Combustion control using LNB with advanced 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 0.23 lb/MMBtu on a 30-day rolling average, equal to EPA's presumptive limit of 0.23 lb/MMBtu for wall-fired boilers burning sub-bituminous coal, though it is not applicable, is justified for Unit 1.

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 98^{th} percentile visibility improvement from the baseline summed across both Class I areas achieved with LNB with advanced OFA, upgrading the existing dry FGD, and a new full-scale fabric filter, Post-Control Scenario A for Unit 1, was 0.996 Δdv.

5. Annual NO_x emission reduction from baseline achieved by applying LNB with advanced OFA on Unit 1 is 1,483 tons.

LNB with advanced OFA and SCR was not determined to be BART for Unit 1 for NO_x based, in part, on the following conclusions:

1. The cost of compliance for installing SCR on the unit is significantly higher than LNB with advanced OFA. Capital cost for SCR on Unit 1 is $171,900,000. Annual SCR O&M costs for Unit 1 are $2,557,934.

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

3. Operation of LNB with advanced OFA and SCR is parasitic and requires an estimated 2.4 MW from Unit 1.

4. While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of SCR. Subtracting the modeled 98th percentile values from each other yield the incremental 98th percentile visibility improvement from SCR. The cumulative 3-year averaged 98th percentile visibility improvement from Post-Control Scenario A summed across both Class I areas achieved with Post-Control Scenario B was 0.665 Δdv.

The Division considers the installation and operation of the BART-determined NO_x control, new LNB with advanced OFA on Unit 1 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

Wyodak Unit 1:	Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.23 lb/MMBtu (30-day rolling average), 1,081.0 lb/hr (30-day rolling average), and 4,735 tpy as BART for NO_x.

PM/PM_{10}

A new full-scale fabric filter is determined to be BART for Unit 1 for PM/PM_{10} based, in part, on the following conclusions:

1. While the Division considers the cost of compliance for a full-scale fabric filter on Unit 1 not reasonable, PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter on Unit 1 in a recently issued New Source Review construction permit. A full-scale fabric filter is the most stringent PM/PM_{10} control technology and therefore the Division will accept it as BART.

The Division considers the installation and operation of the BART-determined PM/PM_{10} control, new full-scale fabric filter on Unit 1 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

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

Wyodak Unit 1:	Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 71.0 lb/hr, and 309 tpy as BART for PM/PM_{10}.

SO_2: WESTERN BACKSTOP SULFUR DIOXIDE TRADING PROGRAM

PacifiCorp evaluated control SO_2 control technologies that can achieve a SO_2 emission rate of 0.16 lb/MMBtu or lower from the coal-fired boilers. PacifiCorp proposed upgrading the existing dry FGD and installing a full-scale fabric filter as SO_2 BART controls on Wyodak Unit 1.

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 in Table 20.

Table 20: 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 21 to underscore the improvements associated with SO_2 reductions.

Table 21: 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 the installation costs of the pollution control systems.

PacifiCorp's BART-eligible or subject-to-BART power plant fleet is shown in Table 22. 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 22: 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.

Based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART application for Wyodak Unit 1, 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 not requiring additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan in this permitting action. Additional controls may be required in future actions related to the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan.

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

PacifiCorp's Wyodak 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 Wyodak Unit 1.

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 Wyodak Unit 1.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Wyodak Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-2-101, was issued for the facility on February 18, 2009. In accordance with Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations, PacifiCorp will need to modify their operating permit to include the changes authorized in this permitting action.

CONCLUSION:

The Division is satisfied that PacifiCorp's Wyodak 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 to install new LNB with advanced OFA and a new full-scale fabric filter on Unit 1.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Wyodak 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, 1866 South Sheridan Avenue, Sheridan, WY 82801.

5. Effective upon completion of the initial performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Wyodak Unit 1 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 oil into the boiler and ends no later than the point in time when the flue gas desulfurization system on Unit 1 reaches a temperature of 275°F and three (3) coal pulverizers have been placed in service.

Pollutant	lb/MMBtu	lb/hr	tpy
NO_x	0.23 (30-day rolling)	1,081.0 (30-day rolling)	4,735
PM/PM_{10} [a]	0.015	71.0	309

[a] Filterable portion only

6. That initial performance tests be conducted, 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.

7. Performance tests shall consist of the following:

    Coal-fired Boiler (Wyodak Unit 1):

    <u>NO_x Emissions</u> – 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.

    <u>PM/PM_{10} Emissions</u> – 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.

8. 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.

9. 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.

10. Compliance with the NO_x limits set forth in this permit for the coal-fired boiler (Wyodak Unit 1) shall be determined with data from the continuous monitoring system 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).

11. 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).

12. Compliance with the PM/PM_{10} limits set forth in this permit for the coal-fired boiler (Wyodak Unit 1) 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.

13. 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.

14. PacifiCorp shall install new low NO_x burners with advanced overfire air and a new full-scale fabric filter on Unit 1, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 6 no later than December 31, 2011.

Appendix A
Facility Location

UAE Exhibit RR 2.7

WDEQ BART ANALYSIS - DJ

DEPARTMENT OF ENVIRONMENTAL QUALITY
AIR QUALITY DIVISION

BART Application Analysis
AP-6041

May 28, 2009

NAME OF FIRM:	PacifiCorp
NAME OF FACILITY:	Dave Johnston Plant
FACILITY LOCATION:	Sections 7 and 18, T33N, R74W UTM Zone: 13 Easting: 436,592 m, Northing: 4,742,918 m Converse County, Wyoming
TYPE OF OPERATION:	Coal-Fired Electric Generating Plant
RESPONSIBLE OFFICIAL:	Gary Slanina, Managing Director
MAILING ADDRESS:	1591 Tank Farm Road Glenrock, WY 82637
TELEPHONE NUMBER:	(307) 436-2001
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 22, 2007 and on January 29, 2007, in accordance with the requirements of WAQSR Chapter 6 Section 9(e)(i), the Division received BART applications for two existing coal-fired boilers, Units 3 and 4, respectively, at the PacifiCorp Dave Johnston Power Plant. A map showing the location of PacifiCorp's Dave Johnston Power Plant is attached as Appendix A.

On June 5, 2007, PacifiCorp submitted additional copies of the January applications for the two (2) units subject to BART at Dave Johnston.

On October 15, 2007, PacifiCorp submitted updated applications for the two (2) units subject to BART at Dave Johnston. Additional modeling performed after the June 5, 2007 submittal and revised emissions reduction calculations were included.

On December 5, 2007, PacifiCorp submitted revised applications incorporating changes to the post-processing of the visibility model runs for each of the two (2) Dave Johnston units.

On March 31, 2008, PacifiCorp submitted addendums to each of the BART applications for Dave Johnston Units 3 and 4. Revised cost estimates and updated visibility modeling for two (2) NO_x control scenarios were included in the addendums.

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. Two existing coal-fired boilers at PacifiCorp's Dave Johnston Power Plant, Units 3 and 4, 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 Dave Johnston Power Plant is comprised of four (4) units burning pulverized sub-bituminous Powder River Basin coal for a total net generating capacity of a nominal 772 megawatts (MW). Dave Johnston Units 1 and 2 are nominal 106 MW pulverized coal-fired units. Unit 1 began operation in 1958 and Unit 2 in 1960. Since both units were in operation before August 7, 1962 they are not subject to BART regulation. However, Dave Johnston Units 3 and 4 are subject to BART review. Dave Johnston Unit 3 is a nominal 230 MW pulverized coal-fired boiler that commenced service in 1964. It was manufactured by Babcock & Wilcox and equipped with burners in a cell configuration. It is the only boiler in Wyoming subject to BART with burners in a cell configuration. The original burners have not been replaced or upgraded to low NO_x burners. Dave Johnston Unit 3 is not equipped with any SO_2 control equipment. Particulate matter (PM) emissions from Unit 3 are controlled using a Lodge-Cottrell single-chamber electrostatic precipitator (ESP) installed in 1976. Dave Johnston Unit 4 is a nominal 330 MW pulverized coal-fired boiler that commenced service in 1972. It is a tangential-fired boiler and was manufactured by Combustion Engineering, now Alstom. The original burners were replaced in 1976 with concentric-firing first generation low NO_x burners (LNB). A Venturi scrubber is used to control PM emissions. Additional SO_2 emission control is achieved in the scrubber by adding lime to the scrubber liquor.

Table 1: Dave Johnston Units 3 & 4 Pre-2005 Emission Limits [(a)]

Source	Firing Rate (MMBtu/hour)	Existing Controls	NO_x (lb/MMBtu)	SO_2 (lb/MMBtu)	PM/PM_{10} (lb/MMBtu) [(c)(d)]
Unit 3	2,464 [(b)]	ESP	0.75 (3-hour rolling) 0.59 (annual)	1.2 (2-hour block)	0.23
Unit 4	4,100	LNB, Venturi Scrubber	0.75 (3-hour rolling) 0.53 (annual)	1.2 (3-hour block) 0.5 (30-day rolling)	0.21

(a) Emissions taken from Operating Permit 31-148-1 which does not include the most recent New Source Review construction permit limits.
(b) Boiler heat input reported in the Operating Permit 31-148-1.
(c) Based on PM limit calculation of $0.8963/I^{0.1743}$ lb/MMBtu where I=boiler heat input in MMBtu/hr.
(d) Averaging period is 1 hour as determined by the appropriate test method.

On June 27, 2008, Air Quality Permit MD-5098 was issued to PacifiCorp to replace the original burners on Unit 3 with a new low NO_x firing system including additional advanced overfire air (OFA). In addition, Unit 4's first generation LNB will be replaced with Alstom TFS 2000[TM] LNB with overfire air. Installation of dry flue gas desulfurization control equipment on both Units 3 and 4 is also authorized by this permitting action. Finally, the replacement of the existing ESP on Unit 3 with a baghouse and the installation of a new baghouse on Unit 4 are authorized by MD-5098. The emission levels established for Dave Johnston Units 3 and 4 in MD-5098 are summarized in Table 2.

Table 2: Dave Johnston Units 3 & 4 MD-5098 Emission Limits [(a)]

Source	Permitted Controls	NO_x	SO_2	PM/PM_{10}
Unit 3	New LNB with advanced OFA, Dry FGD, Baghouse	0.28 lb/MMBtu (12-month rolling) 784 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 0.5 lb/MMBtu (30-day rolling) 0.5 lb/MMBtu (3-hr block) 420 lb/hr (24-hr rolling)	0.015 lb/MMBtu 42.1 lb/hr 184 tpy
Unit 4	New LNB with advanced OFA, Dry FGD, Baghouse	0.15 lb/MMBtu (12-month rolling) 697 lb/hr (12-month rolling)	0.15 lb/MMBtu (12-month rolling) 0.5 lb/MMBtu (30-day rolling) 0.5 lb/MMBtu (3-hr block) 615 lb/hr (24-hr rolling)	0.015 lb/MMBtu 61.5 lb/hr 269 tpy

[(a)] Emissions limits effective upon installation or upgrade of the applicable control equipment.

By letter dated July 18, 2008, PacifiCorp notified the Division that construction activities for installation of the FGD/baghouse control equipment on Units 3 and 4 were anticipated to begin July 28, 2008. March 31, 2009, PacifiCorp notified the Division of the anticipated startup of Unit 4, with new LNB and advanced OFA installed, on May 23, 2009. The construction activities are in line with the construction schedule proposed by PacifiCorp in the application for permit MD-5098. A construction summary is provided in Table 3.

Table 3: MD-5098 Permitted Upgrades to Dave Johnston Units 3 & 4

Source	New Low NO_x Burners with advanced Overfire Air (status, year)	New Dry FGD/baghouse (status, year)
Unit 3	Planned, 2010	Initiated, 2008
Unit 4	Initiated, 2009	Initiated, 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 Dave Johnston Units 3 and 4 thereby conducting a comprehensive BART analysis for NO_x, SO_2 and PM/PM_{10}.

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

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

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.

PacifiCorp's Dave Johnston Power Plant generates a cumulative nominal 772 MW from all four units. Unit 3, a nominal 230 MW unit, and Unit 4, a nominal 330 MW unit, qualify for presumptive limits. Unit 3 does not have SO_2 controls installed. Unit 4 controls SO_2 emissions using the existing Venturi scrubber. Neither unit currently operates with NO_x post-combustion controls. Presumptive SO_2 limits of 95% reduction or 0.15 lb/MMBtu and presumptive NO_x limits of 0.45 lb/MMBtu and 0.15 lb/MMBtu, based on unit type and coal type, could apply to Unit 3 and Unit 4, respectively. 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: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

PacifiCorp identified four control technologies to control NO_x emissions: (1) low NO_x burners with advanced overfire air, (2) rotating opposed fire air (ROFA), (3) selective non-catalytic reduction (SNCR), and (4) selective catalytic reduction (SCR). LNB with advanced 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

[4] Ibid. (70 Federal Register 39171).

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 Advanced 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 advanced 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 advanced 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 advanced 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 advanced 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 Dave Johnston units and to collect data from boiler vendors. Based on results from the study, PacifiCorp indicates that new LNB with advanced OFA on Dave Johnston Units 3 and 4 would result in a NO_x emission rate of 0.24 lb/MMBtu and 0.15 lb/MMBtu, respectively. On page 3-5 of the December 2007 submittal for Dave Johnston Unit 3 and on page 3-4 of the December 2007 submittal for Dave Johnston Unit 4 PacifiCorp states: "PacifiCorp has indicated that this rate [0.24 lb/MMBtu for Unit 3 and 0.15 lb/MMBtu for Unit 4] corresponds to a vendor guarantee plus an added operating margin, 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 on Unit 3 equipped with cell burners, PacifiCorp proposes an additional NO_x increase of 0.04 lb/MMBtu on Unit 3 for a final proposed emission rate of 0.28 lb/MMBtu.

PacifiCorp worked with Mobotec to conduct an analysis of retrofitting the existing boilers at the Dave Johnston Power Plant with Mobotec's ROFA. Mobotec analyzed the operation of existing burners and OFA ports. Typically the existing burner 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 0.15 lb/MMBtu was achievable on Units 3 and 4 using ROFA technology. PacifiCorp added an additional operating margin of 0.04 lb/MMBtu to Unit 3 to account for site specific issues, such as burner configuration, for total proposed emission rate of 0.19 lb/MMBtu. No additional operating margin was applied to Unit 4 so the anticipated emission rate is 0.15 lb/MMBtu.

S&L evaluated emission reductions associated with installing SNCR in addition to retrofitting the boilers with LNB with advanced OFA. Based on installing LNB with advanced OFA capable of achieving a NO_x emission rate of 0.24 lb/MMBtu on Unit 3 and 0.15 lb/MMBtu on Unit 4, S&L concluded that SNCR can reduce emissions by 20% resulting in projected emission rates of 0.19 lb/MMBtu for Unit 3 and 0.12 lb/MMBtu for Unit 4. 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. PacifiCorp did not model visibility improvement from installing SNCR on Unit 3 on account of the expected marginal emission rate improvement, the burden of significant ongoing parasitic costs, the operating difficulties, and the potential ammonia slip.

S&L prepared the design conditions and cost estimates for installing SCR on Dave Johnston Units 3 and 4. 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 reactor containing the catalyst to increase physical space occupied by the catalyst to improve the NO_x removal rate. Additional catalyst would be added to accommodate nitrogen levels in the coal feedstock. Based on the S&L design, which included installing both LNB with advanced OFA and SCR, PacifiCorp concluded Units 3 and 4 can achieve a NO_x emission rate of 0.07 lb/MMBtu.

Table 4: NO_x Emission Rates Per Boiler

Control Technology	Unit 3 Resulting NO_x Emission Rate (lb/MMBtu)	Unit 4 Resulting NO_x Emission Rate (lb/MMBtu)
Combustion Control	0.70/0.59 [(a)]	0.40/0.53 [(a)]
New LNB with advanced OFA	0.28	0.15
ROFA	0.19	0.15
New LNB with advanced OFA and SNCR	0.19	0.12
New LNB with advanced OFA and SCR	0.07	0.07

[(a)] PacifiCorp proposed emission rate/annual averaged NO_x emissions established through 40 CFR part 76 in Operating Permit 31-148-1.

NO_x: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts associated with installing each of the proposed control technologies. Installing new LNB with advanced OFA on Dave Johnston Units 3 and 4 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 a significant energy impact on Dave Johnston. One 1,900 horsepower (hp) ROFA fan on Unit 3 and one 3,000-3,700 hp ROFA fan on Unit 4 are required to induct a sufficient volume of air into each boiler to cause rotation of the combustion air throughout the boiler. The annual energy impact from operating the proposed ROFA fans is 21,800 Mega Watt-hour (MW-hr) for Unit 3 and 34,100 MW-hr for Unit 4.

PacifiCorp determined the SNCR system would require between 200 kilo Watt (kW) and 300 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 requirement for SCR installation on Unit 3 would be approximately 1.6 MW and 2.1 MW for Unit 4.

PacifiCorp evaluated the environmental impacts from the proposed NO_x control technologies. Installing LNB with advanced 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 Dave Johnston Units 3 and 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 Dave Johnston Unit 3 and Unit 4 are summarized in the following tables.

Table 5: Dave Johnston Unit 3 Economic Costs

Cost	Combustion Control	New LNB with advanced OFA	ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$17,500,000	$12,054,022	$24,035,544	$129,700,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$1,664,775	$1,146,699	$2,286,501	$12,338,361
Annual O&M Costs	$0	$100,000	$1,237,992	$392,691	$4,009,159
Annual Cost of Control	$0	$1,764,775	$2,384,691	$2,679,192	$16,347,519

Table 6: Dave Johnston Unit 3 Environmental Costs

	Combustion Control	New LNB with advanced OFA	Existing burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.59	0.28	0.19	0.19	0.07
Annual NO_x Emission (tpy)	5,814[(a)]	3,091 [(b)]	2,097 [(b)]	2,097 [(b)]	773 [(b)]
Annual NO_x Reduction (tpy)	N/A	2,723	3,717	3,717	5,041
Annual Cost of Control	$0	$1,764,775	$2,384,691	$2,679,192	$16,347,519
Cost per ton of Reduction	N/A	$648	$642	$721	$3,243
Incremental Cost per ton of Reduction	N/A	$648	$623	$920 [(c)]	$10,324

[(a)] Annual emissions based on unit heat input rate of 2,500 MMBtu/hr and 7,884 hours of operation per year.
[(b)] Annual emissions based on unit heat input rate of 2,800 MMBtu/hr and 7,884 hours of operation per year.
[(c)] Incremental cost from installing ROFA cannot be calculated since the reduced tons of NO_x are anticipated to be the same. Therefore, the incremental cost from installing new LNB with advanced OFA was calculated.

Table 7: Dave Johnston Unit 4 Economic Costs

Cost	Combustion Control	New LNB with advanced OFA	Existing burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
Control Equipment Capital Cost	$0	$7,900,000	$14,719,868	$17,905,780	$151,900,000
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$751,527	$1,400,301	$1,703,377	$14,450,247
Annual O&M Costs	$0	$90,000	$1,841,886	$438,409	$1,980,281
Annual Cost of Control	$0	$841,527	$3,242,187	$2,141,786	$16,430,528

Table 8: Dave Johnston Unit 4 Environmental Costs

	Combustion Control	New LNB with advanced OFA	Existing burners with ROFA	New LNB with advanced OFA and SNCR	New LNB with advanced OFA and SCR
NO_x Emission Rate (lb/MMBtu)	0.53	0.15	0.15	0.12	0.07
Annual NO_x Emission (tpy) [(a)]	8,566	2,424	2,424	1,940	1,131
Annual NO_x Reduction (tpy)	N/A	6,142	6,142	6,626	7,435
Annual Cost of Control	$0	$841,527	$3,242,187	$2,141,786	$16,430,528
Cost per ton of Reduction	N/A	$137	$528	$323	$2,210
Incremental Cost per ton of Reduction	N/A	$137	$528 [(b)]	-$2,274 [(c)]	$17,662

[(a)] Annual emissions based on individual heat input rate of 4,100 MMBtu/hr for 7,884 hours of operation per year.
[(b)] Incremental cost from installing new LNB with advanced OFA cannot be calculated since the reduced tons of NO_x are anticipated to be the same. Therefore, the incremental cost from combustion control was calculated.
[(c)] Incremental cost is negative because the annual cost of control for existing burners with ROFA is significantly higher than new LNB with advanced OFA and SNCR.

The cost effectiveness of the four proposed BART technologies for NO_x are all reasonable. The incremental cost effectiveness is reasonable for all NO_x control technologies except new LNB with advanced OFA and SCR. PacifiCorp modeled the range of anticipated visibility improvement from the company-proposed BART controls for Units 3 and 4 by modeling LNB with advanced OFA and LNB with advanced OFA and SCR. While the installation of SNCR and 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 Dave Johnston Units 3 and 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. Table 23 on page 34 and Table 24 on page 35 list the modeled control scenarios and associated emission rates.

PM_{10}: IDENTIFY AVAILABLE RETROFIT CONTROL TECHNOLOGIES

Dave Johnston Unit 3 is currently equipped with an electrostatic precipitator (ESP) to control PM emissions from the boiler. As discussed below in more detail below, ESPs control PM from the flue gas stream by creating a strong electro-magnetic field in which fly ash particles gain an electric charge. The existing ESP controls PM emissions to 0.030 lb/MMBtu. Dave Johnston Unit 4 is equipped with a Venturi particulate scrubber. This technology is no longer the state-of-art and Pacific did not propose keeping the unit in service as an additional particulate control device. Venturi scrubbers are designed with a decreasing throat diameter that mechanically forces particles in the flue gas and water droplets together. They are similar to cyclone systems in that particle momentum greatly influences the control efficiency. A Venturi scrubber is less effective as a control device for smaller particles because they have less momentum. Operating cost is greatly affected by increasing either the water-side or air-side pressure drop, which increases the removal efficiency, but results in increased electricity cost and operating cost from the pump and/or motor power providing the additional pressure. PacifiCorp reports 2001 to 2006 PM emissions data indicate that the Dave Johnston Unit 4 Venturi particulate scrubber controls PM_{10} emissions to 0.061 lb/MMBtu. PacifiCorp analyzed three state-of-the-art PM control technologies for application on Units 3 and 4: 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 the use of either the baghouse or an ESP to control PM emissions as technically infeasible. However, PacifiCorp did not further analyze the use of FGC. According to PacifiCorp, the existing ESP on Unit 3 is well designed and provides adequate space and residence time for the flue gas particles to gain an electric charge and migrate to the collection plate. The application of FGC is not expected to significantly improve PM/PM_{10} removal efficiency. PacifiCorp did not evaluate the application of FGC on Unit 4 because it is typically used to enhance the removal efficiency of an existing, constrained ESP. The existing Venturi scrubber will likely be replaced by an entirely new PM control device and the co-benefit of enhancing dry flue gas desulfurization makes the installation of a more effective state-of-the-art fabric filter the company-preferred PM control measure over installing a FGC system.

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 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.

Unit 3 has an existing ESP and rather than evaluate costs of replacing the unit, PacifiCorp evaluated additional controls to improve the PM removal efficiency. An ESP is an effective PM control device, as the existing units are already capable of controlling PM_{10} emissions from Unit 3 to 0.030 lb/MMBtu. The technology continually improves and is commonly proposed for consideration in BACT analyses to control particulate emissions from new PC boilers. In addition to maintaining the existing ESP, 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 ESP on Unit 3 can reduce emissions an additional 50% resulting in a PM emission rate of 0.015 lb/MMBtu. PacifiCorp did not further evaluate the installation on a new full-scale fabric filter on Unit 3 since there is a substantial capital cost associated with the control and no anticipated benefit when compared to COHPAC.

Unit 4 has an existing Venturi scrubber. PacifiCorp determined that continued operation of this control technology was not cost effective. In place of the scrubber, a new ESP or a new FF was evaluated for additional PM control. Due to the higher electrical resistivity of western coals, the ESP is not able to reduce PM emissions as well as a FF. An ESP is not as effective as a FF at capturing small particles. For these reasons, a fabric filter is the company-preferred particulate control device, especially for use with a dry FGD system. PacifiCorp's proposed emission rates for each technology as applied to Units 3 and 4 are shown in Table 9.

Table 9: PM_{10} Emission Rates Per Boiler

Source	Existing ESP PM_{10} Emission (lb/MMBtu)	Polishing FF & Existing ESP PM_{10} Emission (lb/MMBtu)	Existing Venturi Scrubber PM_{10} Emission (lb/MMBtu)	New ESP PM_{10} Emission (lb/MMBtu)	New Full-scale FF PM_{10} Emission (lb/MMBtu)
Unit 3	0.030	0.015	--	--	--
Unit 4	--	--	0.061	0.030	0.015

PM_{10}: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impact of installing the COHPAC retrofit on Unit 3. 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 an 85 percent annual plant capacity factor. The installation of a COHPAC fabric filter would require approximately 1.4 MW of power, equating to an annual power usage of approximately 10.3 million kW-hr. Similar to the installation of the COHPAC on Unit 3, the installation of a full-scale fabric filter on Unit 4 would incur energy losses from the additional pressure drop. PacifiCorp calculated the additional energy costs from the installation of the fabric filter based on a 90 percent annual plant capacity factor. The fabric filter would require approximately 2.4 MW of power, equating to an annual power usage of approximately 18.5 million kW-hr. PacifiCorp's proposed PM control on Unit 4 is the full-scale fabric filter. No costs were provided for the installation and operation of a new ESP on Unit 4.

PacifiCorp evaluated the environmental impacts from the proposed installation of COHPAC on Unit 3 and the installation of a new fabric filter on Unit 4. PacifiCorp did not anticipate negative environmental impacts from the addition of either control technologies on the two units.

PacifiCorp anticipates operating Dave Johnston Units 3 and 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 PM/PM_{10} emission control. Economic and environmental costs for additional PM/PM_{10} controls on Dave Johnston Unit 3 and Unit 4 are summarized in the following tables.

Table 10: Dave Johnston Unit 3 Economic Costs

Cost	Existing ESP	Existing ESP and New COHPAC Fabric Filter
Control Equipment Capital Cost	$0	$29,795,555
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$2,834,451
Annual O&M Costs	$0	$809,282
Annual Cost of Control	$0	$3,643,733

Table 11: Dave Johnston Unit 3 Environmental Costs

	Existing ESP	Existing ESP and New COHPAC Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.030	0.015
Annual PM_{10} Emission (tpy) [a]	331	165
Annual PM_{10} Reduction (tpy)	N/A	166
Annual Cost of Control	$0	$3,643,733
Cost per ton of Reduction	N/A	$21,950
Incremental Cost per ton of Reduction	N/A	$21,950

[a] Annual emissions based on unit heat input rate of 2,800 MMBtu/hr and 7,884 hours of operation per year.

Table 12: Dave Johnston Unit 4 Economic Costs

Cost	Existing Venturi Scrubber	New Fabric Filter
Control Equipment Capital Cost	$0	$50,073,428
Capital Recovery Factor	N/A	0.09513
Annual Capital Recovery Costs	$0	$4,763,485
Annual O&M Costs	$0	$1,284,088
Annual Cost of Control	$0	$6,047,573

Table 13: Dave Johnston Unit 4 Environmental Costs

	Existing Venturi Scrubber	New Fabric Filter
PM_{10} Emission Rate (lb/MMBtu)	0.061	0.015
Annual PM_{10} Emission (tpy) [a]	986	242
Annual PM_{10} Reduction (tpy)	N/A	744
Annual Cost of Control	$0	$6,047,573
Cost per ton of Reduction	N/A	$8,129
Incremental Cost per ton of Reduction	N/A	$8,129

[a] Annual emissions based on unit heat input rate of 4,100 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of applying a new polishing fabric filter to Unit 3 and a new full-scale fabric filter on Unit 4 are not reasonable. However, the controls were included in the final step in the PM/PM_{10} BART determination process for Dave Johnston Units 3 and 4, Step 5: Evaluate visibility impacts, which 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. Table 23 on page 34 and Table 24 on page 35 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 Dave Johnston Units 3 and 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. <u>Wet FGD</u> – 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. <u>Dry FGD</u> – 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%.

<u>SO_2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS</u>

PacifiCorp did not eliminate either control technology listed above as technically infeasible. Both dry FGD and wet FGD are proven SO_2 control technologies. PacifiCorp analyzed the impact of both SO_2 emission reduction technologies on Dave Johnston Units 3 and 4.

<u>SO_2: EVALUATE EFFECTIVENESS OF REMAINING CONTROL TECHNOLOGIES</u>

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 evaluated the application of DFGD on Unit 3 using the existing ESP to remove particulates formed by injecting the lime slurry into the flue gas. This combination of control devices is projected to achieve 81.7 % SO_2 removal resulting in a SO_2 emission rate of 0.22 lb/MMBtu, based on a average sulfur content of 0.47% by weight in the feed coal. The combination of the existing ESP and a new polishing fabric filter is projected to reduce SO_2 emissions by 87.5%, resulting in a controlled SO_2 emission rate of 0.15 lb/MMBtu from Unit 3 using a 0.47% coal sulfur content. If the existing ESP on Unit 3 is replaced with a new full-scale fabric filter, DFGD is anticipated to reduce SO_2 emissions down to 0.12 lb/MMBtu. PacifiCorp did not provide cost information for installing a full-scale fabric filter on Unit 3, so the technology was not considered any further in the SO_2 analysis.

DFGD with a new full-scale fabric filter capable of treating the entire flue gas stream on Unit 4 is projected to achieve 87.5% SO_2 removal, resulting in an emission rate of 0.15 lb/MMBtu. An average coal sulfur content of 0.47% by weight was used to calculate the emission reduction.

The application of wet FGD on Unit 3 would likely use lime/limestone scrubbing, which is available in several variations from vendors. Wet lime/limestone scrubbing is projected to achieve a SO_2 removal rate of 95% and an outlet SO_2 emission rate of 0.058 lb/MMBtu, based on a sulfur content of 0.47% by weight in the feed coal.

A new wet lime/limestone FGD system with a new full-scale fabric filter applied to Unit 4 is projected to achieve 91.7% SO_2 removal, resulting in an outlet emission rate of 0.10 lb/MMBtu based on a sulfur content of 0.47% by weight. PacifiCorp noted in the analysis for Unit 4 that they consider it to be technically infeasible for a new wet FGD system to achieve a 95% SO_2 removal, 0.06 lb/MMBtu, on a continuous basis. PacifiCorp evaluated SO_2 controls for Unit 4 to meet presumptive levels for SO_2. The application of wet FGD with a new full-scale fabric filter on Unit 4 is capable of continuously reducing SO_2 emissions by 90% resulting in a SO_2 emission rate of 0.10 lb/MMBtu, below the 0.15 lb/MMBtu presumptive SO_2 limit.

Table 14: Dave Johnston Unit 3 SO_2 Emission Rates

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Combustion Control	1.20
Dry FGD with existing ESP	0.22
Dry FGD with existing ESP and Polishing Fabric Filter	0.15
Dry FGD with Fabric Filter	0.12
Wet Lime FGD with existing ESP	0.06

Table 15: Dave Johnston Unit 4 SO_2 Emission Rates

Control Technology	SO_2 Emission Rate (lb/MMBtu)
Combustion Control	1.20
Dry FGD with Fabric Filter	0.15
Wet FGD with Fabric Filter	0.10

SO_2: EVALUATE IMPACTS AND DOCUMENT RESULTS

PacifiCorp evaluated the energy impacts of applying a dry FGD system with the existing ESP on Unit 3. DFGD requires less electric power than a wet FGD system. A dry FGD system on Dave Johnston 3 using the existing ESP would require approximately 2.5 MW of power, while a wet FGD would require approximately 3.5 MW. This equates to an annual power savings of approximately 7.5 million kW-hr for dry FGD, when the plant operates at 90% capacity for the year. Applying a dry FGD system with a new full-scale fabric filter to Dave Johnston Unit 4 requires 4.5 MW of power, compared to approximately 6.3 MW for wet FGD with a new fabric filter. Dry FGD on Unit 4 to control SO_2 emission could generate a power savings of approximately 13.8 million kW-hr if the unit operates for 90% of its annual capacity.

PacifiCorp compared the environmental impacts of dry FGD versus wet FGD technology. PacifiCorp concluded that dry FGD has five significant environmental advantages over wet FGD. These advantages are taken directly from PacifiCorp's environmental analyses for SO_2 controls on Dave Johnston Units 3 and 4 and listed below.

- Sulfuric Acid Mist Sulfur trioxide (SO_3) in the flue gas, which condenses to liquid sulfuric acid at temperatures below the acid dew point, is removed efficiently with a lime spray dryer system. Wet scrubbers capture less than 40 to 60 percent of SO_3 and may require the addition of a wet electrostatic precipitator (ESP) or hydrated lime injection when medium to high sulfur coal is burned in a unit to remove the balance of SO_3. Otherwise, the emission of sulfuric acid mist, if above a threshold value, may result in a visible plume after the vapor plume dissipates.

- Plume Buoyancy Flue gas following a dry FGD system is not saturated with water (gas temperature 30°F to 50°F above dew point), which reduces or eliminates a visible moisture plume. Wet FGD scrubbers produce flue gas saturated with water, which would require a gas-gas heat exchanger to reheat the flue gas if it were to operate as a dry stack. Because of the high capital and operating costs associated with heating the flue gas, all recent wet FGD systems in the United States have used wet stack operation.

- Liquid Waste Disposal There is no liquid waste from a dry FGD system. However, wet FGD systems produce a wastewater blowdown stream that must be treated to limit chloride buildup in the absorber scrubbing loop. In some cases, a wastewater treatment plant must be installed to treat the liquid waste prior to disposal. The wastewater treatment plant would produce a small volume of solid waste, which may be contaminated with toxic metals (including mercury), requiring proper disposal.

- Solid Waste Disposal The creation of a wet sludge from the wet FGD process creates a solid waste handling and disposal challenge. This sludge must be handled properly to prevent groundwater contamination. Wet FGD systems can produce saleable gypsum if a gypsum market is available, reducing the quantity of solid waste from the power plant to be disposed.

- Makeup Water Requirements Dry FGD has advantages over a wet scrubber, producing a dry waste material and requiring less makeup water in the absorber. Given that water is a valuable commodity in Wyoming, the reduced water consumption required for dry FGD is major advantage for this technology.

PacifiCorp anticipates operating Dave Johnston Units 3 and 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 SO_2 emission control. Economic and environmental costs for additional SO_2 controls on Dave Johnston Unit 3 and Unit 4 are summarized in the following tables.

Table 16: Dave Johnston Unit 3 Economic Costs

Cost	Existing Combustion Control	Dry FGD with ESP	Dry FGD with ESP and Polishing Fabric Filter	Wet FGD with ESP
Control Equipment Capital Cost	$0	$91,499,734	$169,500,000	$144,300,464
Capital Recovery Factor	N/A	0.09513	0.09513	0.09513
Annual Capital Recovery Costs	$0	$8,704,370	$16,124,535	$13,727,303
Annual O&M Costs	$0	$4,455,188	$5,295,598	$6,044,908
Annual Cost of Control	$0	$13,159,558	$21,420,133	$19,772,211

Table 17: Dave Johnston Unit 3 Environmental Costs

	Existing Combustion Control	Dry FGD with ESP	Dry FGD with ESP and Polishing Fabric Filter	Wet FGD with ESP
SO_2 Emission Rate (lb/MMBtu)	1.2	0.22	0.15	0.06
Annual SO_2 Emission (tpy) [a]	13,316	2,428	1,656	662
Annual SO_2 Reduction (tpy)	N/A	10,888	11,660	12,654
Annual Cost of Control	$0	$13,159,558	$21,420,133	$19,772,211
Cost per ton of Reduction	N/A	$1,209	$1,837	$1,563
Incremental Cost per ton of Reduction	N/A	$1,209	$10,700	-$1,658 [b]

[a] Annual emissions based on unit heat input rate of 2,800 MMBtu/hr and 7,884 hours of operation per year.
[b] Incremental cost from dry FGD with ESP and fabric filter is negative as a result of the lower annual cost of control for wet FGD with ESP.

Table 18: Dave Johnston Unit 4 Economic Costs

Cost	Existing Combustion Control	Dry FGD with Full-scale Fabric Filter	Wet FGD with Full-scale Fabric Filter
Control Equipment Capital Cost	$0	$243,100,000	$289,166,335
Capital Recovery Factor	N/A	0.09513	0.09513
Annual Capital Recovery Costs	$0	$23,126,103	$27,508,393
Annual O&M Costs	$0	$5,318,117	$6,961,183
Annual Cost of Control	$0	$28,444,220	$34,469,576

Table 19: Dave Johnston Unit 4 Environmental Costs

	Existing Combustion Control	Dry FGD with Full-scale Fabric Filter	Wet FGD with Full-scale Fabric Filter
SO_2 Emission Rate (lb/MMBtu)	0.5 [a]	0.15	0.10
Annual SO_2 Emission (tpy) [b]	8,081	2,424	1,616
Annual SO_2 Reduction (tpy)	0	5,657	6,465
Annual Cost of Control	$0	$28,444,220	$34,469,576
Cost per ton of Reduction	N/A	$5,028	$5,332
Incremental Cost per ton of Reduction	N/A	$5,028	$7,457

[a] 30-day rolling average SO_2 limit from Operating Permit 31-148-1 used as baseline.
[b] Annual emissions based on unit heat input rate of 4,100 MMBtu/hr and 7,884 hours of operation per year.

The cost effectiveness and incremental cost effectiveness of the proposed wet FGD and dry FGD controls for Units 3 and 4 are reasonable, except for the incremental cost effectiveness of installing a new polishing fabric filter with dry FGD on Unit 3. The final step in the SO_2 BART determination process for Dave Johnston Units 3 and 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. Table 23 on page 34 and Table 24 on page 35 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 Dave Johnston plant with an EPA-approved dispersion modeling system (CALPUFF) to predict the changes 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 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.

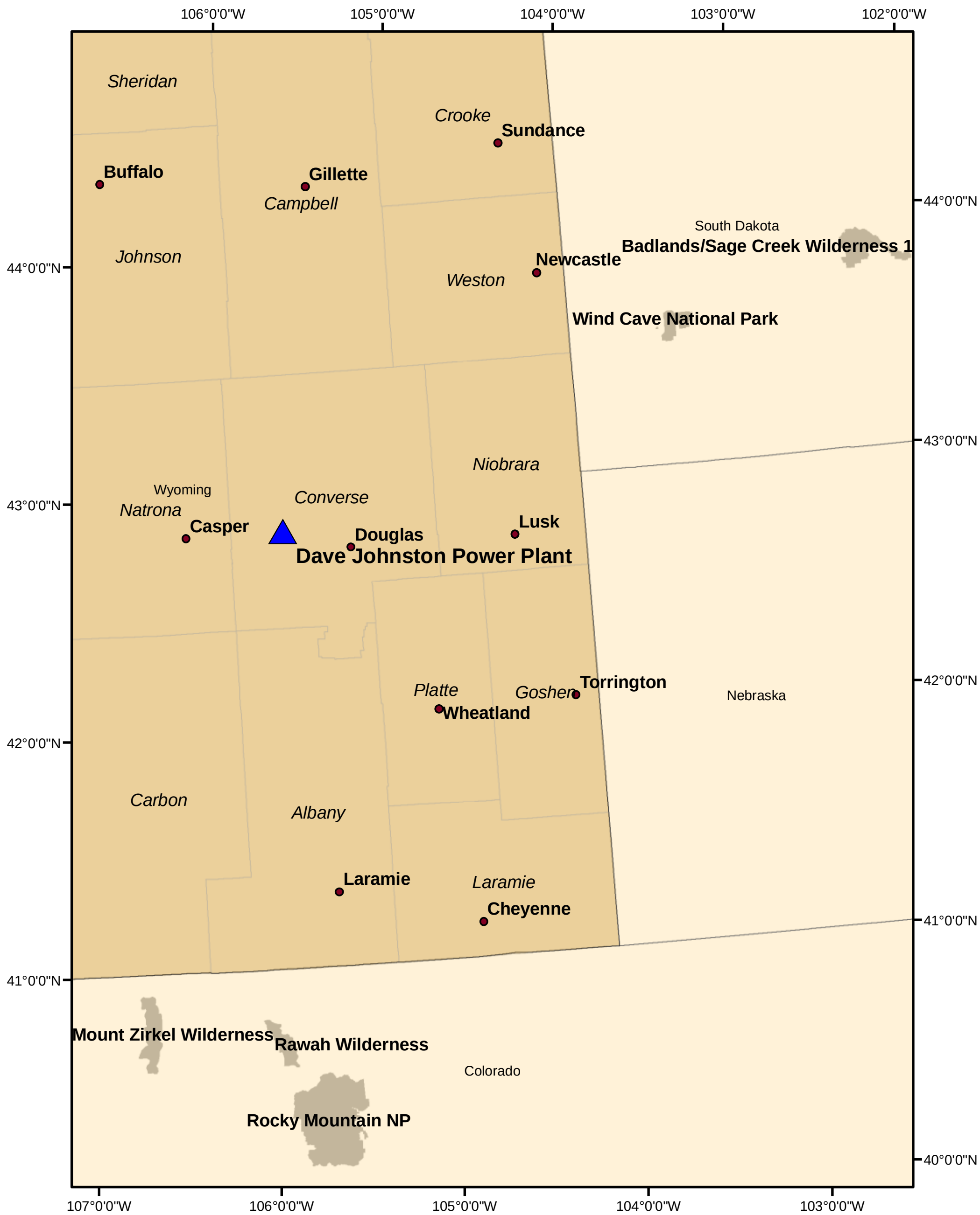
Wind Cave and Badlands National Parks (NP) in South Dakota are Class I areas located to the northeast of the plant at a distance of approximately 200 kilometers (km) and 290 km, respectively. Toward the south in Colorado, Rawah Wilderness Area (WA) and Mount Zirkel WA are both located approximately 220 km from the plant, with Rocky Mountain NP located beyond Rawah WA.

Only those Class I areas most likely to be impacted by the Dave Johnston sources were modeled, as determined by source/Class I area locations and professional judgment considering meteorological and terrain factors. Those areas chosen for modeling the Dave Johnston sources were the following:

- Wind Cave NP
- Badlands NP
- Rawah WA
- Mount Zirkel WA

Rocky Mountain National Park (RMNP) was not modeled because it is located along a similar direction from the plant as Rawah WA (a path of less frequent plume transport), and it can be reasonably assumed that RMNP would experience lower predicted impacts than those at Rawah WA. Figure 1 shows the relative locations of the plant and the nearest Class I areas.

Figure 1
Dave Johnston Power Plant and Class I Areas



SCREENING MODELING

To determine if the Dave Johnston plant would be subject to BART, the Division conducted CALPUFF visibility modeling for the closest Class I areas downwind of predominant wind flows (Wind Cave NP and Badlands NP) using three years of meteorological data. These data, from 2001-2003, consisted of surface and upper-air observations from individual weather stations and gridded output from the Mesoscale Model (MM5). Resolution of the MM5 data was 36-km for all three of the modeled years. Potential emissions for current operation from the two BART-eligible, coal-fired boilers at the Dave Johnston plant were input to the model.

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 Badlands NP and Wind Cave NP 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 20: Results of the Class I Area Screening Modeling

Class I Area	Maximum Modeled Value (Δdv)	98th Percentile Value (Δdv)
2001		
Badlands NP	4.3	2.6
Wind Cave NP	4.5	2.5
2002		
Badlands NP	4.0	2.0
Wind Cave NP	4.7	2.2
2003		
Badlands NP	3.5	2.4
Wind Cave NP	4.3	3.3

Δdv = delta deciview
NP = national park

REFINED MODELING

Because of the results of the Division's screening modeling, PacifiCorp was required to conduct a BART analysis that included refined 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). Pacificorp's modeling included assessments of the impacts at Wind Cave NP and Badlands NP, as required by the Division's BART modeling protocol. The Division supplemented PacifiCorp's analyses with model runs for Rawah and Mount Zirkel Wilderness Areas in Colorado.

<u>CALPUFF System</u>

Predicted visibility impacts from the Dave Johnston plant 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 21: Key Programs in CALPUFF System

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

Meteorological Data Processing (CALMET)

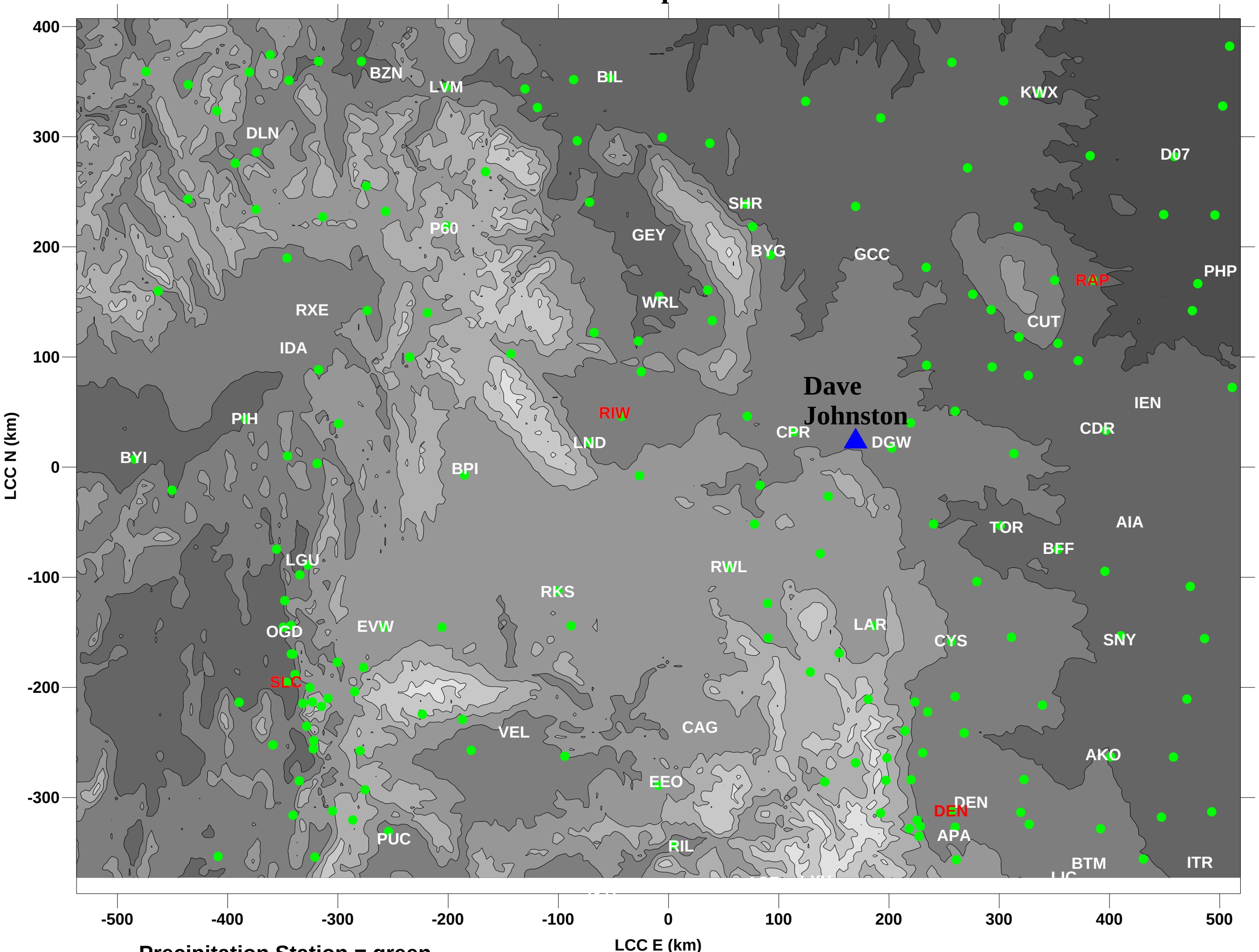
As required by the Division's modeling protocol, the CALMET model was used to construct an initial three-dimensional windfield using data from the MM5 model. Surface and upper-air observations were input to CALMET to adjust the initial windfield, but because of the relative scarcity of wind observations 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 the figure below. 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 22: 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 2
Observations Input to CALMET



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

<u>CALPUFF Modeling Setup</u>

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 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 3-6 show the receptor configurations that were used for Badlands NP, Wind Cave NP, Rawah WA, and Mount Zirkel WA. Receptor spacing within Wind Cave NP is approximately 0.7 km in the east-west direction and approximately 0.9 km in the north-south direction. For Badlands NP, the receptor spacing is approximately 1.3 km in the east-west direction and approximately 1.8 km in the north-south direction. For the Colorado Class I areas (Rawah and Mount Zirkel), the spacing is approximately 1.4 km in the east-west direction and approximately 1.9 km in the north-south direction.

Figure 3
Receptors for Wind Cave NP

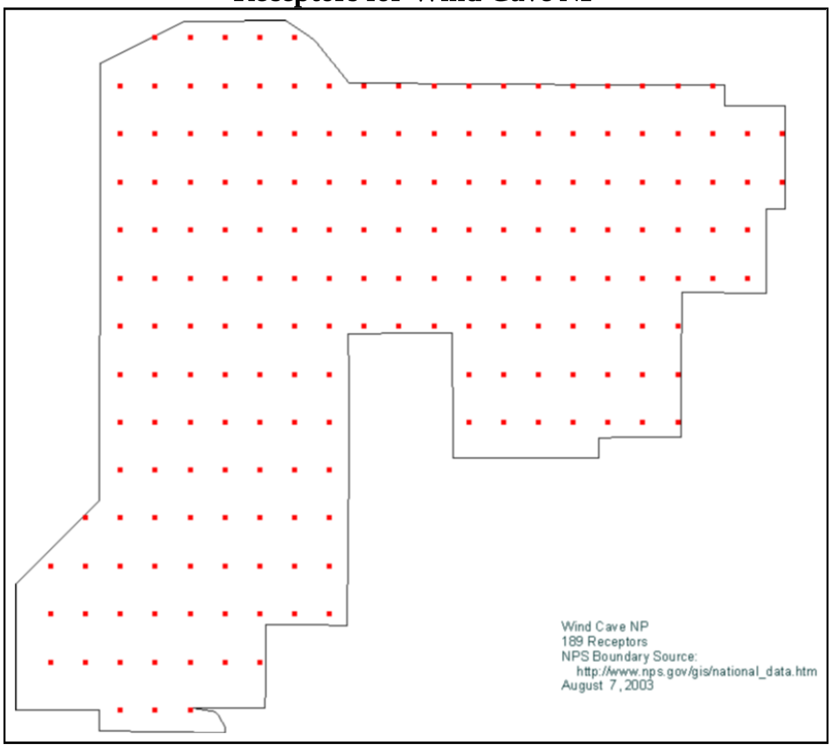


Figure 4
Receptors for Badlands NP

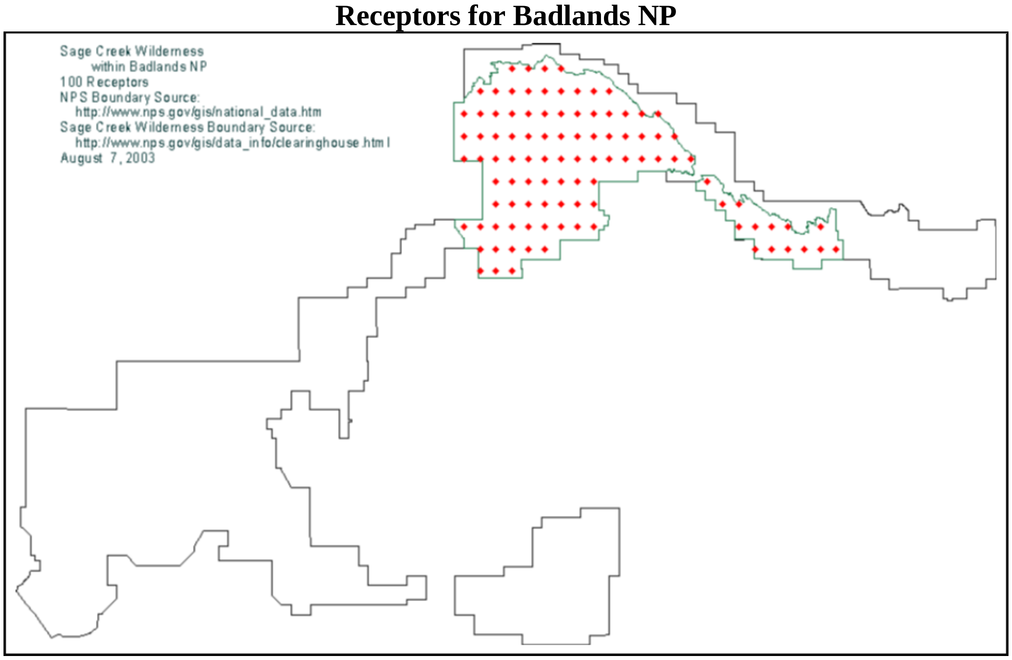


Figure 5
Receptors for Rawah WA

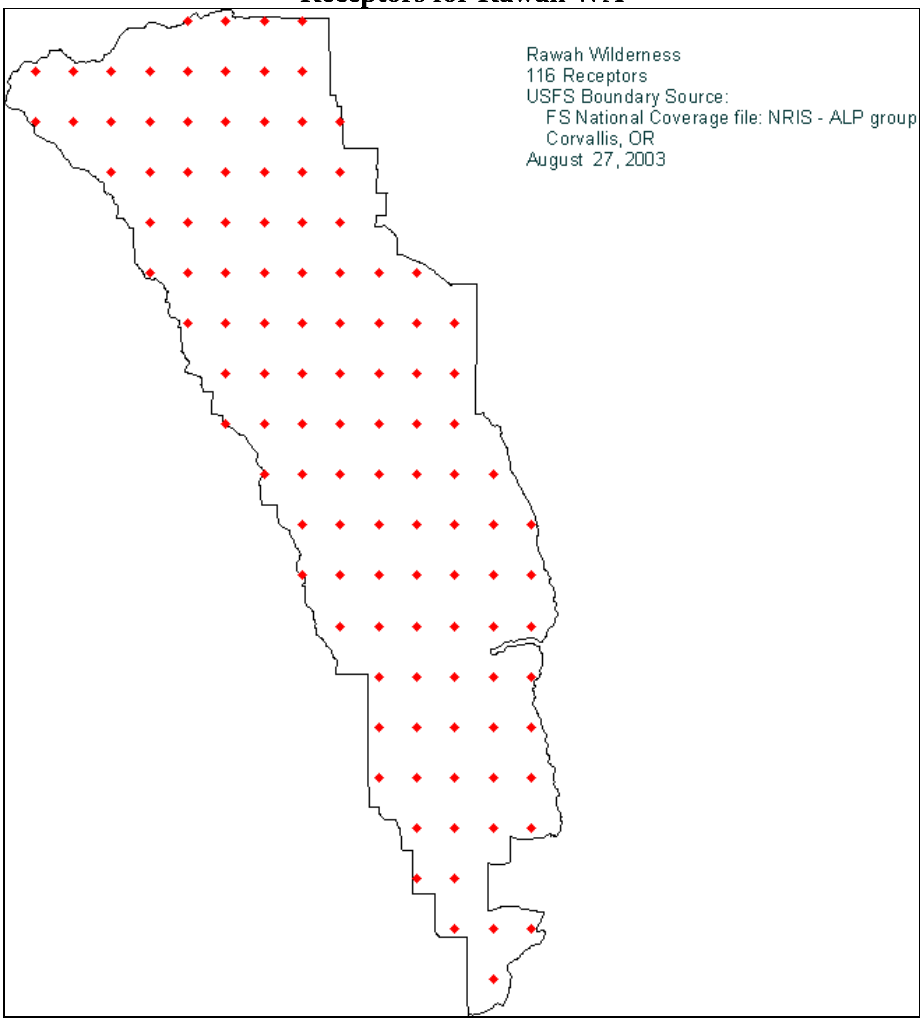
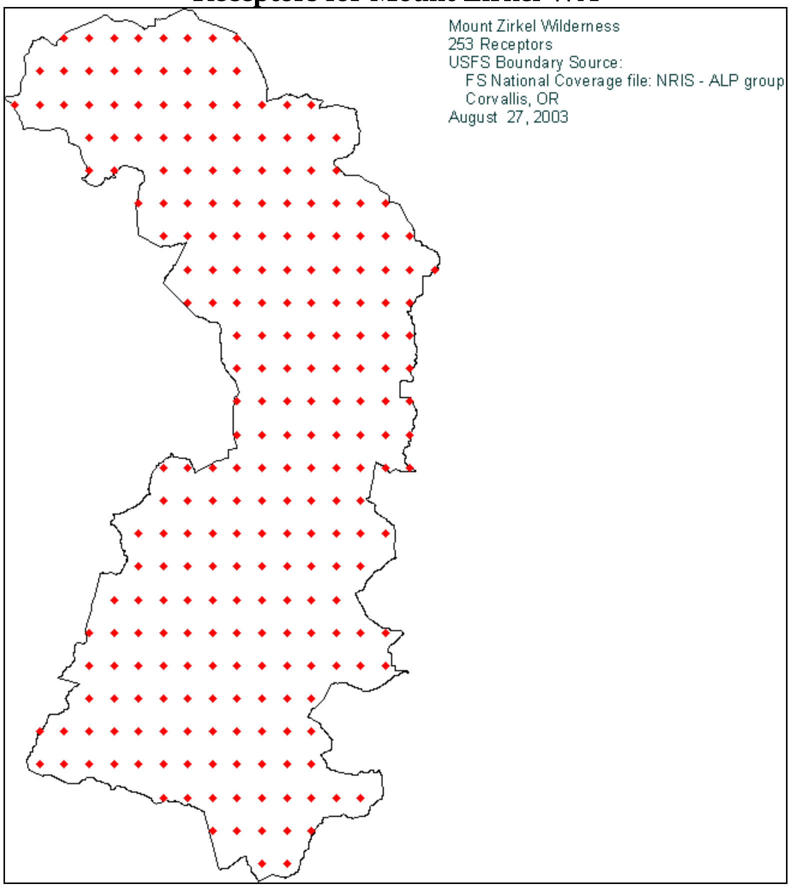


Figure 6
Receptors for Mount Zirkel WA



CALPUFF Inputs – Baseline and Control Options

Source release parameters and emissions for baseline and control options for Unit 3 and Unit 4 at the Dave Johnston plant are shown in the tables below.

Table 23: CALPUFF Inputs for Dave Johnston Unit 3

DAVE JOHNSTON UNIT 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 Operation with Electrostatic Precipitator (ESP)	Low-NOx Burners (LNBs) with advanced Over-fire Air (OFA), Dry FGD, ESP	LNB with advanced OFA, Dry FGD, New Fabric Filter	LNB with advanced OFA and Selective Catalytic Reduction (SCR), Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, Existing ESP, New Stack	Committed Controls: LNB with advanced OFA, Dry FGD, New Fabric Filter	Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	2,500	2,800	2,800	2,800	2,800	2,800	2,800
Sulfur Dioxide (SO_2) (lb/mmBtu)	1.20	0.22	0.12	0.12	0.06	0.15	0.15
Sulfur Dioxide (SO_2) (lb/hr)	3,000	616	336	336	162	420	420
Nitrogen Oxide (NO_x) (lb/mmBtu)	0.70	0.24	0.24	0.07	0.07	0.28	0.07
Nitrogen Oxide (NO_x) (lb/hr)	1,750	672	672	196	196	784	196
PM_{10} (lb/mmBtu)	0.030	0.030	0.015	0.015	0.030	0.015	0.015
PM_{10} (lb/hr)	75.0	75.0	42.0	42.0	75.0	42.0	42.0
Coarse Particulate ($PM_{2.5}$ <diameter < PM_{10}) (lb/hr)[(a)]	32.3	32.3	23.9	23.9	32.3	23.9	23.9
Fine Particulate (diameter < $PM_{2.5}$) (lb/hr)[(b)]	42.8	42.8	18.1	18.1	42.8	18.1	18.1
Sulfuric Acid (H_2SO_4) (lb/hr)	46.0	2.6	2.6	3.6	43.9	2.6	3.7
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	0.7	3.3	--	0.7
$(NH_4)HSO_4$ (lb/hr)	--	--	--	1.1	5.8	--	1.2
H_2SO_4 as Sulfate (SO_4) (lb/hr)	45.1	2.5	2.5	3.6	43.1	2.5	3.6
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.5	2.4	--	0.5
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	0.9	4.8	--	1.0
Total Sulfate (SO_4) (lb/hr)[(c)]	45.1	2.5	2.5	5.0	50.3	2.5	5.1
Stack Conditions							
Stack Height (meters)	152.4	152.4	152.4	152.4	152.4	152.4	152.4
Stack Exit Diameter (meters)	4.57	4.57	4.57	4.57	4.57	4.57	4.57
Stack Exit Temperature (Kelvin)	445	350	355	355	322	348	348
Stack Exit Velocity (meters per second)	32.0	25.1	25.5	25.5	16.7	25.5	25.5

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.
(c) Total Sulfate (SO4) (lb/hr) = H2SO4 as Sulfate (SO4) Stack Emissions (lb/hr) + (NH4)2SO4 as SO4 Stack Emissions (lb/hr) + (NH4)HSO4 as SO4 Stack Emissions (lb/hr).

Table 24: CALPUFF Inputs for Dave Johnston Unit 4

DAVE JOHNSTON UNIT 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	Existing Operations with Venturi Scrubber	Low-NOx Burner (LNB) with advanced Over-Fire Air (OFA), Dry FGD, Fabric Filter	LNB with advanced OFA, Wet FGD, Fabric Filter	LNB with advanced OFA and Selective Catalytic Reduction (SCR), Dry FGD, New Fabric Filter	LNB with advanced OFA and SCR, Wet FGD, Fabric Filter	Committed Controls: LNB with advanced OFA, Dry FGD, New Fabric Filter	Committed Controls and SCR
Hourly Heat Input (mmBtu/hour)	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Sulfur Dioxide (SO_2) (lb/mmBtu)	0.50	0.15	0.10	0.15	0.10	0.15	0.15
Sulfur Dioxide (SO_2) (lb/hr)	2,050	615	410	615	410	615	615
Nitrogen Oxide (NO_x) (lb/mmBtu)	0.40	0.15	0.15	0.07	0.07	0.15	0.07
Nitrogen Oxide (NO_x) (lb/hr)	1,640	615	615	287	287	615	287
PM_{10} (lb/mmBtu)	0.061	0.015	0.015	0.015	0.015	0.015	0.015
PM_{10} (lb/hr)	250.0	61.5	61.5	61.5	61.5	61.5	61.5
Coarse Particulate ($PM_{2.5}$ <diameter < PM_{10}) (lb/hr)[(a)]	107.5	35.1	35.1	35.1	35.1	35.1	35.1
Fine Particulate (diameter < $PM_{2.5}$) (lb/hr)[(b)]	142.5	26.4	26.4	26.4	26.4	26.4	26.4
Sulfuric Acid (H_2SO_4) (lb/hr)	37.7	3.7	37.7	5.3	64.1	3.8	5.8
Ammonium Sulfate [$(NH_4)_2SO_4$] (lb/hr)	--	--	--	1.0	4.8	--	0.8
$(NH_4)HSO_4$ (lb/hr)	--	--	--	1.6	8.5	--	1.4
H_2SO_4 as Sulfate (SO_4) (lb/hr)	37.0	3.6	37.0	5.2	63.1	3.7	5.6
$(NH_4)_2SO_4$ as SO_4 (lb/hr)	--	--	--	0.7	3.5	--	0.6
$(NH_4)HSO_4$ as SO_4 (lb/hr)	--	--	--	1.4	7.1	--	1.2
Total Sulfate (SO_4) (lb/hr)[(c)]	37.0	3.6	37.0	7.3	73.6	3.7	7.4
Stack Conditions							
Stack Height (meters)	76	152	152	152	152	152	152
Stack Exit Diameter (meters)	9.75	5.79	7.01	5.79	7.01	5.79	5.79
Stack Exit Temperature (Kelvin)	322	350	322	350	322	350	350
Stack Exit Velocity (meters per second)	8.5	25.7	16.5	25.7	16.5	25.7	25.7

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.

(c) Total Sulfate (SO4) (lb/hr) = H2SO4 as Sulfate (SO4) Stack Emissions (lb/hr) + (NH4)2SO4 as SO4 Stack Emissions (lb/hr) + (NH4)HSO4 as SO4 Stack Emissions (lb/hr).

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 this analysis are shown in the table below.

Table 25: Relative Humidity Factors for CALPOST

Month	Rawah WA	Mount Zirkel WA	Badlands NP & Wind Cave NP
January	2.10	2.20	2.65
February	2.10	2.20	2.65
March	2.00	2.00	2.65
April	2.10	2.10	2.55
May	2.30	2.20	2.70
June	2.00	1.80	2.60
July	1.80	1.70	2.30
August	2.00	1.80	2.30
September	2.00	2.00	2.20
October	1.90	1.90	2.25
November	2.10	2.10	2.75
December	2.00	2.10	2.65

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 Badlands NP. From Appendix B in the EPA natural visibility guidance document, the deciview value for the 20 percent best days at Badlands NP is 2.18 dv. To obtain the speciated background concentrations representative of the 20 percent best days, the deciview value (2.18 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 2.18, one obtains an equivalent light extinction value of 12.44 Mm^{-1}. Next, the annual average natural visibility concentrations were set equal to a total extinction value of 12.44 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 μg/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 Badlands NP, and including a coefficient for scaling, one obtains:

12.44 = (3)(2.55)[0.12]X + (3)(2.55)[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 0.402. Table 26 presents the annual average natural background concentrations, the calculated scaling factor, and the calculated background concentrations for the 20 percent best days for Badlands NP.

Table 26: Calculated Background Components for Badlands NP

Component	Annual Average for West Region (μg/m^3)	Calculated Scaling Factor	20% Best Days for Badlands NP (μg/m^3)
Ammonium Sulfate	0.12	0.402	0.048
Ammonium Nitrate	0.10	0.402	0.040
Organic Carbon	0.47	0.402	0.189
Elemental Carbon	0.02	0.402	0.008
Soil	0.50	0.402	0.201
Coarse Mass	3.00	0.402	1.205

The scaled aerosol concentrations were averaged for Badlands NP and Wind Cave NP because of their geographical proximity and similar annual background visibility. The 20 percent best days aerosol concentrations for the four Class I areas in question are listed in the table below.

Table 27: Natural Background Aerosol Concentrations (µg/m^3)

Aerosol Component	Rawah WA	Mount Zirkel WA	Wind Cave NP & Badlands NP
Ammonium Sulfate	0.045	0.046	0.047
Ammonium Nitrate	0.038	0.038	0.040
Organic Carbon	0.178	0.179	0.186
Elemental Carbon	0.008	0.008	0.008
Soil	0.189	0.190	0.198
Coarse Mass	1.135	1.141	1.191

Visibility Post-Processing Results

The results of the visibility modeling for each of the two 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. Note that the Division's modeling for the Class I areas in northern Colorado examined baseline, Scenario A (proposed BART), and Scenario B (proposed BART + SCR) only.

Table 28: CALPUFF Visibility Modeling Results for Dave Johnston Unit 3 (South Dakota Class I Areas)

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – ESP								
Badlands NP	1.635	59	1.176	37	1.652	47	1.488	48
Wind Cave NP	1.596	57	1.806	43	2.406	49	1.936	50
Post-Control Scenario 1 – LNB w/ advanced OFA, Dry FGD, ESP								
Badlands NP	0.477	7	0.351	4	0.478	7	0.435	6
Wind Cave NP	0.567	10	0.488	7	0.748	11	0.601	9
Post-Control Scenario 2 – LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.378	6	0.305	0	0.401	3	0.361	3
Wind Cave NP	0.481	5	0.404	5	0.624	10	0.503	7
Post-Control Scenario 3 – LNB w/ advanced OFA and SCR, Dry FGD, Fabric Filter								
Badlands NP	0.208	1	0.143	0	0.188	0	0.180	0
Wind Cave NP	0.213	1	0.211	0	0.305	1	0.243	1
Post-Control Scenario 4 – LNB w/ advanced OFA and SCR, Wet FGD, ESP, New Stack								
Badlands NP	0.253	3	0.155	0	0.233	0	0.214	1
Wind Cave NP	0.269	1	0.205	0	0.312	1	0.262	1
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.448	7	0.360	4	0.469	6	0.426	6
Wind Cave NP	0.570	10	0.480	5	0.735	11	0.595	9
Post-Control Scenario B – Committed Controls + SCR								
Badlands NP	0.230	3	0.168	0	0.218	0	0.205	1
Wind Cave NP	0.249	1	0.241	0	0.345	2	0.278	1

Table 29: CALPUFF Visibility Modeling Results for Dave Johnston Unit 4 (South Dakota Class I Areas)

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Venturi Scrubber								
Badlands NP	1.347	50	1.100	29	1.449	45	1.299	41
Wind Cave NP	1.527	47	1.344	37	2.078	40	1.650	41
Post-Control Scenario 1 – LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.456	6	0.340	3	0.480	7	0.425	5
Wind Cave NP	0.467	7	0.465	7	0.751	10	0.561	8
Post-Control Scenario 2 – LNB w/ advanced OFA, Wet FGD, Fabric Filter								
Badlands NP	0.454	7	0.336	2	0.437	5	0.409	5
Wind Cave NP	0.551	9	0.460	5	0.663	10	0.558	8
Post-Control Scenario 3 – LNB w/ advanced OFA and SCR, Dry FGD, Fabric Filter								
Badlands NP	0.326	4	0.230	1	0.329	1	0.295	2
Wind Cave NP	0.353	3	0.347	3	0.492	7	0.397	4
Post-Control Scenario 4 – LNB w/ advanced OFA and SCR, Wet FGD, Fabric Filter								
Badlands NP	0.409	4	0.262	0	0.327	1	0.333	2
Wind Cave NP	0.443	4	0.339	3	0.518	8	0.433	5
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Badlands NP	0.456	6	0.340	3	0.480	7	0.425	5
Wind Cave NP	0.469	7	0.465	7	0.751	10	0.562	8
Post-Control Scenario B – Committed Controls + SCR								
Badlands NP	0.326	4	0.230	1	0.327	1	0.294	2
Wind Cave NP	0.354	3	0.347	3	0.492	7	0.398	4

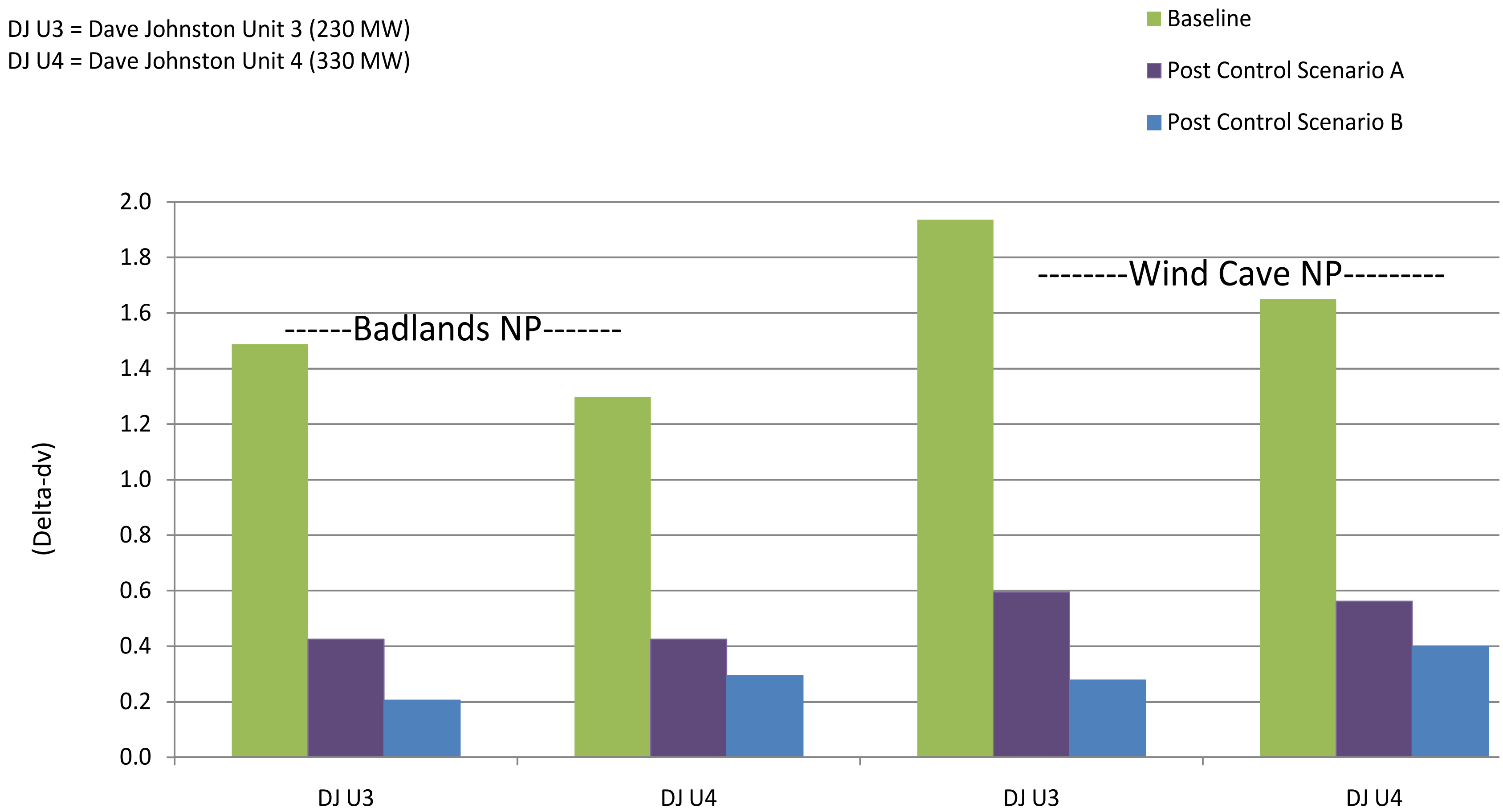
Table 30: CALPUFF Visibility Modeling Results for Dave Johnston Unit 3 (Colorado Class I Areas)

Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – ESP								
Rawah WA	0.718	11	1.075	14	0.918	14	0.904	13
Mt Zirkel WA	0.515	8	0.707	14	0.802	16	0.675	13
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Rawah WA	0.163	2	0.283	5	0.265	2	0.237	3
Mt Zirkel WA	0.125	0	0.191	1	0.245	0	0.187	0
Post-Control Scenario B – Committed Controls + SCR								
Rawah WA	0.087	0	0.142	0	0.119	0	0.116	0
Mt Zirkel WA	0.066	0	0.100	0	0.109	0	0.092	0

Table 31: CALPUFF Visibility Modeling Results for Dave Johnston Unit 4 (Colorado Class I Areas)

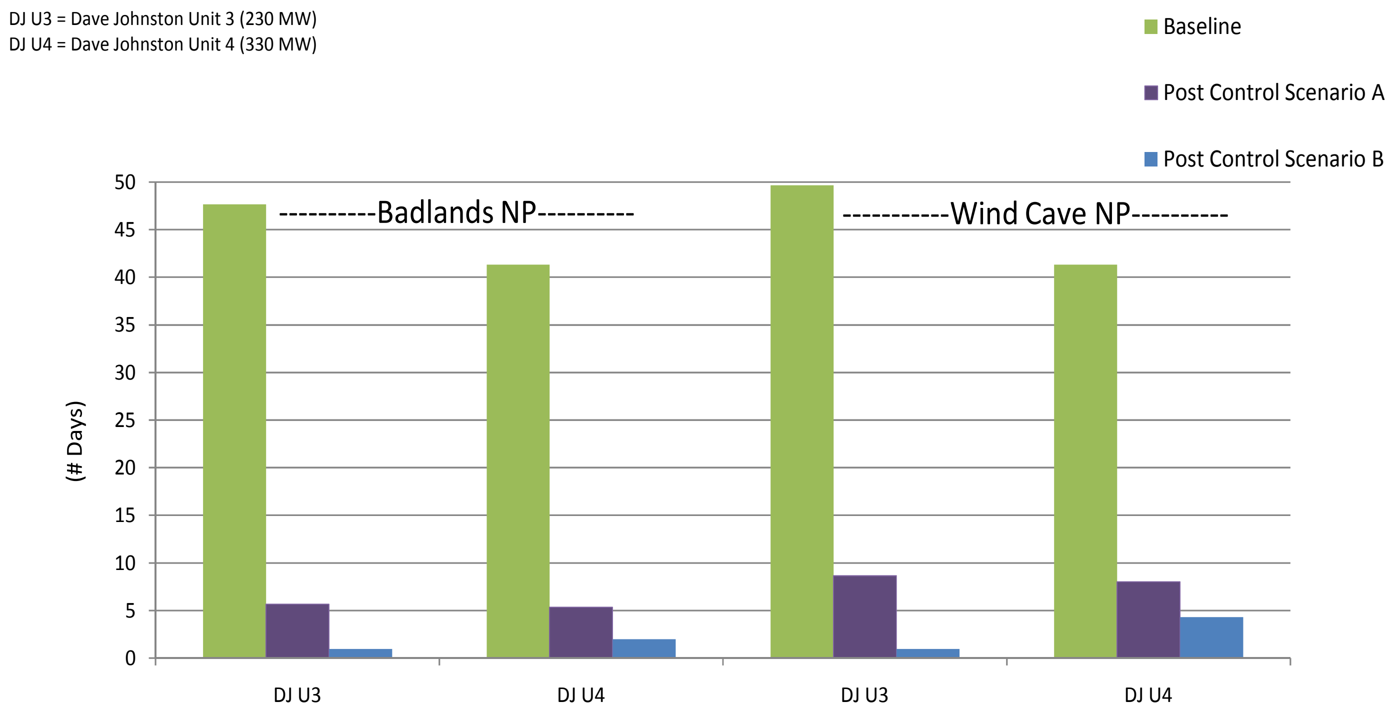
Class I Area	2001		2002		2003		3-Year Average	
	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv	98th Percentile Value (Δdv)	No. of Days > 0.5 Δdv
Baseline – Venturi Scrubber								
Rawah WA	0.514	8	0.841	14	0.827	13	0.727	12
Mt Zirkel WA	0.387	6	0.659	11	0.654	11	0.567	9
Post-Control Scenario A – Committed Controls: LNB w/ advanced OFA, Dry FGD, Fabric Filter								
Rawah WA	0.178	1	0.284	3	0.240	2	0.234	2
Mt Zirkel WA	0.127	0	0.190	0	0.238	0	0.185	0
Post-Control Scenario B – Committed Controls + SCR								
Rawah WA	0.133	0	0.214	1	0.172	1	0.173	1
Mt Zirkel WA	0.103	0	0.142	0	0.164	0	0.136	0

Figure 7
Modeled BART Impacts at South Dakota Class I Areas: 98th Percentile (delta-dv)



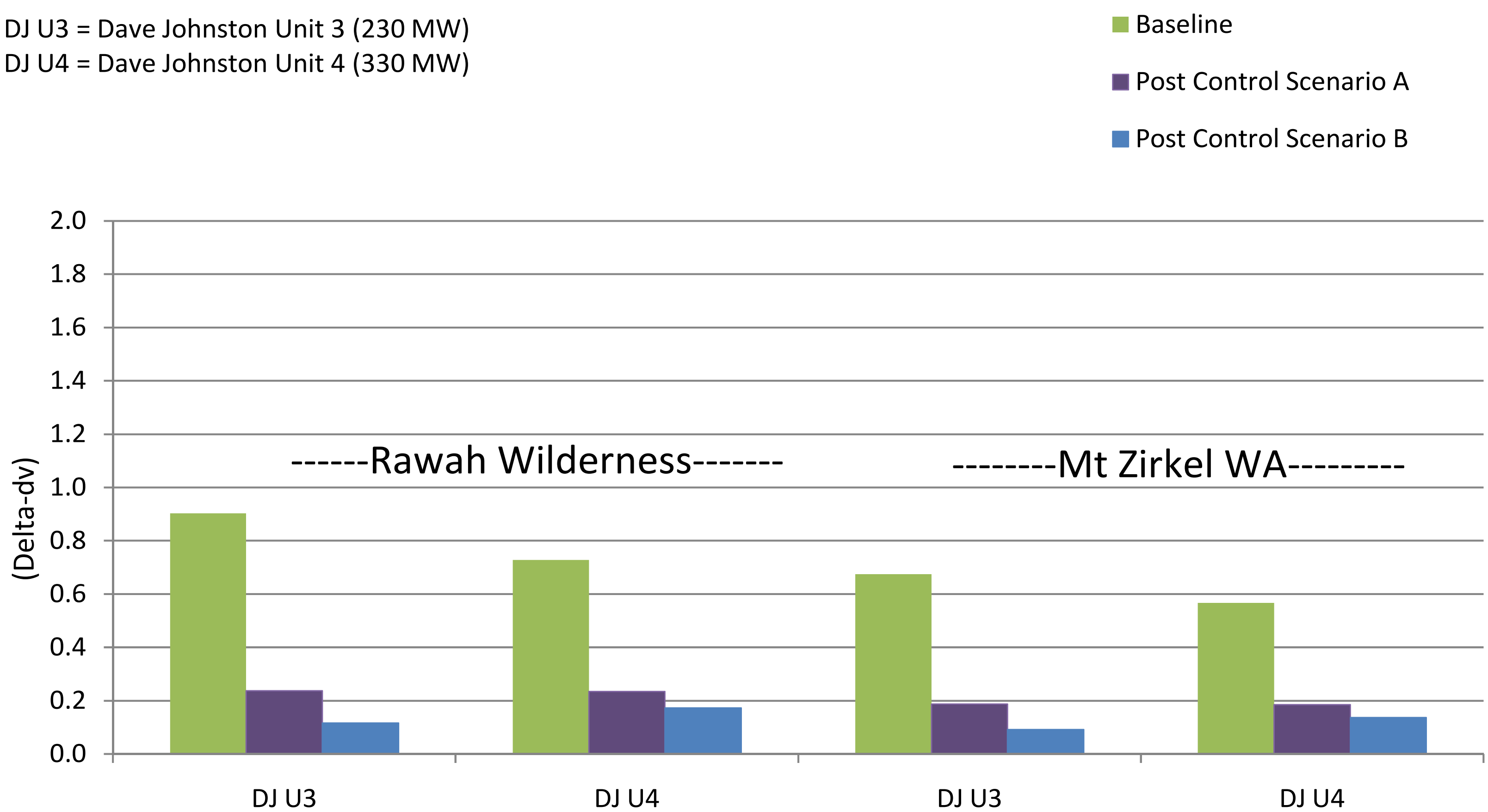
(Modeling results represent the three-year average of results using 2001-2003 meteorology)

Figure 8
Modeled BART Impacts at South Dakota Class I Areas: Number of Days > 0.5 delta-dv



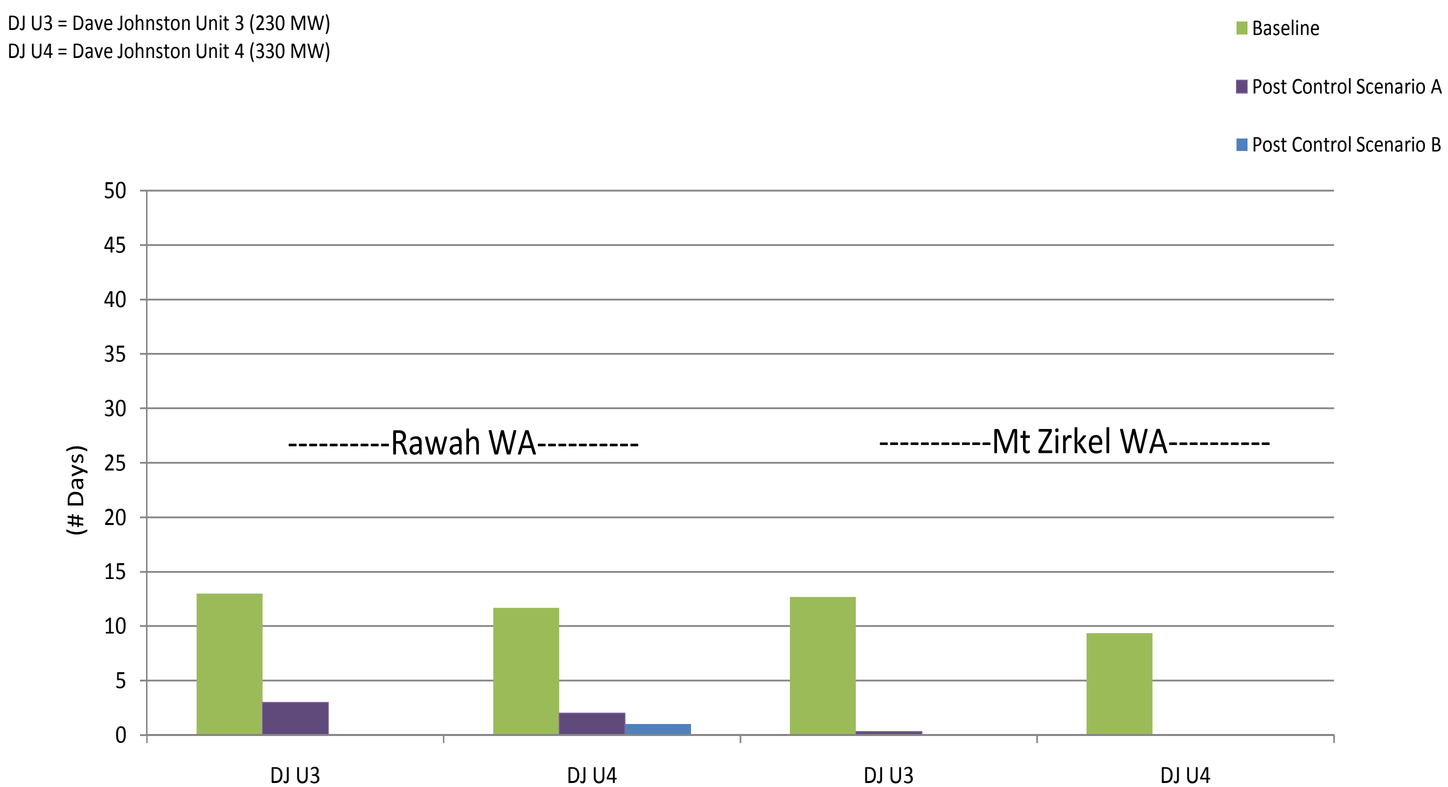
(Modeling results represent the three-year average of results using 2001-2003 meteorology)

Figure 9
Modeled BART Impacts at Colorado Class I Areas: 98th Percentile (delta-dv)



(Modeling results represent the three-year average of results using 2001-2003 meteorology)

Figure 10
Modeled BART Impacts at Colorado Class I Areas: Number of Days > 0.5 delta-dv



(Modeling results represent the three-year average of results using 2001-2003 meteorology)

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 two units subject to BART at the Dave Johnston Power Plant.

NO_x

LNB with advanced OFA is determined to be BART for Units 3 and 4 for NO_x based, in part, on the following conclusions:

1. LNB with advanced OFA on Units 3 and 4 was cost effective with a capital cost of $17,500,000 and $7,900,000 per unit, respectively. The average cost effectiveness, over a twenty year operational life, is $648 per ton of NO_x removed for Unit 3 and $137 per ton for Unit 4.

2. Combustion control using LNB with advanced 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 0.28 lb/MMBtu on a 30-day rolling average, below EPA's applicable presumptive limit of 0.45 lb/MMBtu for cell-fired boilers burning sub-bituminous coal, is justified for Unit 3.

4. 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 0.15 lb/MMBtu on a 30-day rolling average, equal to EPA's applicable presumptive limit for tangential-fired boilers burning sub-bituminous coal, is justified for Unit 4.

5. Visibility impacts were addressed in a comprehensive visibility analysis covering all three visibility impairing pollutants and associated control options. The cumulative 3-year averaged 98^{th} percentile visibility improvement from the baseline summed across all four Class I areas achieved with LNB with advanced OFA, dry FGD, and a new full-scale fabric filter, Post-Control Scenario A for each unit, was 3.558 Δdv from Unit 3 and 1.963 Δdv from Unit 4.

6. Annual NO_x emission reductions from baseline achieved by applying LNB with advanced OFA on Units 3 and 4 are 2,723 tons and 6,142 tons, respectively.

LNB with advanced OFA and SCR was not determined to be BART for Units 3 and 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 advanced OFA. Capital cost for SCR on Unit 3 is $129,700,000 and $151,900,000 for Unit 4. Annual SCR O&M costs for Unit 3 are $4,009,159 and $1,980,281 for Unit 4.

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

3. Operation of LNB with advanced OFA and SCR is parasitic and requires an estimated 1.6 MW from Unit 3 and 2.1 MW from Unit 4.

4. While visibility impacts were addressed in a cumulative analysis of all three pollutants, Post-Control Scenario B is directly comparable to Post-Control Scenario A as the only difference is directly attributable to the installation of SCR. Subtracting the modeled 98th percentile values from each other yield the incremental 98th percentile visibility improvement from SCR. The cumulative 3-year averaged 98th percentile visibility improvement from Post-Control Scenario A summed across all four Class I areas achieved with Post-Control Scenario B was 0.754 Δdv from Unit 3 and 0.405 Δdv from Unit 4.

The Division considers the installation and operation of the BART-determined NO_x controls, new LNB with advanced OFA on Units 3 and 4 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

Unit-by-unit NO_x BART determinations:

<u>Dave Johnston Unit 3</u>: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.28 lb/MMBtu (30-day rolling average), 784 lb/hr (30-day rolling average), and 3,434 tpy as BART for NO_x.

<u>Dave Johnston Unit 4</u>: Installing new LNB with advanced OFA and meeting NO_x emission limits of 0.15 lb/MMBtu (30-day rolling average), 615 /hr (30-day rolling average), and 2,694 tpy as BART for NO_x.

<u>**PM/PM$_{10}$**</u>

A new full-scale fabric filter is determined to be BART for Units 3 and 4 for PM/PM$_{10}$ based, in part, on the following conclusions:

1. While the Division considers the costs of compliance for full-scale fabric filters on Units 3 and 4 not reasonable, PacifiCorp is committed to installing this control device and has permitted the installation of a full-scale fabric filter Unit 3 and Unit 4 in Air Quality Permit MD-5098. A full-scale fabric filter is the most stringent PM/PM$_{10}$ control technology and therefore the Division will accept it as BART.

The Division considers the installation and operation of the BART-determined PM/PM$_{10}$ controls, new full-scale fabric filter on Units 3 and 4 to meet corresponding emission limits on a continuous basis, to meet the statutory requirements of BART.

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

<u>Dave Johnston Unit 3</u>: Installing a new full-scale fabric filter and meeting PM/PM$_{10}$ emission limits of 0.015 lb/MMBtu, 42.1 lb/hr, and 184 tpy as BART for PM/PM$_{10}$.

Dave Johnston Unit 4: Installing a new full-scale fabric filter and meeting PM/PM_{10} emission limits of 0.015 lb/MMBtu, 61.5 lb/hr, and 269 tpy as BART for PM/PM_{10}.

SO_2: WESTERN BACKSTOP SULFUR DIOXIDE 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 proposed dry FGD, and a full-scale fabric filter as SO_2 BART controls on both Units 3 and 4.

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 in Table 32.

Table 32: 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 33 to underscore the improvements associated with SO_2 reductions.

Table 33: 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 the installation costs of the pollution control systems.

PacifiCorp's BART-eligible or subject-to-BART power plant fleet is shown in Table 34. 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 34: 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.

Based on the cost of compliance and visibility improvement presented by PacifiCorp in the BART applications for Dave Johnston Units 3 and 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 not requiring additional controls under the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan in this permitting action. Additional controls may be required in future actions related to the Long-Term Strategy of the Wyoming Regional Haze State Implementation Plan.

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

PacifiCorp's Dave Johnston 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 Dave Johnston Units 3 and 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 Dave Johnston Units 3 and 4.

CHAPTER 6, SECTION 3 – OPERATING PERMIT:

The Dave Johnston Power Plant is a major source under Chapter 6, Section 3 of the Wyoming Air Quality Standards and Regulations. The most recent Operating Permit, 3-2-148, was issued for the facility on September 2, 2008. 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 the changes authorized in this permitting action.

CONCLUSION:

The Division is satisfied that PacifiCorp's Dave Johnston 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 to install new LNB with advanced OFA and a new full-scale fabric filter on Units 3 and 4.

PROPOSED PERMIT CONDITIONS:

The Division proposes to issue an Air Quality Permit to PacifiCorp for the modification of the Dave Johnston 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, 152 North Durbin Street, Suite 100, Casper, WY 82601.

5. Effective upon completion of the initial performance tests to verify the emission levels below, as required by Condition 6 of this permit, emissions from Dave Johnston Units 3 and 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 oil into the boiler and ends no later than the point in time when coal is introduced as fuel.

Unit	Pollutant	lb/MMBtu	lb/hr	tpy
3	NO_x	0.28 (30-day rolling)	784 (30-day rolling)	3,434
4	NO_x	0.15 (30-day rolling)	615 (30-day rolling)	2,694
3	PM/PM_{10} [a]	0.015	42.1	184
4	PM/PM_{10} [a]	0.015	61.5	269

[a] Filterable portion only

6. That initial performance tests be conducted, 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.

7. Performance tests shall consist of the following:

Coal-fired Boilers (Dave Johnston Units 3 and 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.

8. 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.

9. 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.

10. Compliance with the NO_x limits set forth in this permit for the coal-fired boilers (Dave Johnston Units 3 and 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).

11. 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).

12. Compliance with the PM/PM_{10} limits set forth in this permit for the coal-fired boilers (Dave Johnston Units 3 and 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.

13. 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.

14. PacifiCorp shall install new low NO_x burners with advanced overfire air on Units 3 and 4, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 6 no later than December 31, 2010 and December 31, 2009, respectively.

15. PacifiCorp shall install new full-scale fabric filters on Units 3 and 4, in accordance with the Division's BART determination, and conduct the initial performance tests required in Condition 6 no later than December 31, 2010 and December 31, 2012, respectively.

Appendix A
Facility Location

UAE Exhibit RR 2.8

BART REPORT ADDENDUM – DJ3

Addendum to Dave Johnston Unit 3 BART Report

PREPARED FOR: Wyoming Division of Air Quality

PREPARED BY: CH2M HILL

COPIES: Bill Lawson/PacifiCorp

DATE: March 26, 2008

Introduction

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

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

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

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

Stack Parameters, Emissions Information, and Capital Cost

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

TABLE 1
Control Scenario Summary
Dave Johnson Unit 3

	Equipment Type			Capital Cost
	NO_x	SO_2	PM_{10}	Million dollars
Baseline	No control	No control	ESP	—
Scenario A	LNB with OFA	Dry FGD	Fabric Filter	$187.0
Scenario B	LNB with OFA and SCR	Dry FGD	Fabric Filter	$299.2

Emissions were modeled for the following pollutants:

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

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

TABLE 2
Calpuff Model Inputs
Dave Johnston Unit 3

	BART Comparison[d]		
Model Input Data	Baseline	Scenario A [e]	Scenario B [f]
Hourly Heat Input (mmBtu/hour)	2,500	2,800	2,800
Sulfur Dioxide (SO_2) Stack Emissions (lb/hr)	3,000	420	420
Nitrogen Oxide (NO_X) Stack Emissions (lb/hr)	1,750	784	196
PM_{10} Stack Emissions (lb/hr)	75	42.0	42.0
Coarse Particulate ($PM_{2.5}$ <diameter< PM_{10}) Stack Emissions (lb/hr)[a]	32.3	23.9	23.9
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[b]	42.8	18.1	18.1
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	46	2.6	3.7
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)	—	—	0.7
$(NH_4)HSO_4$ Stack Emissions (lb/hr)	—	—	1.2
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	45.1	2.5	3.6
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	0.5
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	1.0

TABLE 2
Calpuff Model Inputs
Dave Johnston Unit 3

		BART Comparison[d]	
Model Input Data	**Baseline**	**Scenario A [e]**	**Scenario B [f]**
Total Sulfate (SO_4) (lb/hr)[c]	45.1	2.5	5.1
Stack Conditions			
Stack Height (meters)	152	152.4	152.4
Stack Exit Diameter (meters)	4.6	4.57	4.57
Stack Exit Temperature (Kelvin)	445	348	348
Stack Exit Velocity (meters per second)	32	25.5	25.5

NOTES:
[a] Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43% ESP and 57% Baghouse. PM_{10} and $PM_{2.5}$ refer to particulate matter less than 10 and 2.5 micrometers, respectively, in aerodynamic diameter.
[b] Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57% ESP and 43% Baghouse.
[c] Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)
[d] SO_2, NO_x, and PM rates are expressed in terms of permitted emission rates. Actual emissions will be less than the permitted rates.
[e] PacifiCorp Committed Controls @ permitted rates: LNB with OFA, Dry FGD, New Fabric Filter
[f] PacifiCorp Committed Controls and SCR @ permitted rates

Economic Analysis

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

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

TABLE 3
Scenario A Control Cost
Dave Johnston Unit 3

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario A
	LNB with OFA	**Dry FGD**	**Fabric Filter**	**Control Cost**
Total Installed Capital Costs (million dollars)	$17.5	$169.5	—	$187.0
Annualized First-Year Capital Costs	$1.66	$16.12	—	$17.79
First Year Fixed & Variable O&M Costs (million dollars)	$0.10	$5.30	—	$5.40
Total First Year Annualized Costs (million dollars) [a]	$1.76	$21.42	—	$23.19
Power Consumption (MW)	—	3.88	—	3.88
Annual Power Usage (Million kWh/Yr)	—	30.59	—	30.59
Permitted Emission Rate (lb/mmBtu)	0.28	0.15	0.02	—
Additional Tons of Pollutant Removed per Year over Baseline	4,636	11,589	166	16,391
First Year Average Control Cost ($/Ton of Pollutant Removed)	381	1,848	—	1,414

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

TABLE 4
Scenario B Control Cost
Dave Johnston Unit 3

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario B
	LNB with OFA & SCR	**Dry FGD**	**Fabric Filter**	**Control Cost**
Total Installed Capital Costs (million dollars)	$129.7	$169.5	—	$299.2
Annualized First-Year Capital Costs	$12.34	$16.12	—	$28.46
First Year Fixed & Variable O&M Costs (million dollars)	$4.01	$5.30	—	$9.30
Total First Year Annualized Costs (million dollars) [a]	$16.35	$21.42	—	$37.77
Power Consumption (MW)	0.23	3.88	—	5.45
Annual Power Usage (Million kWh/Yr)	12.34	30.59	—	42.97
Permitted Emission Rate (lb/mmBtu)	0.07	0.15	0.02	—
Additional Tons of Pollutant Removed per Year over Baseline	6,954	11,589	166	18,709
First Year Average Control Cost ($/Ton of Pollutant Removed)	2,351	1,848	—	2,019

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

TABLE 5
Incremental Control Costs, Scenario B compared to Scenario A
Dave Johnston Unit 3

	NO_x Control	SO_2 Control	PM_{10} Control	Total Control Cost
Incremental Installed Capital Costs (million dollars)	$112.2	0	0	$112.2
Incremental Annualized First-Year Capital Costs	$10.67	0	0	$10.67
Incremental First Year Fixed & Variable O&M Costs (million dollars)	$3.91	0	0	$3.91
Incremental First Year Annualized Costs (million dollars) [a]	$14.58	0	0	$14.58
Incremental Power Consumption (MW)	1.57	0	0	1.57
Incremental Annual Power Usage (Million kWh/Yr)	12.38	0	0	12.38
Incremental Improvement in Emission Rate (lb/mmBtu)	0.21	0	0	—
Incremental Tons of Pollutant Removed	2,318	0	0	2,318
Incremental First Year Average Control Cost ($/Ton of Pollutant Removed)	6,291	0	0	6,291

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

Modeling Results and Least-Cost Envelope Analysis

CH2M HILL modeled Dave Johnston Unit 3 for two post-control scenarios. The results determine the change in deciview based on each alternative at the Class I areas specific to the project. The Class I areas potentially affected are Badlands National Park and Windcave National Park for this unit.

Modeled Scenarios

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

- Baseline: Current operations with ESP
- Scenario A: LNB with OFA, Dry FGD, new fabric filter
- Scenario B: Scenario A with SCR

Summary of Visibility Analysis

Tables 6 and 7 present a summary of the modeling period (2001–2003) results for each scenario and Class I area.

TABLE 6
Costs and Visibility Modeling Results as Applicable to Badlands National Park
Dave Johnston Unit 3

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with ESP	—	4.202	1.500	59
Scenario A	Scenario A: PacifiCorp Committed Controls	$23,184,500	1.297	0.432	7
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$37,766,998	0.638	0.208	3

TABLE 7
Costs and Visibility Modeling Results as Applicable to Wind Cave National Park
Dave Johnston Unit 3

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98th Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with ESP	—	5.191	1.971	57
Scenario A	Scenario A: PacifiCorp Committed Controls	$23,184,500	1.805	0.583	11
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$37,766,998	0.904	0.262	2

Results

Tables 8 and 9 present a summary of the costs and modeling results for each scenario and Class I area.

TABLE 8
Incremental Costs and Incremental Visibility Improvements Relative to Badlands National Park
Dave Johnston Unit 3

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$23.18	1.068	52	$21.71	$0.45
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$37.77	1.292	56	$29.23	$0.67
Scenario B Compared To Scenario A	Addition of SCR	$14.58	0.224	4	$65.10	$3.65

TABLE 9
Incremental Costs and Incremental Visibility Improvements Relative to Wind Cave National Park
Dave Johnston Unit 3

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$23.18	1.388	46	$16.70	$0.50
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$37.77	1.709	55	$22.10	$0.69
Scenario B Compared To Scenario A	Addition of SCR	$14.58	0.321	9	$45.43	$1.62

Least-Cost Envelope Analysis

The least-cost envelope graphs for Badlands National Park are shown in Figures 1 and 2 and for Wind Cave National Park are shown in Figures 3 and 4.

FIGURE 1

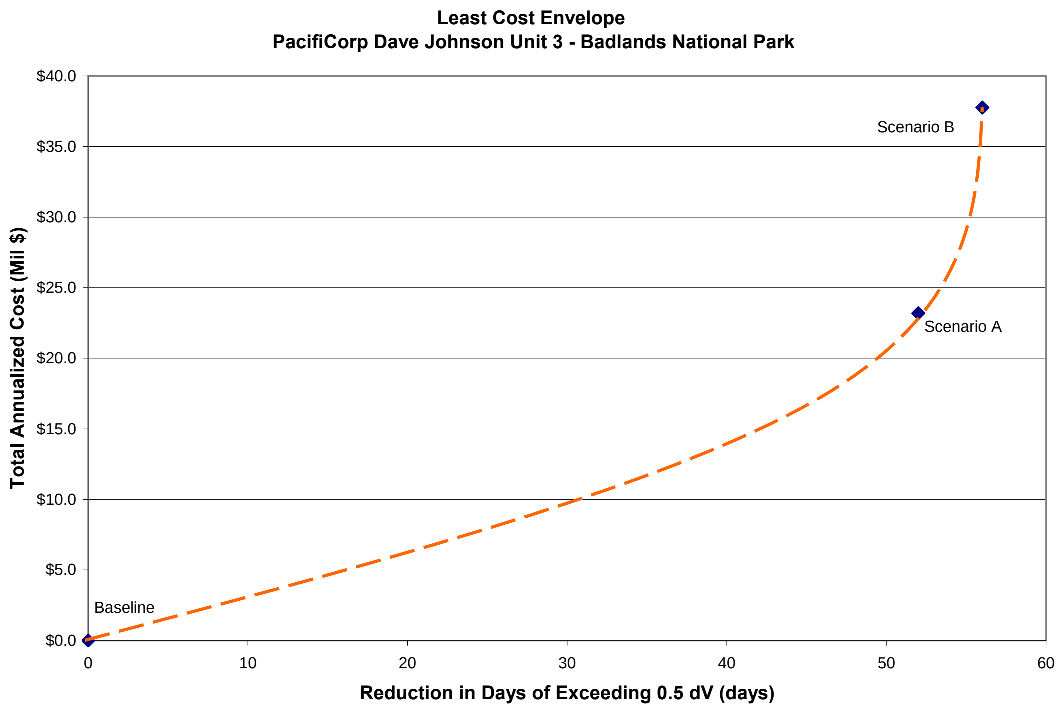


FIGURE 2

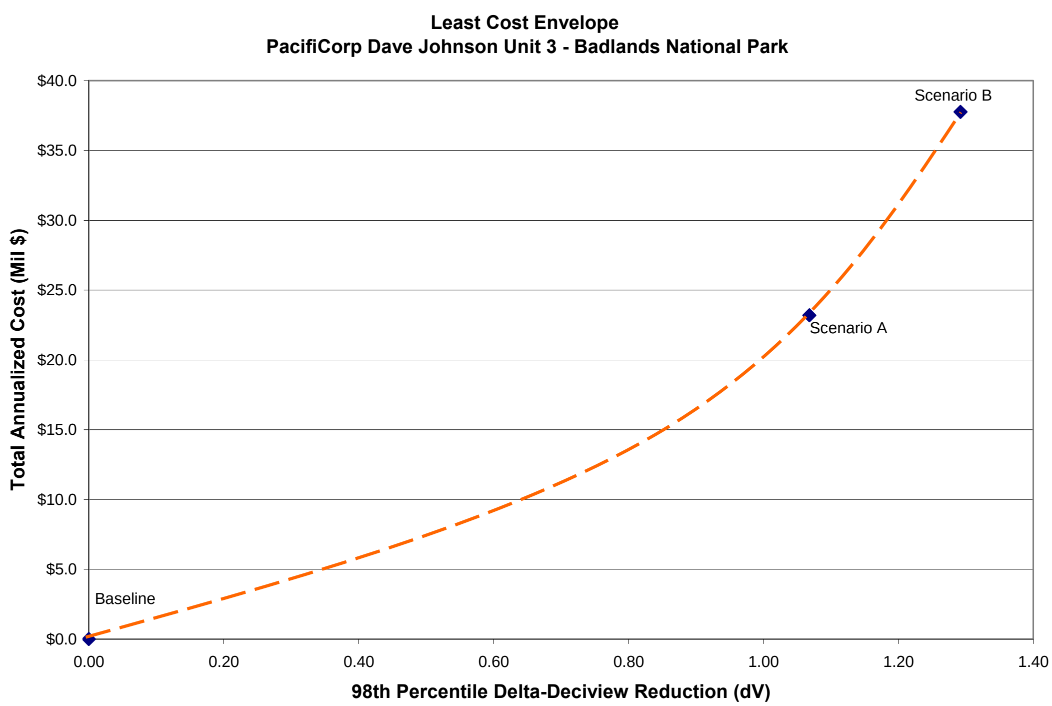


FIGURE 3

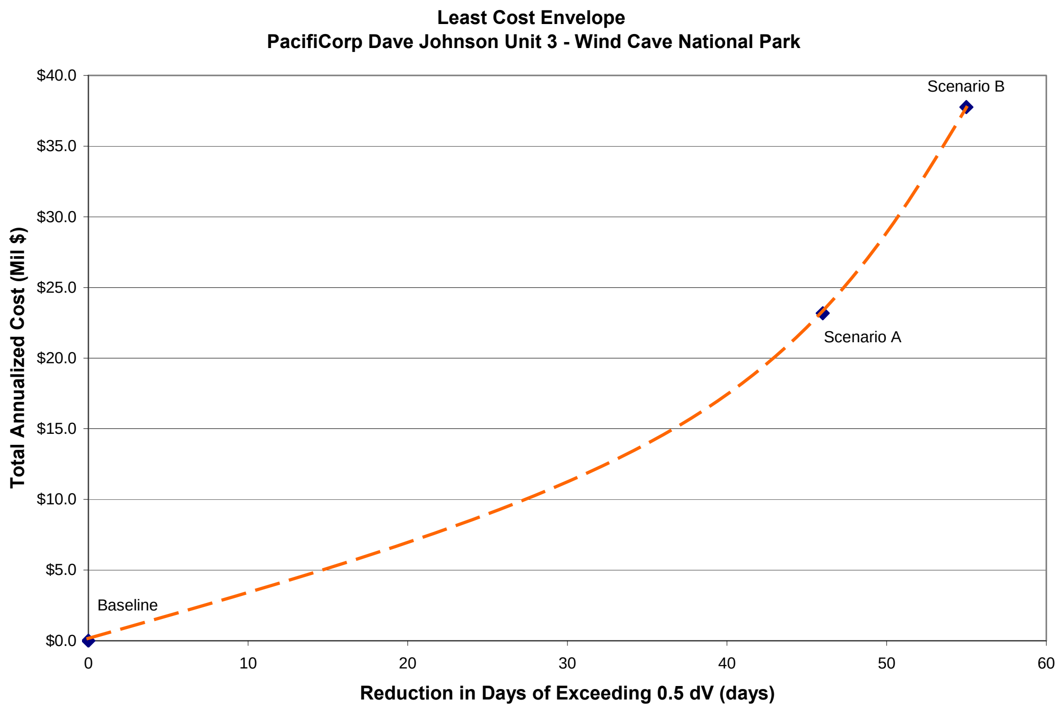
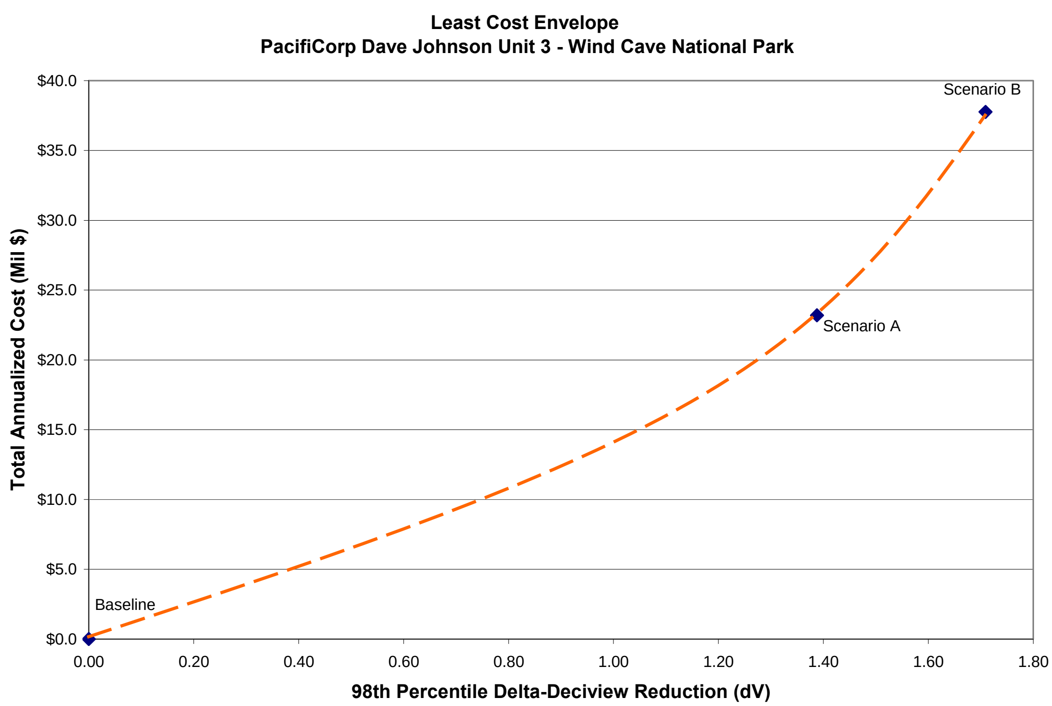


FIGURE 4



ATTACHMENT 1

Complete Economic Analyses for Scenarios A and B

ECONOMIC ANALYSIS SUMMARY - FIRST YEAR COSTS

DJ3 **Boiler Design: 3-Cell BurnerOpposed Wall-Fired PC**

TYPE OF EMISSIONS CONTROLS		NO_x Control				SO_2 and PM Control			Scenario A	Scenario B
Technology Label	**BASE**	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**A+F**	**D+F**
	Current Operation	Low NO_x Burners with Overfire Air	Rotating Overfire Air	Low NO_x Burners with Overfire Air and Non-Selective Catalytic Reduction	Low NO_x Burners with Overfire Air and Selective Catalytic Reduction	Dry FGD w/ESP	Upgraded Dry FGD & Fabric Filter	Wet FGD w/ ESP	LNB w/OFA, Dry Flue Gas Desulfurization and Fabric Filter Baghouse	LNB w/OFA, SCR. Dry Flue Gas Desulfurization and Fabric Filter Baghouse
CAPITAL INVESTMENT										
Total Installed Capital Costs ($)	$0	$17,500,000	$12,054,022	$24,035,544	$129,700,000	$91,499,734	$169,500,000	$144,300,464	$187,000,000	$299,200,000
FIRST YEAR DEBT SERVICE ($/Yr)	**$0**	**$1,664,737**	**$1,146,673**	**$2,286,449**	**$12,338,079**	**$8,704,171**	**$16,124,166**	**$13,726,989**	**$17,788,903**	**$28,462,245**
FIRST YEAR FIXED O&M Costs ($/Yr)										
Operating Labor ($/Yr)	$0	$0	$0	$0	$0	$506,128	$506,128	$809,804	$506,128	$506,128
Maintenance Material ($/Yr)	$0	$40,000	$60,000	$98,000	$155,000	$714,175	$714,175	$1,182,587	$754,175	$869,175
Maintenance Labor ($/Yr)	$0	$60,000	$90,000	$147,000	$2,325,000	$476,928	$476,928	$788,391	$536,928	$2,801,928
Administrative Labor ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FIRST YEAR FIXED O&M COST	**$0**	**$100,000**	**$150,000**	**$245,000**	**$2,480,000**	**$1,697,231**	**$1,697,231**	**$2,780,782**	**$1,797,231**	**$4,177,231**
FIRST YEAR VARIABLE O&M Costs ($/Yr)										
Makeup Water Costs ($/Yr)	$0	$0	$0	$0	$0	$99,566	$99,566	$132,371	$99,566	$99,566
Reagent Costs ($/Yr)	$0	$0	$0	$57,025	$526,265	$1,104,023	$1,182,881	$1,025,183	$1,182,881	$1,709,146
SCR Catalyst / FF Bag Costs ($/Yr)	$0	$0	$0	$0	$384,000	$0	$151,528	$0	$151,528	$535,528
Waste Disposal Costs ($/Yr)	$0	$0	$0	$0	$0	$572,810	$634,896	$746,581	$634,896	$634,896
Electric Power Costs ($/Yr)	$0	$0	$1,087,992	$90,666	$618,894	$981,558	$1,529,496	$1,359,990	$1,529,496	$2,148,390
TOTAL FIRST YEAR VARIABLE O&M Costs ($/Yr)	**$0**	**$0**	**$1,087,992**	**$147,691**	**$1,529,159**	**$2,757,957**	**$3,598,367**	**$3,264,126**	**$3,598,367**	**$5,127,527**
SUMMARY OF FIRST YEAR COSTS ($/Yr)										
First Year Debt Service ($/Yr)	$0	$1,664,737	$1,146,673	$2,286,449	$12,338,079	$8,704,171	$16,124,166	$13,726,989	$17,788,903	$28,462,245
First Year Fixed O&M Costs ($/Yr)	$0	$100,000	$150,000	$245,000	$2,480,000	$1,697,231	$1,697,231	$2,780,782	$1,797,231	$4,177,231
First Year Variable O&M Costs ($/Yr)	$0	$0	$1,087,992	$147,691	$1,529,159	$2,757,957	$3,598,367	$3,264,126	$3,598,367	$5,127,527
Total First Year Costs ($/Yr)	**$0**	**$1,764,737**	**$2,384,665**	**$2,679,140**	**$16,347,238**	**$13,159,358**	**$21,419,765**	**$19,771,897**	**$23,184,501**	**$37,767,002**
CONTROL COST COMPARISONS										
NO_x Technology Comparison										
Additional NO_x Removed From Base Case (Tons/Yr)	0	4,636	5,629	5,298	6,954					
First Year Average Control Cost ($/Ton NO_x Removed)	$0	$381	$424	$506	$2,351					
Technology Case Comparison		A-BASE	B-A	C-A	D-A					
Incremental NO_x Removed (Tons/Yr)	0	4,636	993	662	2,318					
Incremental Control Cost ($/Ton NO_x Removed)	$0	$381	$624	$1,381	$6,291					
SO_2 Technology Comparison	0.5%					81.8%	87.6%	95.0%		
Additional SO_2 Removed From Base Case (Tons/Yr)	0					10,817	11,589	12,583		
First Year Average Control Cost ($/Ton SO_2 Removed)	$0					$1,217	$1,848	$1,571		
Technology Case Comparison						E-BASE	F-E	G-F		
Incremental SO_2 Removed (Tons/Yr)	0					10,817	773	993		
Incremental Control Cost ($/Ton SO_2 Removed)	$0					$1,217	$10,691	-$1,659		
PM Technology Comparison	0.0%									
Additional PM Removed From Base Case (Tons/Yr)	0					0	166	0		
First Year Average Control Cost ($/Ton PM Removed)	$0					#DIV/0!	$129,375	#DIV/0!		
Technology Case Comparison						E-BASE	F-E	G-F		
Incremental PM Removed (Tons/Yr)	0					0	166	-166		
Incremental Control Cost ($/Ton PM Removed)	$0					#DIV/0!	$0	$0		
SCENARIO A AND B COMPARISONS										
Additional NO_x, SO_2, & PM Removed From Base Case (Tons/Yr)	**0**								**16,391**	**18,709**
First Year Average Control Cost Compared to Base Case ($/Ton Removed)	**$0**								**$1,414**	**$2,019**
Incremental Tons Removed - Scenario B vs Scenario A (Tons/Yr)	**0**									**2,318**
Incremental Control Costs - Scenario B vs Scenario A ($/Ton Removed)	**$0**									**$6,291**

INPUT CALCULATIONS

DJ3 Boiler Design: 3-Cell BurnerOpposed Wall-Fired PC

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 and PM Control Technologies			Scenario A	Scenario B
Control Technologies										
NO_x Emission Control System	Good Practices	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR				LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System						Dry FGD w/ESP	Upgraded Dry FGD	Wet FGD w/ ESP	Upgraded Dry FGD	Upgraded Dry FGD
PM Emission Control System	ESP						Fabric Filter		Fabric Filter	Fabric Filter
General Plant Design and Operating Data										
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC
Annual Power Plant Capacity Factor	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Net Power Output (kW)	223,214	223,214	223,214	223,214	223,214	223,214	223,214	223,214	223,214	223,214
Net Plant Heat Rate (Btu/kW-Hr)	12,175	12,175	12,175	12,175	12,175	12,175	12,175	12,175	12,175	12,175
Boiler Heat Input, Measured by Fuel Input (MMBtu/Hr)	2,718	2,718	2,718	2,718	2,718	2,718	2,718	2,718	2,718	2,718
Annual Heat Input, Measured by Fuel Input (MMBtu/Year)	21,425,798	21,425,798	21,425,798	21,425,798	21,425,798	21,425,798	21,425,798	21,425,798	21,425,798	21,425,798
Boiler Heat Input, Measured by CEM (MMBtu/Hr)	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800	2,800
Annual Heat Input, Measured by CEM (MMBtu/Year)	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200	22,075,200
Plant Fuel Source										
Boiler Fuel Source	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB
Coal Heating Value (Btu/Lb)	7,784	7,784	7,784	7,784	7,784	7,784	7,784	7,784	7,784	7,784
Coal Sulfur Content (wt.%)	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.470%	0.47%	0.47%
Coal Ash Content (wt.%)	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%
Coal Flow Rate (Lb/Hr)	349,130	349,130	349,130	349,130	349,130	349,130	349,130	349,130	349,130	349,130
Coal Consumed (Ton/Yr)	1,376,272	1,376,272	1,376,272	1,376,272	1,376,272	1,376,272	1,376,272	1,376,272	1,376,272	1,376,272
Nitrogen Oxide Emissions										
NO_x Emission Rate (Lb/MMBtu)	0.70	0.28	0.19	0.22	0.07				0.28	0.07
NO_x Emission Rate (Lb/Hr)	1,960	784	532	616	196				784	196
NO_x Emission Rate (Lb Moles/Hr)	65.31	26.12	17.73	20.53	6.53				26.12	6.53
NO_x Emission Rate (Ton/Yr)	7,726	3,091	2,097	2,428	773				3,091	773
Add'l NO_x Removed from Current Operations (Lb/Hr)	0	1,176	1,428	1,344	1,764				1,176	1,764
Add'l NO_x Removed from Current Operations (Ton/Yr)	0	4,636	5,629	5,298	6,954				4,636	6,954
Sulfur Dioxide Emissions										
Uncontrolled SO_2 (Lb/MMBtu)	1.21					1.21	1.21	1.21	1.21	1.21
Uncontrolled SO_2 (Lb/Hr)	3,378					3,378	3,378	3,378	3,378	3,378
Uncontrolled SO_2 (Lb Moles/Hr)	52.73					52.73	52.73	52.73	52.73	52.73
Uncontrolled SO_2 (Tons/Yr)	13,316					13,316	13,316	13,316	13,316	13,316
Controlled SO_2 Emission Rate (Lb/MMBtu)	1.20					0.22	0.15	0.06	0.15	0.15
SO_2 Removal Efficiency (%)	0.5%					81.8%	87.6%	95.0%	87.6%	87.6%
Controlled SO_2 Emissions (Lb/Hr)	3,360					616	420	168	420	420
Controlled SO_2 Emissions (Ton/Yr)	13,245					2,428	1,656	662	1,656	1,656
SO_2 Removed (Lb/Hr)	18					2,762	2,958	3,210	2,958	2,958
SO_2 Removed (Ton/Yr)	71					10,887	11,660	12,654	11,660	11,660
Add'l SO_2 Removed from Current Operations (Lb/Hr)	0					2,744	2,940	3,192	2,940	2,940
Add'l SO_2 Removed from Current Operations (Ton/Yr)	0					10,817	11,589	12,583	11,589	11,589
Particulate Matter Emissions										
Uncontrolled Fly Ash (Lb/Hr)	13,993					13,993	13,993	13,993	13,993	13,993
Uncontrolled Fly Ash (Lb/MMBtu)	4.998					4.998	4.998	4.998	4.998	4.998
Uncontrolled Fly Ash (Tons/Yr)	55,161					55,161	55,161	55,161	55,161	55,161
Controlled Fly Ash Emission Rate (Lb/MMBtu)	0.030					0.030	0.015	0.030	0.015	0.015
Controlled Fly Ash Removal Efficiency (%)	99.4%					99.4%	99.7%	99.4%	99.7%	99.7%
Controlled Fly Ash Emissions (Lb/Hr)	84					84	42	84	42	42
Controlled Fly Ash Emissions (Ton/Yr)	331					331	166	331	166	166
Fly Ash Removed (Lb/Hr)	13,909					13,909	13,951	13,909	13,951	13,951
Fly Ash Removed (Ton/Yr)	54,830					54,830	54,995	54,830	54,995	54,995
Add'l Ash Removed from Current Operation (Lb/Hr)	0					0	42	0	42	42
Add'l Ash Removed from Current Operation (Ton/Yr)	0					0	166	0	166	166
Economic Factors										
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20	20

INPUT CALCULATIONS

DJ3 **Boiler Design:** **3-Cell BurnerOpposed Wall-Fired PC**

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 and PM Control Technologies			Scenario A	Scenario B
Control Technologies										
NO_x Emission Control System	Good Practices	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR				LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System						Dry FGD w/ESP	Upgraded Dry FGD	Wet FGD w/ ESP	Upgraded Dry FGD	Upgraded Dry FGD
PM Emission Control System	ESP						Fabric Filter		Fabric Filter	Fabric Filter
Installed Capital Costs										
NO_x Emission Control System ($2006)		$17,500,000	$12,054,022	$24,035,544	$129,700,000				$17,500,000	$129,700,000
SO_2 Emission Control System ($2006)						$91,499,734	$169,500,000	$144,300,464	$169,500,000	$169,500,000
PM Emission Control System ($2006)						$0	$0	$0	$0	$0
Total Emission Control System Capital Costs ($2006)		$17,500,000	$12,054,022	$24,035,544	$129,700,000	$91,499,734	$169,500,000	$144,300,464	$187,000,000	$299,200,000
NO_x Emission Control System ($/kW)		$78	$54	$108	$581				$78	$581
SO_2 Emission Control System ($/kW)						$410	$759	$646	$759	$759
PM Emission Control System ($/kW)										
Total Emission Control Capital Costs ($/kW)		$78	$54	$108	$581	$410	$759	$646	$838	$1,340
Fixed Operating & Maintenance Costs										
Operating Labor ($)		$0	$0	$0	$0	$506,128	$506,128	$809,804	$506,128	$506,128
Maintenance Material ($)		$40,000	$60,000	$98,000	$155,000	$714,175	$714,175	$1,182,587	$754,175	$869,175
Maintenance Labor ($)		$60,000	$90,000	$147,000	$2,325,000	$476,928	$476,928	$788,391	$536,928	$2,801,928
Administrative Labor ($)		$0	$0	$0	$0	$0	$0	$0	$0	$0
Total 1st Fixed Year O&M Cost ($)		$100,000	$150,000	$245,000	$2,480,000	$1,697,231	$1,697,231	$2,780,782	$1,797,231	$4,177,231
Annual Fixed O&M Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Fixed O&M Cost ($/Yr)		$118,550	$177,825	$290,448	$2,940,047	$2,012,072	$2,012,072	$3,296,625	$2,130,623	$4,952,120
Variable Operating & Maintenance Costs										
Water Cost										
Makeup Water Usage (gpm)		0	0	0	0	173	173	230	173	173
Unit Price ($/1000 gallons)		$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22
First Year Water Cost ($)		$0	$0	$0	$0	$99,566	$99,566	$132,371	$99,566	$99,566
Annual Water Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Water Costs ($/Yr)		$0	$0	$0	$0	$118,036	$118,036	$156,926	$118,036	$118,036
Reagent Cost										
Type of Reagent		None	None	Urea	Anhydrous NH_3	Lime	Lime	Lime	Lime	Lime & Anhydrous NH_3
Unit Cost ($/Ton)		$0.00		$370.00	$400.00	$91.25	$91.25	$91.25		
Unit Cost ($/Lb)		$0.000		$0.185	$0.200	$0.046	$0.046	$0.046		
Molar Stoichiometry		0.00		0.41	1.00	1.15	1.15	1.02		
Reagent Purity (Wt.%)		100%		100%	100%	90%	90%	100%		
Reagent Usage (Lb/Hr)				39	334	3,069	3,288	2,850		
First Year Reagent Cost ($)		$0		$57,025	$526,265	$1,104,023	$1,182,881	$1,025,183	$1,182,881	$1,709,146
Annual Reagent Cost Escalation Rate (%)		2.00%		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Reagent Costs ($/Yr)				$67,603	$623,889	$1,308,822	$1,402,309	$1,215,358	$1,402,309	$2,026,198
SCR Catalyst / Fabric Filter Bag Replacement Cost										
Material Replaced					SCR Catalyst		Bags		Bags	Bags & SCR Catalyst
Annual SCR Catalyst (m3) / No. FF Bags					128		1,457			
SCR Catalyst ($/m3) / Bag Cost ($/ea.)					$3,000		$104			
First Year SCR Catalyst / Bag Replacement Cost ($)					$384,000		$151,528		$151,528	$535,528
Annual SCR Catalyst / Bag Cost Escalation Rate (%)					2.00%		2.00%		2.00%	2.00%
Levelized Catalyst/Fabric Fitler Bag Costs ($/Yr)					$455,233		$179,637		$179,637	$634,870
FGD Waste Disposal Cost										
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)						5,972	6,620	7,784	6,620	6,620
FGD Waste Disposal Unit Cost ($/Dry Ton)						$24.33	$24.33	$24.33	$24.33	$24.33
First Year FGD Waste Disposal Cost ($)						$572,810	$634,896	$746,581	$634,896	$634,896
Annual Waste Disposal Cost Esc. Rate (%)						2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Waste Disposal Costs ($/Yr)						$679,068	$752,671	$885,074	$752,671	$752,671
Auxiliary Power Cost										
Auxiliary Power Requirement (MW)		0.00	2.76	0.23	1.57	2.49	3.88	3.45	3.88	5.45
Auxiliary Power Requirement (% of Plant Output)		0.00%	1.24%	0.10%	0.70%	1.12%	1.74%	1.55%	1.74%	2.44%
Auxilliary Power Useage (MWh)		0	21,760	1,813	12,378	19,631	30,590	27,200	30,590	42,968
Unit Cost ($2006/MW-Hr)		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
First Year Auxiliary Power Cost ($)		$0	$1,087,992	$90,666	$618,894	$981,558	$1,529,496	$1,359,990	$1,529,496	$2,148,390
Annual Power Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Auxilliary Power Costs ($/Yr)		$0	$1,289,818	$107,485	$733,701	$1,163,640	$1,813,222	$1,612,272	$1,813,222	$2,546,923

UAE Exhibit RR 2.9

BART REPORT ADDENDUM – DJ4

Addendum to Dave Johnston Unit 4 BART Report

PREPARED FOR:	Wyoming Division of Air Quality
PREPARED BY:	CH2M HILL
COPIES:	Bill Lawson/PacifiCorp
DATE:	March 26, 2008

Introduction

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

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

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

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

Stack Parameters, Emissions Information, and Capital Cost

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

TABLE 1
Control Scenario Summary
Dave Johnson Unit 4

	Equipment Type			Capital Cost
	NO_x	**SO_2**	**PM_{10}**	**Million dollars**
Baseline	LNB	Lime—add Venturi scrubber	Venturi scrubber	—
Scenario A	LNB with OFA	Dry FGD	Fabric Filter	$251.0
Scenario B	LNB with OFA and SCR	Dry FGD	Fabric Filter	$395.0

Emissions were modeled for the following pollutants:

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

Table 2 shows stack parameters and emission rates that were used for the Dave Johnston Unit 4 BART modeling and analysis.

TABLE 2
Calpuff Model Inputs
Dave Johnston Unit 4

	BART Comparison[d]		
Model Input Data	**Baseline**	**Scenario A [e]**	**Scenario B [f]**
Hourly Heat Input (mmBtu/hour)	4,100	4,100	4,100
Sulfur Dioxide (SO_2) Stack Emissions (lb/hr)	2,050	615	615
Nitrogen Oxide (NO_x) Stack Emissions (lb/hr)	1,640	615	287
PM_{10} Stack Emissions (lb/hr)	250	61.5	61.5
Coarse Particulate ($PM_{2.5}$ <diameter< PM_{10}) Stack Emissions (lb/hr)[a]	108	35.1	35.1
Fine Particulate (diameter<$PM_{2.5}$) Stack Emissions (lb/hr)[b]	143	26.4	26.4
Sulfuric Acid (H_2SO_4) Stack Emissions (lb/hr)	37.7	3.8	5.8
Ammonium Sulfate [$(NH_4)_2SO_4$] Stack Emissions (lb/hr)	—	—	0.8
$(NH_4)HSO_4$ Stack Emissions (lb/hr)	—	—	1.4
H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr)	37	3.7	5.6
$(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	0.6
$(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)	—	—	1.2

TABLE 2
Calpuff Model Inputs
Dave Johnston Unit 4

	BART Comparison[d]		
Model Input Data	**Baseline**	**Scenario A** [e]	**Scenario B** [f]
Total Sulfate (SO_4) (lb/hr)[c]	37	3.7	7.4
Stack Conditions			
Stack Height (meters)	76	152	152
Stack Exit Diameter (meters)	9.75	5.79	5.79
Stack Exit Temperature (Kelvin)	322	350	350
Stack Exit Velocity (meters per second)	8.53	25.7	25.7

NOTES:
[a] Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43% ESP and 57% Baghouse. PM_{10} and $PM_{2.5}$ refer to particulate matter less than 10 and 2.5 micrometers, respectively, in aerodynamic diameter.
[b] Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57% ESP and 43% Baghouse.
[c] Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)
[d] SO_2, NO_x, and PM rates are expressed in terms of permitted emission rates. Actual emissions will be less than the permitted rates.
[e] PacifiCorp Committed Controls @ permitted rates: LNB with OFA, Dry FGD, New Fabric Filter
[f] PacifiCorp Committed Controls and SCR @ permitted rates

Economic Analysis

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

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

TABLE 3
Scenario A Control Cost
Dave Johnston Unit 4

	NO_x Control	**SO_2 Control**	**PM_{10} Control**	**Scenario A**
	LNB with OFA	**Dry FGD**	**Fabric Filter**	**Control Cost**
Total Installed Capital Costs (million dollars)	$7.90	$243.1	—	$251.0
Annualized First-Year Capital Costs	$0.75	$23.13	—	$23.88
First Year Fixed and Variable O&M Costs (million dollars)	$0.09	$5.32	—	$5.41
Total First Year Annualized Costs (million dollars) [a]	$0.84	$28.77	—	$29.61
Power Consumption (MW)	—	4.45	—	4.54
Annual Power Usage (Million kWh/Yr)	—	35.79	—	35.79
Permitted Emission Rate (lb/mmBtu)	0.15	0.15	0.02	—
Additional Tons of Pollutant Removed per Year over Baseline	4,041	5,657	743	10,441
First Year Average Control Cost ($/Ton of Pollutant Removed)	208	5,028	—	2,805

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

TABLE 4
Scenario B Control Cost
Dave Johnston Unit 4

	NO_x Control	SO_2 Control	PM_{10} Control	Scenario B
	LNB with OFA & SCR	**Dry FGD**	**Fabric Filter**	**Control Cost**
Total Installed Capital Costs (million dollars)	$151.9	$243.1	—	$395.0
Annualized First-Year Capital Costs	$14.45	$23.13	—	$37.58
First Year Fixed & Variable O&M Costs (million dollars)	$1.98	$5.32	—	$7.30
Total First Year Annualized Costs (million dollars) [(a)]	$16.43	$28.44	—	$44.87
Power Consumption (MW)	2.29	4.54	—	6.83
Annual Power Usage (Million kWh/Yr)	18.05	35.79	—	53.85
Permitted Emission Rate (lb/mmBtu)	0.07	0.15	0.02	—
Additional Tons of Pollutant Removed per Year over Baseline	5,334	5,657	743	11,734
First Year Average Control Cost ($/Ton of Pollutant Removed)	3,081	5,028	—	3,824

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

TABLE 5
Incremental Control Costs, Scenario B compared to Scenario A
Dave Johnston Unit 4

	NO_x Control	**SO_2 Control**	**PM_{10} Control**	**Total Control Cost**
Incremental Installed Capital Costs (million dollars)	$144.0	0	0	$144.0
Incremental Annualized First-Year Capital Costs	$13.70	0	0	$13.70
Incremental First Year Fixed & Variable O&M Costs (million dollars)	$1.89	0	0	$1.89
Incremental First Year Annualized Costs (million dollars) [(a)]	$15.59	0	0	$15.59
Incremental Power Consumption (MW)	2.29	0	0	2.29
Incremental Annual Power Usage (Million kWh/Yr)	18.05	0	0	18.05
Incremental Improvement in Emission Rate (lb/mmBtu)	0.08	0	0	—
Incremental Tons of Pollutant Removed	1,293	0	0	1,293
Incremental First Year Average Control Cost ($/Ton of Pollutant Removed)	12,056	0	0	12,056

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

Modeling Results and Least-Cost Envelope Analysis

CH2M HILL modeled Dave Johnston Unit 4 for two post-control scenarios. The results determine the change in deciview based on each alternative at the Class I areas specific to the project. The Class I areas potentially affected are Badlands National Park and Wind Cave National Park for this unit.

Modeled Scenarios

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

- Baseline: Current operations with LNB and Venturi Scrubber
- Scenario A: LNB with OFA, Dry FGD, new fabric filter
- Scenario B: Scenario A with SCR

Summary of Visibility Analysis

Tables 6 and 7 present a summary of the modeling period (2001–2003) results for each scenario and Class I area.

TABLE 6
Costs and Visibility Modeling Results as Applicable to Badlands National Park
Dave Johnston Unit 4

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98^{th} Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and Venturi Scrubber	—	3.610	1.291	49
Scenario A	Scenario A: PacifiCorp Committed Controls	$29,285,200	1.291	0.435	7
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$44,873,886	0.938	0.302	4

TABLE 7
Costs and Visibility Modeling Results as Applicable to Wind Cave National Park
Dave Johnston Unit 4

Scenario	Controls	Total First Year Annualized Cost	Highest ΔdV	98^{th} Percentile ΔdV	Maximum Annual Number of Days Above 0.5 dV
Baseline	Current Operations with FGD and Venturi Scrubber	—	4.304	1.695	47
Scenario A	Scenario A: PacifiCorp Committed Controls	$29,285,200	1.727	0.543	9
Scenario B	Scenario B: PacifiCorp Committed Controls and SCR	$44,873,886	1.260	0.374	7

Results

Tables 8 and 9 present a summary of the costs and modeling results for each scenario and Class I area.

TABLE 8
Incremental Costs and Incremental Visibility Improvements Relative to Badlands National Park
Dave Johnston Unit 4

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98^{th} Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$29.29	0.856	42	$34.21	$0.70
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$44.87	0.989	45	$45.37	$1.00
Scenario B Compared To Scenario A	Addition of SCR	$15.59	0.133	3	$117.21	$5.20

TABLE 9
Incremental Costs and Incremental Visibility Improvements Relative to Wind Cave National Park
Dave Johnston Unit 4

Scenario Comparison	Controls	Incremental Annualized Cost (Million$)	Reduction in 98th Percentile maximum dV	Reduction in Number of Days Above 0.5 dV	Cost per dV Reduction (Million$/dV Reduced)	Cost per Day to Achieve a Reduction in the Days above 0.5 dV (Million$/Day)
Scenario A Compared to Baseline	Scenario A: PacifiCorp Committed Controls	$29.29	1.152	38	$25.42	$0.77
Scenario B Compared to Baseline	Scenario B: PacifiCorp Committed Controls and SCR	$44.87	1.321	40	$33.97	$1.12
Scenario B Compared To Scenario A	Addition of SCR	$15.59	0.169	2	$92.24	$7.79

Least-Cost Envelope Analysis

The least-cost envelope graphs for Badlands National Park are shown in Figures 1 and 2 and for Wind Cave National Park are shown in Figures 3 and 4.

FIGURE 1

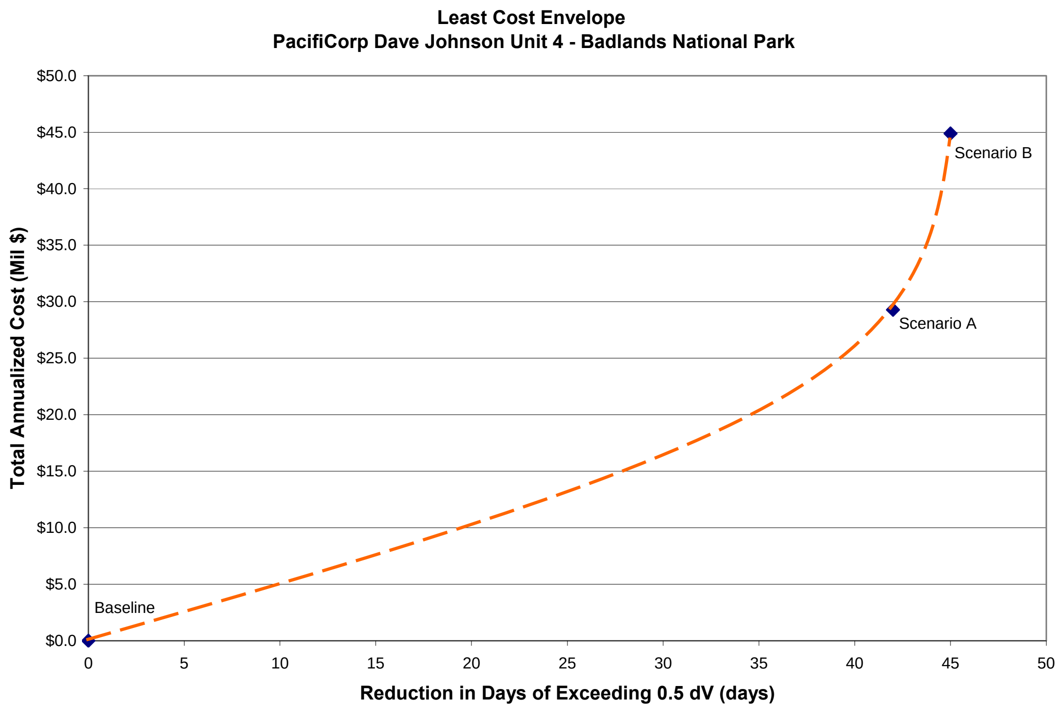


FIGURE 2

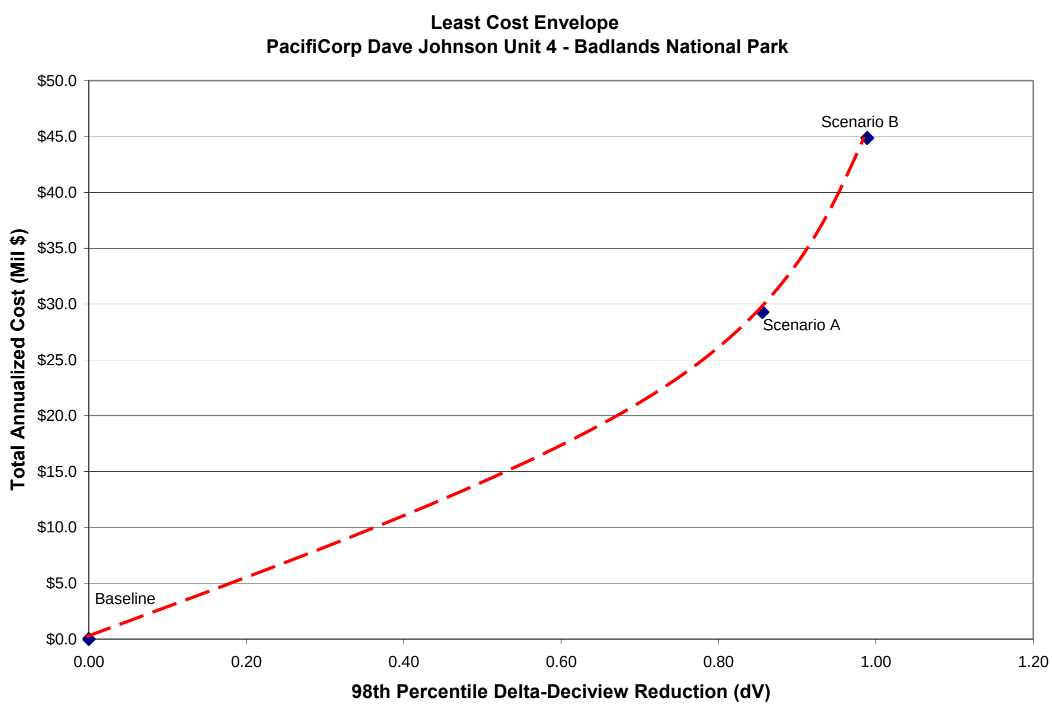


FIGURE 3

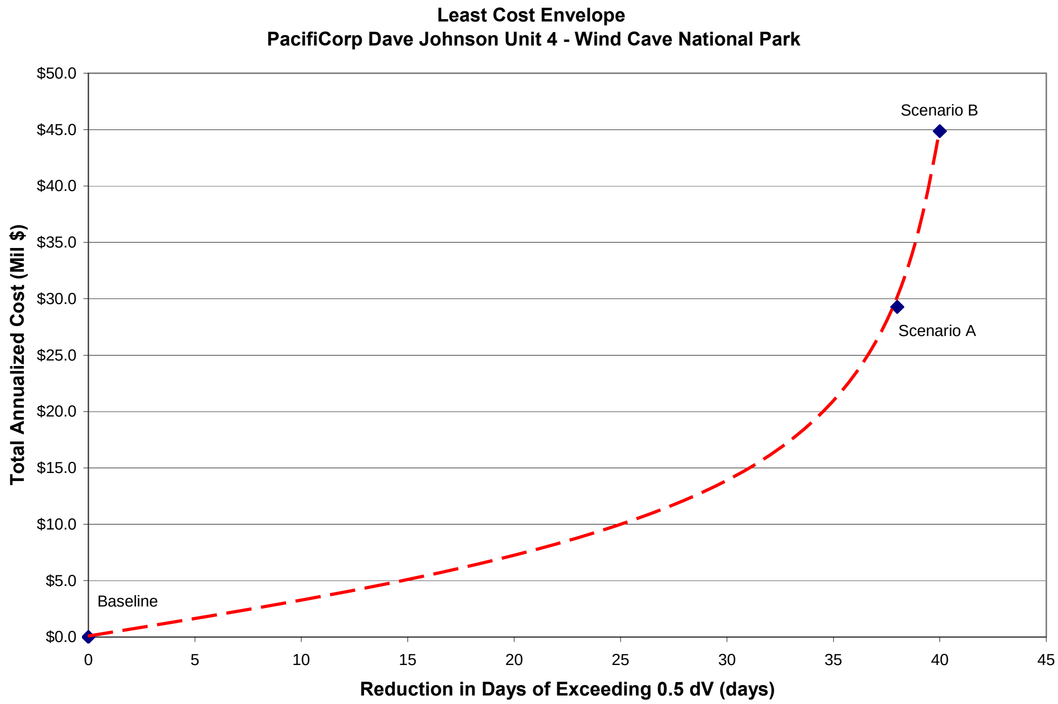
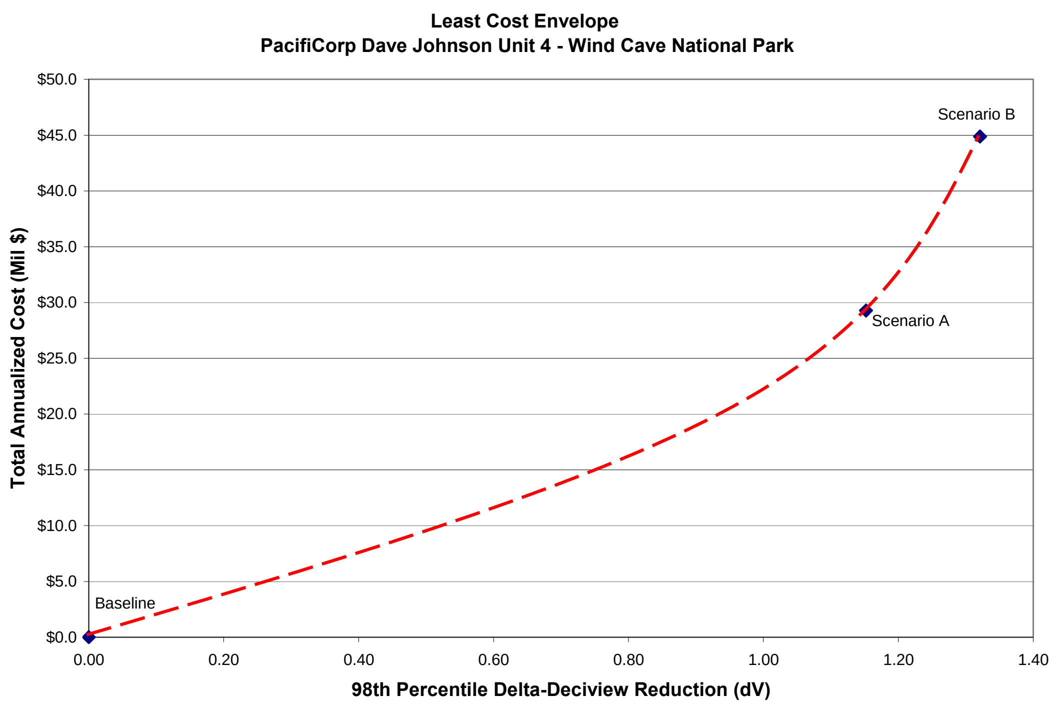


FIGURE 4



ATTACHMENT 1

Complete Economic Analyses for Scenarios A and B

ECONOMIC ANALYSIS SUMMARY - FIRST YEAR COSTS

DJ4 **Boiler Design: Tangential-Fired PC**

TYPE OF EMISSIONS CONTROLS		NO_x Control						Scenario A	Scenario B
Technology Label	**BASE**	**A**	**B**	**C**	**D**	**F**	**G**	**A+F**	**D+F**
	Current Operation	Low NO_x Burners with Overfire Air	Rotating Overfire Air	Low NO_x Burners with Overfire Air and Non-Selective Catalytic Reduction	Low NO_x Burners with Overfire Air and Selective Catalytic Reduction	Dry FGD & Fabric Filter	Wet FGD w/ Fabric filter	LNB w/OFA, Dry Flue Gas Desulfurization and Fabric Filter Baghouse	LNB w/OFA, SCR. Dry Flue Gas Desulfurization and Fabric Filter Baghouse
CAPITAL INVESTMENT									
Total Installed Capital Costs ($)	$0	$7,900,000	$14,719,868	$17,905,780	$151,900,000	$243,100,000	$289,166,335	$251,000,000	$395,000,000
FIRST YEAR DEBT SERVICE ($/Yr)	**$0**	**$751,510**	**$1,400,269**	**$1,703,338**	**$14,449,916**	**$23,125,574**	**$27,507,764**	**$23,877,084**	**$37,575,490**
FIRST YEAR FIXED O&M Costs ($/Yr)									
Operating Labor ($/Yr)	$0	$0	$0	$0	$0	$506,128	$809,804	$506,128	$506,128
Maintenance Material ($/Yr)	$0	$36,000	$54,000	$105,000	$166,000	$1,102,288	$1,430,784	$1,138,288	$1,268,288
Maintenance Labor ($/Yr)	$0	$54,000	$81,000	$157,500	$249,000	$734,858	$953,856	$788,858	$983,858
Administrative Labor ($/Yr)	$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL FIRST YEAR FIXED O&M COST	**$0**	**$90,000**	**$135,000**	**$262,500**	**$415,000**	**$2,343,274**	**$3,194,444**	**$2,433,274**	**$2,758,274**
FIRST YEAR VARIABLE O&M Costs ($/Yr)									
Makeup Water Costs ($/Yr)	$0	$0	$0	$0	$0	$142,730	$189,923	$142,730	$142,730
Reagent Costs ($/Yr)	$0	$0	$0	$45,823	$293,563	$552,256	$526,723	$552,256	$845,819
SCR Catalyst / FF Bag Costs ($/Yr)	$0	$0	$0	$0	$369,000	$186,992	$186,992	$186,992	$555,992
Waste Disposal Costs ($/Yr)	$0	$0	$0	$0	$0	$303,197	$383,582	$303,197	$303,197
Electric Power Costs ($/Yr)	$0	$0	$1,706,886	$130,086	$902,718	$1,789,668	$2,479,518	$1,789,668	$2,692,386
TOTAL FIRST YEAR VARIABLE O&M Costs ($/Yr)	**$0**	**$0**	**$1,706,886**	**$175,909**	**$1,565,281**	**$2,974,843**	**$3,766,739**	**$2,974,843**	**$4,540,124**
SUMMARY OF FIRST YEAR COSTS ($/Yr)									
First Year Debt Service ($/Yr)	$0	$751,510	$1,400,269	$1,703,338	$14,449,916	$23,125,574	$27,507,764	$23,877,084	$37,575,490
First Year Fixed O&M Costs ($/Yr)	$0	$90,000	$135,000	$262,500	$415,000	$2,343,274	$3,194,444	$2,433,274	$2,758,274
First Year Variable O&M Costs ($/Yr)	$0	$0	$1,706,886	$175,909	$1,565,281	$2,974,843	$3,766,739	$2,974,843	$4,540,124
Total First Year Costs ($/Yr)	**$0**	**$841,510**	**$3,242,155**	**$2,141,747**	**$16,430,197**	**$28,443,691**	**$34,468,947**	**$29,285,201**	**$44,873,888**
CONTROL COST COMPARISONS									
NO_x Technology Comparison									
Additional NO_x Removed From Base Case (Tons/Yr)	0	4,041	4,041	4,525	5,334				
First Year Average Control Cost ($/Ton NO_x Removed)	$0	$208	$802	$473	$3,081				
Technology Case Comparison		A-BASE	B-A	C-A	D-A				
Incremental NO_x Removed (Tons/Yr)	0	4,041	0	485	1,293				
Incremental Control Cost ($/Ton NO_x Removed)	$0	$208	#DIV/0!	$2,682	$12,056				
SO_2 Technology Comparison	58.6%					87.6%	91.7%		
Additional SO_2 Removed From Base Case (Tons/Yr)	0					5,657	6,465		
First Year Average Control Cost ($/Ton SO_2 Removed)	$0					$5,028	$5,332		
Technology Case Comparison						F-E	G-F		
Incremental SO_2 Removed (Tons/Yr)	0					-2,424	808		
Incremental Control Cost ($/Ton SO_2 Removed)	$0					-$11,197	$7,456		
PM Technology Comparison	0.0%								
Additional PM Removed From Base Case (Tons/Yr)	0					743	0		
First Year Average Control Cost ($/Ton PM Removed)	$0					$38,258	#DIV/0!		
Technology Case Comparison						F-E	G-F		
Incremental PM Removed (Tons/Yr)	0					-242	-743		
Incremental Control Cost ($/Ton PM Removed)	$0					-$111,967	-$8,104		
SCENARIO A AND B COMPARISONS									
Additional NO_x, SO_2, & PM Removed From Base Case (Tons/Yr)	**0**							**10,441**	**11,734**
First Year Average Control Cost Compared to Base Case ($/Ton Removed)	**$0**							**$2,805**	**$3,824**
Incremental Tons Removed - Scenario B vs Scenario A (Tons/Yr)	**0**								**1,293**
Incremental Control Costs - Scenario B vs Scenario A ($/Ton Removed)	**$0**								**$12,056**

INPUT CALCULATIONS

DJ4 **Boiler Design:** **Tangential-Fired PC**

PARAMETER	Current Operation	NO_x Control Technologies				SO_2 and PM Control Technologies		Scenario A	Scenario B
Control Technologies									
NO_x Emission Control System	Good Practices	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR			LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System	Lime addition					Dry FGD	Wet FGD w/ Fabric filter	Dry FGD	Dry FGD
PM Emission Control System	Venturi Scrubber					Fabric Filter		Fabric Filter	Fabric Filter
General Plant Design and Operating Data									
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC
Annual Power Plant Capacity Factor	90%	90%	90%	90%	90%	90%	90%	90%	90%
Annual Operation (Hours/Year)	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884	7,884
Net Power Output (kW)	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000	330,000
Net Plant Heat Rate (Btu/kW-Hr)	12,425	12,425	12,425	12,425	12,425	12,425	12,425	12,425	12,425
Boiler Heat Input, Measured by Fuel Input (MMBtu/Hr)	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Annual Heat Input, Measured by Fuel Input (MMBtu/Year)	32,326,371	32,326,371	32,326,371	32,326,371	32,326,371	32,326,371	32,326,371	32,326,371	32,326,371
Boiler Heat Input, Measured by CEM (MMBtu/Hr)	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100	4,100
Annual Heat Input, Measured by CEM (MMBtu/Year)	32,324,400	32,324,400	32,324,400	32,324,400	32,324,400	32,324,400	32,324,400	32,324,400	32,324,400
Plant Fuel Source									
Boiler Fuel Source	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB	Dry Fork PRB
Coal Heating Value (Btu/Lb)	7,784	7,784	7,784	7,784	7,784	7,784	7,784	7,784	7,784
Coal Sulfur Content (wt.%)	0.47%	0.47%	0.47%	0.47%	0.47%	0.47%	0.470%	0.47%	0.47%
Coal Ash Content (wt.%)	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%	5.01%
Coal Flow Rate (Lb/Hr)	526,754	526,754	526,754	526,754	526,754	526,754	526,754	526,754	526,754
Coal Consumed (Ton/Yr)	2,076,463	2,076,463	2,076,463	2,076,463	2,076,463	2,076,463	2,076,463	2,076,463	2,076,463
Nitrogen Oxide Emissions									
NO_x Emission Rate (Lb/MMBtu)	0.40	0.15	0.15	0.12	0.07			0.15	0.07
NO_x Emission Rate (Lb/Hr)	1,640	615	615	492	287			615	287
NO_x Emission Rate (Lb Moles/Hr)	54.65	20.49	20.49	16.39	9.56			20.49	9.56
NO_x Emission Rate (Ton/Yr)	6,465	2,424	2,424	1,939	1,131			2,424	1,131
Add'l NO_x Removed from Current Operations (Lb/Hr)	0	1,025	1,025	1,148	1,353			1,025	1,353
Add'l NO_x Removed from Current Operations (Ton/Yr)	0	4,041	4,041	4,525	5,334			4,041	5,334
Sulfur Dioxide Emissions									
Uncontrolled SO_2 (Lb/MMBtu)	1.21					1.21	1.21	1.21	1.21
Uncontrolled SO_2 (Lb/Hr)	4,946					4,946	4,946	4,946	4,946
Uncontrolled SO_2 (Lb Moles/Hr)	77.21					77.21	77.21	77.21	77.21
Uncontrolled SO_2 (Tons/Yr)	19,498					19,498	19,498	19,498	19,498
Controlled SO_2 Emission Rate (Lb/MMBtu)	0.50					0.15	0.10	0.15	0.15
SO_2 Removal Efficiency (%)	58.6%					87.6%	91.7%	87.6%	87.6%
Controlled SO_2 Emissions (Lb/Hr)	2,050					615	410	615	615
Controlled SO_2 Emissions (Ton/Yr)	8,081					2,424	1,616	2,424	2,424
SO_2 Removed (Lb/Hr)	2,896					4,331	4,536	4,331	4,331
SO_2 Removed (Ton/Yr)	11,417					17,074	17,882	17,074	17,074
Add'l SO_2 Removed from Current Operations (Lb/Hr)	0					1,435	1,640	1,435	1,435
Add'l SO_2 Removed from Current Operations (Ton/Yr)	0					5,657	6,465	5,657	5,657
Particulate Matter Emissions									
Uncontrolled Fly Ash (Lb/Hr)	21,112					21,112	21,112	21,112	21,112
Uncontrolled Fly Ash (Lb/MMBtu)	5.149					5.149	5.149	5.149	5.149
Uncontrolled Fly Ash (Tons/Yr)	83,225					83,225	83,225	83,225	83,225
Controlled Fly Ash Emission Rate (Lb/MMBtu)	0.061					0.015	0.061	0.015	0.015
Controlled Fly Ash Removal Efficiency (%)	98.8%					99.7%	98.8%	99.7%	99.7%
Controlled Fly Ash Emissions (Lb/Hr)	250					62	250	62	62
Controlled Fly Ash Emissions (Ton/Yr)	986					242	986	242	242
Fly Ash Removed (Lb/Hr)	20,862					21,051	20,862	21,051	21,051
Fly Ash Removed (Ton/Yr)	82,239					82,982	82,239	82,982	82,982
Add'l Ash Removed from Current Operation (Lb/Hr)	0					189	0	189	189
Add'l Ash Removed from Current Operation (Ton/Yr)	0					743	0	743	743
Economic Factors									
Interest Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Discount Rate (%)	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%	7.10%
Plant Economic Life (Years)	20	20	20	20	20	20	20	20	20

INPUT CALCULATIONS									
DJ4	**Boiler Design:**		**Tangential-Fired PC**						
PARAMETER	**Current Operation**	**NO_x Control Technologies**				**SO_2 and PM Control Technologies**		**Scenario A**	**Scenario B**
Control Technologies									
NO_x Emission Control System	Good Practices	LNB w/OFA	ROFA	LNB w/OFA & SNCR	LNB w/OFA & SCR			LNB w/OFA	LNB w/OFA & SCR
SO_2 Emission Control System	Lime addition					Dry FGD	Wet FGD w/ Fabric filter	Dry FGD	Dry FGD
PM Emission Control System	Venturi Scrubber					Fabric Filter		Fabric Filter	Fabric Filter
Installed Capital Costs									
NO_x Emission Control System ($2006)		$7,900,000	$14,719,868	$17,905,780	$151,900,000			$7,900,000	$151,900,000
SO_2 Emission Control System ($2006)						$243,100,000	$289,166,335	$243,100,000	$243,100,000
PM Emission Control System ($2006)						$0	$0	$0	$0
Total Emission Control System Capital Costs ($2006)		$7,900,000	$14,719,868	$17,905,780	$151,900,000	$243,100,000	$289,166,335	$251,000,000	$395,000,000
NO_x Emission Control System ($/kW)		$24	$45	$54	$460			$24	$460
SO_2 Emission Control System ($/kW)						#REF!	$876	$737	$737
PM Emission Control System ($/kW)									
Total Emission Control Capital Costs ($/kW)		$24	$45	$54	$460	$737	$876	$761	$1,197
Fixed Operating & Maintenance Costs									
Operating Labor ($)		$0	$0	$0	$0	$506,128	$809,804	$506,128	$506,128
Maintenance Material ($)		$36,000	$54,000	$105,000	$166,000	$1,102,288	$1,430,784	$1,138,288	$1,268,288
Maintenance Labor ($)		$54,000	$81,000	$157,500	$249,000	$734,858	$953,856	$788,858	$983,858
Administrative Labor ($)		$0	$0	$0	$0	$0	$0	$0	$0
Total 1st Fixed Year O&M Cost ($)		$90,000	$135,000	$262,500	$415,000	$2,343,274	$3,194,444	$2,433,274	$2,758,274
Annual Fixed O&M Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Fixed O&M Cost ($/Yr)		$106,695	$160,043	$311,195	$491,984	$2,777,958	$3,787,023	$2,884,653	$3,269,942
Variable Operating & Maintenance Costs									
Water Cost									
Makeup Water Usage (gpm)		0	0	0	0	248	330	248	248
Unit Price ($/1000 gallons)		$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22	$1.22
First Year Water Cost ($)		$0	$0	$0	$0	$142,730	$189,923	$142,730	$142,730
Annual Water Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Water Costs ($/Yr)		$0	$0	$0	$0	$169,207	$225,155	$169,207	$169,207
Reagent Cost									
Type of Reagent		None	None	Urea	Anhydrous NH_3	Lime	Lime	Lime	Lime & Anhydrous NH_3
Unit Cost ($/Ton)		$0.00		$370.00	$400.00	$91.25	$91.25		
Unit Cost ($/Lb)		$0.000		$0.185	$0.200	$0.046	$0.046		
Molar Stoichiometry		0.00		0.45	1.00	1.10	1.02		
Reagent Purity (Wt.%)		100%		100%	100%	90%	100%		
Reagent Usage (Lb/Hr)				31	186	1,535	1,464		
First Year Reagent Cost ($)		$0		$45,823	$293,563	$552,256	$526,723	$552,256	$845,819
Annual Reagent Cost Escalation Rate (%)		2.00%		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Reagent Costs ($/Yr)				$54,324	$348,020	$654,701	$624,432	$654,701	$1,002,721
SCR Catalyst / Fabric Filter Bag Replacement Cost									
Material Replaced					SCR Catalyst	Bags		Bags	Bags & SCR Catalyst
Annual SCR Catalyst (m3) / No. FF Bags					123	1,798	1,798		
SCR Catalyst ($/m3) / Bag Cost ($/ea.)					$3,000	$104	$104		
First Year SCR Catalyst / Bag Replacement Cost ($)					$369,000	$186,992	$186,992	$186,992	$555,992
Annual SCR Catalyst / Bag Cost Escalation Rate (%)					2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Catalyst/Fabric Fitler Bag Costs ($/Yr)					$437,451	$221,680	$221,680	$221,680	$659,130
FGD Waste Disposal Cost									
FGD Solid Waste Disposal Rate, Dry (Lb/Hr)						3,161	3,999	3,161	3,161
FGD Waste Disposal Unit Cost ($/Dry Ton)						$24.33	$24.33	$24.33	$24.33
First Year FGD Waste Disposal Cost ($)						$303,197	$383,582	$303,197	$303,197
Annual Waste Disposal Cost Esc. Rate (%)						2.00%	2.00%	2.00%	2.00%
Levelized Waste Disposal Costs ($/Yr)						$359,441	$454,738	$359,441	$359,441
Auxiliary Power Cost									
Auxiliary Power Requirement (MW)		0.00	4.33	0.33	2.29	4.54	6.29	4.54	6.83
Auxiliary Power Requirement (% of Plant Output)		0.00%	1.31%	0.10%	0.69%	1.38%	1.91%	1.38%	2.07%
Auxilliary Power Useage (MWh)		0	34,138	2,602	18,054	35,793	49,590	35,793	53,848
Unit Cost ($2006/MW-Hr)		$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00	$50.00
First Year Auxiliary Power Cost ($)		$0	$1,706,886	$130,086	$902,718	$1,789,668	$2,479,518	$1,789,668	$2,692,386
Annual Power Cost Escalation Rate (%)		2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%	2.00%
Levelized Auxilliary Power Costs ($/Yr)		$0	$2,023,518	$154,217	$1,070,175	$2,121,657	$2,939,476	$2,121,657	$3,191,832

UAE Exhibit RR 2.10

DATA RESPONSE TO UAE 3.4

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

201 South Main, Suite 2300
Salt Lake City, Utah 84111

May 2, 2011

VIA EMAIL AND OVERNIGHT DELIVERY

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RE: UT Docket No. 10-035-124
UAE 3rd Set Data Request (1-4)

Please find enclosed Rocky Mountain Power's Responses to UAE 3rd Set Data Requests 3.1 -3.4. If you have any questions, please call Barry Bell at (801) 220-4985.

Sincerely,

Dave Taylor / [signature]

Dave Taylor
Manager, Regulation

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UAE Data Request 3.1

Please identify each of PacifiCorp's coal-fired generating units for which RMP's proposed rate base in this docket includes any capital costs associated with conversion of an electrostatic precipitator to a fabric filter baghouse within the past five years.

Response to UAE Data Request 3.1

The following coal-fired generating units have capital costs related to an electrostatic precipitator to fabric filter baghouse conversion included in the proposed rate base: Huntington Unit 2 completed in 2006; Huntington Unit 1 completed in 2010; and Hunter Unit 2 to be completed in 2011.

UAE Data Request 3.2

With respect to each unit identified in response to UAE Data Request 3.1, please identify the total capital costs associated with each such conversion and related activities and costs, itemize and explain all such costs, and provide documents reflecting all such costs.

Response to UAE Data Request 3.2

The total capital costs of projects related to the electrostatic precipitator to fabric filter baghouse conversions for the units identified in the Company's response to UAE Data Request 3.1 are as follows including a brief description of the work involved:

Huntington Unit 2: $38,952,221

The breakdown of the cost above is as follows:

Electrical	$ 3,073,729
Flue Gas System	$ 7,473,295
Baghouse	$ 20,400,604
Fly Ash Handling	$ 800,595
Steam Air Heater	$ 3,230,871
Boiler Reinforcement	$ 0
Owner's Costs	$ 3,973,126
Total	**$ 38,952,221**

The existing Buell electrostatic precipitator (ESP) was removed leaving the steel shell box. New inlet and outlet dampers were installed in the ductwork into and out of the existing ESP box. A pulse jet fabric filter (PJFF) was installed in the ESP box using Hamon Research Cottrell technology. Approximately 18,000 filter bags were installed in eight isolatable compartments. Two new booster fans were installed, including new electrical supplies, to overcome the added pressure drop through the fabric filters. Approximately ½ of the pressure drop is needed by the fabric filter and the other half was required by the new scrubber installed at the same time. New steam air preheaters were installed to maintain baghouse temperature.

The Huntington Unit 2 ESP to baghouse conversion project placed in service in 2006 was included as an integral part of a larger project contract that included the addition of a scrubber, new booster fans and a new reagent preparation facility. As such, costs for common facilities and infrastructure needs such as power supplies and contractor support were allocated across the overall project. Additionally boiler reinforcement was not required on this unit, as boiler reinforcement had already been completed in the early 1980's.

Huntington Unit 1: $74,372,601

The breakdown of the cost above is as follows:

Electrical	$ 15,883,420
Flue Gas System	$ 8,215,517
Baghouse	$ 30,074,855
Fly Ash Handling	$ 7,216,794
Steam Air Heater	$ 2,641,076
Boiler Reinforcement	$ 3,500,104
Owner's Costs	$ 6,840,834
Total	**$ 74,372,601**

The existing Buell electrostatic precipitator (ESP) was removed leaving the steel shell box. New inlet and outlet dampers were installed in the ductwork into and out of the existing ESP box. A pulse jet fabric filter (PJFF) was installed in the ESP box using Hamon Research Cottrell technology. Approximately 19,100 filter bags were installed in eight isolatable compartments to achieve the optimum air to cloth ratio of 3.5 with one compartment out-of-service. The booster fans were modified to overcome the new pressure drop from the fabric filter and the added flue gas flow through the scrubbers. The booster fan modifications included new electrical supplies and booster fan motors and rotors. With a scrubber already present on Huntington Unit 1, approximately 90% of the pressure drop and associated fan / flue gas system modification costs have been allocated to the fabric filter. The remaining 10% of the costs has been assigned to the scrubber upgrades installed at the same time. New steam air preheaters were installed to maintain baghouse temperature. Boiler reinforcement was completed to maintain NFPA 85 compliance as a result of modifications of the booster fans.

Hunter Unit 2: $69,310,593

The approximate (project not yet complete) breakdown of the cost above is as follows:

Electrical	$ 13,919,983
Flue Gas System	$ 7,199,952
Baghouse	$ 26,357,137
Fly Ash Handling	$ 6,324,686
Steam Air Heater	$ 3,000,000
Boiler Reinforcement	$ 4,693,631
Owner's Costs	$ 7,815,204
Total	**$ 69,310,593**

The existing Buell electrostatic precipitator (ESP) was removed leaving the steel shell box. New inlet and outlet dampers were installed in the ductwork into and out of the existing ESP box. A pulse jet fabric filter (PJFF) was installed in the

ESP box using Hamon Research Cottrell technology. Approximately 19,500 filter bags were installed in eight isolatable compartments to achieve the optimum air to cloth ratio of 3.5 with one compartment out-of-service. The booster fans were modified to overcome the new pressure drop from the fabric filter and the added flue gas flow through the scrubbers. The booster fan modifications include new electrical supplies and booster fan motors and rotors. With a scrubber already present on Hunter Unit 2, approximately 90% of the pressure drop and associated fan / flue gas system modification costs have been allocated to the fabric filter. The remaining 10% of the costs has been assigned to the scrubber upgrades installed at the same time. New steam air preheaters were installed to maintain baghouse temperature. Boiler reinforcement was completed to maintain NFPA 85 compliance as a result of modifications of the booster fans.

UAE Data Request 3.3

Please identify each of PacifiCorp's coal-fired generating units for which RMP's proposed rate base in this docket includes any capital costs associated with additions, changes or upgrades to an existing scrubber or flue gas desulfurization facilities.

Response to UAE Data Request 3.3

The following coal-fired generating units have capital costs related to an existing scrubber upgrade or modification to existing flue gas desulfurization facilities in the proposed rate base:

- Huntington Unit 1 completed in 2011.
- Hunter Unit 1 scrubber reagent preparation phase completed in the current test period and additional phases to be completed no later than 2014.
- Hunter Unit 2 to be completed in 2012.
- Jim Bridger Unit 1 completed in 2010.
- Jim Bridger Unit 2 completed in 2009.
- Jim Bridger Unit 3 to be completed in 2011.
- Jim Bridger Unit 4 to be completed in 2012.
- Wyodak Unit 1 to be completed in 2011.
- Cholla Unit 4 completed in 2008.

UAE Data Request 3.4

With respect to each unit identified in response to UAE Data Request 3.3, please identify the total capital costs associated with each such change, addition or upgrade and related activities and costs, itemize and explain all such costs, and provide documents reflecting all such costs.

Response to UAE Data Request 3.4

The total capital costs for changes, additions, upgrades and removal efficiency improvements to the existing scrubbers and/or flue gas desulfurization systems as identified in the Company's response to UAE Data Request 3.3 are as follows, including a brief discussion of the work. These cost breakdowns are approximate based on information available at the time of this response.

Huntington Unit 1: $ 53,024,393

The breakdown of the cost above is as follows:

Flue Gas System – Wet Stack/ID Fan	$ 11,909,297
Scrubber System	$ 5,840,318
Lime Preparation System	$ 0
Waste Disposal System	$ 29,264,893
Owner's Costs	$ 6,009,886
Total	**$ 53,024,393**

The existing scrubber SO_2 removal efficiency will be increased from 80% to near 95% to allow compliance with the new emission control limit of 0.12 pounds of SO_2 per million Btu (lb/mmBtu) of heat input when burning coal with a sulfur content of up to 1.3%. Project activities include the addition of forced oxidation equipment to allow the retirement of the scrubber thickener and a replacement with hydroclones, as well as new agitators, replacement of recycle pumps, ductwork repair and nozzle replacement; and address end-of-life issues (particularly the recycle pump replacements, nozzle replacements and ductwork repair work). The addition of forced oxidation equipment also will allow the addition of vacuum drum filters to replace the fly ash blending equipment to comply with existing waste disposal regulations. Vacuum drum filters will allow the scrubber waste to be disposed without the need for blending with fly ash. At the new SO_2 emission limit and projected coal sulfur content, scrubber waste production will exceed fly ash production required to effectively blend and dry the scrubber waste to meet waste disposal standards. The scrubber bypass dampers will be closed and the stack converted to wet operation. Wet stack operation requires the addition of a false floor in the chimney and a larger drain system. The stack bypass dampers were also blanked off. Opacity monitoring will be relocated to two locations before the scrubber. Recycle pumps will be replaced due to a combination of end-of-life issues as well as the need to have three pumps operational to meet the higher SO_2 removal requirements.

Approximately 10% of the booster fan related costs in the electrostatic precipitator (ESP) to pulse jet fabric filter (PJFF) conversion project are attributable to scrubber due to the higher pressure drop through the scrubber with the bypass closed. New reagent preparation facilities were not added. The reagent preparation system installed in 2006 with the Huntington Unit 2 scrubber is of sufficient capacity to support Huntington Unit 1.

Hunter Unit 1: $ 62,175,244 ($78,061,382 total after 2014)

The breakdown of the cost above is as follows:

Flue Gas System – Wet Stack/ID Fan (to be done in 2014)	$ 15,886,138
Scrubber System	$ 5,589,194
Lime Preparation System	$ 15,546,534
Waste Disposal System	$ 27,848,596
Owner's Costs	$ 13,190,919
Total	**$ 78,061,382**

The existing scrubber SO_2 removal efficiency will be increased from 80% to near 95% to allow compliance with the new emission control limit of 0.12 pounds of SO_2 per million Btu of heat input when burning coal with a sulfur content of up to 1.3%. Project activities include the addition of forced oxidation equipment to allow the retirement of the scrubber thickener and a replacement with hydroclones, as well as new agitators, replacement of recycle pumps, ductwork repair and nozzle replacement; and address end-of-life issues (particularly the recycle pump replacements, nozzle replacements and ductwork repair work). The addition of forced oxidation equipment also will allow the addition of vacuum drum filters to replace the fly ash blending equipment to comply with new waste disposal regulations. Vacuum drum filters will allow the scrubber waste to be disposed without the need for blending with fly ash. At the new SO_2 emission limit and projected coal sulfur content, scrubber waste production will exceed fly ash production required to effectively blend and dry the scrubber waste to meet waste disposal standards. The scrubber bypass dampers will be closed and the stack converted to wet operation. Wet stack operation requires the addition of a false floor in the chimney and a larger drain system. Moisture collectors were added based on a flow study. The stack bypass dampers were also blanked off. Opacity monitoring will be relocated to two locations before the scrubber. Recycle pumps will be replaced due to a combination of end-of-life issues as well as the need to have three pumps operational to meet the higher SO_2 removal requirements. Approximately 10% of the booster fan related costs in the ESP to PJFF conversion project are attributable to scrubber due to the higher pressure drop through the scrubber with the bypass closed. New reagent preparation facilities will be added to be shared between Unit 1 and Unit 2. The new reagent preparation facility is required because of end-of-life issues with the existing reagent preparation facility, as well as the higher reagent preparation capacity needs due to future higher sulfur coal.

The Hunter Unit 1 costs, identified above, do not include costs required to convert the chimney to wet operation. Those costs will be included with the ESP to PJFF baghouse project to be completed in 2014 and are not yet included in the requested rate increase. The Hunter Unit 1 wet stack conversion work, to be done in 2014, is expected to cost approximately \$15.9 million. Without these costs the value of the Hunter Unit 1 scrubber work is \$62,175,244.

<u>Hunter Unit 2</u>: \$ 70,168,382

The breakdown of the cost above is as follows:

Flue Gas System – Wet Stack/ID Fan	\$ 14,710,036
Scrubber System	\$ 5,589,194
Lime Preparation System	\$ 15,546,534
Waste Disposal System	\$ 25,860,190
Owner's Costs	\$ 8,462,428
Total	**\$ 70,168,382**

The existing scrubber SO_2 removal will be increased from 80% to near 95% to allow compliance with the new emission control limit of 0.12 pounds of SO_2 per million Btu of heat input when burning coal with a sulfur content of up to 1.3%. Project activities include the addition of forced oxidation equipment to allow the retirement of the scrubber thickener and a replacement with hydroclones, as well as new agitators, replacement of recycle pumps, nozzle replacements and ductwork repair; and address end-of-life issues (particularly the recycle pump replacements, nozzle replacements and ductwork repair work). The addition of forced oxidation equipment also will allow the addition of vacuum drum filters to replace the fly ash blending equipment to comply with new waste disposal regulations. Vacuum drum filters will allow the scrubber waste to be disposed without the need for blending with fly ash. At the new SO_2 emission limit and projected coal sulfur content, scrubber waste production will exceed fly ash production required to effectively blend and dry the scrubber waste to meet waste disposal standards. The scrubber bypass dampers will be closed and the stack converted to wet operation. Wet stack operation requires the addition of a false floor in the chimney and a larger drain system. Moisture collectors were added based on a flow study. The stack bypass dampers were also blanked off. Opacity monitoring will be relocated to two locations before the scrubber. Recycle pumps will be replaced due to a combination of end-of-life issues as well as the need to have three pumps operational to meet the higher SO_2 removal requirements. Approximately 10% of the booster fan related costs in the ESP to PJFF conversion project are attributable to scrubber due to the higher pressure drop through the scrubber with the bypass closed. New reagent preparation facilities will be added to be shared between Unit 1 and Unit 2. The new reagent preparation facility is required because of end-of-life issues with the existing reagent preparation facility, as well as the higher reagent preparation capacity needs due to future higher sulfur coal.

Jim Bridger Unit 1: $ 21,786,416

The breakdown of the cost above is as follows:

Civil/Structural Work	$ 0
Flue Gas System – ID Fan	$ 7,582,774
Scrubber Mechanical	$ 4,432,675
Scrubber Electrical	$ 1,183,966
Contractor Overheads	$ 2,570,512
Owner's Costs	$ 6,016,490
Total	**$21,786,416**

The SO_2 emission limit on the Jim Bridger units is being reduced from 0.5 lb/mmBtu to 0.15 lb/mmBtu to comply with the Wyoming best available retrofit technology (BART) permit requirements. The reductions in SO_2 will be accomplished by reducing the amount of flue gas bypassing the existing absorber modules. To continue to measure opacity in the chimney, and avoid the installation of a new chimney, the bypass damper opening will be reduced and the individual absorber efficiency increased. Absorber efficiency will be increased by adjusting the hole sizes in the absorber trays as well as rebuilding and increasing the size of the recycle pumps. The internal absorber piping and nozzles need to be replaced because of the increase in liquid to gas ratio. New mist eliminators will be installed optimized to the new flue gas flow rate. To overcome the higher pressure drop, across the absorbers from the higher flue gas flows with the reduced bypass opening, the induced draft (ID) fans will be replaced with a new fan with a variable frequency drive. The ID fans are sized to accommodate a future selective catalytic reduction (SCR) addition. Boiler reinforcement has been deferred until future SCR installation.

Jim Bridger Unit 2: $ 21,691,962

The breakdown of the cost above is as follows:

Civil/Structural Work	$ 0
Flue Gas System – ID Fan	$ 7,549,038
Scrubber Mechanical	$ 4,412,954
Scrubber Electrical	$ 1,178,698
Contractor Overheads	$ 2,559,076
Owner's Costs	$ 5,992,194
Total	**$21,691,962**

The SO_2 emission limit on the Jim Bridger units is being reduced from 0.5 lb/mmBtu to 0.15 lb/mmBtu to comply with Wyoming best available retrofit technology (BART) permit requirements. The reductions in SO_2 will be accomplished by reducing the amount of flue gas bypassing the existing absorber modules. To continue to measure opacity in the chimney, and avoid the installation of a new chimney, the bypass damper opening will be reduced and the individual absorber efficiency increased. Absorber efficiency will be increased by adjusting the hole sizes in the absorber trays as well as rebuilding and increasing the size of the recycle pumps. The internal absorber piping and nozzles need to be replaced because of the increase in liquid to gas ratio. New mist eliminators will be installed optimized to the new flue gas flow rate. To overcome the higher pressure drop, across the absorbers from the higher flue gas flows with the reduced bypass opening, the ID fans will be replaced with a new fan with a variable frequency drive. The ID fans are sized to accommodate a future SCR addition. Boiler reinforcement has been deferred until future SCR installation.

Jim Bridger Unit 3: $ 24,640,780

The breakdown of the cost above is as follows:

Civil/Structural Work	$ 0
Flue Gas System – ID Fan	$ 7,808,548
Scrubber Mechanical	$ 4,564,656
Scrubber Electrical	$ 1,219,218
Contractor Overheads	$ 2,647,048
Owner's Costs	$ 8,401,309
Total	**$24,640,780**

The SO_2 emission limit on the Jim Bridger units is being reduced from 0.5 lb/mmBtu to 0.15 lb/mmBtu to comply with Wyoming best available retrofit technology (BART) permit requirements. The reductions in SO_2 will be accomplished by reducing the amount of flue gas bypassing the existing absorber modules. To continue to measure opacity in the chimney, and avoid the installation of a new chimney, the bypass damper opening will be reduced and the individual absorber efficiency increased. Absorber efficiency will be increased by adjusting the hole sizes in the absorber trays as well as rebuilding and increasing the size of the recycle pumps. The internal absorber piping and nozzles need to be replaced because of the increase in liquid to gas ratio. New mist eliminators will be installed optimized to the new flue gas flow rate. To overcome the higher pressure drop, across the absorbers from the higher flue gas flows with the reduced bypass opening, the ID fans will be replaced with a new fan with a variable frequency drive. The ID fans are sized to accommodate a future SCR addition. Boiler reinforcement has been deferred until future SCR installation although some ductwork reinforcement has been included.

Jim Bridger Unit 4: $ 3,204,794

The breakdown of the cost above is as follows:

Civil/Structural Work	$ 1,800,000
Flue Gas System – ID Fan	$ 0
Scrubber Mechanical	$ 0
Scrubber Electrical	$ 0
Contractor Overheads	$ 357,839
Owner's Costs	$ 1,046,955
Total	**$ 3,204,794**

The existing scrubber on Jim Bridger Unit 4 was already capable of meeting the new emission limit imposed by Wyoming BART permit requirements and the project is limited to improvements to the existing chimney to allow near-wet operation. A new drain and moisture collection system will be installed during the 2012 outage to handle the additional expected moisture due to meeting the new 0.12 lb/mmBtu emission limit.

Wyodak Unit 1: $128,233,546

The breakdown of the cost above is as follows:

Electrical	$11,417,177
Flue Gas – ID Fans	$21,021,821
Baghouse	$37,687,511
Contractor Overheads	$26,837,807
Boiler Reinforcement	$ 6,000,000
Owner's Costs	$25,269,231
Total	**$128,233,546**

A new stand-alone PJFF will be installed in 2011 to improve the SO_2 removal capability of the existing dry scrubber. A baghouse behind the existing spray dryer will improve the SO_2 removal capability to above 92% and allow compliance with the new emission limit of 0.16 lb/mmBtu. The project will consist of ductwork repairs and new ductwork to move flue gas from the discharge of the existing spray dryer modules to the inlet of the new PJFF. New ID fans will be installed to overcome the PJFF pressure drop and added ductwork.

Cholla Unit 4: $ 78,470,150

The breakdown of the cost above is as follows:

Scrubber	$64,967,755
Lime Preparation	$ 6,806,479
Waste Disposal	$ 1,906,631
Owner's Costs	$ 4,789,285
Total	**$78,470,150**

A new scrubber was installed at Cholla 4 in 2008 to replace the former partial scrubber system. The previous scrubber system only treated approximately 40% of the flue gas flow. The new 100% gas flow single absorber wet lime system replaced the previous equipment. Other additions were upgrades to the existing reagent preparation facility, as well as additional waste disposal equipment. Waste disposal utilizes a fly ash blending system. The chimney was converted to a wet stack and the opacity monitors were moved before the scrubber but after the new PJFF baghouse. The identified cost is for the scrubber system only and does not include the new PJFF baghouse installed at the same time.

UAE Exhibit RR 2.11

BART REPORT ADDENDUM – JB3

Addendum to Jim Bridger Unit 3 BART Report

PREPARED FOR: Wyoming Division of Air Quality

PREPARED BY: CH2M HILL

COPIES: Bill Lawson/PacifiCorp

DATE: March 26, 2008

Introduction

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

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

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

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

Stack Parameters, Emissions Information, and Capital Cost

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

TABLE 1
Control Scenario Summary
Jim Bridger Unit 3

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

Emissions were modeled for the following pollutants:

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

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

TABLE 2
Calpuff Model Inputs
Jim Bridger Unit 3

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

TABLE 2
Calpuff Model Inputs
Jim Bridger Unit 3

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

NOTES:
[a] Based on AP-42, Table 1.1-6, the coarse particulates are counted as a percentage of PM_{10}. This equates to 43% ESP and 57% Baghouse. PM_{10} and $PM_{2.5}$ refer to particulate matter less than 10 and 2.5 micrometers, respectively, in aerodynamic diameter.
[b] Based on AP-42, Table 1.1-6, the fine particulates are counted as a percentage of PM_{10}. This equates to 57% ESP and 43% Baghouse.
[c] Total Sulfate (SO_4) (lb/hr) = H_2SO_4 as Sulfate (SO_4) Stack Emissions (lb/hr) + $(NH_4)_2SO_4$ as SO_4 Stack Emissions (lb/hr) + $(NH_4)HSO_4$ as SO_4 Stack Emissions (lb/hr)
[d] SO_2, NO_x, and PM rates are expressed in terms of permitted emission rates. Actual emissions will be less than the permitted rates.
[e] PacifiCorp Committed Controls @ permitted rates: LNB with OFA, Wet FGD, ESP with SO_3
[f] PacifiCorp Committed Controls and SCR @ permitted rates

Economic Analysis

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

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

TABLE 3
Scenario A Control Cost
Jim Bridger Unit 3

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

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

TABLE 4
Scenario B Control Cost
Jim Bridger Unit 3

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

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

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

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

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

Modeling Results and Least-Cost Envelope Analysis

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

Modeled Scenarios

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

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

Summary of Visibility Analysis

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

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

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

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

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

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

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

Results

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

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

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

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

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

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

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

Least-Cost Envelope Analysis

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

FIGURE 1

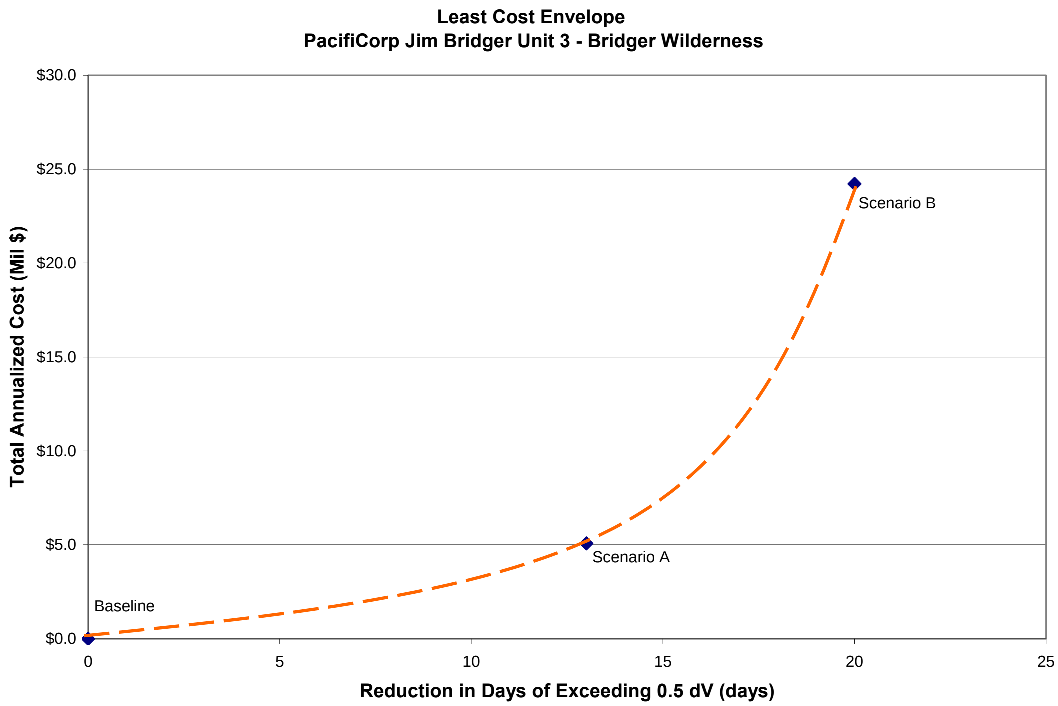


FIGURE 2

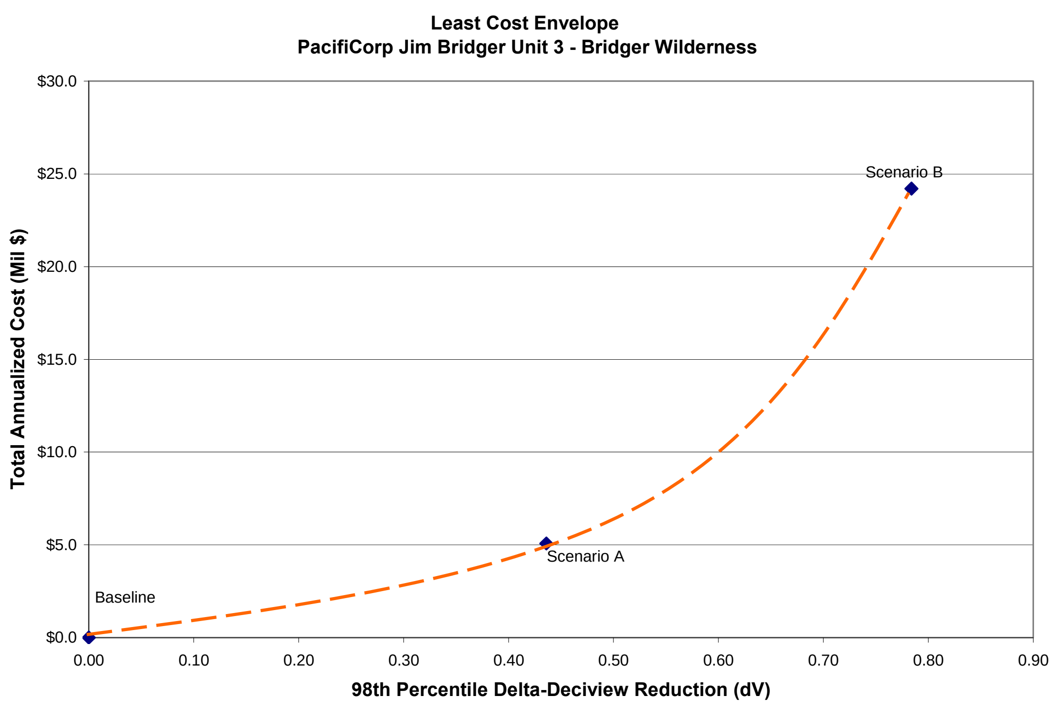


FIGURE 3

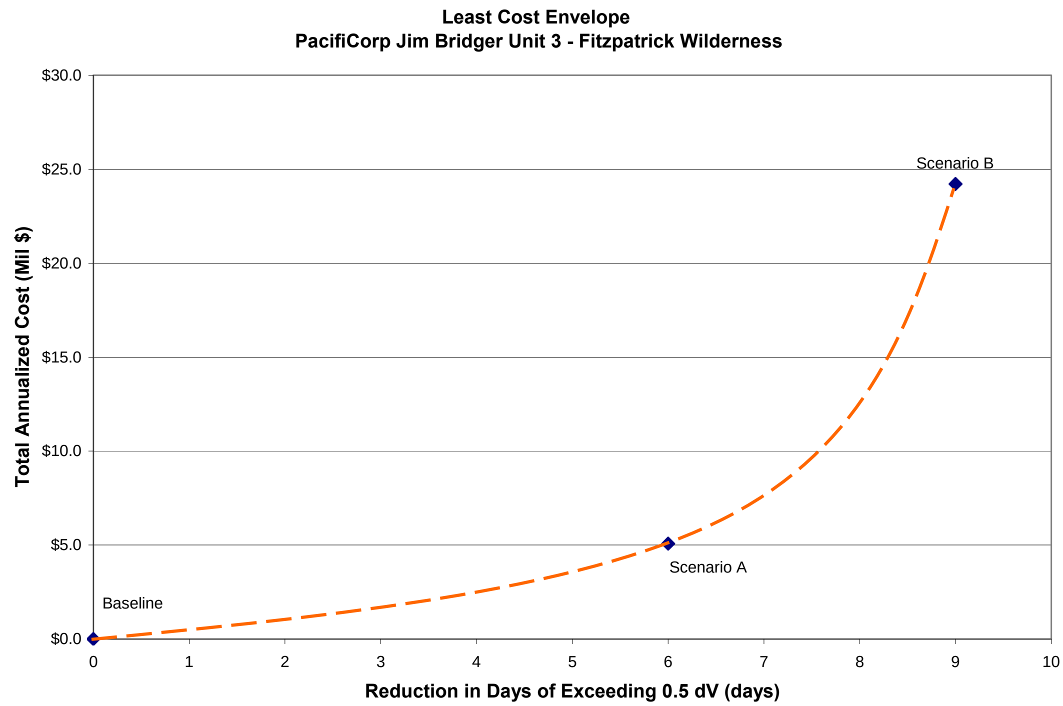


FIGURE 4

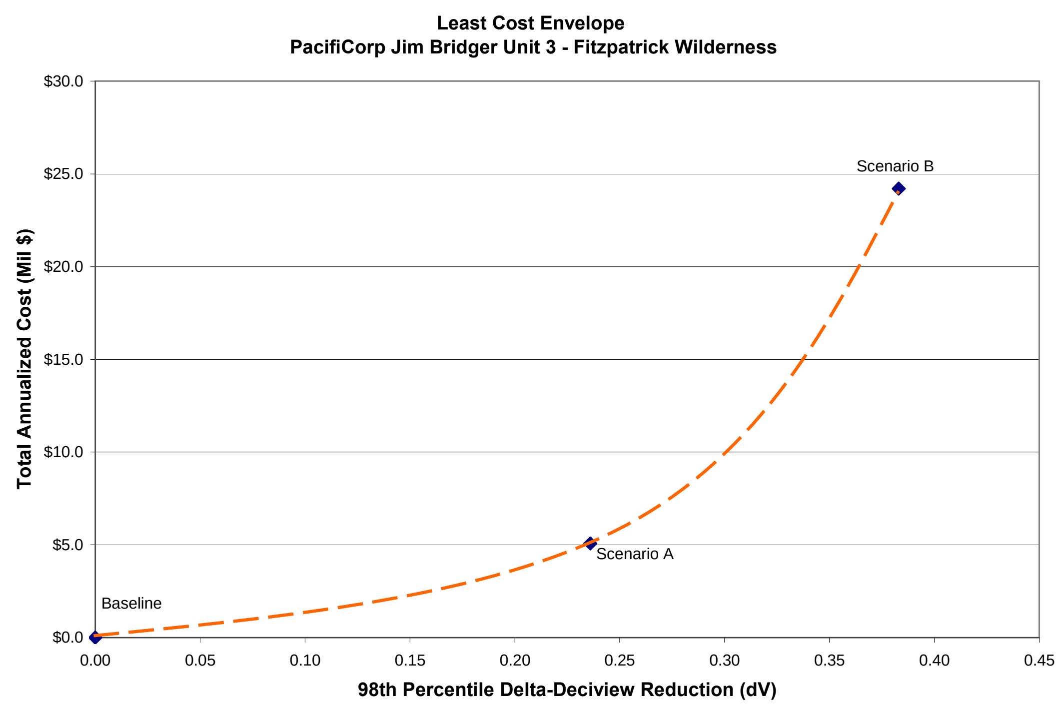


FIGURE 5

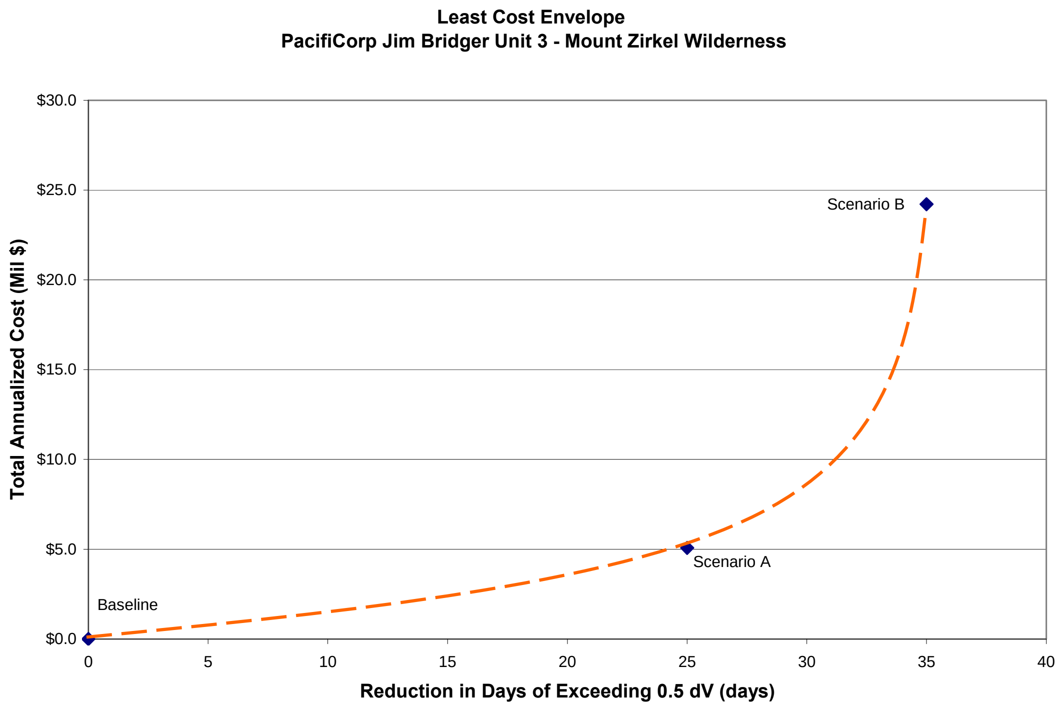
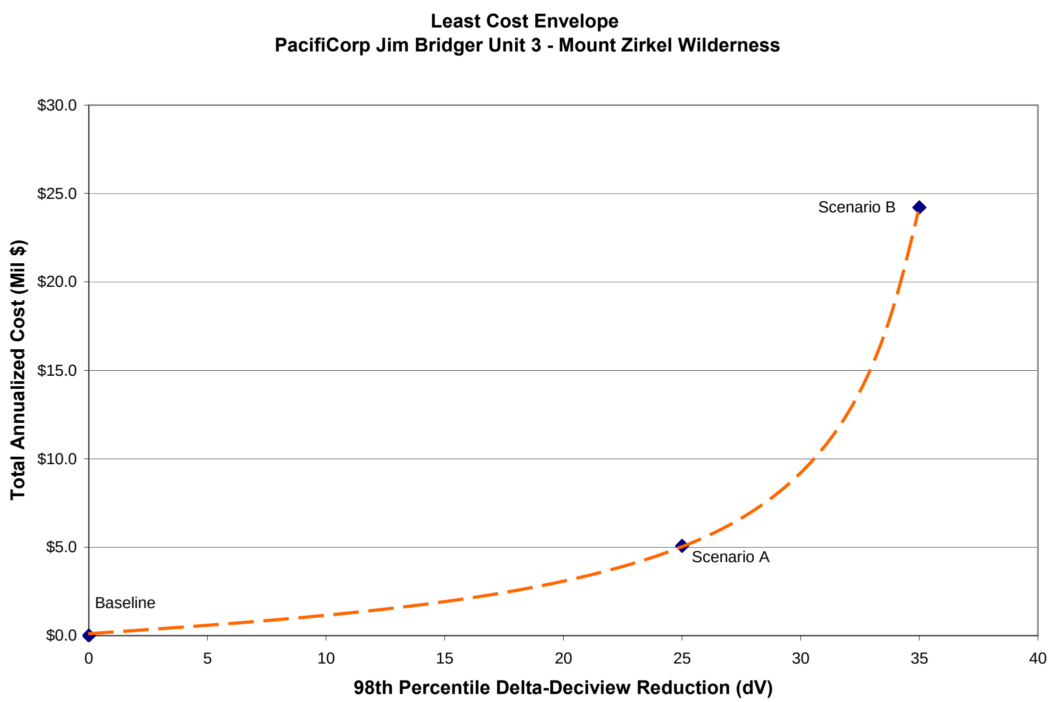


FIGURE 6



ATTACHMENT 1

Complete Economic Analyses for Scenarios A and B

ECONOMIC ANALYSIS SUMMARY - FIRST YEAR COSTS

Jim Bridger 3 **Boiler Design: Tangential fired PC**

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

INPUT CALCULATIONS

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

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

INPUT CALCULATIONS

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

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

UAE Exhibit RR 2.12

WDEQ BART ANALYSIS - JB

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

[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:

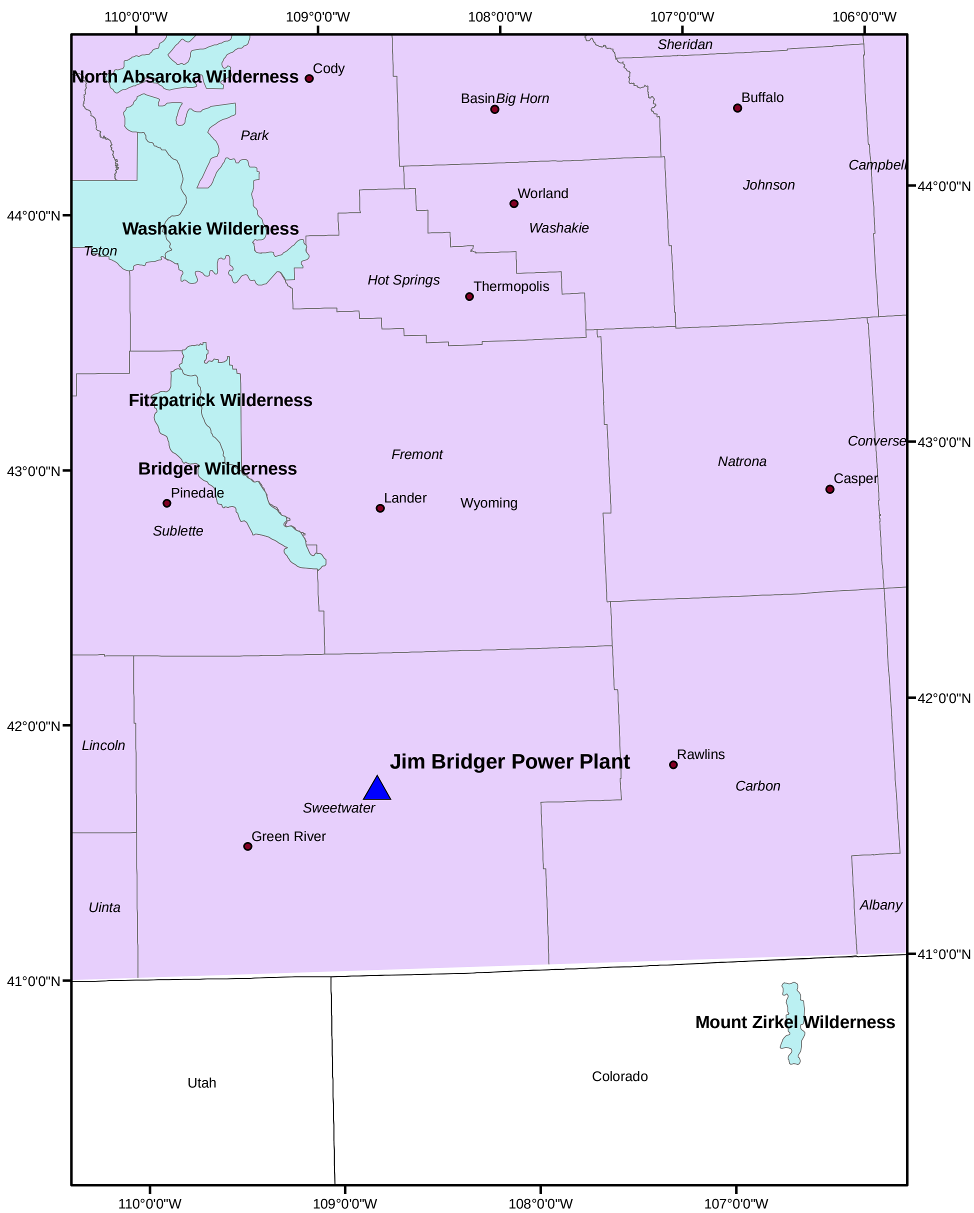
The fifth of five steps in a BART determination analysis, as required by 40 CFR part 51 Appendix Y, is the determination of the degree of Class I area visibility improvement that would result from installation of the various options for control technology. This factor was evaluated for the PacifiCorp 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

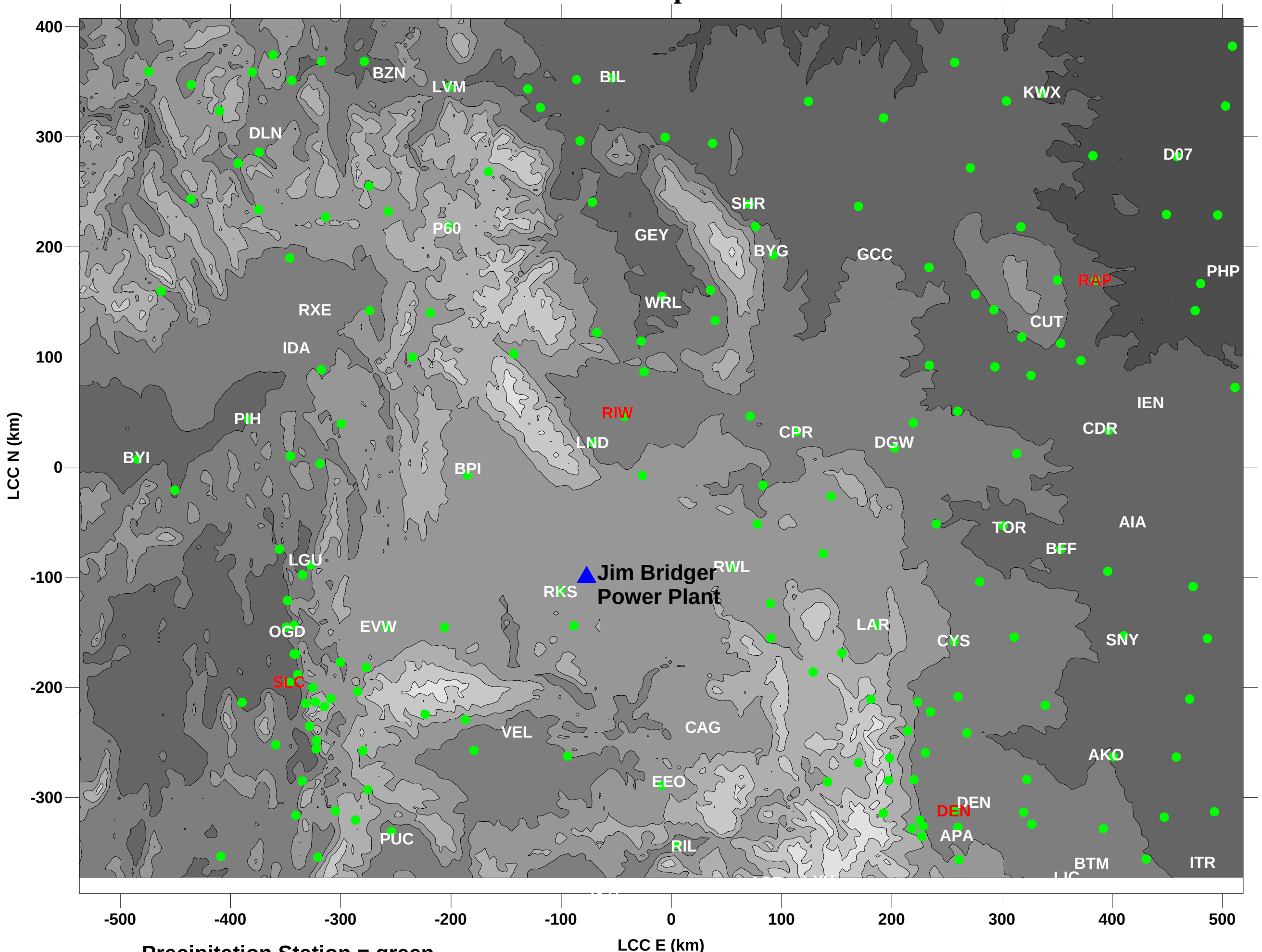
Meteorological Data Processing (CALMET)

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

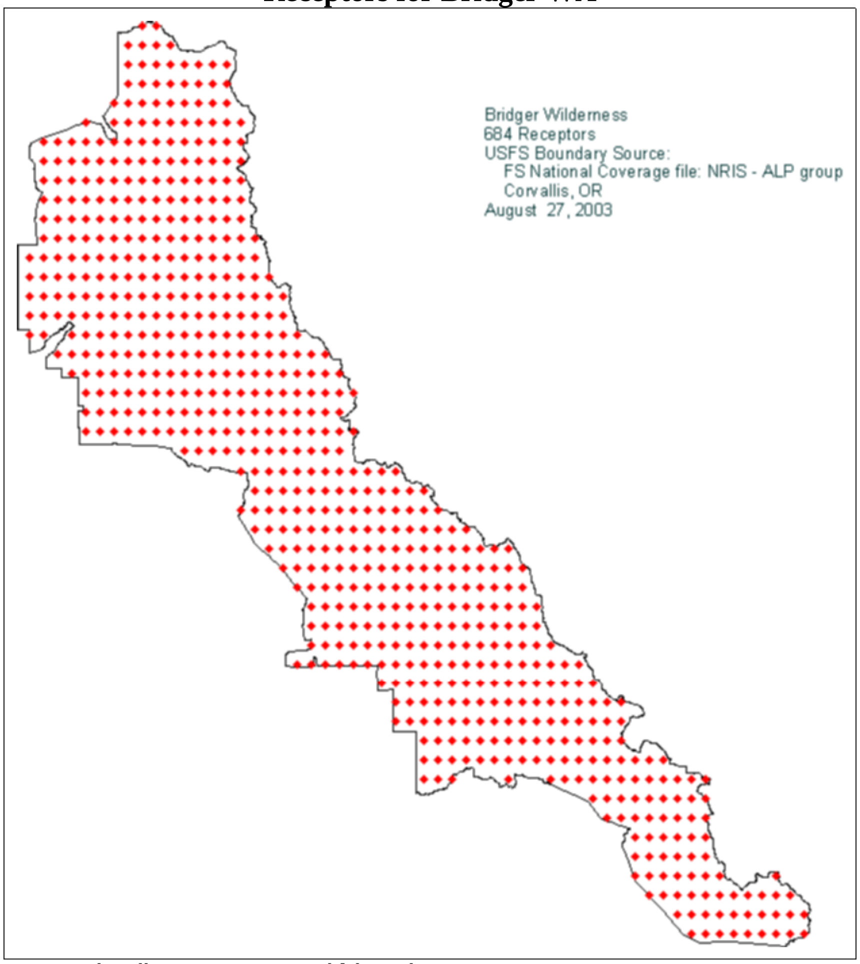
To allow chemical transformations within CALPUFF using the recommended chemistry mechanism (MESOPUFF II), the model required input of background ozone and ammonia concentrations. For ozone, hourly data collected from the following stations were used:

- 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.

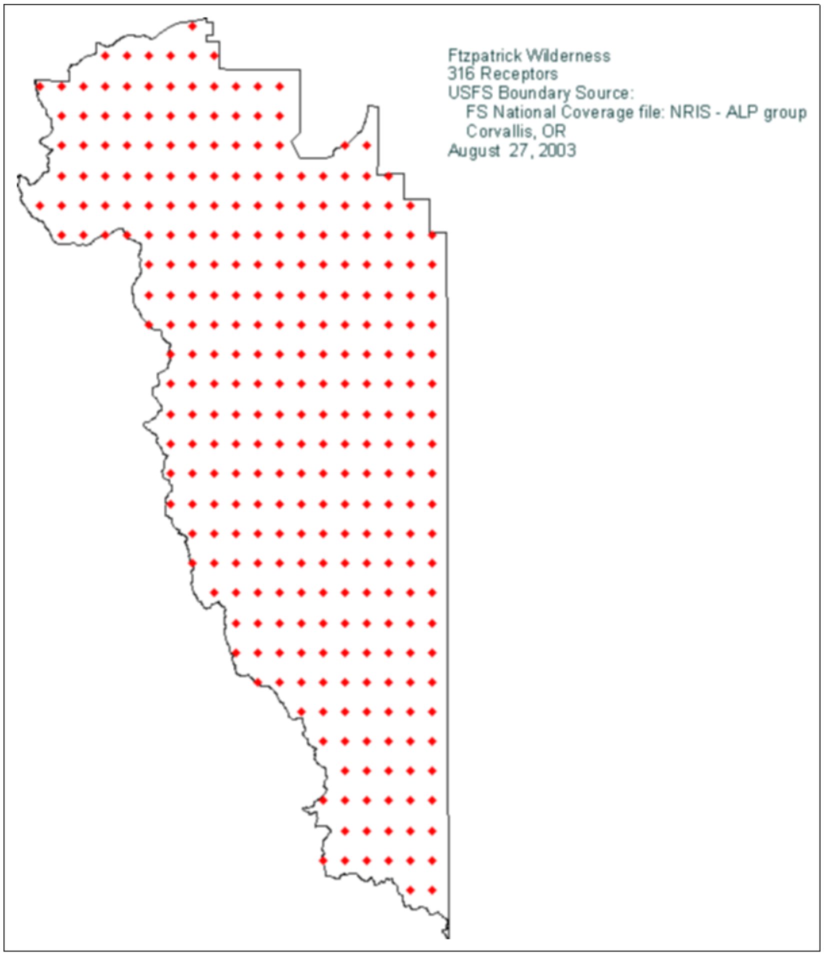
Latitude and longitude coordinates for Class I area discrete receptors were taken from the National Park Service (NPS) Class I Receptors database and converted to the appropriate Lambert Conformal Conic coordinates. Figures 4-6 show the receptor configurations that were used for Bridger WA, Fitzpatrick 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



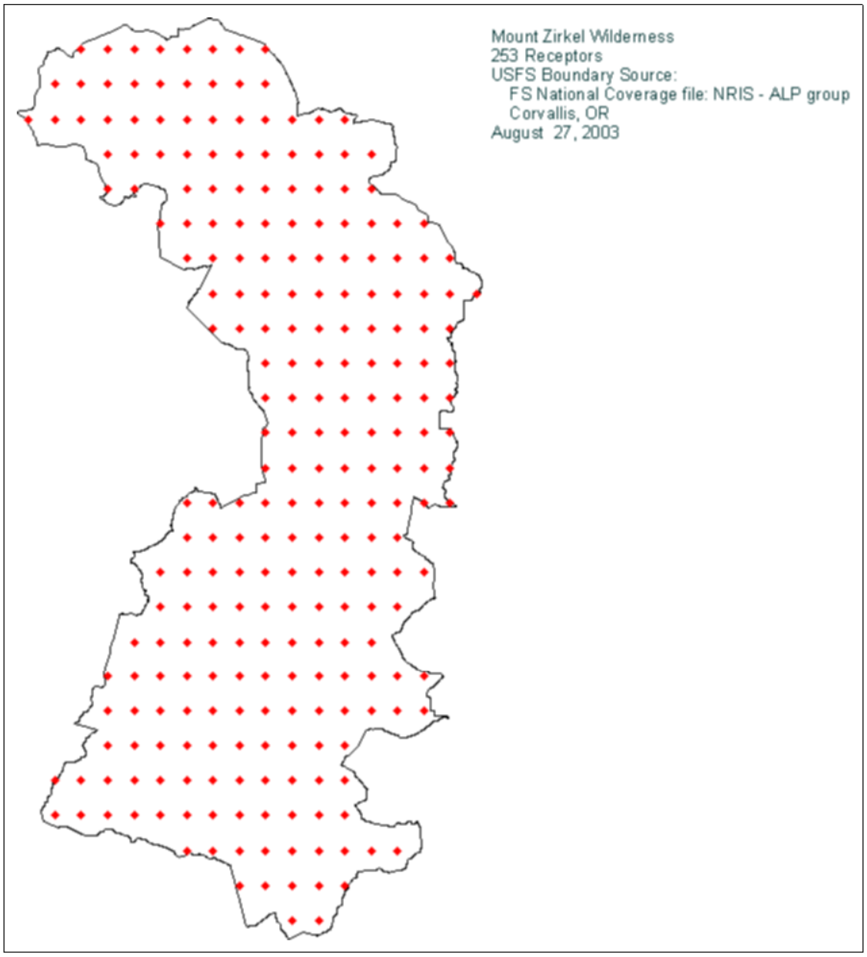
Source: http://www.nature.nps.gov/air/Maps/Receptors

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

	2001		2002		2003		3-Year Average	
Class I Area	**98th Percentile Value (Δdv)**	**No. of Days > 0.5 Δdv**	**98th Percentile Value (Δdv)**	**No. of Days > 0.5 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	0.746	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

	2001		2002		2003		3-Year Average	
Class I Area	**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

	2001		2002		2003		3-Year Average	
Class I Area	**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)

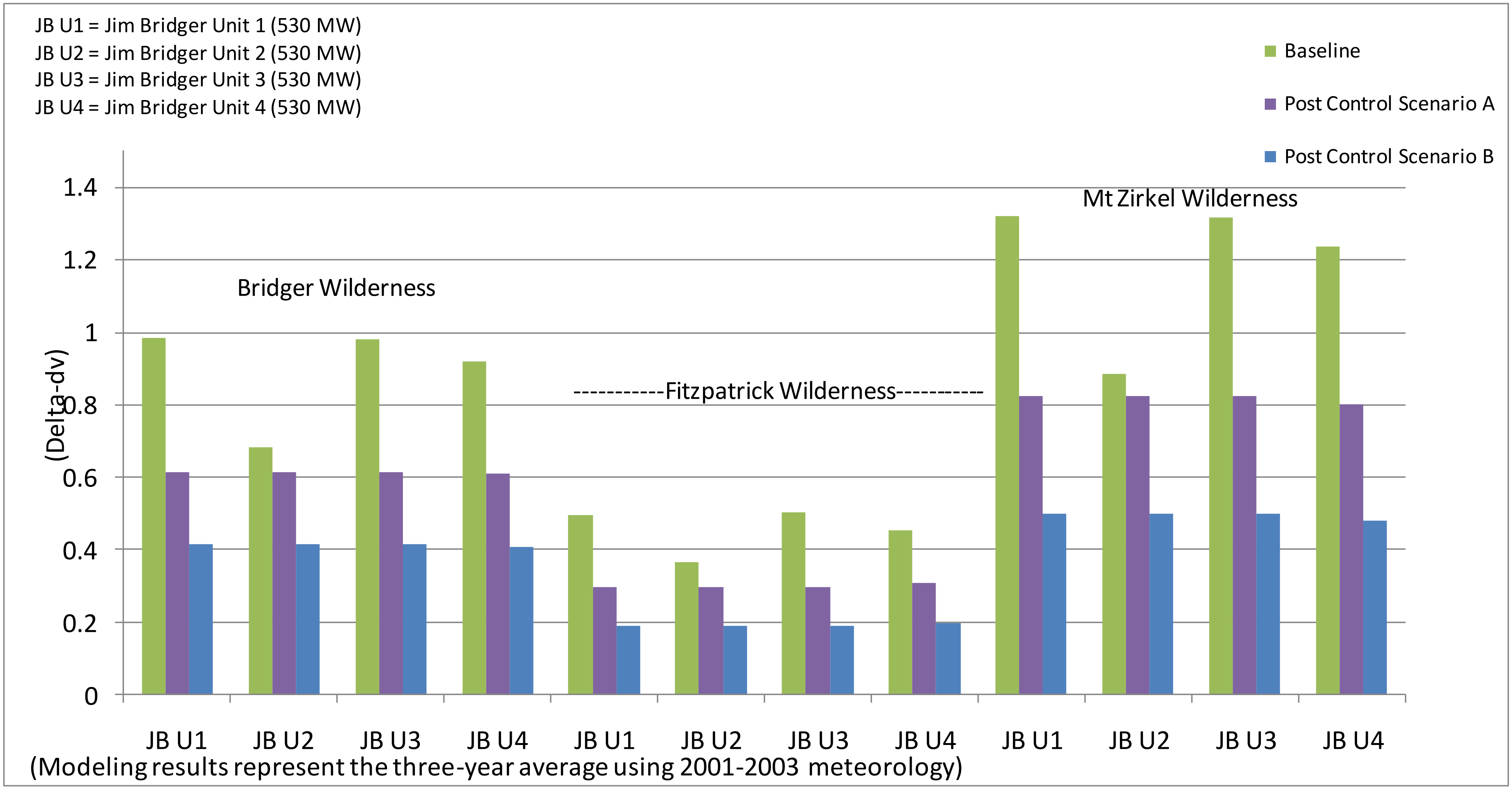
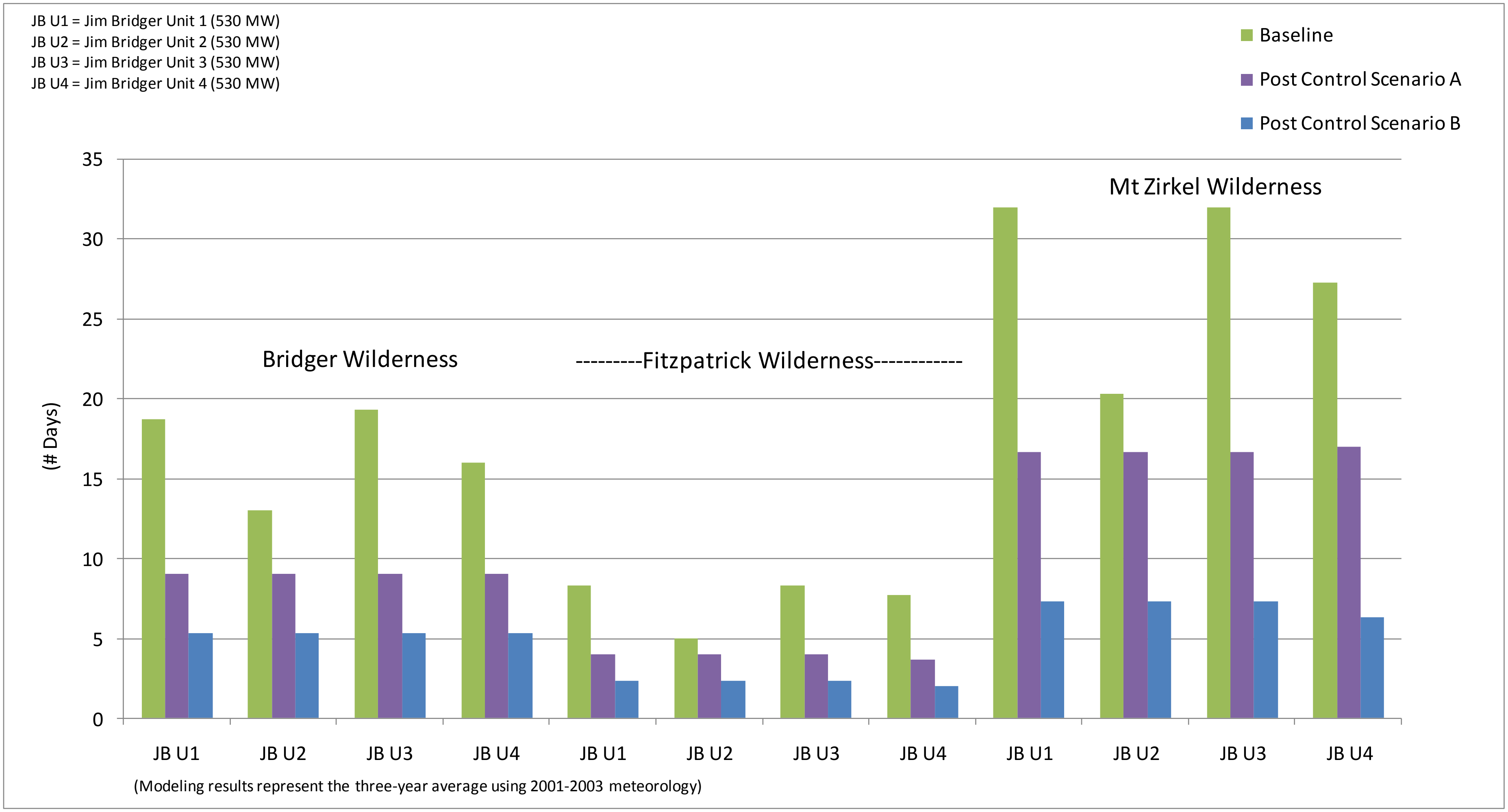


Figure 8
Modeled BART Impacts: Number of Days > 0.5 delta-dv



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:

<u>Jim Bridger Unit 1</u>:	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.
<u>Jim Bridger Unit 2</u>:	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.
<u>Jim Bridger Unit 3</u>:	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.
<u>Jim Bridger Unit 4</u>:	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.

<u>PM/PM_{10}</u>

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:

Jim Bridger Unit 1:	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}.
Jim Bridger Unit 2:	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}.
Jim Bridger Unit 3:	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}.
Jim Bridger Unit 4:	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.

[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

UAE Exhibit RR 2.13

HOWARD GEBHART ARBITRATION REPORT

Technical Review of Hunter Unit #2 Emissions Control Projects

Expert Report

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January 26, 2011

EXHIBIT
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Executive Summary

This report provides an assessment of the proposed upgrades to the sulfur dioxide (SO_2) and particulate matter (PM) emission controls at the Hunter Unit #2 electric generating station in Utah. Each of the proposed projects has been analyzed to determine the extent to which upgrades were necessary to satisfy regional haze and other applicable air emissions regulations. The review further evaluates the emission controls selected for Hunter Unit #2 against the EPA regulatory requirements for installing Best Available Retrofit Technology (BART) and compares the pollution controls selected for Hunter Unit #2 to BART determinations for other coal-fired electric generating units (EGUs) in the western United States.

For SO_2, the Hunter Unit #2 pollution controls are scheduled to be upgraded so that 100% of the exhaust flue gas would now pass through the emissions control system. Currently, only some of the flue gas is routed through the control equipment, and the remaining flue gas is used to reheat the exhaust gas. These changes are expected to increase the sulfur removal efficiency of the Hunter Unit #2 scrubber to 90% or greater, reducing the current allowable SO_2 emissions from 0.21 to 0.12 lb/MMBtu. For PM emissions, the proposed changes would replace the current Hunter Unit #2 electrostatic precipitator (ESP) control equipment with a fabric filter baghouse. The proposed emissions reductions in PM would be from the current allowance of 0.05 to 0.015 lb/MMBtu. However, current monitoring data show that actual emissions of SO_2 and PM at Hunter Unit #2 are already significantly below the current allowable emission limits.

The primary regulatory driver for the Hunter Unit #2 pollution control upgrades is compliance with requirements of the Utah State Implementation Plan (SIP) for regional haze. The regional haze SIP is designed to help protect visibility in designated Class I areas under the Prevention of Significant Deterioration (PSD) program and return future visibility to "natural conditions," or the goal of zero man-made visibility impairment.

Achieving the national visibility goal requires emission reductions at existing sources that contribute to man-made visibility impairment in Class I areas. Current federal regulations adopted by the US Environmental Protection Agency (EPA) require that selected emission sources contributing to visibility impairment install BART. Alternatively, states may participate in a regional visibility program that achieves equivalent results. Utah's Regional Haze State Implementation Plan (SIP) follows the regional approach.

The accepted industry practice is to perform a standard "five factor" BART analysis for each unit deemed "BART Eligible" before selecting or committing to perform emissions control upgrades. Notwithstanding this accepted industry practice, a standard BART determination was not performed for Hunter Unit #2. Instead, Utah developed its regional haze SIP by incorporating PacifiCorp's pre-existing proposal to upgrade Hunter Unit #2 pollution control equipment. PacifiCorp had previously committed to perform these upgrades as early as 2005, in connection with its Public Service Commission application for authority to conclude a merger/purchase involving MidAmerican Energy Holdings Company (MidAmerican). PacifiCorp's and MidAmerican's merger commitment required the company to voluntarily invest sizeable amounts in pollution upgrades at Hunter Unit #2, among other selected units. Utah determined that the pre-existing merger commitment to install pollution control upgrades at Hunter Unit #2 would, in all cases, enable the unit to meet or exceed any applicable standard that might otherwise apply under regional haze requirements. As such, the improved emission level at Hunter Unit #2 was accepted by the Utah state environmental regulators into the regional haze SIP without further analysis.

This report concludes that the decision to install emissions control upgrades at Hunter Unit #2 resulted in technology selections that were not as favorable to the owners of Hunter Unit #2 when compared to other decisions regarding pollution control technology at BART eligible, coal-fired power plants elsewhere in the western United States, including other units within PacifiCorp's fleet of BART eligible units.

The major findings of this Hunter Unit #2 study are summarized below:

- Utah did not perform a formal "five-factor" BART review for its "subject-to-BART" sources such as Hunter Unit #2. Instead, Utah established the "presumptive BART" SO_2 emissions level of 0.15 lb/MMBtu from EPA regulations as the benchmark for addressing the "better than BART" requirements for SO_2 emissions. However, under the EPA BART rules, "presumptive BART" applies only to currently uncontrolled electric generating units (EGUs). Since Hunter Unit #2 already employs SO_2 pollution control equipment, it was not subject to presumptive BART. In any event, Hunter Unit #2 already met the "Presumptive BART" SO_2 standard established as the "better-than-BART" benchmark by the Utah Regional Haze SIP without any added emission control.

- The allowable SO_2 emissions limit established at Hunter Unit #2 at PacifiCorp's request is 0.12 lb/MMBtu, effective once the improved emission controls are in place. This is more stringent than the "presumptive BART" SO_2 emissions level of 0.15 lb/MMBtu described above. However, available emissions data from Hunter Unit #2 show that the actual SO_2 emissions are already at or below the "presumptive BART" emissions level before any additional controls are added. As such, based on current actual SO_2 emissions, Hunter Unit #2 is already "better-than-BART" and the added emissions control from the scrubber upgrade project were not needed to meet the minimum regulatory requirements.

- The proposed upgrades at Hunter Unit #2 are not necessary or essential in meeting the SO_2 emissions reductions mandated by the Utah Regional Haze SIP. The Utah Regional Haze SIP identifies an SO_2 emissions reduction of only 240 tons per year (tpy) at Hunter Unit #2, representing only 0.13% of the total regionwide emission reductions required under the SIP by 2018. The modeled visibility improvement attributable to the added emission controls at Hunter Unit #2 was also insignificant (0.019 deciviews or less at nearby Class I areas). I prepared independent calculations that derived a similar SO_2 control level of 485 tpy for the scrubber upgrade project. By comparison, the regional SO_2 reductions required by the Utah Regional Haze SIP on or before 2018 are more than 186,000 tpy. Overall, the SO_2 emission reductions attributable to the Hunter Unit #2 scrubber upgrade project are inconsequential in terms of meeting the regional SO_2 emission reductions required under the Utah Regional Haze SIP. Likewise, these emission reductions provide no tangible benefit toward achieving the national visibility goal established under the regional haze regulations. This same conclusion is also valid if a higher SO_2 control level associated with consumption of higher sulfur coal at Hunter Unit #2 is included in the analysis.

- The Hunter Unit #2 costs for the scrubber upgrade project are estimated to range between about $16,000 and $33,000 per ton of SO_2 removed, depending on the level of emission reductions claimed. These costs are at least ten times higher than typical compliance costs for other coal-fired EGUs that required Best Available Retrofit Technology (BART) for SO_2 emissions. Based upon the SO_2 emission control costs and the projected level of SO_2 emission reductions, the SO_2 emissions control project at Hunter Unit #2 cannot be justified under BART. Regardless of the emissions control scenario considered, the cost-effectiveness of the scrubber control project does not meet reasonable cost criteria for BART.

- Hunter Unit #2 was originally constructed using ESPs for particulate matter (PM) emissions control at a current allowable emissions rate of 0.05 lb/MMBtu. Based on testing data, the actual PM emissions at Hunter Unit #2 range from 0.014 to 0.029 lb/MMBtu. After installation of a fabric filter baghouse, the allowable PM emissions at Unit #2 are to be reduced to 0.015 lb/MMBtu. However, other BART decisions for western coal-fired EGUs did not require replacing existing ESP equipment with fabric filter baghouses. Generally, in situations such as Hunter Unit #2 – where ESPs are an existing emissions control device – the recommended PM BART would utilize the existing ESPs and upgrade as needed to achieve PM emissions of 0.03 lb/MMBtu. Based on available emissions testing data, Hunter Unit #2 already meets the 0.03 lb/MMBtu BART PM emission standard without further upgrades. In some cases, existing ESPs were replaced with fabric filter baghouses, but any such decisions appear to be based upon case-by-case factors specific to the individual plant, which were driven by concerns other than BART compliance. These case-by-case factors are not applicable at Hunter Unit #2.

- Besides BART, another factor that PacifiCorp claims to have played a role in the decision to upgrade the Hunter Unit #2 emissions controls was a reported desire to reduce mercury emissions. Currently, no federal emission standards exist for mercury removal at EGUs, but EPA is expected to adopt such rules sometime in 2011. In 2007, Utah adopted a state emissions standard for mercury that would apparently apply to Hunter Unit 2 beginning December 31, 2012. However, the Utah mercury emissions standard was adopted and established after PacifiCorp had already committed in 2005 to install upgraded pollution controls at Hunter Unit 2 and certain of its other Utah EGUs. Because the Utah mercury standard was adopted based on PacifiCorp's voluntary pollution control commitments, the Utah standard cannot be used to justify the installation of such controls.

- Environmental regulatory drivers known or reasonably anticipated over the past decade do not justify the environmental upgrades planned at Hunter Unit #2. Moreover, the decision to upgrade SO_2 and PM controls at Hunter Unit #2 is not as favorable to the owners of Hunter Unit #2 when compared to other western coal-fired EGUs, including some owned by PacifiCorp. The cost and level of incremental SO_2 control achieved by the scrubber upgrade project is not cost-effective when reviewed under a standard five-factor analysis under BART. When a formal five-factor evaluation was prepared for specific BART-eligible emission units (such as PacifiCorp's Jim Bridger Station), PacifiCorp elected to forego similar upgrades to the particulate pollution control systems at these other plants and to continue the use of existing control equipment including ESPs.

1.0 Introduction & Background

This report provides an assessment of recent pollution control projects at the Hunter Unit #2 electric generating station, located near Castle Dale, Utah. Hunter Unit #2 is operated by PacifiCorp, a subsidiary of MidAmerican Energy Holdings Company. Deseret Generation & Transmission Cooperative (Deseret) is a minority owner of Hunter Unit #2.

The report focuses on the proposed upgrades to the sulfur dioxide (SO_2) and particulate matter (PM) emission controls at Hunter Unit #2. For SO_2 control, PacifiCorp plans to upgrade the system so that 100% of the exhaust flue gas passes through the emissions control system. Currently, only a portion of the flue gas is routed through the SO_2 pollution controls and the remaining flue gas is used to reheat the exhaust gas. These changes are expected to increase the sulfur removal efficiency of the scrubber to 90% or greater, reducing the allowable SO_2 emissions from 0.21 to 0.12 lb/MMBtu. For PM emissions, PacifiCorp plans to replace the current electrostatic precipitator (ESP) control equipment with a fabric filter baghouse. The proposed emissions reductions in PM would be from the current allowable of 0.05 to 0.015 lb/MMBtu. However, current emissions monitoring data at Hunter Unit #2 show that actual emissions of SO_2 and PM are significantly below the current allowable permit limits.

The principal regulatory driver for the Hunter Unit #2 pollution control upgrades is compliance with requirements of the Utah State Implementation Plan (SIP) for regional haze. The regional haze SIP is designed to help protect visibility in designated Class I areas under the Prevention of Significant Deterioration (PSD) program and return future visibility to "natural conditions", which represents a goal of no man-made visibility impairment.

Achieving the national visibility goal generally requires emission reductions at existing sources that contribute to man-made visibility impairment in Class I areas. Current federal regulations adopted by the US Environmental Protection Agency (EPA) require that selected emission sources install Best Available Retrofit Technology (BART) or that states participate in a regional visibility program that achieves equivalent results. The Hunter Unit #2 review described in this report evaluates the emission controls selected for Hunter Unit #2 against the federal regulatory requirements for BART and also compares the selected controls to other BART determinations for coal-fired electric generating units (EGUs) in the western United States.

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3.0 Technical Analysis

3.1 Utah Regional Haze State Implementation Plan

3.1.1 Overview

This section provides a summary of the Utah Regional Haze State Implementation Plan (SIP) as is pertains to emissions and planned controls for the Hunter Unit #2 electric generating station.

The current Utah Regional Haze SIP was adopted in 2008. Utah has elected to complete its regional haze SIP under 40 CFR Part 51 Section 309, where the SIP constitutes a regional planning approach. This "regional" approach to regional haze regulation is an alternative regulatory framework which four states have opted to implement: Arizona, New Mexico, Utah, and Wyoming. Other western states such as Colorado have opted for a state-by-state program under Section 308. Oregon originally participated in the regional Section 309 SIP planning effort, but has since dropped out and is now operating its regional haze program under Section 308. Arizona is also currently preparing a SIP under Section 308 in lieu of the regional approach.

Under Section 309, states may elect to implement a regional emissions trading program or other alternative measures in lieu of requiring eligible sources to install Best Available Retrofit Technology (BART). The alternative program is required to achieve greater reasonable progress toward the national visibility goal than would otherwise be required through installation and operation of BART on individual emission sources (See 40 CFR 51.309(d)(4) and 40 CFR 51.308(e)).

3.1.2 Hunter Unit #2 and the Utah Regional Haze SIP

The SIP determination that Hunter Unit #2 with improved emission controls would satisfy BART requirements does not answer the relevant inquiry of whether the upgrades were needed or necessary in order for the unit to comply with the applicable regulatory standards.

To better explain, an overview of the process used by Utah to develop the SIP is useful. BART controls are not required to be installed on individual emission sources located in Section 309 states, such as Utah. Nevertheless, in order for the State to demonstrate that the SIP control strategy meets the requirement for "better than BART" emission controls, some determination must be undertaken to assess what amount of emission reduction would result if the BART standard were to be applied to each subject unit. Once this is done, the actual emission reductions that result from the SIP can be compared to what would have been achieved if every affected unit were equipped with the prescribed BART technology. Overall, if the SIP as a whole is expected to achieve emission reductions that would exceed those achieved under a source-by-source BART approach, then the SIP would meet the "better-than-BART" standard. However, the SIP may achieve this goal without specifically requiring BART controls at any individual emissions source.

As detailed below, Utah accepted PacifiCorp's pre-existing commitment to install pollution control upgrades at Hunter Unit #2 and found that, no matter the level of control which might have been needed to satisfy BART, the proposed upgrades would meet or exceed the required regulatory level.

Hunter Unit #2 has been determined under the Utah SIP to be a "BART eligible" source. BART-eligible sources are defined as those sources that fall within one of 26 specific source categories (one such category includes fossil-fuel fired electric generating stations), which were built between 1962 and 1977, and have emissions of at least 250 tons per year of any visibility-impairing air pollutant (See 40 CFR 51.301).

Once a source is determined to be BART-eligible, further analysis is required to determine if a source is "subject to BART". Subject-to-BART includes those BART-eligible sources which "may be reasonably expected to cause or contribute to any impairment of visibility in any mandatory federal Class I area" (See 40 CFR 51.308(e)).

In Utah, all BART-eligible sources were modeled by the Western Regional Air Partnership (WRAP) Regional Modeling Center using the EPA CALPUFF modeling system. Based on this modeling, the Hunter Unit #2 emissions were determined to contribute to more than a 0.5 deciview change on visibility in one or more mandatory federal Class I areas in Utah and/or adjoining states. Following the guidance in 40 CFR 51 Appendix Y (EPA's BART Guidelines), this modeling concluded that Hunter Unit #2 would be "subject-to-BART".

In 2005, during the process of obtaining approvals for an acquisition by MidAmerican Energy Holding Company of PacifiCorp, PacifiCorp and MidAmerican committed to make sizeable investments in upgrading emission controls at some of PacifiCorp's coal-fired generating units. At Hunter Unit #2, MidAmerican and PacifiCorp agreed of their own volition to install such emission controls, including upgrading the SO_2 and the PM control systems. At PacifiCorp's request, these controls are now reflected in the current Title V operating permit and other air quality permits issued for the Hunter plants. The Utah Department of Environmental Quality (UDAQ) has also determined that the emission controls at Hunter Unit #2 are at least stringent enough to meet or exceed a standard of "better than BART" for the purpose of the Regional Haze SIP (See: *Demonstration that the SO_2 Milestones Provide Greater Reasonable Progress than BART*, dated April 23, 2008).

In approving an equivalent BART emissions limitation for Hunter Unit #2, PacifiCorp did not submit, nor did Utah require, the standard "five-factor" BART analysis listed under 40 CFR 51 Appendix Y. Under the EPA's five-factor BART analysis, technological alternatives are first identified for each unit that is "subject to BART," whereupon those alternatives, which are either technically impracticable or otherwise ineffective, are eliminated from further study. Once feasible and effective alternatives have been identified, the alternatives are evaluated further for their cost effectiveness in producing significant emission reductions for specified pollutants. EPA guidelines provide relevant ranges of cost effectiveness in establishing which of the alternatives, if any, would be required in order to comply with regional haze requirements. Only if an evaluated upgrade is determined both technically feasible and warranted from a cost effectiveness standpoint will it be selected for implementation at the specific emissions unit under evaluation, and only then does it become a legal requirement in order to satisfy BART.

Utah's determination that Hunter Unit #2 controls are "better than BART" is predicated on the fact that the allowable SO_2 emissions (0.12 lb/MMBtu) once the upgraded controls are installed will be less than the 0.15 lb/MMBtu "presumptive BART" emissions limit from Appendix Y. In the SIP, Utah takes credit for an SO_2 emissions reduction of just 240 tpy at Hunter Unit #2. The total reduction from all Utah sources due to implementation of BART-like emission controls is estimated to be 13,189 tpy, most of which come from Huntington Unit #2. Huntington Unit #2 did not have any SO_2 emissions control prior to the Utah Regional Haze SIP. Hunter Unit #2 is thus expected by Utah to contribute only 0.13% of the total reduction in SO_2 emissions – an inconsequential reduction that cannot be cost-justified under a standard BART analysis.

It is important to note that the "presumptive BART" emissions limit in Appendix Y legally applies only to previously uncontrolled electric generation units. Hunter Unit #2 has existing SO_2 emission controls and as such would not have been subject to the "presumptive BART" requirements under a Section 308 SIP. According to EPA guidelines, where the "presumptive BART" limit does not expressly apply, as is the case with Hunter Unit #2, such an emissions level will only be deemed equivalent to BART where the incremental emissions control can be achieved at a reasonable cost.

The modeled improvement in visibility from the planned pollution control upgrades at Hunter Unit #2 is listed in the Utah Regional Haze SIP. The largest modeled visibility improvement occurs at Capitol Reef National Park, but is only 0.019 deciviews. By contrast, the overall visibility impacts modeled from Hunter Unit #2 at Capitol Reef was 1.905 deciviews, so the modeled improvement in visibility attributable to the Hunter Unit #2 pollution control upgrades is very small on a percentage basis (1%). It should be noted that the modeled change in visibility would reflect all of the pollution control improvements planned at Hunter Unit #2 and not just the SO_2 emission reductions.

Finally, available emissions data show that SO_2 emissions at Hunter Unit #2 are below the presumptive BART emissions level of 0.15 lb/MMBtu, without any pollution control upgrades. In the UDAQ files, Hunter's "Environmental Status" report dated June 23, 2010 for the continuous emissions monitoring system (CEMS) reports that the Hunter 12-month rolling average SO_2 emissions at Unit #2 were 0.126 lb/MMBtu. Also, the Hunter CEMS data reports on file at UDAQ for the 1st quarter and 2nd quarter of 2010 showed that SO_2 emissions (30-day rolling average) were below 0.15 lb/MMBtu at all times.

3.1.3 Regional SO_2 Emission Milestones

The Utah Regional Haze SIP relies principally on achieving stated milestones for regional SO_2 emissions. These milestones (representing the total SO_2 emissions from the four-state region) started at 420,637 tpy in 2003 and will gradually decline each year to 234,624 tpy by 2018.

The most recent compliance report completed by the Western Regional Air Partnership (WRAP) was for the 2008 SO_2 emissions milestone of 378,398 tpy. The 2008 milestone is compared to the average of the 2006-08 regional SO_2 emissions. Based on WRAP's *2008 Regional SO_2 Emissions and Milestone Report*, the actual SO_2 emissions over the four-state region (AZ, NM, UT, & WY) totaled 265,662 tpy, or about 70% of the applicable milestone. The actual SO_2 emissions reported for 2008 are about equal to the 2014 milestone in the Utah Regional Haze SIP, which means that the milestone will be achieved even if no further regional emissions reductions are achieved prior to 2014.

The Hunter contribution to the actual emissions total is provided by the Milestone Report for the plant as a whole, but not individually for Hunter Unit #2. The Hunter total SO_2 emissions reported in the 2008 Milestone Report is 6,072 tpy, which represents about 2% of the total four-state regional SO_2 emissions.

If at any point, the SO_2 emission milestones are not achieved, then a regional SO_2 emissions trading program would be triggered. At that time, SO_2 emission allocations would be distributed to individual sources, including Hunter Unit #2, according to the procedures listed in the Utah Regional Haze SIP. However, given the current margin of compliance with the emission milestones, there does not appear to be a realistic threat that the SO_2 emission milestones would be exceeded in the near future.

3.1.4 Findings – Utah Regional Haze SIP Review

- The Utah Regional Haze SIP was written under 40 CFR 51 Section 309, which provides for a regional planning effort. Regional SO_2 emission milestones were set based on a 2003 baseline of 420,637 tpy and decrease annually to 234,624 tpy by 2018, for an overall reduction of 186,013 tpy. If the SO_2 emission milestones are not met, a backstop SO_2 emissions trading program will be triggered. As of 2008, the annual SO_2 emissions were only 70% of the applicable milestone and further emission reductions appear unnecessary to achieve the milestone prior to 2014. As of this date, the backstop trading program has not been triggered and as such, SO_2 allowances have not been allocated to individual emission units, such as Hunter Unit #2.

- Under Section 309, individual emission sources like Hunter Unit #2 do not need to install BART provided that the SIP control strategy developed produces emission reductions that are "better than BART".

- Although BART does not apply to individual sources under Section 309, an assessment of appropriate BART controls is necessary and appropriate to assess whether or not the regional strategy will achieve "better than BART" results. Utah did not perform a formal BART review for its "subject-to-BART" sources, but instead established the "presumptive BART" SO_2 emissions level of 0.15 lb/MMBtu as the "better than BART" benchmark. For Hunter Unit #2 and other facilities operated by PacifiCorp, this was done because PacifiCorp had, as part of an earlier merger commitment, already volunteered to install the proposed emission control upgrades, the effect of which would be to achieve emissions levels more stringent than "presumptive BART." However, given that Hunter Unit #2 SO_2 emissions were already controlled by the current flue gas desulphurization (FGD) system, the "presumptive BART" requirements would not have legally applied under a formal BART analysis. In any event, even had the 0.15 lb/MMBtu "presumptive BART" limit applied to Hunter Unit #2, it is already able to meet that requirement for SO_2 emissions without any added emission control.

- Hunter Unit #2 has an allowable SO_2 emissions limit of 0.12 lb/MMBtu, effective once the improved emission controls are in place. This is more stringent than the "presumptive BART" SO_2 emissions level, which is 0.15 lb/MMBtu. However, existing emissions data showed that Hunter Unit #2 already had actual SO_2 emissions at or below the "presumptive BART" emissions before any added controls were in place. During the first six months of 2010, Hunter CEMS data reported a maximum SO_2 emission rate of 0.148 lb/MMBtu based on a 30-day rolling average.

- The Utah Regional Haze SIP identifies an SO_2 emissions reduction of 240 tpy at Hunter Unit #2. The Unit #2 SO_2 emission reductions are only 0.13% of the total regionwide emission reductions required under Utah's Regional Haze SIP. The modeled visibility improvement attributable to the added emission controls at Hunter Unit #2 was also insignificant (0.019 deciviews or less at nearby Class I areas). The incremental emissions reduction achieved by the Hunter Unit #2 scrubber upgrade project are inconsequential in meeting the regional emission reductions mandated under Utah's Regional Haze SIP.

3.2 Hunter Unit #2 SO_2 Emission Control Projects

3.2.1 Overview

This section summarizes the evaluation of the emissions controls and related cost information for sulfur dioxide (SO_2) emissions at Hunter Unit #2. Costs for SO_2 emissions control at Hunter Unit #2 have been compared to other coal-fired power plants in the western United States where Best Available Retrofit Technology (BART) has been proposed or determined.

3.2.2 BART Overview

The concept of Best Available Retrofit Technology (BART) was introduced by the Clean Air Act Section 169 as part of the national strategy to remedy existing impairment of visibility at Class I areas. The federal regional haze rule promulgated by the U.S. Environmental Protection Agency (EPA) at 40 CFR 51.308(e)(1)(ii)(B) directs states to identify the "best system of continuous emissions control technology" taking into account "the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any air pollution control equipment in use at the source, and the remaining useful life of the source".

In a formal BART review, the analysis proceeds using five steps as described in the applicable EPA guidance (40 CFR 51, Appendix Y). The "five factor" BART review is summarized below:

STEP 1: Identify all available retrofit control technologies. In order to be considered "available", the technology of interest must have a practical potential for application to the emissions unit and regulated pollutant being considered. Technologies which have not been applied to the source category or similar category on a commercial-scale are not considered to be "available". Emission control technologies to consider at this step may include inherently lower emitting processes, add-on emissions control technologies, or a combination of the two.

STEP 2: Eliminate technically infeasible options. Technologies identified at Step 1 are considered feasible if they have already been installed and operated on the type of source under review under similar conditions or if the technology could reasonably be applied to the source under review. Any claim of technical infeasibility needs to be documented based on physical, chemical, or engineering principles and explain why technical difficulties preclude the application of the particular technology on the emission source under review.

STEP 3: Evaluate control effectiveness of the remaining feasible technologies. The two key elements in describing the control effectiveness of a particular technology are to express the control level using a metric that allows for comparison between different alternatives and to consider how controls may perform over a wide range of operating conditions. Generally, the most common metrics used to describe pollution control performance are to consider emissions (lb/MMBtu) or a control efficiency (% of pollutant removed).

STEP 4: Perform the impact analysis. Relevant impacts to consider during the BART review are the costs of compliance, energy impacts, non-air quality environmental impacts, and remaining useful life of the source. Costs are generally evaluated in terms of the "cost-effectiveness" of the pollutant controlled, normally expressed as dollars ($) per ton of pollutant removed. With respect to any other impacts (energy and/or non-air quality environmental impacts), any significant impacts on these items tend to also have financial implications, so any such impacts that are significant would also be expected to be reflected in the economic analysis.

STEP 5: Evaluate the visibility impacts. In this step, the projected improvement in visibility from implementing each of the BART alternatives is evaluated. This is accomplished through dispersion modeling of the source emissions.

As summarized above, the "cost of compliance" is one of several factors that must be considered in selecting an appropriate BART air pollution control technology. Based on the formal five-factor BART decision-making process, cost is one of the factors that can be used to exclude a particular control technology from selection as BART.

Although an appropriate cost level for BART is not defined in the applicable rules or guidance, comparison of BART compliance costs between different plants is one method identified by EPA's guidelines to decide whether or not the compliance costs to select and install BART at a particular facility are reasonable. For those coal-fired electric generating units (EGUs) where SO_2 emissions are currently uncontrolled, EPA's rulemaking also establishes "presumptive BART" at 95% or greater SO_2 removal and/or an SO_2 emissions limit of 0.15 lb/MMBtu (See Federal Register, Vol 70, No. 128, July 6, 2005, Page 39132).

Because Hunter Unit #2 has existing SO_2 emissions controls, the presumptive BART regulatory requirements do not apply. Nevertheless, at PacifiCorp's request, the Hunter Unit #2 SO_2 emissions level was set by the Utah Regional Haze SIP at 0.12 lb/MMBtu, which is more stringent that the presumptive BART emissions level established by the applicable federal regulations.

3.2.3 BART Description and Costs – Hunter Unit #2

Hunter Unit #2 currently scrubs about 80% of the exhaust flue gas for SO_2 emissions control. The balance of the flue gas is used to reheat the exhaust gas for operation as a dry stack. With the proposed pollution control upgrades, 100% of the Hunter Unit #2 flue gas will be routed to the SO_2 emissions control system. Once this modification occurs, the Hunter Unit #2 will exhaust as a wet stack.

Prior to the proposed modification, Hunter Unit #2 had an allowable SO_2 emission rate of 0.21 lb/MMBtu. The maximum allowable SO_2 emissions will decrease to 0.12 lb/MMBtu once the upgraded pollution controls are installed and operational. Based on various emission reports filed by PacifiCorp with the Utah Division of Air Quality, the actual SO_2 emissions were already at or near 0.12 lb/MMBtu (these documents were reviewed during the UDAQ Public Records search).

Capital costs for the proposed Hunter Unit #2 scrubber upgrade are estimated at approximately $77.4 million. These capital costs are itemized in Table 3-1. The capital costs include the wet chimney modifications that were originally counted in the capital costs for the particulate matter (PM) control project. However, the costs for the wet chimney modifications logically cannot be avoided once the scrubber upgrade is installed and the chimney is converted to a wet stack. As such, the wet chimney modifications and associated opacity monitor relocation are legitimate costs to be included with the scrubber upgrade project.

The capital costs for the SO_2 scrubber upgrade project were annualized by computing the "cost recovery factor" (CRF), which accounts for the total cost of the equipment based on the life of the equipment and the interest rate. The CRF is computed as follows, based on EPA's *Office of Air Quality Planning & Standards (OAQPS) Cost Control Manual*.

$CRF = i\,(1 + i)^n / (1 + i)^n - 1$, where i = interest rate and n = equipment life

For this project, the interest rate was estimated at 4.5% and the equipment life was estimated at 15 years. Using the equation above, these data yield a CRF of 0.093. Using $77.4 million for the capital cost, the annualized capital equipment cost is $7,198,559.

The CRF used in the Hunter Unit #2 analysis was compared to other PacifiCorp BART analyses in Wyoming where an economic analysis was performed. In all of the Wyoming BART analyses for PacifiCorp units, the CRF used was 0.095, although the Wyoming CRF is based on a 20-year life of equipment at a higher interest rate (7.1%). This comparison shows that the CRF used in this analysis of Hunter Unit #2 is consistent with other PacifiCorp data.

Table 3-1

Hunter Unit #2 SO_2 Control Upgrades – Capital Cost

Item		Capital Cost
Capital Items for Scrubber Upgrade		
Site Work		$900,000
Recycle Pumps		$3,600,000
Forced Oxidation & Absorber Work		$5,740,200
Hydroclones (Tanks, Pumps and Piping)		$2,392,200
Vacuum Drum Filters		$7,200,000
Miscellaneous, Including Electrical		$3,591,582
Lime Preparation Facility		$16,107,000
Wet Chimney Modifications		$16,072,624
Opacity Monitor Relocation		$1,373,708
Subtotal – Capital Items		**$56,977,314**
Contingency on Direct Capital Costs	20.7% of capital	$11,794,304
Subtotal – Direct Costs		**$68,771,618**
Indirect Costs		
Engineering, Procurement & Project Services	4.0% of direct costs	$2,750,865
Construction Management & Field Engineering	1.5% of direct costs	$1,031,574
Start-up Commissioning	1.0% of direct costs	$687,716
Subtotal – Direct and Indirect Costs		**$73,241,773**
Project Contingency (on subtotal above)	5.0% of direct plus indirect costs	$3,662,089
PacifiCorp Surcharge		$500,000
SUM – Revised Capital Cost		**$77,403,862**

The interest rate estimate is based on the interest rate for Baa-rated bonds listed in the Wall Street Journal (http://online.wsj.com) as of early December 2010. Based on PacifiCorp's Form 10-Q for the quarter ending June 30, 2010, the company's unsecured debt is rated by Moody's at Baa1 (lower medium grade). Using the Wall Street Journal, the Baa-rated bond index yield was 4.15%, with a 52-week range of 4.08% to 5.16%. The 4.5% interest rate selected by ARS is approximately the mid-range of the 52-week yield spread for the Baa bond index.

The 15 year equipment life is based on the estimated operating costs for the equipment provided by Deseret G&T, which span a total of approximately 15 years.

The incremental operating and maintenance (O&M) costs for the SO_2 emission controls at Hunter Unit #2 were also provided by Deseret G&T. For these calculations, we used the 2010 O&M costs, which is the initial year of full-time operation for the proposed scrubber upgrade. The annual O&M costs are estimated to be $760,329.

The total annual cost for the Hunter Unit #2 SO_2 emissions control upgrade is summarized below.

Capital Cost ($77.4 million, CRF = 0.093)	$7,198,559
Incremental O&M Costs	$ 760,329
Total Costs	$7,958,888

Based upon the Utah Regional Haze State Implementation Plan (SIP), the scrubber upgrade at Hunter Unit #2 will reduce SO_2 emissions by about 240 tpy. Based on this figure, the cost effectiveness for the SO_2 BART at Hunter Unit #2 would be $33,162 per ton SO_2 removed.

As a check on the above emissions control figure estimated in the Utah SIP, I conducted an independent review to confirm an appropriate level of emissions control that can properly be attributed to the Hunter Unit #2 scrubber upgrade project. Following the BART guidelines in 40 CFR 51, Appendix Y, the initial step was to estimate the "baseline emissions" at Hunter Unit #2. For this, I used SO_2 emissions information for Hunter Unit #2 as contained in PacifiCorp's May 2, 2007 Notice of Intent that resulted in the current Utah Approval Order (AO) and Title V Operating Permit. UDAQ and PacifiCorp used these same baseline emissions to establish the current facility-wide SO_2 emissions cap as contained in the Hunter AO and Title V Operating Permit. These data represent a baseline emissions period from October 2002 to September 2007 from data recorded by the continuous emissions monitoring system (CEMS) at Hunter. Over the baseline period, the maximum annual SO_2 emissions at Hunter Unit #2 based on a rolling 24-month average was 2,670 tons per year (tpy).

For the "controlled" emissions, the calculations are based on the allowable SO_2 emissions from the current Hunter AO and Title V Operating Permit (0.12 lb/MMBtu) and the heat input capacity of the Hunter Unit #2 boiler (4,157 MMBtu/hr). This derives a post-control emissions estimate of 2,185 tpy at Hunter Unit #2, which is the same "post-control" SO_2 emissions estimate listed in the Utah Regional Haze SIP. Subtracting this figure from the baseline emissions yields an estimate of the SO_2 emissions controlled by the Hunter Unit #2 scrubber upgrade project, or 485 tpy (2,670 – 2,185 = 485).

Using this independently-derived calculation of emissions control (485 tons), the cost-effectiveness of the Hunter Unit #2 scrubber upgrade project is $16,410 per ton of

SO_2 removed. Because this independent estimate can be verified against other data, it is believed to be more reliable than the other SO_2 emission control estimates.

PacifiCorp has apparently claimed that a higher SO_2 removal efficiency may result in the event of an increase in the sulfur content of coal that it may use in the future at Hunter Unit #2. However, a PacifiCorp emissions control value based on higher sulfur coal could not be independently verified. Also, Bret Moran (PacifiCorp's Fuel Supply Manager) has testified that an exact value for the expected future coal content cannot be provided. Without these data, it is not possible to accurately determine the level of emissions control associated with higher fuel sulfur inputs. Moreover, I understand that PacifiCorp has acknowledged that it learned of a possible increase in the sulfur content of its coal only after it had already committed to install the SO_2 emission control upgrades.

As explained below, the Hunter Unit #2 SO_2 control costs are significantly higher than typical costs normally associated with BART at western coal-fired EGUs. The conclusions below regarding the reasonableness of the BART cost-effectiveness are valid regardless of which control scenario is used for the Hunter Unit #2 scrubber cost data.

3.2.4 Comparison with Western Coal-Fired EGU BART Decisions

Data concerning BART decisions at EGUs across the country were for a time maintained by the Western Regional Air Partnership (WRAP) and listed on the WRAP website at www.wrapair.org. For the WRAP BART Clearinghouse, this information is current as of December 10, 2009. WRAP indicated that it will not be providing any future updates to the BART Clearinghouse data after December 2009.

Within the WRAP BART Clearinghouse, cost data for the different BART technologies were maintained by Don Shepherd of the National Park Service (NPS). The NPS cost data have been used to evaluate the relative costs of the Hunter Unit #2 proposal versus other coal-fired plants where BART has been implemented or proposed.

Table 3-2 below lists the BART cost information as obtained from the NPS information in the WRAP BART Clearinghouse. In this table, the BART information considered was for plants where the SO_2 emissions control system was being upgraded as this control strategy is considered more applicable to Hunter Unit #2. No other BART decisions were listed for comparison in Table 3-2. The other units for which BART information is available from the WRAP Clearinghouse either involved a completely new flue gas desulphurization system or were for EGUs using oil as the primary fuel, and neither situation is applicable to the proposed SO_2 emission controls at Hunter Unit #2. Costs are listed in dollars per ton of pollutant (SO_2) removed. Also, ARS has not independently verified any of the cost information listed in the WRAP BART Clearinghouse.

Table 3-2

BART Cost Information – SO_2 Scrubber Upgrades
(from December 10, 2009 WRAP BART Clearinghouse, www.wrapair.org)

EGU & Location	*Estimated SO_2 BART Costs ($ per ton)*
Jim Bridger (WY)	$620 to $729 per ton
Coal Creek (ND)	$555 per ton
King (MN)	$49 per ton
Laramie River (WY)	$1,564 to $1,571 per ton
MR Young (ND)	$247 to $565 per ton
Naughton Unit #3 (WY)	$290 per ton
Sherburne County (MN)	$236 to $238 per ton
Wyodak (WY)	$1,428

The highest BART control costs were at the Laramie River Station where the cost for the incremental emissions control was slightly more than $1,500 per ton SO_2 removed. Otherwise, at most other locations where improved SO_2 scrubbing was selected as BART, the compliance costs were less than $750 per ton.

By comparison, the Hunter Unit #2 SO_2 control costs are substantially higher. Based on the level of incremental SO_2 control, the Hunter Unit #2 costs ($16,410 to $33,162 per ton SO_2 removed) are substantially higher than other BART decisions, by more than an order of magnitude or more.

Other data on the expected cost effectiveness for SO_2 BART emissions controls can be found in EPA's preamble for the BART rulemaking (See Federal Register, Vol. 70, No 128, July 6, 2005, Page 39133). Here, for uncontrolled coal-fired EGUs, EPA projects the cost-effectiveness of SO_2 BART at an average of $919 per ton, with a range of $400 to $2,000 per ton SO_2 removed for a majority of the uncontrolled BART-eligible EGUs. EPA's cost data are consistent with the WRAP BART Clearinghouse. EPA provided cost information only for uncontrolled EGUs and not for scrubber upgrades.

3.2.5 Findings – Hunter Unit #2 SO_2 Control Upgrades

The Hunter Unit #2 SO_2 control system costs are estimated to be in the range of $16,410 to $33,162 per ton of SO_2 removed.

The Hunter Unit #2 SO_2 compliance costs are significantly higher than typical compliance costs for other coal-fired EGUs where Best Available Retrofit Technology (BART) was required. The BART compliance costs for Hunter Unit #2 are at least ten times higher than the upper range of the typical SO_2 compliance costs.

As explained previously, critical factors in the decision matrix for selection of BART emissions control are cost and cost-effectiveness. Emission control strategies that have excessive costs relative to the level of emission reductions achieved may be excluded from consideration under BART. Based on the cost for SO_2 emission controls and the level of SO_2 emission reductions achieved by these controls, the SO_2 emissions control project at Hunter Unit #2 cannot be justified under BART.

3.3 Hunter Unit #2 PM Emissions Control Projects

3.3.1 Overview

This section provides a review of the proposed PM emission controls for Hunter Unit #2 along with a corresponding review of regulatory agency decisions regarding Best Available Retrofit Technology (BART) for particulate matter (PM) emissions at other coal-fired electric generating units (EGUs) located in western states. The purpose of this evaluation is to compare the PM BART at other locations to the proposed emission controls at Hunter Unit #2.

At Hunter, emissions testing is being conducted annually to document the actual PM emissions level. These data for Unit #2 are summarized in Table 3 of the McRanie Expert Report dated December 30, 2010. Over the period 2004-2010, the PM emissions averaged 0.020 lb/MMBtu, with a range of 0.014 to 0.029 lb/MMBtu.

3.3.2 PM BART at Other Coal-Fired EGUs

Table 3-3 summarizes the BART for PM emissions at western coal-fired EGUs. Except for Arizona sources, this table was derived from information listed in the Western Regional Air Partnership (WRAP) BART Clearinghouse dated December 10, 2009 available at www.wrapair.org. Information on EGUs located in Arizona was taken from an Arizona Department of Environmental Quality (ADEQ) PowerPoint presentation, *BART Recommendations for Arizona Stationary Sources*, dated October 19, 2010 and available at www.azdeq.gov/environ/air/haze. Where possible, the WRAP data on BART controls was verified against the actual BART decisions published by the relevant regulatory agencies.

Table 3-3

BART Summary Table: Western Coal-Fired Electric Generating Units (from: WRAP BART Clearinghouse (12/10/09), available on www.wrapair.org, except for Arizona, which is taken from Arizona DEQ PowerPoint Presentation, *BART Recommendations for Arizona Stationary Sources - October 19, 2010*)

State	Utility	Plant	Units	PM BART Limit (lb/MMBtu)
Arizona	AEPCO	Apache	2 & 3	0.03
	Arizona Public Service	Cholla	1, 2 & 3	0.015
	Salt River Project	Coronado	1 & 2	0.03
Colorado	City of Colorado Springs	Drake	5, 6 & 7	0.03
	Public Service Company of Colorado	Valmont	5	0.03
	Public Service Company of Colorado	Cherokee	4	0.03
	Public Service Company of Colorado	Comanache	1 & 2	0.03
	Public Service Company of Colorado	Hayden	1 & 2	0.03
	Public Service Company of Colorado	Pawnee	1	0.03
	Tri-State Generation & Transmission	Craig	1 & 2	0.03
North Dakota	Basin Electric	Leland Olds	1 & 2	0.07
	Great River Energy	Coal Creek	1 & 2	0.07
	Great River Energy	Stanton	1	0.07
	Minnkota Power Cooperative	Milton R Young	1 & 2	0.03
Nevada	Nevada Power	Reid Gardner	1, 2 & 3	0.015
	Sierra Pacific	Fort Churchill	1 & 2	0.03
	Sierra Pacific	Tracy	1, 2, & 3	0.03
Oregon	Portland Electric	Boardman		0.012
Utah	PacifiCorp	Hunter	1 & 2	0.015
	PacifiCorp	Huntington	1 & 2	0.015
Wyoming	Basin Electric	Laramie River	1, 2, & 3	0.03
	PacifiCorp	Dave Johnston	3 & 4	0.015
	PacifiCorp	Jim Bridger	1, 2, 3, & 4	0.03
	PacifiCorp	Naughton	1	0.04
	PacifiCorp	Naughton	2	0.03
	PacifiCorp	Naughton	3	0.015
	PacifiCorp	Wyodak	1	0.015

The majority of PM BART decisions for western coal-fired EGU derived an emissions limit of 0.03 lb/MMBtu. Generally, EGUs with allowable emissions of 0.03 lb/MMBtu reflect use of existing (or in some cases upgraded) electrostatic precipitator (ESP) equipment for controlling PM emissions. However, in some cases, the PM control device described as BART was a baghouse, yet an allowable PM emissions level of 0.03 lb/MMBtu was prescribed.

The higher end of the BART range is 0.07 lb/MMBtu. These particular EGUs are located in North Dakota and combust lignite as fuel, so these particular BART limits may not be directly applicable to Hunter Unit #2.

The lower end of the PM emissions range is 0.012 lb/MMBtu to 0.015 lb/MMBtu. PM BART based this range is generally achieved using fabric filter baghouses. These baghouses can be either stand-alone equipment or they may be polishing baghouses downstream of an existing ESP. The choice to use a baghouse may also be based on the type of scrubber used for sulfur dioxide (SO_2) emissions control. If a "dry" scrubber is used for SO_2 removal, a baghouse is typically employed as a necessary and integral part of the dry scrubbing system. However, as Hunter Unit #2 employs "wet" scrubbers for SO_2 removal, a fabric filter baghouse would not be essential; selection of a baghouse for PM control, in this case, should be based upon the merits of the application and any related costs.

Excluding western coal-fired EGUs operated by PacifiCorp, only three such units have PM BART at 0.015 lb/MMBtu or lower: (Cholla Units 2-4 operated by Arizona Public Service (APS), Reid Gardner Units 1-3 operated by Nevada Power, and Boardman operated by Portland Electric). Details on each of these units are provided below. In general, it was found that the selection of a fabric filter baghouse as BART for PM emissions occurred: 1) when a fabric filter baghouse already existed at the unit, 2) when the baseline PM emissions control (mechanical collection) were not as effective as an ESP resulting in higher baseline emissions, or 3) when the baghouse was a required element of the selected SO_2 emissions control system.

It is emphasized that this review found no circumstances where an ESP was replaced with a fabric filter baghouse system based solely on BART.

- Cholla: The Cholla Station is sized at 300 MW for Units 2 and 3 and 425 MW for Unit 4. Unit 2 currently uses mechanical dust collectors for PM control with four wet lime venturi scrubbers providing combined SO_2 and PM control. Units 3 & 4 originally used hot-side ESPs for PM emissions control, but these systems were upgraded to fabric filter baghouse systems in 2008-09. For BART, the planned PM emissions control at each unit is a fabric filter baghouse meeting 0.015 lb/MMBtu and these controls were already in place. In reviewing the APS BART application submitted for Cholla Unit #2 (available at www.azdeq.gov/environ/air/haze), a formal BART process appears not to have been followed. Instead, the prescribed PM emission level of 0.015 lb/MMBtu was the accepted PM emissions limit and the operator chose what it believed to be the best technology to meet such a limit. The reported costs for the fabric filter baghouse at Cholla Unit 2 was more than $160,000/ton PM removed and these costs are substantially above what would be accepted as BART using a standard analysis. As such, although a fabric filter baghouse was chosen to meet PM BART at Cholla Unit 2, this choice appears to be based on other non-BART considerations, and is a deviation from more widely accepted practices among EGUs in the western U.S.

- Reid Gardner: The Reid Gardner Station in Nevada has three identical 100 MW units, none of which is currently equipped with an ESP or baghouse. Current PM emissions control at Reid Gardner includes mechanical collectors and Reid Gardner plans to replace each of the mechanical collectors with a baghouse for PM BART (Source: *WRAP Region BART Status - March 27, 2009* available at www.wrapair.org). The existing mechanical collectors would generally not be as effective as an ESP and would also have higher baseline PM emissions.

- Boardman: The Boardman Station in Oregon is a 600 MW coal-fired EGU. The current PM emissions control uses a cold-side ESP, with baseline emissions at 0.017 lb/MMBtu. PM BART at Boardman proposed installing a fabric filter baghouse downstream of the ESP. The PM emissions control choice was dictated by the choice of a "semi-dry" limestone scrubber for SO_2 emissions control, which required the installation of a conventional pulse jet fabric filter baghouse for the scrubber system to function. (Source: *Boardman Power Plant BART Report*, prepared by Oregon Department of Environmental Quality, Updated December 19, 2008).

The remaining western coal-fired EGUs where baghouses were selected for PM BART are all owned and operated by PacifiCorp. These include Hunter (Units 1 & 2), Huntington (Units 1 & 2), Dave Johnston (Units 3 & 4), Naughton (Unit 3), and Wyodak (Unit 1). However, not all PacifiCorp plants have baghouses for PM BART. Most notably in this latter group are the Jim Bridger Units 1-4 in Wyoming.

At Jim Bridger, a formal five-factor BART analysis was conducted to identify the appropriate emission controls for PM and other air pollutants. Jim Bridger Units 1-4 currently control PM emissions using ESPs, with baseline emissions ranging between 0.030 and 0.074 lb/MMBtu, depending on the specific unit. The selected BART control for PM at Jim Bridger Units 1-4 was flue gas conditioning to aid the current ESP control in achieving 0.03 lb/MMBtu. Besides the ESP, the BART review at Jim Bridger looked at adding a polishing baghouse downstream of the ESP. This option was rejected as BART at Bridger, largely due to the high cost effectiveness of these controls. The fabric filter baghouse at Bridger had an estimated capital cost of about $48 million for each unit with a cost effectiveness of about $17,500 per ton PM removed. (Source: *BART Analysis for Jim Bridger Unit 1,* Prepared for PacifiCorp by CH2MHill, December 2007; similar BART reports for Jim Bridger Units 2-4 provided almost identical data). By comparison, the Hunter Unit #2 baghouse capital costs are significantly higher – on the order of about $65 million (excluding the modifications to convert the system to a "wet" stack which was included as part of the scrubber upgrade project costs).

At those Wyoming units where PacifiCorp opted for a fabric filter baghouse meeting 0.015 lb/MMBtu to achieve BART, the economic analysis presented by the Wyoming Department of Environmental Quality (WDEQ) BART review document listed control costs that ranged between $8,000 up to $31,000 per ton PM removed. WDEQ determined that these costs were excessive and the fabric filter baghouse options would not have been needed for BART at any of the subject EGUs (Source: *WDEQ BART Application Analysis: Dave Johnston Plant* (AP-6041, May 28, 2009; *WDEQ BART Application Analysis: Naughton Plant* (AP-6042, May 28, 2009; *WDEQ BART Application Analysis: Wyodak Plant* (AP-6043, May 28, 2009). As such, PacifiCorp's selection of a fabric filter baghouse to achieve PM BART at these units appears to have been voluntary.

The final western EGU reviewed was the Coronado Station in Arizona owned and operated by Salt River Project (SRP). Coronado has two units sized at 395 MW (Unit 1) and 390 MW (Unit 2). Coronado is also subject to a Consent Decree entered into between SRP and the U.S. Environmental Protection Agency (EPA) in December 2008 which stipulated additional emission controls for NOx and SO_2 emissions, which have formed the basis for the BART emissions for those pollutants. Coronado is similar to Hunter Unit #2 in that the units are partially scrubbed for SO_2 emissions and use ESPs for existing PM emissions control.

At Coronado, baseline PM emissions are estimated to be in the range of 0.01 to 0.03 lb/MMBtu. The BART review conducted by Arizona did not formally evaluate any additional emission controls (e.g., fabric filter baghouses) and instead decided that no additional controls were necessary based on the low level already achieved by the current PM emission controls (ESPs) along with BART decisions elsewhere for similar units. At Coronado, the existing PM emission controls (ESP) was determined to represent BART with an allowable emissions limit of 0.03 lb/MMBtu.

3.3.3 Mercury Control Issues

Another factor identified by PacifiCorp in support of the baghouse emissions control project at Hunter Unit #2 is the desire for increased control of mercury (Hg) emissions. Expert reports submitted by PacifiCorp also point to a Utah state mercury control rule that sets an Hg emissions limit of 6.50 E-07 lb/MMBtu or a 90% reduction in uncontrolled Hg emissions for larger EGUs (See: Utah Air Conservation Regulations, R307-424-4). Based on the size threshold for applicable EGUs under Utah's mercury rule (1,500 MMBtu/hr), only larger EGUs such as the Hunter and Huntington units operated by PacifiCorp are covered by Utah's mercury emissions standard.

It should be noted that the Utah mercury rule as written does not require a specific emissions control technology (e.g., ESP or baghouse). The only requirement is that the Hg emissions limit be achieved on or before the applicability date of December 31, 2012. Also, given Utah's legal requirement that state clean air rules be no more stringent than any comparable federal rules, the enforceability of Utah's mercury emissions rule may come into question at such time that a federal mercury emissions standard is adopted. The U.S. Environmental Protection Agency (EPA) has announced its intention to adopt federal air toxics emission standards covering mercury emissions and other pollutants at EGUs under Section 112 of the Clean Air Act. EPA expects to propose a draft rule by March 2011 and finalize this rule by November 2011. If EPA maintains the proposed rulemaking schedule, the federal mercury emissions standards for large EGUs will be promulgated prior to the applicability date of Utah's mercury rule.

Utah is one of only a handful of states that has adopted state-specific mercury regulations covering emissions from existing EGUs. Some of these other states are in the west (Arizona, Colorado, Montana New Mexico, and Oregon), while others are generally in the Great Lakes region and the northeastern United States. Comparing the mercury control regulations among the western states listed above, there is wide variability in both the stringency of the Hg emission limits and the applicability dates. For example, in Colorado, certain requirements of their mercury rule apply only to specific EGUs while other EGUs have been specifically exempted. Overall, it appears that state EGU mercury rules currently on-the-books have been crafted to reflect the level of emissions control that currently exists or is planned for the future at specific EGUs in the jurisdiction of interest. In other words, the Hg emission controls were known prior to crafting each state rule and the stringency of each mercury rule was developed only after knowing the expected Hg emissions and/or control level at the subject units. The state mercury control rules adopted by any regulatory authority in the western United States do not appear to be technology-forcing. The same is true of Utah's mercury control rule.

Given the outcomes in the various state mercury rulemakings, my view is that it is inappropriate to use the Utah mercury control rule at R307-424-4 as justification for the baghouse control project. The Utah mercury rule was adopted with full knowledge of the control equipment in place or planned at subject emission units within Utah such as Hunter Unit #2. The rule was adopted long after PacifiCorp had already committed to install the new emissions control equipment. The emissions control equipment project at Hunter Unit #2 was formally disclosed to Utah with the submission of the original Notice of Intent (NOI) in August 2006 while Utah did not formally adopt its mercury emissions control rule until May 2007.

3.3.4 Findings – Hunter Unit #2 PM Control Upgrades

Hunter Unit #2 was originally permitted using ESPs for PM emissions control, with the current allowable PM emissions of 0.05 lb/MMBtu. Actual emissions at Hunter Unit #2 based on stack testing dating back to 2004 showed PM emissions at or below 0.03 lb/MMBtu. After installation of a fabric filter baghouse, the allowable PM emissions at Unit #2 will decrease to 0.015 lb/MMBtu.

In reviewing BART decisions for western coal-fired EGUs, no indication was found that replacing existing ESP equipment with fabric filter baghouses represented BART for any western coal-fired EGUs. In fact, the only western coal-fired EGU units with fabric filter baghouses designated as BART for PM emissions were either: 1) when a fabric filter baghouse already existed at the unit, 2) when the baseline PM emissions control (mechanical collection) was not as effective as an ESP, or 3) when the baghouse was a required element of the selected SO_2 emissions control system. In all cases reviewed where replacing or supplementing an existing ESP was formally evaluated as BART (including a full economic analysis), the option for a replacement and/or supplemental fabric filter baghouse was determined to be too costly to represent BART controls. Indeed, PacifiCorp itself reached this same conclusion in its BART analysis at the Jim Bridger Station in Wyoming. Jim Bridger appears to be the only PacifiCorp facility where a formal five-factor BART analysis was performed for the PM emissions control equipment. At Jim Bridger, the existing ESP emissions control equipment was retained with some upgrade and replacement of the ESP with a fabric filter baghouse was deemed to be not cost-effective.

Given situations similar to Hunter Unit #2 where ESPs are the existing PM emissions control device, the recommended PM BART for western coal-fired EGUs was generally to use the existing ESP equipment and upgrade as needed to achieve 0.03 lb/MMBtu, provided that the costs for any such upgrades were reasonable. In some cases, BART included replacing an existing ESP with a fabric filter baghouse, but any such decision appeared to be based on factors other than BART compliance. These factors are unique to each unit and are not present at Hunter Unit #2.

Lastly, mercury control is not a reasonable justification for the baghouse emissions control project. PacifiCorp committed to install the baghouse equipment at Hunter Unit #2 prior to adoption of Utah's mercury emissions control standard in R307-424-4. In fact, the Utah mercury control rule appears to have been adopted with the full knowledge of the existing and/or proposed upgrades to emissions control equipment at subject units. As such, compliance with R307-424-4 does not represent a reasonable justification for adopting the proposed baghouse controls at Hunter Unit #2.

Based on annual PM emissions testing data collected over the period 2004-2010, the Hunter Unit #2 PM emissions were generally already at or below the typical BART emissions standard of 0.03 lb/MMBtu. The 0.03 lb/MMBtu emission level appears to be achievable at Hunter Unit #2 without any significant upgrade to the existing ESP control equipment. The significant capital cost for the baghouse project is not justified to meet any applicable emissions control requirement.

4.0 Summary & Conclusions

An assessment was conducted of pollution control projects planned for the Hunter Unit #2 electric generating station, located near Castle Dale, Utah. This report was focused on the proposed upgrades to the sulfur dioxide (SO_2) and particulate matter (PM) emission controls at Hunter Unit #2.

The principal regulatory driver for the Hunter Unit #2 pollution control upgrades is compliance with requirements of the Utah State Implementation Plan (SIP) for regional haze. Utah's SIP follows current federal regulations adopted by the US Environmental Protection Agency (EPA) which require that selected emission sources install Best Available Retrofit Technology (BART) or that states participate in a regional visibility program that achieves equivalent results. Utah's SIP falls follows 40 CFR 51 Section 309 which establishes a regional emissions control program designed to achieve emission reductions that are "better-than-BART".

The Hunter Unit #2 review described in this report evaluated the emission controls selected for Hunter Unit #2 against the federal regulatory requirements for BART and also compared the selected controls to other BART determinations for coal-fired electric generating units (EGUs) in the western United States. The major findings are described below:

- The Utah Regional Haze SIP was written under 40 CFR 51 Section 309, which provides for a regional planning effort. Under Section 309, individual emission sources such as Hunter Unit #2 do not need to install BART provided that the overall SIP control strategy developed produces emission reductions that are "better than BART".

- PacifiCorp did not submit a formal BART analysis for Hunter Unit #2, or other Utah units under its control, as was done for its Wyoming plants, i.e. Jim Bridger Station. Given that PacifiCorp had already committed to the scrubber upgrades at all of its BART-eligible facilities, Utah relied upon the "presumptive BART" SO_2 emissions level of 0.15 lb/MMBtu as the benchmark for addressing the "better than BART" regulatory requirements. SO_2 emissions were already controlled at Hunter Unit #2, so the "presumptive BART" requirements would not have applied at Unit #2, even under a formal BART analysis. Also, without any upgraded emission controls, Hunter Unit #2 already meets the "presumptive BART" requirements established as the SO_2 emissions control benchmark under the Utah Regional Haze SIP.

Additional emissions control at Hunter Unit #2 would have been prescribed under BART only if such controls were technically appropriate and cost-effective under the "five factor" BART analysis following 40 CFR 51 Appendix Y, which they would not have been.

- Hunter Unit #2 has an allowable SO_2 emissions limit of 0.12 lb/MMBtu, effective once the improved emission controls are in place. This is more stringent than the "presumptive BART" SO_2 emissions level of 0.15 lb/MMBtu. However, existing emissions data showed that Hunter Unit #2 already had actual SO_2 emissions at or below the "presumptive BART" emissions standard before any added controls were in place.

- The SO_2 emission reductions attributable to the Hunter Unit #2 scrubber upgrade are insignificant. The Utah Regional Haze SIP identifies an SO_2 emissions reduction of only 240 tpy at Hunter Unit #2. These SO_2 emission reductions are only 0.13% of the total regionwide emission reductions required under Utah's Regional Haze SIP. Also, the modeled visibility improvement attributable to the added emission controls at Hunter Unit #2 was insignificant (0.019 deciviews or less at nearby Class I areas).

- Based upon the SO_2 emission control costs and the achieved level of SO_2 emission reductions, the SO_2 emissions control project at Hunter Unit #2 cannot be justified under BART. The Hunter Unit #2 control equipment costs are estimated to range between about \$16,000 and \$33,000 per ton of SO_2 removed depending on the level of SO_2 control claimed. These costs are at least ten times higher than typical compliance costs for other coal-fired EGUs where Best Available Retrofit Technology (BART) was required for SO_2 emissions.

- The decision to replace the Hunter Unit #2 PM controls with a fabric filter baghouse also would not have been required and cannot be justified under a BART analysis. In reviewing other BART decisions for western coal-fired EGUs, no indication was found that replacing existing ESP equipment with fabric filter baghouses represented BART. To the contrary, in situations such as Hunter Unit #2 where ESPs are an existing PM emissions control device, the recommended BART was generally to use the existing ESP equipment and upgrade as needed to achieve emissions of 0.03 lb/MMBtu. In a few cases, PM BART for coal-fired EGUs included replacing an existing ESP with a fabric filter baghouse, but these decisions appeared to be based upon factors other than BART compliance, which are unique to these units but not applicable at Hunter Unit #2. Where fabric filter baghouses were formally evaluated as BART (including a full economic analysis), replacing ESPs with fabric filter baghouses was determined to not be cost-effective and would therefore not represent BART. This conclusion was confirmed in Wyoming with respect to PacifiCorp's own plants.

- PacifiCorp also attempts to support its decision to upgrade the Hunter Unit #2 emissions controls based on a reported desire to reduce emissions of mercury. No federal emission standards currently exist for mercury removal at EGUs, but EPA is expected to adopt such rules sometime in 2011. Utah has adopted a state emissions standard for mercury that may apply to Hunter Unit 2 beginning December 31, 2012. However, the Utah mercury emissions standard appears to have been adopted and established based on PacifiCorp's voluntary commitment to install upgraded pollution controls at Hunter Unit 2 and certain of its other Utah EGUs. Because the Utah mercury standard was adopted based on PacifiCorp's voluntary pollution control commitments, the Utah standard cannot be used to justify the installation of such controls.

- In summary, it is not reasonable to conclude that the decision to install pollution control upgrades at Hunter Unit #2 was driven by compliance with the requirements of the Utah State Implementation Plan (SIP) for regional haze or Utah's mercury emissions rule. Neither the scrubber upgrade nor the conversion of ESP's to a fabric filter baghouse would reasonably be selected as BART for Hunter Unit #2 under a formal "five factor" BART analysis consistent with 40 CFR 51 Appendix Y. Furthermore, Utah's mercury rule was established based on the voluntary pollution control projects being advanced by PacifiCorp and do not constitute an appropriate regulatory driver for the pollution control project.