CTS# 174655

abitibi bowater

Snowflake Division

ADEQ
AIR QUALITY DIVISION

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PO Box 128
Snowflake, AZ 85937
928 536-4314

January 17, 2008

Nancy C. Wrona, Director
Air Quality Division
Arizona Department of Environmental Quality
1110 West Washington Street
Phoenix, AZ 85007

Subject Best Available Retrofit Technology Determination for AbitibiBowater Inc., Snowflake Division

Dear Ms. Wrona:

Reference is made to your letter dated July 13, 2007 regarding Best Available Retrofit Technology (BART) eligibility for Power Boiler No. 2 for AbitibiBowater, Snowflake Division (AbitibiBowater). As requested in the letter, AbitibiBowater is submitting the BART analysis report to assist Arizona Department of Environmental Quality (ADEQ) in preparation of the Regional Haze State Implementation Plan.

The BART analysis was conducted for Nitrogen Oxides and Sulfur Dioxide for Power Boiler No. 2 in accordance with the BART guidance EPA promulgated in the Federal Register Volume 70, Number 128, on Wednesday, July 6, 2005. Costs, energy and environmental impacts, remaining useful life of the boiler and modeled visibility improvements were considered in the evaluation.

If you have any questions regarding this report, please do not hesitate to contact Prabhat Bhargava of CH2M HILL at (480) 377-6211. I can be reached at (928) 536-9201.

Sincerely,

John McKee

John McKee
General Manager

cc: Arthur "Skip" Hellerud
Env. File
Prabhat Bhargava - CH2M HILL
Don Caniparoli - CH2M HILL

Report

Best Available Retrofit Technology Assessment for Snowflake Paper Mill

Prepared for

AbitibiBowater Inc.

Snowflake Division
P.O. Box 128
Snowflake, AZ 85937

January 2008

CH2MHILL
2665 S Plaza Drive
Tempe, AZ 85282

Report

Best Available Retrofit Technology Assessment for Snowflake Paper Mill

Submitted to

AbitibiBowater Inc.

January 2008

CH2MHILL

Executive Summary

Sources that meet certain criteria and could potentially cause or contribute to degradation of visibility at mandatory Class I federal areas are considered to be best available retrofit technology (BART)-eligible under the Regional Haze Rule (40 *Code of Federal Regulations* [CFR] 51). BART-eligible sources are required to evaluate possible retrofit emissions control technologies for reducing visibility-impairing pollutants emitted from certain combustion units constructed between 1962 and 1977.

The Arizona Department of Environmental Quality (ADEQ) has determined that the No. 2 Power Boiler at the AbitibiBowater Snowflake Paper Mill (Snowflake Paper Mill) is BART-eligible. AbitibiBowater has evaluated a range of demonstrated control technologies using alternatives appropriate for bituminous coal-fired boilers. The evaluation was conducted in accordance with 40 CFR Part 51, Appendix Y, "Guidelines for BART Determinations Under the Regional Haze Rule." Costs, energy and environmental impacts, remaining useful life of the boiler, and modeled visibility improvements were considered in the evaluation.

Setting

Twelve Class I areas are present within 300 kilometers of the Snowflake Paper Mill. The Class I areas are presented below and are shown in relation to the Snowflake Paper Mill in Figure ES-1.

- Petrified Forest National Park (NP)
- Sierra Ancha Wilderness Area (WA)
- Mount Baldy WA
- Mazatzal WA
- Superstition WA
- Pine Mountain WA
- Sycamore Canyon WA
- Gila WA
- Galiuro WA
- Grand Canyon NP
- Saguaro National Monument (NM)
- Chiricahua NM

BART Engineering Analysis

Visibility-impairing sulfur dioxide (SO_2) and nitrogen oxides (NO_x) pollutants were considered in the retrofit control technology evaluation. Available control technologies for SO_2 include upgrading the existing soda ash scrubber and adding a second soda ash scrubber. Available control technologies for NO_x include using a currently unused over fire air (OFA) fan, adding low-NO_x burners (LNB), selective catalytic reduction (SCR), and selective noncatalytic reduction (SNCR).

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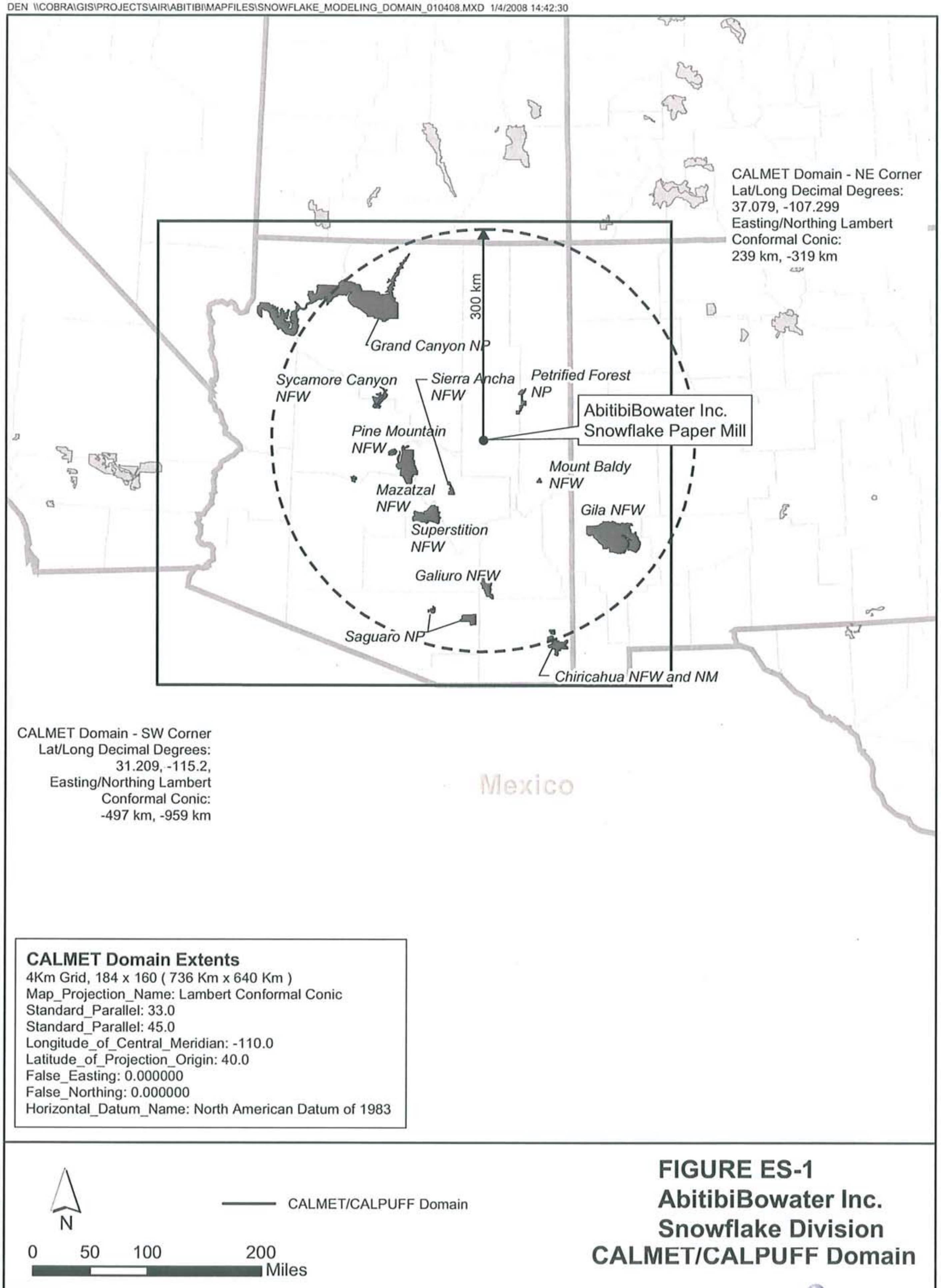


FIGURE ES-1
AbitibiBowater Inc.
Snowflake Division
CALMET/CALPUFF Domain

CH2MHILL

BART Modeling Analysis

The CALPUFF model was used to evaluate visibility impacts from the No. 2 Power Boiler for present emission rates and for the addition of BART control alternatives. ADEQ Western Regional Air Partnership (WRAP) files for model setup and input meteorological and emissions data were used with the modifications described in Section 4.0 of this report.

Modeling results indicate that the highest annual 98th percentile daily visibility impact of emissions from the unit at current maximum actual emissions occurs in the Sierra Ancha WA Class I area.

Table ES-1 presents a summary of the visibility modeling results for the control scenarios at Sierra Ancha WA.

TABLE ES-1
NO_x and SO_2 Control Scenario Results for Sierra Ancha WA
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	98^{th} Percentile ΔdV Reduction
1	Existing Wet Soda Ash Scrubber	0.000
2	Upgraded Wet Soda Ash Scrubber	0.018
3	Add Second Scrubber to Upgraded Wet Soda Ash Scrubber	0.200
4	Operate Existing OFA Fan with Existing Wet Soda Ash Scrubber	0.076
5	Operate Existing OFA Fan with Upgraded Wet Soda Ash Scrubber	0.094
6	New LNB with Upgraded Wet Soda Ash Scrubber	0.182
7	New LNB with OFA Modifications and Upgraded Wet Soda Ash Scrubber	0.225
8	New LNB with OFA, high-energy reagent technology (HERT) SNCR, and Upgraded Wet Soda Ash Scrubber	0.270
9	Mobotec ROFA with Upgraded Wet Soda Ash Scrubber	0.193
10	Mobotec ROFA and Rotamix SNCR with Upgraded Wet Soda Ash Scrubber	0.213
11	New LNB with OFA, SCR, and Upgraded Wet Soda Ash Scrubber	0.327

BART Summary

A cost-effectiveness study was conducted for the control scenarios using least-cost envelope plots. Four scenarios (4, 5, 6, and 7) had similar cost-effectiveness and were more cost-effective than the others.

Studies have been conducted that demonstrate that visibility differences of 1.5 to 2.0 deciviews (dV) or more are perceptible by the human eye. Visibility differences of less than 1.5 dV cannot be distinguished by the average person. (Henry, 2002)

Modeling results demonstrated that the Sierra Ancha WA would be the Class I area with the highest impacts. Impacts at this area (0.73 dV) are only slightly above the threshold for BART eligibility (0.5 dV). The difference of 0.23 dV is not perceptible.

Implementation of the control scenarios presented in this report for the four Class I areas with the highest impacts would result in visibility improvements of less than 0.33 dV—an imperceptible improvement.

Minimal improvements in visibility and a baseline visibility approaching the BART-eligibility threshold lead to the conclusion that none of the alternative control scenarios presented in this report is justifiable. The current control scenario with emission rates of 0.7 pounds per million British thermal units (lb/MMBtu) for NO_x and 0.8 lb/MMBtu for SO_2 is, therefore, BART.

Contents

Tables

Figures

Appendixes

Acronyms and Abbreviations

AACE	American Association of Cost Engineers
ADEQ	Arizona Department of Environmental Quality
ASTM	American Society for Testing and Materials
B&W	Babcock & Wilcox
BACT	best available control technology
BART	best available retrofit technology
Btu	British thermal unit
Btu/lb	British thermal units per pound
CDPHE	Colorado Department of Health and Environment
CFR	*Code of Federal Regulations*
dV	deciview
ΔdV	delta deciview, change in deciview
EIA	Energy Information Administration
ESP	electrostatic precipitator
EPA	U.S. Environmental Protection Agency
FGD	flue gas desulfurization
f(RH)	relative humidity factors
HERT	high-energy reagent technology
hp	horse power
kW	kilowatts
LAER	lowest achievable emission rate
lb/MMBtu	pounds per million British thermal units
LCC	Lambert conformal conic
LNB	low-NO_x burner
$\mu g/m^3$	micrograms per cubic meters
MMBtu	million British thermal units
MM5	Mesoscale Meteorological Model, Version 5
NM	national monument
NO_x	nitrogen oxides
NP	national park
NPS	National Park Service

O&M	operations and maintenance
OFA	over fire air
$PM_{2.5}$	particulate matter less than 2.5 micrometers in aerodynamic diameter
PM_{10}	particulate matter less than 10 micrometers in aerodynamic diameter
ROFA	rotating opposed fire air
SCR	selective catalytic reduction
SIP	state implementation plan
SNCR	selective noncatalytic reduction
SO_2	sulfur dioxide
USGS	U.S. Geological Survey
WA	wilderness area
WRAP	Western Regional Air Partnership

SECTION 1.0
Introduction

The Clean Air Act established goals for visibility improvement in national parks (NPs), wilderness areas (WAs), and international parks. Through the 1977 amendments to the Clean Air Act in Section 169A, Congress set a national goal for visibility as "the prevention of any future, and the remedying of any existing, impairment of visibility in mandatory Class I Federal areas which impairment results from manmade air pollution."

The 1977 amendments required the U.S. Environmental Protection Agency (EPA) to issue regulations to ensure "reasonable progress" toward meeting the national goal. In 1990, Congress again amended the Clean Air Act, providing additional emphasis on regional haze issues. These regulations adopted by USEPA include requirements for states to establish goals for improving visibility in NPs and WAs and to develop long-term strategies for reducing emissions of air pollutants that cause visibility impairment. In 1999, numerous NPs and WAs across the country were classified as mandatory Class I areas by USEPA.

One of the principal elements of the visibility protection provisions of the Clean Air Act addresses installation of best available retrofit technology (BART) for certain existing combustion sources placed into operation between 1962 and 1977. The 1999 Regional Haze Rule requires the following three basic state plan elements related to BART:

- A list of BART-eligible sources (includes sources of air pollutants that are reasonably anticipated to contribute to visibility impairment in a Class I area)
- An analysis of the emission reductions and changes in visibility that would result from "best retrofit" control levels on sources subject to BART
- The BART emission limits for each subject source or an alternative measure, such as an emissions trading program, for achieving greater reasonable progress in visibility protection than implementation of source-by-source BART controls

In determining BART, the state can take into account several factors, including the existing control technology in place at the source, costs of compliance, energy and non-air environmental impacts of compliance, remaining useful life of the source, and degree of visibility improvement that is reasonably anticipated from the use of such technology (USEPA 1999).

In July 2005, the EPA released specific BART guidelines for states to use when determining which facilities must install additional controls and the type of controls that must be used. Under current regulatory deadlines, states—including Arizona—must submit a Regional Haze Rule state implementation plan (SIP) amendment that addresses BART implementation by December 2007. In this plan amendment, states will identify facilities that need to reduce emissions under BART, then set BART emission limits for those facilities or identify any alternative plan for reducing visibility-impairing pollutants that would achieve greater reductions than those realized from BART emission limits (USEPA 2005).

Using information from the Western Regional Air Partnership (WRAP) and its Regional Modeling Center, the State of Arizona has identified eligible in-state sources that are required to meet requirements for BART and has directed those sources to complete BART analyses to identify potential reductions for emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter less than 10 micrometers in aerodynamic diameter (PM_{10}) that would be associated with additional or new air pollution controls. This information was to be included in the SIP due in December 2007. At this time, it is expected that Arizona's SIP will address reduction of SO_2 emissions at BART sources through an alternative measure in the form of a four-state backstop cap-and-trade program. Reduction of NO_x and PM_{10} emissions will be addressed by establishing BART emission limits in source operating permits.

The EPA BART guidelines state that the BART emission limits established as a result of BART analyses must be fully implemented within 5 years of EPA's approval of the SIP. For purposes of this project, that date is assumed to be 2013.

This report documents the BART analysis that was performed on AbitibiBowater No. 2 Power Boiler. The analysis was performed for NO_x and SO_2. No BART analysis for PM_{10} was conducted as ADEQ specifically exempted PM_{10} from BART analysis requirement for No. 2 Power Boiler.

Section 2.0 of this report describes the present unit operation, including a discussion of fuel used in No 2 Power Boiler. The BART engineering analysis by pollutant type is provided in Section 3.0. Section 4.0 provides the methodology and results of the BART modeling analysis, followed by recommendations in Section 5.0. References are provided in Section 6.0. Appendixes provide additional information related to the economic analysis and modeling analysis performed to support the BART assessment.

SECTION 2.0

Present Unit Operation

AbitibiBowater is a 100 percent recycled pulp and paper mill producing newsprint, newsprint-like grades, bag paper, kraft linerboards, and corrugating medium using paper/corrugated box recycling processes and purchased pulps. Byproducts of the process include coal ash, sludge, and agricultural products. The recycling processes use paper, magazines, coated sections, cores, DLK, corrugated boxes, and chipboard as raw materials for reprocessing to obtain the cellulose fibers for producing paper. Operations at the facility include two de-inking systems in the recycling process for removing ink and other contaminants on recycled paper, an old corrugated container recycling facility, a corrugated waste facility, a powerhouse, and a wastewater treatment facility.

The No. 2 Power Boiler (boiler) is a BART-eligible source. It was installed in 1975 as a wall-fired pulverized coal-fired boiler manufactured by Babcock & Wilcox (B&W). The boiler has a maximum rated heat input of 1,132 million British thermal units (MMBtu) per hour and is capable of continuously producing approximately 830,000 pounds per hour of steam at 1,200 pounds per square inch using coal. The boiler produces sufficient steam for the turbine generators' electrical load and for the mill's steam load. The turbine generators normally produce 100 percent of the mill's electrical load, excluding electrical needs at the water wellfield.

Emission controls at the boiler include two electrostatic precipitators (ESP)—one in service, one as backup—for particulate control and a Fläkt Peabody MoDo wet sodium flue gas desulfurization (FGD) system tray tower scrubber for SO_2 control (installed in 1990). The permitted SO_2 emission limit is 0.8 pounds per million British thermal units (lb/MMBtu) heat input. The average actual SO_2 emissions, as measured by the 2001-2007 annual emission source tests, is 0.42 lb/MMBtu (range = 0.33-0.47 lb/MMBtu).

The boiler has an inactive over-fire air (OFA) fan for NO_x control. The permitted NO_x emission limit is 0.7 lb/MMBtu heat input. The average actual NO_x emissions, as measured by the 2001-2007 annual emission source tests, is 0.52 lb/MMBtu (range = 0.43-0.59 lb/MMBtu).

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

TABLE 2-1
Unit Operation and Study Assumptions
AbitibiBowater No. 2 Power Boiler

General Facility Data	
Site Elevation (feet)	6,000
Stack Height (feet)	214
Stack Exit Area (square feet)	113.04
Stack Exit Temperature (°Fahrenheit)	225
Stack Exit Velocity (feet/second)	60.2
Stack Flow (actual cubic feet per minute)	408,300
Latitude (degrees: minutes: seconds)	34:30:00 north
Longitude (degrees: minutes: seconds)	110:20:00 west
Boiler Heat Input (MMBtu/hour)(100 percent load)	1,132
Type of Boiler	Wall-fired
Boiler Fuel	Coal
Coal Sources	Gallup Field McKinley Mine (historical) Lee Ranch El Segundo Mine (current)
Coal Heating Value (Btu/lb)*	9,290
Coal Sulfur Content (percent weight)*	1.03
Coal Ash Content (percent weight)*	17.9
Coal Moisture Content (percent weight)*	14.9
Current NO_x Controls	None (inactive OFA fan)
NO_x Emission Rate (lb/MMBtu)*	0.70
Current SO_2 Controls	Sodium-based wet scrubber
SO_2 Emission Rate (lb/MMBtu)*	0.80
Current PM_{10} Controls	ESP
PM_{10} Emission Rate (lb/MMBtu)	0.10

*Based on Lee Ranch El Segundo coal

SECTION 3.0

BART Engineering Analysis

This section presents the required BART engineering analysis.

3.1 BART Process

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

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

These steps are incorporated into the BART analysis as follows:

Step 1—Identify All Available Retrofit Control Technologies

Step 2—Eliminate Technically Infeasible Options

- The identification of available, technically feasible, retrofit control options
- Consideration of any pollution control equipment in use at the source (which affects the applicability of options and their impacts)

Step 3—Evaluate Control Effectiveness of Remaining Control Technologies

Step 4—Evaluate Impacts and Document the Results

- The costs of compliance with the control options
- The remaining useful life of the facility
- The energy and non-air quality environmental impacts of compliance

Step 5—Evaluate Visibility Impacts

- The degree of visibility improvement that may reasonably be anticipated from BART use

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

Separate analyses have been conducted for NO_x and SO_2 emissions. All costs included in the BART analysis are in 2007 dollars, and costs have not been escalated to the assumed 2013 BART implementation date.

3.1.1 BART NO_x Analysis

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

3.1.1.1 Formation of NO_x

During coal combustion, NO_x is formed in three different ways. The dominant source of NO_x formation is the oxidation of fuel-bound nitrogen (fuel NO_x). During combustion, part of the fuel-bound nitrogen is released from the coal with the volatile matter and part is retained in the solid portion (char). The nitrogen chemically bound in the coal is partially oxidized to nitrogen oxides (NO and NO_2) and partially reduced to molecular nitrogen (N_2). A smaller part of NO_x formation is caused by high-temperature fixation of atmospheric nitrogen in the combustion air (thermal NO_x). A very small amount of NO_x is called "prompt" NO_x. Prompt NO_x results from an interaction of hydrocarbon radicals, nitrogen, and oxygen.

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

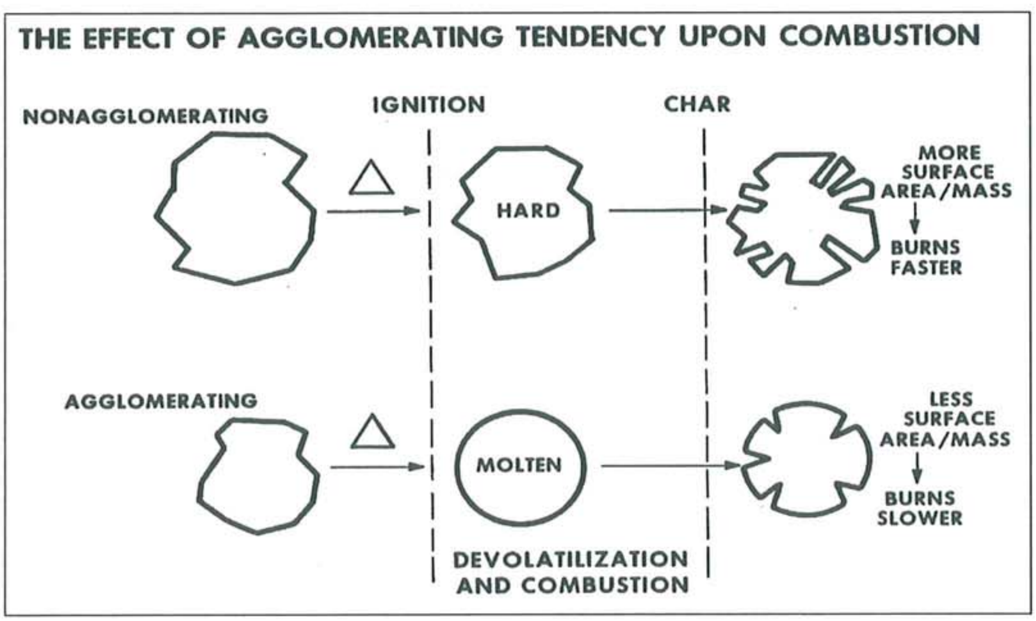
Coal characteristics directly and significantly affect NO_x emissions from coal combustion. Coal ranking is a means of classifying coals according to their degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous and on to anthracite. Lower-rank coals, such as the sub-bituminous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

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

A number of western coals are classified as sub-bituminous; however, they border on being ranked as bituminous and do not display many of the qualities of PRB coals, including most of the low-NO_x-forming characteristics. Coal from the Lee Ranch Mine falls into this category. Lee Ranch coal falls into the transition area between high-volatile C bituminous and sub-bituminous A. Both classifications have gross calorific value limits on a moist, mineral-matter-free basis equal to or greater than 10,500 British thermal units per pound (Btu/lb) and less than 11,500 Btu/lb. The Lee Ranch coal has a moist mineral-matter-free heating value of 11,027 Btu/lb.

As defined by the American Society for Testing and Materials (ASTM), the only distinguishing characteristic that classifies the coal used at AbitibiBowater as bituminous rather than sub-bituminous is that it is "agglomerating" as compared to "non-agglomerating." Agglomerating as applied to coal is "the property of softening when it is heated to above about 400°C in a non-oxidizing atmosphere, and then appearing as a coherent mass after cooling to room temperature." All bituminous coals are agglomerating. Because the agglomerating property of coals is the result of particles transforming into a plastic or semi-liquid state when heated, it reflects a change in surface area of the particle. Thus with the application of heat, agglomerating coals tend to develop a nonporous surface, while the surface of non-agglomerating coals becomes even more porous with combustion. As shown in Figure 3-1, the increased porosity provides more particle surface area, resulting in more favorable combustion conditions. The non-agglomerating characteristic assists in making sub-bituminous coals more amenable to controlling NO_x by allowing less air to be introduced during the initial ignition portion of the combustion process. The coal from the Lee Ranch Mine falls into the category of agglomerating coal. The conditions that make it easier to control NO_x emissions during combustion of typical non-agglomerating coals do not exist during combustion of the Lee Ranch coal.

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



3.1.1.2 Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to AbitibiBowater, including those control technologies identified as best available control technology (BACT) or lowest achievable emission rate (LAER) by permitting agencies across the United States. A broad range of information sources have been reviewed in an effort to identify potentially applicable emission control technologies.

The following potential NO_x control technology options were considered:

- Use of existing OFA fan
- New LNB
- New LNB with OFA modifications
- New LNB with OFA modifications and selective non-catalytic reduction (SNCR) system from Advanced Combustion Technology, Inc.'s (ACT's) high-energy reagent technology (HERT)
- Mobotec rotating opposed fire air (ROFA)
- Mobotec ROFA with Rotamix SNCR
- New LNB with OFA modifications and selective catalytic reduction system (SCR)

3.1.1.3 Step 2: Eliminate Technically Infeasible Options

For AbitibiBowater, a wall-fired configuration burning sub-bituminous coal, technical feasibility will primarily be determined by physical constraints and boiler configuration.

As an integral part of the BART analysis process, cost and expected emission information is assembled from various sources, including technology vendors, AbitibiBowater operating and engineering data, and internal CH2M HILL historical information. For this BART analysis, information pertaining to LNB, OFA, SNCR, and SCR were based on quotes solicited from ACT for its LNB, OFA, and HERT SNCR technology and from Mobotec for its ROFA and Rotamix SNCR technology. The SCR cost and installation factors were based on the EPA Office of Air Quality Planning & Standards (control cost manual (U.S. Environmental Protection Agency, 2002).

Table 3-1 summarizes the control technology options evaluated in this BART analysis along with projected NO_x emission rates.

TABLE 3-1
NO_x Control Technology Emission Rate Ranking
AbitibiBowater No. 2 Power Boiler

Technology	Projected Emission Rate (lb/MMBtu)
Existing OFA	0.525
LNB	0.37
LNB with OFA	0.265
LNB with OFA and HERT SNCR	0.194
ROFA SNCR	0.348
ROFA and Rotamix SNCR	0.291
LNB with OFA and SCR	0.07

3.1.1.4 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

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

The following subsections describe the control technologies and control effectiveness evaluated in this BART analysis.

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

The steps used to determine a level of confidence for the vendors' expected values are as follows:

1. Establish expected NO_x emissions value from vendor.
2. Evaluate vendor experience and historical basis for meeting expected values.
3. Review and evaluate unit physical and operational characteristics and restrictions. The fewer variations in operations, coal supply, and such, the more predictable and less variant the NO_x emissions are.

4. For each technology's expected value, there is a corresponding potential for actual NO_x emissions to vary from it. An adjustment to the expected value can be made from the vendor information presented and anticipated unit operational data.

Existing OFA System. To lower NO_x with OFA, a portion of the combustion air is diverted to the upper furnace to create a fuel-rich zone in the lower furnace. This inhibits fuel-bound nitrogen conversion to NO. Information provided to CH2M HILL by AbitibiBowater indicates that the existing 300-horsepower (hp) OFA fan has not been used since initial startup of the boiler. Based on consultation with B&W, expected NO_x reduction from use of the existing OFA system is approximately 25 percent, resulting in a projected NO_x emission rate of 0.525 lb/MMBtu. The actual performance of the OFA system has not been measured by AbitibiBowater.

New LNBs. To lower NO_x with LNBs, the combustion process is staged to provide a fuel-rich condition initially so that oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x.

LNBs are considered to be a low capital cost, combustion technology retrofit. Information provided to CH2M HILL by ACT indicates that new LNBs at AbitibiBowater would result in a projected NO_x emission rate of 0.37 lb/MMBtu with a safety factor of 0.02 lb/MMBtu applied. This emission rate represents a significant reduction from the current NO_x emission rate.

New LNBs with OFA System. The process of lowering NO_x with LNBs is described above. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char. Both LNBs and OFA are considered to be low capital cost, combustion technology retrofits. Information provided to CH2M HILL by ACT indicates that new LNBs at AbitibiBowater would result in a projected NO_x emission rate of 0.265 lb/MMBtu with a safety factor of 0.02 lb/MMBtu applied. This emission rate represents a significant reduction from the current NO_x emission rate.

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

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

To reduce reagent costs, combustion modifications, including LNBs and advanced OFA, are combined with SNCR. ACT submitted a proposal for its HERT system. Information provided to CH2M HILL by ACT indicates that new LNBs with OFA and HERT SNCR at

AbitibiBowater would result in a projected NO_x emission rate of 0.194 lb/MMBtu with a safety factor of 0.02 lb/MMBtu applied to HERT. This emission rate represents a significant reduction from the current NO_x emission rate.

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

Information supplied to CH2M HILL by Mobotec indicates a projected NO_x emission rate of 0.348 lb/MMBtu with a safety factor of 0.04 lb/MMBtu applied to ROFA because of Mobotec's limited ROFA experience with western coals. This emission rate represents a significant reduction from the current NO_x emission rate.

In its proposal, which is primarily based on ROFA equipment, Mobotec proposes to analyze the operation of existing LNB and OFA ports. While a typical installation does not require modification of the existing LNB system and the existing OFA ports are not used, results of computational fluid dynamics modeling will determine the quantity and location of new ROFA ports. The Mobotec proposal includes bent-tube assemblies for OFA port installation. Mobotec does not provide installation services because it believes the owner can more cost-effectively contract for these services. However, Mobotec does provide one onsite construction supervisor during installation and startup.

ROFA with Rotamix SNCR. The ROFA and SNCR processes are described above. To reduce reagent costs, combustion modifications (including ROFA) are combined with SNCR. Mobotec submitted a proposal for its Rotamix system. Information provided to CH2M HILL by Mobotec indicates that ROFA and Rotamix SNCR at AbitibiBowater would result in an expected NO_x emission rate of 0.291 lb/MMBtu with a safety factor of 0.02 lb/MMBtu applied to Rotamix. This emission rate represents a significant reduction from the current NO_x emission rate.

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

SNCR, it is generally more cost-effective to reduce NO_x emission levels as much as possible through combustion modifications to minimize the catalyst surface area and ammonia requirements of the SCR. The use of LNB with OFA and SCR results in a projected NO_x emission rate of 0.07 lb/MMBtu. This emission rate represents a significant reduction from the current NO_x emission rate.

3.1.1.5 Step 4: Evaluate Impacts and Document the Results

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

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

Use of the existing 300-hp OFA fan requires approximately 224 kilowatts (kW) of additional power. The Mobotec ROFA system requires installation and operation of a 1,300-hp ROFA fan (969 kW total). The SNCR systems require approximately 10 kW of additional power.

SCR retrofit affects the existing flue gas fan system because of the additional pressure drop associated with the catalyst. Total additional power requirements for SCR installation at AbitibiBowater are estimated at approximately 377 kW.

Environmental Impacts. SNCR and SCR installation could potentially create a visible stack plume from excess ammonia slip, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of ammonia to the facility. In addition, fly ash currently sold for beneficial reuse would have to be landfilled (see economic impacts).

Economic Impacts. The facility currently sells 96.6 percent of the fly ash generated for beneficial reuse. The use of OFA and LNBs has the potential to reduce the quantity of combustion air, thereby increasing the amount of unburned carbon in the fly ash , making it unsalable. The quality specification for sale of fly ash from this facility requires the fly ash to meet ASTM C-618 for Class F Fly Ash requirements, except that the loss on ignition shall not exceed 2.5 percent, nor shall the color be darker than 2.5 percent on the Western Ash color scale. The facility is located in a remote location, thus fly ash sale options are limited. If the ash cannot be sold, it must be transported to a permitted landfill for disposal. The lost fly ash sales revenue and additional landfill disposal costs are included in the economic analysis.

For this BART analysis, information pertaining to LNBs, OFA, and SNCR were based on quotes solicited from ACT for its LNB, OFA, and HERT SNCR technology and from Mobotec for its ROFA and Rotamix SNCR technology. The SCR capital and operating costs are based on EPA's *Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers* (U.S. Environmental Protection Agency, 2001). The SCR cost estimate is scaled to 2007 dollars. The LNB, OFA, and SNCR installation and operating costs are based on EPA's *Air Pollution Control Cost Manual* (U.S. Environmental Protection Agency, 2002).

The level of accuracy of the cost estimates can be classified as American Association of Cost Engineers (AACE) Class 5, or "order of magnitude," which can be categorized as

+50 percent/-30 percent. Selecting this range of cost estimates to be included in the BART analysis is primarily a result of the difficulty in receiving detailed and accurate information from technology vendors for retrofit into existing equipment based on limited available data provided. Material and construction labor costs also change rapidly. However, this level of cost estimate precision is adequate for comparison of control technology alternatives. Therefore, when selecting emissions control technologies and establishing emission limitations in permits, variability in cost and expected emissions information must be considered.

Table 3-2 compares technologies on the basis of cost, design control efficiency, and tons of NO_x removed. The first year control costs are shown in Figure 3-2. The complete economic analysis is contained in Appendix A.

3.1.1.6 Step 5: Evaluate Visibility Impacts

Please see Section 4.0, BART Modeling Analysis.

TABLE 3-2
NO_x Control Cost Comparison
AbitibiBowater No. 2 Power Boiler

Factor	OFA Using Existing Fan	LNB	LNB with OFA Modifications	LNB with OFA and HERT SNCR	Mobotec ROFA	Mobotec ROFA and Rotamix SNCR	LNB with OFA and SCR
Total Installed Capital Cost ($million)	$0.02	$1.5	$2.1	$2.8	$4.5	$6.0	$23.0
Total First Year Fixed and Variable Operations and Maintenance (O&M) Cost ($million)	$3.2	$3.2	$3.2	$3.6	$3.6	$4.1	$4.1
Total First Year Annualized Cost ($million)	$3.2	$3.4	$3.5	$4.0	$4.3	$4.9	$7.2
Power Consumption (kW)	224	0	0	10	969	980	567
NO_x Design Control Efficiency	25.0%	47.1%	62.1%	72.3%	50.3%	58.4%	90.0%
NO_x Removed per Year (tons)	868	1,636	2,157	2,509	1,745	2,028	3,124
First Year Average Control Cost ($/ton of NO_x removed)	$3,713	$2,078	$1,627	$1,582	$2,442	$2,418	$2,299
Incremental Control Cost ($/ton of NO_x removed)	$3,713	$233	$211	$1,303	$2,442	$2,268	$3,797

3.1.2 BART SO_2 Analysis

SO_2 forms in the boiler during the combustion process and is primarily dependent on coal sulfur content. The BART analysis of SO_2 emissions from AbitibiBowater No. 2 Power Boiler is described below.

3.1.2.1 Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources was reviewed in an effort to identify potentially applicable emission control technologies for SO_2 at AbitibiBowater. These included control technologies identified as BACT or LAER by permitting agencies across the United States.

The following potential SO_2 control technology options were considered:

- Upgrade current operation of existing wet sodium FGD system
- Add second parallel wet FGD system to treat 100 percent of flue gas

3.1.2.2 Step 2: Eliminate Technically Infeasible Options

All of the technologies are feasible and will reduce SO_2 emissions and improve visibility. Therefore, none of the technologies were eliminated.

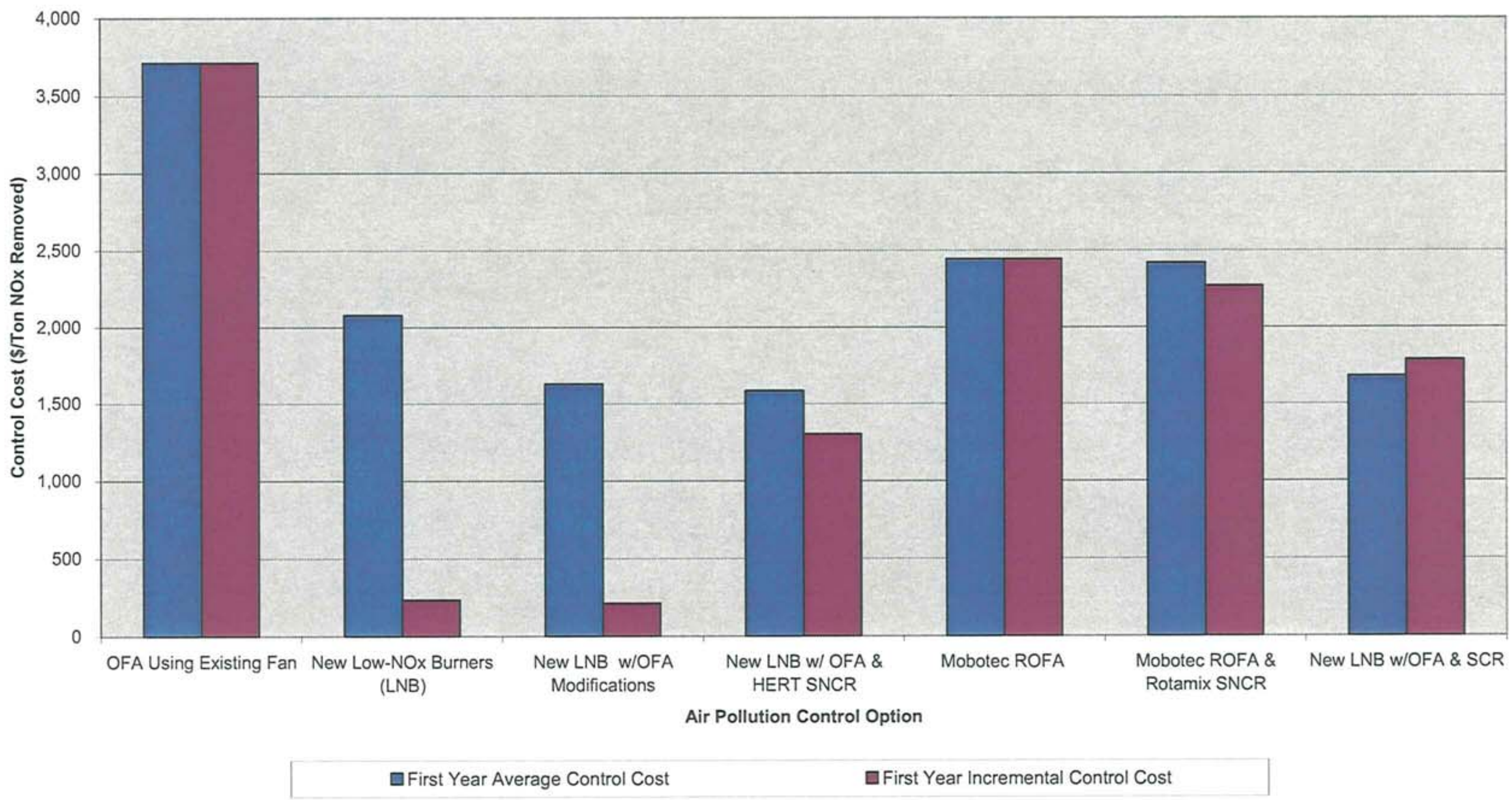
Upgrade Current Wet Sodium FGD System. The current SO_2 emission control at the boiler is a Fläkt Peabody MoDo wet sodium FGD system tray tower scrubber for SO_2 control (installed in 1990). The flue gas leaving the precipitator enters the SO_2 scrubber inlet duct and is divided between the SO_2 scrubber and the bypass duct via a variable position damper. The scrubber system is designed to treat a portion of the total flue gas to meet the permitted emission limit. The scrubber uses a sodium carbonate (soda ash) solution as the scrubbing media and maintains SO_2 emissions at less than the permitted limit of 0.8 pounds of SO_2 per MMBtu of heat input. The average actual SO_2 emissions as measured by the 2001-2007 annual emission source tests is 0.42 lb/MMBtu (range = 0.33-0.47 lb/MMBtu).

The solids concentration of the SO_2 scrubbing solution is maintained by bleeding off a portion of the stream. The scrubber efficiency is a function of several aspects of the process, such as the strength of scrubbing solution, percent of gas stream scrubbed, temperature of flue gas, and amount of particulate in flue gas. The amount of flue gas bypassed must be sufficient to keep the temperature high enough so the moisture in the flue gas will remain in the uncondensed state to enable the opacity monitor to operate correctly. Excessive moisture in the stack also causes deposition in the stack liner. The amount of particulate in the flue gas has a direct effect on the amount of gas that can be scrubbed. Flue gas with a high concentration of particulate causes increased plugging and wear of scrubber components.

The approximate current SO_2 removal efficiency is 94 percent. AbitibiBowater commissioned a study by Alstom, the scrubber manufacturer, to recommend upgrades to the existing system to improve its removal efficiency and reduce operating and maintenance (O&M) issues. They identified the following upgrades to improve scrubber efficiency to 98 percent, resulting in a projected SO_2 emission rate of 0.739 lb/MMBtu based on 32 percent flue gas bypass:

- Wash the integral mist eliminators with demineralized water.
- Improve bypass damper control.

FIGURE 3-2
First Year Control Cost for NOx Air Pollution Control Options
AbitibiBowater No. 2 Power Boiler



- Improve scrubber solution pH control.
- Blowdown spent scrubber liquor based on density control to replace current manual blowdown.
- Add sidewall casing baffles below the recycle spray nozzles and mist eliminator to prevent gas leakage.
- Replace worn and plugged spray nozzles.
- Clean scrubber equipment and piping to remove plugging and buildup.

The amount of flue gas bypassed must be sufficient to maintain scrubber flue gas velocity and throughput within the equipment design capabilities for efficient SO_2 removal and to keep the temperature high enough so the moisture in the flue gas will remain in the uncondensed state to enable the opacity monitor to operate correctly. Excessive moisture in the stack also causes deposition in the stack liner.

Add Second Wet Sodium FGD System to Treat 100 Percent of Flue Gas. Alstom provided a proposal to install a second, parallel wet sodium FGD system that would enable 100 percent of the flue gas to be treated. This would result in a projected SO_2 emission rate of 0.044 lb/MMBtu (98 percent SO_2 removal). Upgrading the system would involve closing the bypass damper to eliminate the bypass flue gas flow used to reheat the treated flue gas from the scrubber, relocating the opacity monitor, modifying ductwork, and adding stack drains for wet operation.

3.1.2.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Table 3-3 summarizes the control technology options evaluated in this BART analysis along with projected SO_2 emission rates. The visibility impact analysis will guide the BART recommendation.

TABLE 3-3
SO_2 Control Technology Emission Rates
AbitibiBowater No. 2 Power Boiler

Technology	Projected Emission Rate (lb/MMBtu)
Upgrade Existing Wet Sodium FGD System	0.739
Add Second Wet Sodium FGD System to Treat 100% of Flue Gas	0.044

3.1.2.4 Step 4: Evaluate Impacts and Document the Results

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

Energy Impacts. Installing a second parallel FGD system will have minimal power impacts.

Environmental Impacts. Treating 100 percent of the flue gas will result in elimination of reheating by the bypassed flue gas and a significant addition to scrubber waste disposal and makeup water requirements.

Economic Impacts. For this BART analysis, information pertaining to the scrubber upgrades and second parallel scrubber were based on technical studies and budgetary quotes from Alstom. The level of accuracy of the cost estimates can be classified as AACE Class 5, or "order of magnitude," which can be categorized as +50 percent/-30 percent. Selecting this range of cost estimates to be included in the BART analysis is primarily a result of the difficulty in receiving detailed and accurate information from technology vendors for retrofit into existing equipment based on limited available data provided. Material and construction labor costs also change rapidly. However, this level of cost estimate precision is adequate for comparison of control technology alternatives. Therefore, when selecting emissions control technologies and establishing emission limitations in permits, variability in cost and expected emissions information must be considered.

Table 3-4 compares the technologies on the basis of cost, design control efficiency, and tons of SO_2 removed. The first year control costs are shown in Figure 3-3. The complete economic analysis is contained in Appendix A.

TABLE 3-4
SO_2 Control Cost Comparison
AbitibiBowater No. 2 Power Boiler

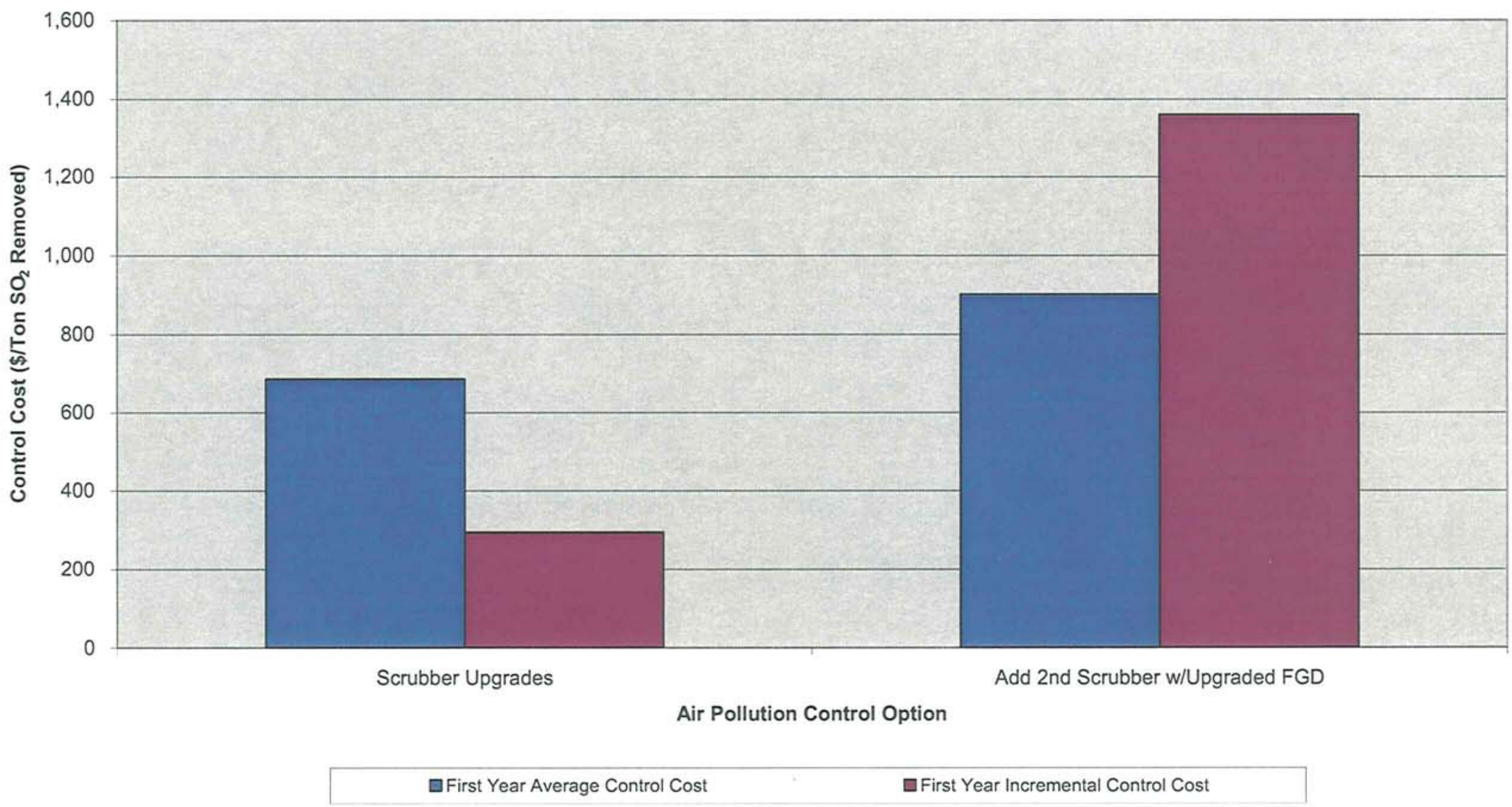
Factor	Upgrade Existing Wet Sodium FGD System	Add Second Wet Sodium FGD System to Treat 100% of Flue Gas
Total Installed Capital Cost ($million)	$0.65	$15.6
Total First Year Fixed and Variable O&M Cost ($million)	$4.9	$7.6
Total First Year Annualized Cost ($million)	$5.0	$9.7
Power Consumption (kW)	2,018	1,918
SO_2 Design Control Efficiency*	66.6%	98.0%
SO_2 Removed per Year (tons)	7,319	10,764
First Year Average Control Cost ($ per ton of SO_2 removed)	$686	$901
Incremental Control Cost ($ per ton of SO_2 removed)	$294	$1,359

Preliminary BART Selection. CH2M HILL recommends upgrading the existing wet sodium FGD system as BART for AbitibiBowater based on significant reduction in SO_2 emissions, reasonable control costs, and the advantages of minimal additional power requirements and environmental impacts.

3.1.2.5 Step 5: Evaluate Visibility Impacts

See Section 4.0, BART Modeling Analysis.

FIGURE 3-3
First Year Control Cost for SO_2 Air Pollution Control Options



SECTION 4.0

BART Determination Modeling Analysis

This section presents the dispersion modeling methods and results for estimating the degree of visibility improvement from BART control technology options for the AbitibiBowater No. 2 Power Boiler.

Input and output files for the CALMET/CALPUFF modeling and post-processing will be provided in electronic format to the Arizona Department of Environmental Quality (ADEQ). Larger files, such as binary files generated by CALMET, have not been included on the submitted disks, but will be provided electronically upon request.

4.1 Methodology

Processed CALMET data from WRAP were not available for the determination modeling. Efforts were made to prepare the CALMET data files to be as similar as possible to those used in the WRAP modeling. The methodology outlined in the WRAP protocol for performing BART analyses (Western Regional Air Partnership, 2006) was followed with some exceptions. The MM5 data sets used in the AbitibiBowater analysis were from different sources than those used in the WRAP analysis. Other differences in the modeling methodologies are noted in the text.

As required by the protocol, the CALPUFF modeling system was used to assess the visibility impacts at Class I areas within 300 kilometers. CALPUFF is a multi-layer, multi-species, non-steady-state puff dispersion model that simulates the effects of time- and space-varying meteorological conditions on pollutant transport, transformation, and removal. The CALPUFF modeling system includes the meteorological data preprocessing program for CALPUFF (CALMET); algorithms for chemical transformation and deposition; and a post-processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST).

EPA has approved Version 5 of the CALPUFF modeling system for BART analyses. The Federal Land Managers and others have noted that the EPA-approved Version 5 contained errors and that a newer version should be used. Therefore, the most recent version (Version 6) of the CALPUFF modeling system preprocessors and models was used (CALMET Version 6.211 Level 060414 and CALPUFF Version 6.112 Level 060412).

The CALPUFF modeling system was applied in a full refined mode. CALMET, CALPUFF, CALPOST, and POSTUTIL were recompiled with the Lahey/Fujitsu Fortran 95 Compiler (Release 7.10.02) to accommodate the large CALMET domain. The recompiled processors were tested against the test case results provided with the source code (TRC, 2007). The difference between the results was an acceptable 0.03 percent.

4.2 CALMET

CALMET was used to generate 3 years of three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. Wind fields were generated for the years 2001, 2002, and 2003.

4.2.1 Dimensions of the Modeling Domain

A CALMET modeling domain has been defined to allow for at least a 50-kilometer buffer around all Class I areas within 300 kilometers of AbitibiBowater. Grid resolution for this domain was 4 kilometers.

The defined domains for Mesoscale Meteorological Model, Version 5 (MM5), CALMET, and CALPUFF were slightly different than those established by WRAP for the Arizona BART modeling (Western Regional Air Partnership, 2006). In addition, the CALMET and CALPUFF Lambert conformal conic (LCC) map projection used in this analysis is based on a central meridian of 110° W rather than 97° W. This puts the central meridian nearer the center of the domain. Figure ES-1 shows the extent of the modeling domain.

The technical options recommended by WRAP were used for CALMET. Vertical resolution of the wind field included 11 layers with vertical cell face heights as follows (in meters): 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, and 5000.

In addition, as recommended by WRAP, ZIMAX was set to 4,500 meters based on the Colorado Department of Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (Colorado Department of Health and Environment, 2005). The CDPHE analyses suggest that mixing heights in the Denver area are often well above the CALMET default value of 3,000 meters during the summer. For example, on some summer days, ozone levels are elevated to 6,000 meters mean sea level or beyond during some meteorological regimes, including some regimes associated with high-ozone episodes. It is assumed that, as in Denver, mixing heights in excess of the 3,000-meter above ground level CALMET default maximum will occur in the domain used for this analysis.

Table 4-1 lists the key user-specified options. The only difference in input parameters between the AbitibiBowater demonstration analysis and the WRAP analysis is the variable IXTRP. This variable represents the extrapolation of surface wind observations and was changed to take advantage of the surface data in the upper layers.

4.2.2 Input Data

MM5 data were used for the CALMET wind fields. The horizontal resolution of the MM5 data is 36 kilometers.

For 2001, MM5 data at 36-kilometer resolution were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for EPA. For 2002, 36-kilometer MM5 data obtained from Alpine Geophysics originally developed for the WRAP were used. Data for 2003 (also from Alpine Geophysics) at 36-kilometer resolution were developed by the Wisconsin Department of Natural Resources, Illinois Environmental Protection Agency, and Lake Michigan Air Directors Consortium (Midwest RPO).

TABLE 4-1
User-Specified CALMET Options
AbitibiBowater No. 2 Power Boiler

Description	CALMET Input Parameter	Value
CALMET Input Group 2		
Map Projection	PMAP	LCC
Datum	DATUM	NAR-C[1]
Matching Parallels for Projection	XLAT1	33.0N
Matching Parallels for Projection	XLAT2	45.0N
Latitude of Projection Origin	RLATO	40.0N[1]
Longitude of Projection Origin	RLONO	110.0W.[1]
Number of X Grids Cells	NX	184[1]
Number of Y Grid Cells	NY	160[1]
Grid Spacing	DGRIDKM	4
Number Vertical Layers	NZ	11
Top of Lowest Layer (meters)		20
Top of Highest Layer (meters)		5,000
CALMET Input Group 4		
Observation Mode	NOOBS	1
CALMET Input Group 5		
Extrapolation of Surface Wind Observations	IEXTRP	-4[1]
Prognostic or MM-FDDA Data Switch	IPROG	14
Maximum Surface Over Land Extrapolation Radius (kilometers)	RMAX1	50
Maximum Aloft Over Land Extrapolation Radius (kilometers)	RMAX2	100
Radius of Influence of Terrain Features (kilometers)	TERRAD	10
Relative Weight at Surface of Step 1 Field and Observations	R1	100
Relative Weight Aloft of Step 1 Field and Observations	R2	200
CALMET Input Group 6		
Maximum Over Land Mixing Height (meters)	ZIMAX	4,500

1. Indicates different value then used by WRAP.

The MM5 data were used as input to CALMET as the "initial guess" wind field. The initial guess field was adjusted by CALMET for local terrain and land use effects to generate a Step 1 wind field, then further refined using local surface observations to create a final Step 2 wind field.

Surface data for 2001 through 2003 were obtained from the National Climatic Data Center. Data from the National Weather Service's Automated Surface Observing System network for all stations in the domain were used in this analysis. This includes additional stations found in the domain that were not included in the WRAP modeling analysis. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website was used to convert the DATSAV3 files to CD 144 format for input to the SMERGE preprocessor and CALMET.

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

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

As recommended by WRAP, upper-air meteorological observations were not used. They are redundant to the MM5 data and may introduce spurious artifacts in the wind fields. In developing the MM5 data, the twice-daily upper-air meteorological observations were used as input with the MM5 model. The MM5 estimates were nudged to the upper-air observations as part of the four-dimensional data assimilation. This results in higher temporal (hourly versus 12-hour) and spatial (36 kilometers versus ~300 kilometers) resolution for the upper-air meteorology in the MM5 field. These MM5 data are more dynamically balanced than those contained in the upper-air observations. Therefore, the use of the upper-air observations with CALMET is not needed and, in fact, will upset the dynamic balance of the meteorological fields, potentially producing spurious vertical velocities.

4.2.3 Validation of CALMET Wind Field

The CALDESK data display and analysis system (v2.97, Enviromodeling Ltd.) was used to evaluate the CALMET wind fields. CALDESK displays were also compared to observed weather conditions as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/ rescue/ dwm/ data_rescue_daily_weather_maps.html).

4.3 CALPUFF

The CALPUFF model was used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios.

4.3.1 Methodology

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

- Model current operating parameters to verify results and determine baseline impacts.
- Model other control scenarios if applicable.
- Determine the degree of visibility improvement.
- Factor visibility results into BART five-step evaluation.

4.3.2 CALPUFF Inputs

4.3.2.1 Meteorology

Meteorological output from CALMET over the CALPUFF modeling domain (Figure 4-1) was used.

4.3.2.2 Background Ozone and Ammonia

Hourly values of background ozone concentrations were used for the calculation of SO_2 and NO_X transformation with the MESOPUFF II chemical transformation scheme. Hourly ozone data generated for the WRAP BART analysis for 2001, 2002, and 2003 were used in this modeling exercise.

For periods of missing hourly ozone data, the chemical transformation relied on a monthly default value of 80 parts per billion. Background ammonia was set to 1 part per billion as recommended by WRAP (Western Regional Air Partnership, 2006).

4.3.2.3 Stack Parameters

The baseline stack parameters for the baseline and post-control scenarios were supplied by AbitibiBowater staff. The stack parameters varied depending on the proposed control option for each scenario. The stack parameters used in each control option are summarized in Table 2-1.

4.3.2.4 Pre-Control Emission Rates

Pre-control emission rates reflect normal maximum-capacity 24-hour emissions that may occur under the source's current permit. The emission rate used in the baseline modeling was significantly higher for NO_x and slightly lower for SO_2 than that used in the WRAP exemption modeling. The emission rates reflect actual emissions under normal operating conditions. As described in the *Regional Haze Regulations and Guidelines for BART Determinations; Final Rule* (*Code of Federal Regulations*, 2005):

> *The emissions estimates used in the models are intended to reflect steady-state operating conditions during periods of high-capacity utilization. We do not generally recommend that emissions reflecting periods of start-up, shutdown, and malfunction be used…*

Available source data and permit restrictions were used to determine the baseline emission rates.

Emissions were modeled for the following species:

- SO_2
- NO_x
- Fine particulate matter less than 2.5 micrometers in diameter ($PM_{2.5}$)

4.3.2.5 Post-Control Emission Rates

Post-control emission rates reflected the effects of the emissions control scenario under consideration. Ten post-control scenarios were modeled for this exercise. Modeled pollutants were the same as listed for the pre-control scenario.

4.3.3 Receptor Grids and Coordinate Conversion

The TRC COORDS program was used to convert the latitude/longitude coordinates to LCC map coordinates for the meteorological stations and source locations. The USGS conversion program PROJ (version 4.4.6) was used to convert the National Park Service (NPS) receptor location data from latitude/longitude to LCC coordinates.

For CALPUFF modeling of the Class I areas within 300 kilometers of AbitibiBowater, discrete receptors were taken from the NPS database for Class I area modeling receptors. The entire area of each Class I area within or intersecting the 300-kilometer circle (Figure 4-1) was included in the modeling analysis. Table 4-2 lists the Class I areas that were modeled for the Abitibi facility.

TABLE 4-2
Class I Areas Modeled
AbitibiBowater No. 2 Power Boiler

Class I Area	Distance (Kilometers)
Petrified Forest NP	59
Sierra Ancha WA	77
Mount Baldy WA	96
Mazatzal WA	100
Superstition WA	115
Pine Mountain WA	124
Sycamore Canyon WA	151
Gila WA	191
Galiuro WA	196
Grand Canyon NP	212
Saguaro NM	248
Chiricahua NM	286

4.4 Visibility Post-Processing

4.4.1 CALPOST

The CALPOST processor was used to determine 24-hour average visibility results. Output is specified in deciview (dV) units.

Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values was used to calculate the change (ΔdV) relative to natural background. The following default extinction coefficients were used:

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

CALPOST Visibility Method 6 (MVISBK=6) was used to determine visibility impacts. Monthly average relative humidity factors (*f*[RH]) were used in the light extinction calculations to account for the hygroscopic characteristic of sulfate and nitrate particles. Monthly *f*(RH) values from the WRAP Regional Modeling Center (RMC) BART modeling were used in CALPOST for the particular Class I area being modeled.

Table 4-3 lists the annual average species concentrations from the EPA guidance.

TABLE 4-3
Average Natural Levels of Aerosol Components for Western Class I Areas
AbitibiBowater No. 2 Power Boiler

Aerosol Component	Concentration ($\mu g/m^3$)
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

$\mu g/m^3$ = micrograms per cubic meters
Taken from Table 2-1 of *Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule*. EPA-454/B-03-005, September 2003.

The natural background conditions used in the post-processing to determine the change in visual range background (ΔdV) represent the average natural background concentration for western Class I areas. To be consistent with the WRAP modeling, background based on actual measurements was not used.

4.5 Results

Although with the minor exceptions noted and a change in emission rates, the same methodologies were used in the AbitibiBowater modeling analysis and the WRAP exemption modeling, the results of the baseline modeling differ significantly from the WRAP modeling results. In particular, the WRAP modeling showed the highest impact at Petrified Forest NP northeast of the plant, whereas the AbitibiBowater modeling showed impacts at that Class I area to be less than 0.5 dV at the 98th percentile level. The Class I area with the highest impact in the AbitibiBowater modeling was Sierra Ancha WA southwest of the plant, which had the highest 98th percentile change in visibility below 0.5 dV in the WRAP modeling.

The threshold for source BART eligibility is 0.5 deciview at 98 percent of the 3-year average. Visibility impacts at the Sierra Ancha WA at that level are modeled at 0.73 deciview, only 0.23 deciview greater than the threshold.

Table 4-4 summarizes the results of the modeling runs for the baseline scenario.

TABLE 4-4
Baseline Modeling Results (ΔdV)
AbitibiBowater No. 2 Power Boiler

Class I Area	8th High 2001	8th High 2002	8th High 2003	22nd 3-Year High	98% 3 Year Average Total Impact
Petrified Forest NP	0.389	0.358	0.483	0.391	0.410
Sierra Ancha WA	0.745	0.739	0.707	0.739	0.730
Mount Baldy WA	0.250	0.233	0.261	0.252	0.248
Mazatzal WA	0.295	0.437	0.358	0.358	0.363
Superstition WA	0.600	0.467	0.461	0.523	0.509
Pine Mountain WA	0.162	0.244	0.194	0.216	0.200
Sycamore Canyon WA	0.093	0.081	0.082	0.085	0.085
Gila WA	0.154	0.187	0.197	0.188	0.179
Galiuro WA	0.176	0.112	0.122	0.146	0.137
Grand Canyon NP	0.003	0.004	0.004	0.004	0.004
Saguaro NM	0.176	0.097	0.094	0.119	0.122
Chiricahua NM	0.134	0.091	0.083	0.106	0.103

The ten control scenarios modeled result in varying degrees of visibility improvement at the Class I areas modeled. All visibility improvement results are less than 0.33 deciview. Tables 4-5 through 4-8 present the modeling results for the Class I areas with the highest visibility impacts (Mazatzal WA, Sierra Ancha WA, Superstition WA, and Petrified Forest NP, respectively). Results for all Class I areas are presented in Appendix B.

TABLE 4-5
Control Scenario Results for Mazatzal WA
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	98th Percentile ΔdV Reduction
1	Existing Wet Soda Ash Scrubber	0.000
2	Upgraded Wet Soda Ash Scrubber	0.017
3	Add Second Scrubber with Upgraded Scrubber	0.130
4	Operate Existing OFA Fan with Existing Wet Soda Ash Scrubber	0.048
5	Operate Existing OFA Fan with Upgraded Wet Soda Ash Scrubber	0.061
6	New LNB with Upgraded Wet Soda Ash Scrubber	0.086
7	New LNB with OFA Modifications and Upgraded Wet Soda Ash Scrubber	0.100
8	New LNB with OFA, HERT SNCR, and Upgraded Wet Soda Ash Scrubber	0.103
9	Mobotec ROFA with Upgraded Wet Soda Ash Scrubber	0.091
10	Mobotec ROFA & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0.099
11	New LNB with OFA, SCR, and Upgraded Wet Soda Ash Scrubber	0.126

TABLE 4-6
Control Scenario Results for Sierra Ancha WA
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	98th Percentile ΔdV Reduction
1	Existing Wet Soda Ash Scrubber	0.000
2	Upgraded Wet Soda Ash Scrubber	0.018
3	Add Second Scrubber with Upgraded Scrubber	0.200
4	Operate Existing OFA Fan with Existing Wet Soda Ash Scrubber	0.076
5	Operate Existing OFA Fan with Upgraded Wet Soda Ash Scrubber	0.094
6	New LNB with Upgraded Wet Soda Ash Scrubber	0.182
7	New LNB with OFA Modifications and Upgraded Wet Soda Ash Scrubber	0.225
8	New LNB with OFA, HERT SNCR, and Upgraded Wet Soda Ash Scrubber	0.270
9	Mobotec ROFA with Upgraded Wet Soda Ash Scrubber	0.193
10	Mobotec ROFA and Rotamix SNCR with Upgraded Wet Soda Ash Scrubber	0.213
11	New LNB with OFA, SCR, and Upgraded Wet Soda Ash Scrubber	0.327

TABLE 4-7
Control Scenario Results for Superstition Wilderness
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	98^{th} Percentile ΔdV Reduction
1	Existing Wet Soda Ash Scrubber	0.000
2	Upgraded Wet Soda Ash Scrubber	-0.005
3	Add 2nd Scrubber with Upgraded Scrubber	0.191
4	Operate Existing OFA Fan with Existing Wet Soda Ash Scrubber	0.042
5	Operate Existing OFA Fan with Upgraded Wet Soda Ash Scrubber	0.059
6	New LNB with Upgraded Wet Soda Ash Scrubber	0.119
7	New LNB with OFA Modifications and Upgraded Wet Soda Ash Scrubber	0.161
8	New LNB with OFA, HERT SNCR, and Upgraded Wet Soda Ash Scrubber	0.187
9	Mobotec ROFA with Upgraded Wet Soda Ash Scrubber	0.130
10	Mobotec ROFA and Rotamix SNCR with Upgraded Wet Soda Ash Scrubber	0.148
11	New LNB with OFA, SCR, and Upgraded Wet Soda Ash Scrubber	0.225

TABLE 4-8
Control Scenario Results for Petrified Forest National Park
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	98^{th} Percentile ΔdV Reduction
1	Existing Wet Soda Ash Scrubber	0.000
2	Upgraded Wet Soda Ash Scrubber	-0.009
3	Add Second Scrubber with Upgraded Scrubber	0.050
4	Operate Existing OFA Fan with Existing Wet Soda Ash Scrubber	0.035
5	Operate Existing OFA Fan with Upgraded Wet Soda Ash Scrubber	0.050
6	New LNB with Upgraded Wet Soda Ash Scrubber	0.104
7	New LNB with OFA Modifications and Upgraded Wet Soda Ash Scrubber	0.130
8	New LNB with OFA, HERT SNCR, and Upgraded Wet Soda Ash Scrubber	0.144
9	Mobotec ROFA with Upgraded Wet Soda Ash Scrubber	0.112
10	Mobotec ROFA and Rotamix SNCR with Upgraded Wet Soda Ash Scrubber	0.122
11	New LNB with OFA, SCR, and Upgraded Wet Soda Ash Scrubber	0.165

SECTION 5.0

BART Summary

This section summarizes the control analysis and effectiveness of the alternative control scenarios evaluated in this BART analysis.

5.1 Costs and Emission Rates

Table 5-1 summarizes the expected NO_x and SO_2 emission rates for each scenario ranked by the annual cost of NO_x and SO_2 controls.

TABLE 5-1
Summary of Expected Emission Rates Ranked by Annual Cost of NO_x and SO_2 Controls
AbitibiBowater No. 2 Power Boiler

Scenario	NO_x Controls	SO_2 Controls	Expected NO_x Emissions (lb/MMBtu)	Expected SO_2 Emissions (lb/MMBtu)	Total Annual Cost of NO_x and SO_2 Controls
4	Operate Existing OFA Fan	Existing Wet Soda Ash Scrubber	0.525	0.800	$8,151,815
5	Operate Existing OFA Fan	Upgraded Wet Soda Ash Scrubber	0.525	0.739	$8,239,726
6	New LNB	Upgraded Wet Soda Ash Scrubber	0.370	0.739	$8,418,552
7	New LNB with OFA Modifications	Upgraded Wet Soda Ash Scrubber	0.265	0.739	$8,528,359
8	New LNB with OFA and HERT SNCR	Upgraded Wet Soda Ash Scrubber	0.194	0.739	$8,987,146
9	Mobotec ROFA	Upgraded Wet Soda Ash Scrubber	0.348	0.739	$9,280,919
1	None	Existing Wet Soda Ash Scrubber	0.700	0.800	$9,860,911
10	Mobotec ROFA and Rotamix SNCR	Upgraded Wet Soda Ash Scrubber	0.291	0.739	$9,921,900
2	None	Upgraded Wet Soda Ash Scrubber	0.700	0.739	$9,948,822
11	New LNB with OFA and SCR	Upgraded Wet Soda Ash Scrubber	0.070	0.739	$12,199,903
3	None	Add Second Scrubber with Upgraded Scrubber	0.700	0.044	$14,630,275

5.2 Cost-Effectiveness Analysis

5.2.1 Analysis Methodology

On page B-41 of the *New Source Review Workshop Manual* (U.S. Environmental Protection Agency, 1990), EPA states:

> *Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives. This is a graphical plot of total annualized costs for total emissions reductions for all control alternatives identified in the BACT analysis...*

Following this guidance, annualized costs and visibility reduction achieved for each NO_x control scenario were plotted for the four Class I areas with the highest visibility impacts. Scenarios that fall on the least-cost envelope curves presented in Figures 5-1 through 5-4 were subjected to an incremental cost-effectiveness analysis. Scenarios 1, 2, 9, and 10 were consistently off the envelope; therefore, none of these scenarios is considered as BART.

Similar incremental cost-effectiveness may be seen in scenarios 4, 5, 6, and 7. Scenarios 3, 8, and 11 were found to be less cost-effective than these four scenarios.

5.3 Visibility Improvement

The existing impacts to visibility and the improvement in visibility associated with each of the control technologies evaluated is described in detail in Section 4.0. The visibility analysis used a conservative methodology, and the results showed maximum visibility impacts greater than the 0.5-dV "contribute to visibility impacts" threshold and less than the 1.0-dV "cause visibility impacts" threshold. This demonstrates that the AbitibiBowater Snowflake Paper Mill has a small impact on visibility.

Studies have been conducted that demonstrate that deciview differences of 1.5 to 2.0 dV or more are perceptible by the human eye. Changes of less than 1.5 dV cannot be distinguished by the average person.

Results from modeling demonstrated that the Class I area with the highest impacts would be Sierra Ancha WA. Impacts at the area (0.73 dV) are only slightly above the threshold for BART eligibility (0.5 dV). The difference of 0.23 dV is not perceptible.

Implementation of the control scenarios presented in this report for the four Class I areas with the highest impacts would result in visibility improvements of less than 0.33 dV. This improvement would not be perceptible.

Minimal improvements in visibility and a baseline visibility approaching the BART-eligibility threshold lead to the conclusion that none of the alternative control scenarios presented in this report can be justified. The current control scenario with emission rates of 0.7 lb/MMBtu for NO_x and 0.8 lb/MMBtu for SO_2 is the BART.

FIGURE 5-1
NO_x and SO_2 Control Scenarios, Mazatzal WA Least-Cost Envelope (98th Percentile Reduction)
AbitibiBowater No. 2 Power Boiler

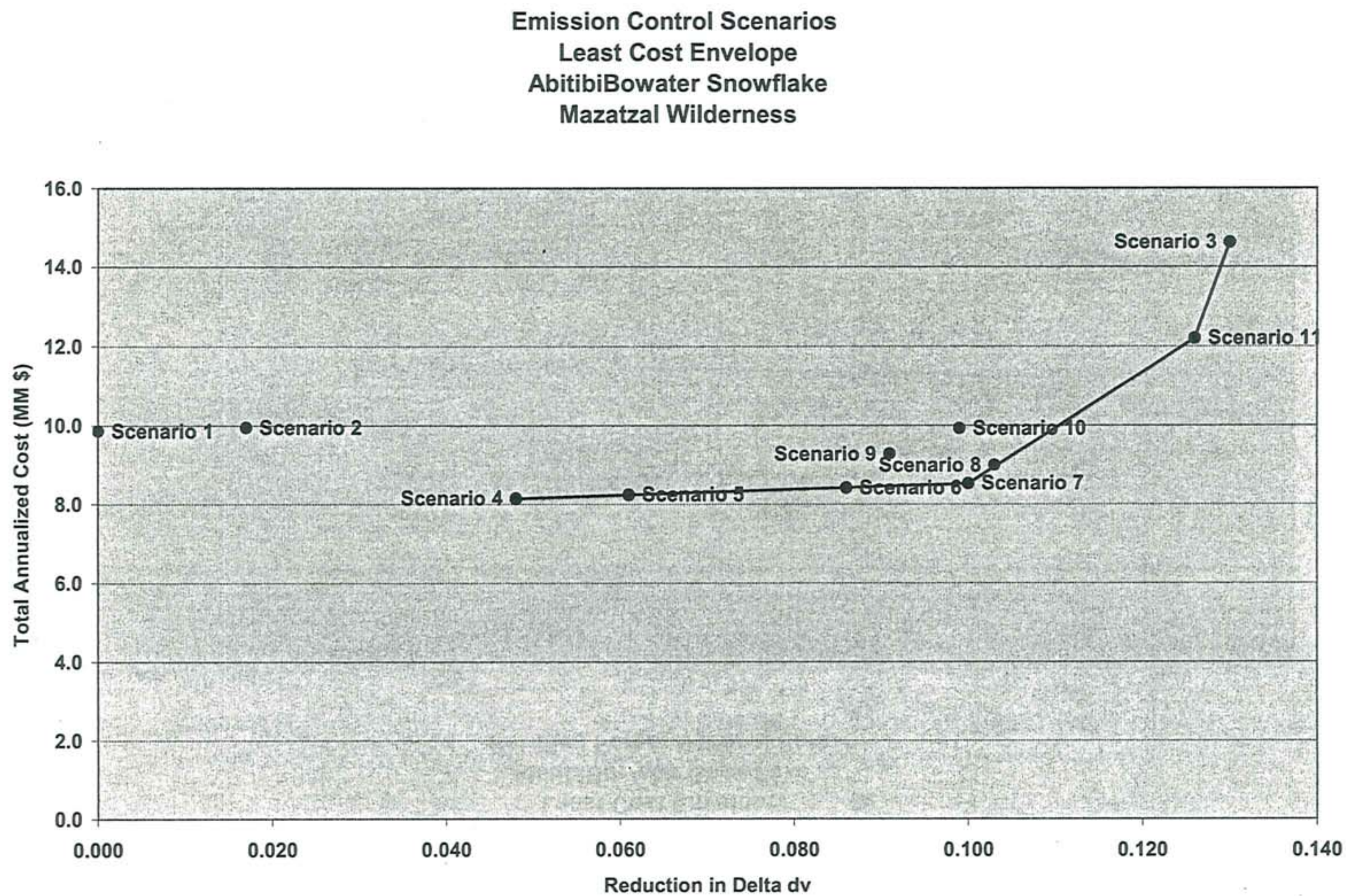


FIGURE 5-2
NO_x and SO_2 Control Scenarios, Petrified Forest NP Least-Cost Envelope (98th Percentile Reduction)
AbitibiBowater No. 2 Power Boiler

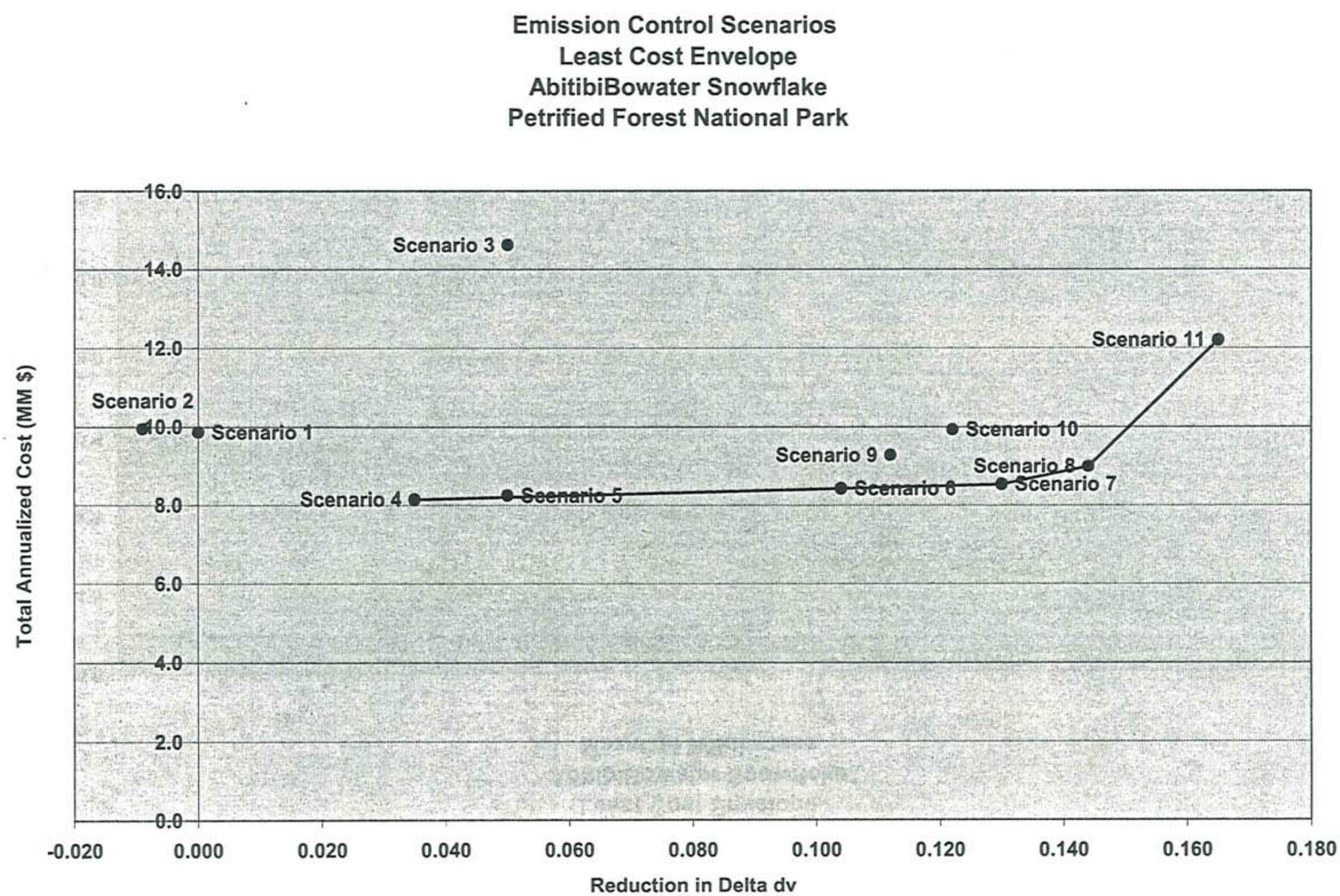


FIGURE 5-3
NO_x and SO_2 Control Scenarios, Sierra Ancha WA Least-Cost Envelope (98th Percentile Reduction)
AbitibiBowater No. 2 Power Boiler

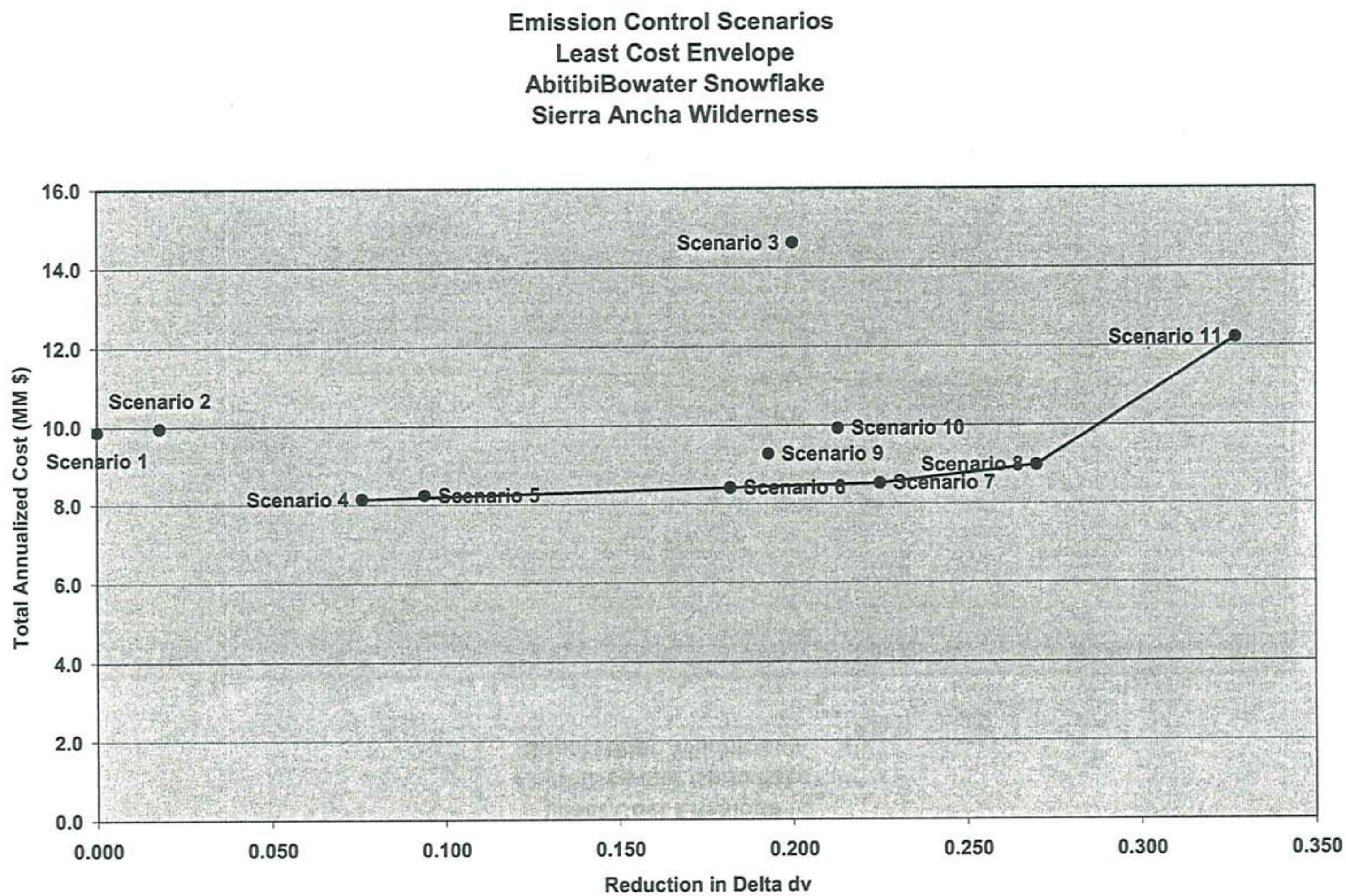
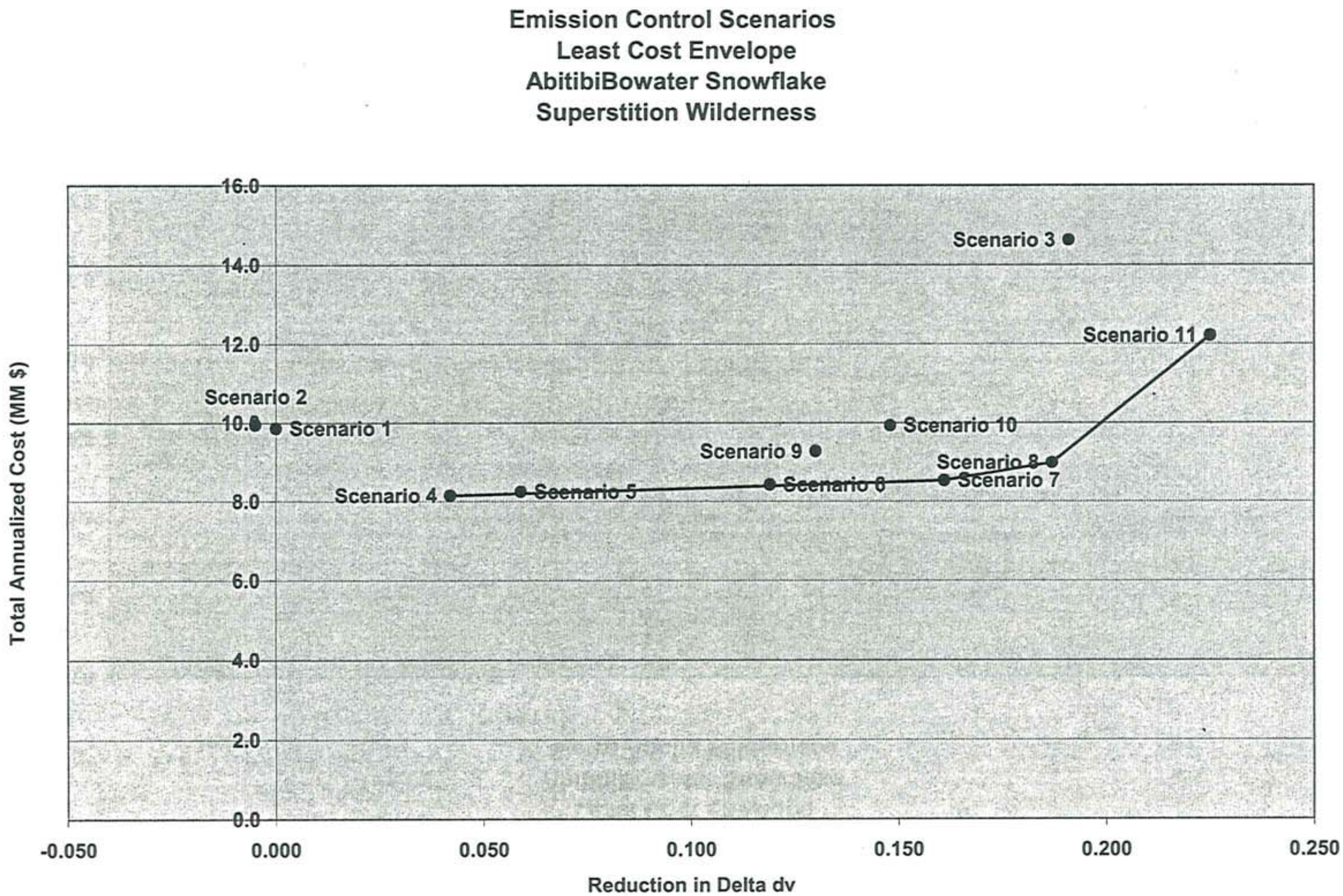


FIGURE 5-4
NO_x and SO_2 Control Scenarios, Superstition WA Least-Cost Envelope (98th Percentile Reduction)
AbitibiBowater No. 2 Power Boiler



SECTION 6.0

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Appendix A
Economic Analysis

Appendix A

Command Summary

ECONOMIC ANALYSIS SUMMARY

Abitibi Snowflake Power Boiler #2 BART Analysis

Case	Historical Case (Low S)	Base Case (High S)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
Air Permitting Scenario	Historical Operation w/McKinley Coal	Current Operation w/Lee Ranch Coal	Scrubber Upgrades	Add 2nd Scrubber w/Upgraded FGD	OFA Using Existing Fan	New Low-NOx Burners (LNB)	New LNB w/OFA Modifications	New LNB w/ OFA & HERT SNCR	Mobotec ROFA	Mobotec ROFA & Rotamix SNCR	New LNB w/OFA & SCR
Total Installed Capital Cost	0	0	650,000	15,650,000	20,000	1,462,020	2,088,600	2,792,400	4,536,126	5,964,840	22,950,507
Total 1st Year Annual Cost ($)	1,563,622	4,930,455	5,018,367	9,699,820	3,221,359	3,400,185	3,509,992	3,968,779	4,262,553	4,903,534	7,181,536
Total 1st Year Annual Cost Less Base Case ($)	NA	0	87,911	4,769,365	103,130	281,956	391,763	850,550	1,144,324	1,785,305	4,063,307
Net Present Worth ($)	13,194,447	40,881,650	41,531,650	78,347,437	26,529,161	27,816,582	28,654,973	32,514,395	34,741,468	40,052,521	56,868,826
APC Control Cost ($/Ton Removed)			SO2 Control Cost	SO2 Control Cost	NOx Control Cost	NOx Control Cost	NOx Control Cost	NOx Control Cost	NOx Control Cost	NOx Control Cost	NOx Control Cost
2008			686	901	3,713	2,078	1,627	1,582	2,442	2,418	2,299
2009			700	916	3,788	2,118	1,658	1,612	2,487	2,463	2,328
2010			715	931	3,865	2,158	1,688	1,643	2,532	2,508	2,357
2011			730	946	3,943	2,199	1,720	1,675	2,578	2,555	2,387
2012			745	962	4,023	2,241	1,752	1,707	2,625	2,603	2,418
2013			761	978	4,104	2,283	1,785	1,740	2,673	2,652	2,450
2014			777	995	4,187	2,327	1,818	1,774	2,723	2,702	2,482
2015			794	1,011	4,272	2,371	1,852	1,808	2,773	2,753	2,515
2016			811	1,029	4,359	2,416	1,887	1,843	2,824	2,805	2,549
2017			828	1,046	4,447	2,463	1,922	1,879	2,877	2,859	2,583
2018			846	1,064	4,538	2,510	1,958	1,916	2,931	2,913	2,618
2019			863	1,082	4,630	2,558	1,995	1,953	2,985	2,969	2,654
2020			882	1,101	4,723	2,607	2,033	1,992	3,041	3,026	2,691
2021			901	1,120	4,819	2,657	2,071	2,031	3,099	3,085	2,729
2022			920	1,139	4,917	2,708	2,110	2,071	3,157	3,145	2,768
Tons SO2 Removed	2,103	7,021	7,319	10,764	7,021	7,021	7,021	7,021	7,021	7,021	7,021
Tons NOx Removed	0	0	0	0	868	1,636	2,157	2,509	1,745	2,028	3,124
First Year Average Control Cost ($/Ton Removed)	NA	NA	686	901	3,713	2,078	1,627	1,582	2,442	2,418	2,299
First Year Incremental Control Cost ($/Ton Removed)	NA	NA	294	1,359	3,713	233	211	1,303	2,442	2,268	3,797

TECHNICAL INPUT CALCULATIONS

Abitibi Snowflake Power Boiler #2 BART Analysis

Parameter	Historical Case (Low S)	Base Case (High S)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Comments
Air Permitting Scenario	Historical Operation w/McKinley Coal	Current Operation w/Lee Ranch Coal	Scrubber Upgrades	Add 2nd Scrubber w/Upgraded FGD	OFA Using Existing Fan	New Low-NOx Burners (LNB)	New LNB w/OFA Modifications	New LNB w/ OFA & HERT SNCR	Mobotec ROFA	Mobotec ROFA & Rotamix SNCR	New LNB w/OFA & SCR	
NOx Emission Control System	None	None	None	None	Operate Existing OFA Fan	New Low-NOx Burners	New LNB w/OFA Modifications	New LNB w/ OFA & HERT	Mobotec ROFA	Mobotec ROFA & Rotamix	New LNB w/OFA & SCR	
SO2 Emission Control System	Wet Soda Ash FGD	Wet Soda Ash FGD	Upgraded Wet Soda Ash FGD	Add 2nd Scrubber w/Upgraded FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	
PM Emission Control System	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	
Unit Design												
Type of Unit	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	PC	
Equivalent Power Plant Unit Size (kWeq @ 11,000 Btu/kW-Hr)	102,909	102,909	102,909	102,909	102,909	102,909	102,909	102,909	102,909	102,909	102,909	
Unit Heat Input, HHV (MMBtu/Hr)	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	1,132	
Boiler Fuel	McKinley Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	Lee Ranch Coal	
Fuel Heating Value, HHV (Btu/Lb)	9,800	9,290	9,290	9,290	9,290	9,290	9,290	9,290	9,290	9,290	9,290	
Fuel Sulfur Content (wt.%)	0.60%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	1.03%	
Fuel Ash Content (wt.%)	12.00%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	
Fly Ash Rate (wt.%)	12.00%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	17.90%	
Flue Gas												
Flue Gas Bypass (%)	63.1%	32.0%	32.0%	0.0%	32.0%	32.0%	32.0%	32.0%	32.0%	32.0%	32.0%	
Flue Gas to Scrubber (%)	36.9%	68.0%	68.0%	100.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	68.0%	
Flue Gas Temp. Exiting AH (Deg. F)	294	294	294	294	294	294	294	294	294	294	294	
Flue Gas Exiting AH (Lb/MMBtu)	839	926	926	926	926	926	926	926	926	926	926	
Flue Gas Temp. Exiting Scrubber (Deg. F)	124	124	124	124	124	124	124	124	124	124	124	
Stack Gas Temperature (Deg. F)	230	177	177	124	177	177	177	177	177	177	177	
Coal Flow Rates												
Coal Flow Rate (Lb/Hr)	115,510	121,851	121,851	121,851	121,851	121,851	121,851	121,851	121,851	121,851	121,851	
(Tons/Hr)	57.8	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	60.9	
(Tons/Yr)	505,935	533,709	533,709	533,709	533,709	533,709	533,709	533,709	533,709	533,709	533,709	
Fly Ash Rate (Tons/Yr)	48,570	76,427	76,427	76,427	76,427	76,427	76,427	76,427	76,427	76,427	76,427	
Annual Unit Capacity Factor												
Annual Unit Capacity Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Annual Operating Hours	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	8,760	
SO2 Emissions												
Uncontrolled SO2 (Lb/MMBtu)	1.223	2.215	2.215	2.215	2.215	2.215	2.215	2.215	2.215	2.215	2.215	
SO2 Removal Rate in Scrubber (%)	94.0%	94.0%	98.0%	98.0%	94.0%	94.0%	94.0%	94.0%	94.0%	94.0%	94.0%	
SO2 Removed (Ton/Yr)	2,103	7,021	7,319	10,764	7,021	7,021	7,021	7,021	7,021	7,021	7,021	
SO2 Emission Rate (Lb/MMBtu)	0.799	0.799	0.739	0.044	0.799	0.799	0.799	0.799	0.799	0.799	0.799	
(Lb/Hr)	905	905	837	50	905	905	905	905	905	905	905	
(Tons/Hr	3,962	3,963	3,664	220	3,963	3,963	3,963	3,963	3,963	3,963	3,963	
NOx Emissions												
Uncontrolled NOx (Lb/MMBtu)	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	0.700	
NOx Removal Rate (%)	0.00%	0.00%	0.0%	0.0%	25.0%	47.1%	62.1%	72.3%	50.3%	58.4%	90.0%	
NOx Removed (Ton/Yr)	0	0	0	0	868	1,636	2,157	2,509	1,745	2,028	3,124	
NOx Emission Rate (Lb/MMBtu)	0.700	0.700	0.700	0.700	0.525	0.370	0.265	0.194	0.348	0.291	0.070	
(Lb/Hr	792	792	792	792	594	419	300	220	394	329	79	

COST INPUT CALCULATIONS

Abitibi Snowflake Power Boiler #2 BART Analysis

Parameter	Historical Case (Low S)	Base Case (High S)	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9	Comments
Air Permitting Scenario	Historical Operation w/McKinley Coal	Current Operation w/Lee Ranch Coal	Scrubber Upgrades	Add 2nd Scrubber w/Upgraded FGD	OFA Using Existing Fan	New Low-NOx Burners (LNB)	New LNB w/OFA Modifications	New LNB w/ OFA & HERT SNCR	Mobotec ROFA	Mobotec ROFA & Rotamix SNCR	New LNB w/OFA & SCR	
NOx Emission Control System	None	None	None	None	Operate Existing OFA Fan	New Low-NOx Burners	New LNB w/OFA Modifications	New LNB w/ OFA & HERT	Mobotec ROFA	Mobotec ROFA & Rotamix	New LNB w/OFA & SCR	
SO2 Emission Control System	Wet Soda Ash FGD	Wet Soda Ash FGD	Upgraded Wet Soda Ash FGD	Add 2nd Scrubber w/Upgraded FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	Wet Soda Ash FGD	
PM Emission Control System	Hot ESP	Hot ESP	Hot ESP	Add. PM Removal in Scrubbers	Add. PM Removal in Scrubbers	Add. PM Removal in Scrubbers	Hot ESP	Hot ESP	Hot ESP	Hot ESP	Hot ESP	
Economic Factors												
Discount Rate (%)	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	Assumed
Plant Economic Life (Years)	15	15	15	15	15	15	15	15	15	15	15	Assumed
Interest Rate on Equity (%)	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	10.5%	Assumed
Equity Amortization Period (Years)	15	15	15	15	15	15	15	15	15	15	15	Assumed
Installed Capital Costs												
Total Emission Control Systems ($)	$0	$0	$650,000	$15,650,000	$20,000	$1,462,020	$2,088,600	$2,792,400	$4,536,126	$5,964,840	$22,950,507	Cost Estimate
($/kWeq)	$0.0	$0.0	$6.3	$152.1	$0.2	$14.2	$20.3	$27.1	$44.1	$58.0	$223.0	
Additional Operating & Maintenance Costs												
Annual Fixed O&M Costs ($)	$60,665	$60,665	$60,665	$90,998	$25,740	$84,221	$109,284	$119,841	$207,185	$228,616	$246,973	Estimated
Fixed O&M Costs ($/MMBtu)	$0.006	$0.006	$0.006	$0.009	$0.003	$0.008	$0.011	$0.012	$0.021	$0.023	$0.02	Calculated
Annual Non-Fuel/Consumables Variable O&M Costs ($)	$42,102	$42,102	$42,102	$84,204	$0	$0	$0	$1,802	$0	$1,802	$0	Estimated
Non-Fuel/Consumables Variable O&M Costs ($/MMBtu)	$0.004	$0.004	$0.004	$0.008	$0.000	$0.000	$0.000	$0.000	$0.000	$0.000	$0.00	Calculated
Annual O&M Cost Escalation Rate (%)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	Assumed
Water Cost												
Makeup Water Usage (Gpm)	64.1	155.6	155.6	228.8	0.0	0.0	0.0	0.7	0.0	5.8	0.0	Estimated
Unit Price ($/1000 Gallons)	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	1.39	From Abitibi
Annual Water Cost Escalation Rate (%)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	Assumed
Alkali Reagent Cost	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	Soda Ash	
Unit Cost ($/Ton)	176.00	176.00	176.00	176.00	176.00	176.00	176.00	176.00	176.00	176.00	176.00	From Abitibi
Stoichiometry (Moles Alkali/Mole Sulfur Removed)	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	1.02	Estimated
Reagent Purity	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	98%	Estimated
Reagent Usage (Lb/Hr)	880	2,936	2,936	4,318	0.0	0.0	0.0	0.0	0.0	0.0	0.0	Calculated
Annual Reagent Cost Escalation Rate (%)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	Assumed
50% Urea (SNCR) Cost												
Usage Rate (Gallons/MMBtu)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.040	0.000	0.048		Estimated
Usage (Gallons/Hr)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	45.3	0.0	54.3		Calculated
Unit Cost ($/Gallon)	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85		Assumed
Annual NH3 Cost (SCR) ($/yr)											84,937	Calculated
Annual Cost Escalation Rate (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	Assumed
Annual SCR Catalyst Cost												
SCR Catalyst Replacement Cost	0	0	0	0	0	0	0	0	0	0	423,026	Estimated
Annual SCR Catalyst Cost Escalation Rate (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	Assumed
Scrubber Waste Disposal Cost												
Solids Content of Waste (%)	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	Estimated
Solid Waste Disposal Rate, Wet (Lb/Hr)	11,789	39,351	39,351	57,869	0	0	0	0	0	0	0	Calculated
Waste Processing & Disposal Unit Cost, Wet ($/Ton)	17.80	17.80	17.80	17.80	17.80	17.80	17.80	17.80	17.80	17.80	17.80	From Abitibi
Annual Waste Disposal Cost Escalation Rate (%)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	Assumed
Fly Ash Disposal Cost + Lost Fly Ash Sales Revenue												
Fly Ash Disposal (%)	3.4%	3.4%	3.4%	3.4%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	From Abitibi
Fly Ash Disposal Cost ($/Ton)	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	40.00	From Abitibi
Fly Ash Sold (%)	96.6%	96.6%	96.6%	96.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	From Abitibi
Fly Ash Sales Price ($/Ton)	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	From Abitibi
Annual Fly Ash Disposal Cost & Sales Price Escalation Rate (%)	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	Assumed
Electric Power Cost												
Total Auxiliary Power Requirement (kW)	2,018	2,018	2,018	1,918	224	0	0	10	969	980	567	Estimated
Unit Cost ($/kW-Hr)	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	0.037	From Abitibi
Annual Power Cost Escalation Rate (%)	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	Assumed

Basis of Installed Capital Cost Estimates:

Case 1: Alstom budgetary proposal letter dated 10/21/2006

Case 2: Alstom budgetary proposal letter dated 10/21/2006, escalated to include additional plant costs for other support equipment and upgrades to install second scrubber. Does not include the cost of relocating stack opacity monitor and additional stack drains.

Case 3: Estimated cost to refurbish existing OFA fan
Case 4: ACT budgetary proposal dated 10/24/2007 with installation factors from OAQPS Control Cost Manual (6th ed. Jan. 2002)
Case 5: ACT budgetary proposal dated 10/24/2007 with installation factors from OAQPS Control Cost Manual (6th ed. Jan. 2002)
Case 6: Mobotec budgetary proposal dated 10/23/2007 with installation factors from OAQPS Control Cost Manual (6th ed. Jan. 2002)
Case 7: Mobotec budgetary proposal dated 10/23/2007 with installation factors from OAQPS Control Cost Manual (6th ed. Jan. 2002)
Case 8: ACT budgetary proposal dated 10/24/2007 with installation factors from OAQPS Control Cost Manual (6th ed. Jan. 2002)
Case 9: ACT budgetary proposal dated 10/24/2007 with SCR cost from USEPA report (EPA-600/R-01-087), escalated to current dollars

Abitibi Snowflake Economic Analysis — Historical Case (Low S) Historical Operation w/McKinley Coal

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST
0															
1	2008	9,916,320	60,665	42,102	102,767	47,801	691,653	-	-	937,462	(889,759)	673,696	1,460,855	-	1,563,622
2	2009	9,916,320	62,182	43,155	105,336	48,757	705,486	-	-	956,212	(907,554)	693,907	1,496,809	-	1,602,145
3	2010	9,916,320	63,736	44,233	107,970	49,732	719,596	-	-	975,336	(925,705)	714,724	1,533,684	-	1,641,654
4	2011	9,916,320	65,330	45,339	110,669	50,727	733,988	-	-	994,843	(944,219)	736,166	1,571,505	-	1,682,174
5	2012	9,916,320	66,963	46,473	113,436	51,742	748,668	-	-	1,014,739	(963,103)	758,251	1,610,297	-	1,723,732
6	2013	9,916,320	68,637	47,635	116,271	52,776	763,641	-	-	1,035,034	(982,365)	780,999	1,650,085	-	1,766,357
7	2014	9,916,320	70,353	48,825	119,178	53,832	778,914	-	-	1,055,735	(1,002,013)	804,429	1,690,897	-	1,810,075
8	2015	9,916,320	72,112	50,046	122,158	54,909	794,492	-	-	1,076,850	(1,022,053)	828,562	1,732,759	-	1,854,917
9	2016	9,916,320	73,914	51,297	125,212	56,007	810,382	-	-	1,098,387	(1,042,494)	853,418	1,775,700	-	1,900,911
10	2017	9,916,320	75,762	52,580	128,342	57,127	826,590	-	-	1,120,354	(1,063,344)	879,021	1,819,748	-	1,948,090
11	2018	9,916,320	77,656	53,894	131,550	58,269	843,122	-	-	1,142,761	(1,084,611)	905,392	1,864,933	-	1,996,484
12	2019	9,916,320	79,598	55,241	134,839	59,435	859,984	-	-	1,165,617	(1,106,303)	932,553	1,911,286	-	2,046,125
13	2020	9,916,320	81,588	56,623	138,210	60,624	877,184	-	-	1,188,929	(1,128,429)	960,530	1,958,837	-	2,097,047
14	2021	9,916,320	83,627	58,038	141,665	61,836	894,727	-	-	1,212,708	(1,150,998)	989,346	2,007,619	-	2,149,285
15	2022	9,916,320	85,718	59,489	145,207	63,073	912,622	-	-	1,236,962	(1,174,018)	1,019,026	2,057,665	-	2,202,872
PW Cost			512,688	355,809	868,497	393,094	5,687,821	-	-	7,709,235	(7,316,942)	5,852,742	12,325,950	-	13,194,447
(% of PW Cost)			3.9%	2.7%	6.6%	3.0%	43.1%	0.0%	0.0%	58.4%	-55.5%	44.4%	93.4%	0.0%	100.0%

Abitibi Snowflake Economic Analysis — Base Case (High S) Current Operation w/Lee Ranch Coal

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST
0															
1	2008	9,916,320	60,665	42,102	102,767	115,960	2,308,793	-	-	3,129,323	(1,400,085)	673,696	4,827,688	-	4,930,455
2	2009	9,916,320	62,182	43,155	105,336	118,279	2,354,969	-	-	3,191,910	(1,428,087)	693,907	4,930,979	-	5,036,315
3	2010	9,916,320	63,736	44,233	107,970	120,645	2,402,069	-	-	3,255,748	(1,456,648)	714,724	5,036,538	-	5,144,507
4	2011	9,916,320	65,330	45,339	110,669	123,058	2,450,110	-	-	3,320,863	(1,485,781)	736,166	5,144,416	-	5,255,085
5	2012	9,916,320	66,963	46,473	113,436	125,519	2,499,112	-	-	3,387,280	(1,515,497)	758,251	5,254,666	-	5,368,101
6	2013	9,916,320	68,637	47,635	116,271	128,029	2,549,095	-	-	3,455,026	(1,545,807)	780,999	5,367,342	-	5,483,613
7	2014	9,916,320	70,353	48,825	119,178	130,590	2,600,076	-	-	3,524,126	(1,576,723)	804,429	5,482,498	-	5,601,677
8	2015	9,916,320	72,112	50,046	122,158	133,202	2,652,078	-	-	3,594,609	(1,608,257)	828,562	5,600,193	-	5,722,350
9	2016	9,916,320	73,914	51,297	125,212	135,866	2,705,120	-	-	3,666,501	(1,640,423)	853,418	5,720,482	-	5,845,694
10	2017	9,916,320	75,762	52,580	128,342	138,583	2,759,222	-	-	3,739,831	(1,673,231)	879,021	5,843,426	-	5,971,768
11	2018	9,916,320	77,656	53,894	131,550	141,355	2,814,406	-	-	3,814,628	(1,706,696)	905,392	5,969,085	-	6,100,635
12	2019	9,916,320	79,598	55,241	134,839	144,182	2,870,695	-	-	3,890,920	(1,740,829)	932,553	6,097,520	-	6,232,359
13	2020	9,916,320	81,588	56,623	138,210	147,065	2,928,108	-	-	3,968,739	(1,775,646)	960,530	6,228,796	-	6,367,006
14	2021	9,916,320	83,627	58,038	141,665	150,007	2,986,671	-	-	4,048,113	(1,811,159)	989,346	6,362,977	-	6,504,643
15	2022	9,916,320	85,718	59,489	145,207	153,007	3,046,404	-	-	4,129,076	(1,847,382)	1,019,026	6,500,130	-	6,645,338
PW Cost			512,688	355,809	868,497	953,599	18,986,395	-	-	25,734,033	(11,513,617)	5,852,742	40,013,153	-	40,881,650
(% of PW Cost)			1.3%	0.9%	2.1%	2.3%	46.4%	0.0%	0.0%	62.9%	-28.2%	14.3%	97.9%	0.0%	100.0%

Abitibi Snowflake Economic Analysis — Case 1 — Scrubber Upgrades

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	SO2 Control Cost ($/Ton SO2 Rem.)
0																
1	2008	9,916,320	60,665	42,102	102,767	115,960	2,308,793	-	-	3,129,323	(1,400,085)	673,696	4,827,688	87,911	5,018,367	686
2	2009	9,916,320	62,182	43,155	105,336	118,279	2,354,969	-	-	3,191,910	(1,428,087)	693,907	4,930,979	87,911	5,124,226	700
3	2010	9,916,320	63,736	44,233	107,970	120,645	2,402,069	-	-	3,255,748	(1,456,648)	714,724	5,036,538	87,911	5,232,419	715
4	2011	9,916,320	65,330	45,339	110,669	123,058	2,450,110	-	-	3,320,863	(1,485,781)	736,166	5,144,416	87,911	5,342,996	730
5	2012	9,916,320	66,963	46,473	113,436	125,519	2,499,112	-	-	3,387,280	(1,515,497)	758,251	5,254,666	87,911	5,456,012	745
6	2013	9,916,320	68,637	47,635	116,271	128,029	2,549,095	-	-	3,455,026	(1,545,807)	780,999	5,367,342	87,911	5,571,524	761
7	2014	9,916,320	70,353	48,825	119,178	130,590	2,600,076	-	-	3,524,126	(1,576,723)	804,429	5,482,498	87,911	5,689,588	777
8	2015	9,916,320	72,112	50,046	122,158	133,202	2,652,078	-	-	3,594,609	(1,608,257)	828,562	5,600,193	87,911	5,810,262	794
9	2016	9,916,320	73,914	51,297	125,212	135,866	2,705,120	-	-	3,666,501	(1,640,423)	853,418	5,720,482	87,911	5,933,605	811
10	2017	9,916,320	75,762	52,580	128,342	138,583	2,759,222	-	-	3,739,831	(1,673,231)	879,021	5,843,426	87,911	6,059,679	828
11	2018	9,916,320	77,656	53,894	131,550	141,355	2,814,406	-	-	3,814,628	(1,706,696)	905,392	5,969,085	87,911	6,188,546	846
12	2019	9,916,320	79,598	55,241	134,839	144,182	2,870,695	-	-	3,890,920	(1,740,829)	932,553	6,097,520	87,911	6,320,271	863
13	2020	9,916,320	81,588	56,623	138,210	147,065	2,928,108	-	-	3,968,739	(1,775,646)	960,530	6,228,796	87,911	6,454,918	882
14	2021	9,916,320	83,627	58,038	141,665	150,007	2,986,671	-	-	4,048,113	(1,811,159)	989,346	6,362,977	87,911	6,592,554	901
15	2022	9,916,320	85,718	59,489	145,207	153,007	3,046,404	-	-	4,129,076	(1,847,382)	1,019,026	6,500,130	87,911	6,733,249	920
PW Cost			512,688	355,809	868,497	953,599	18,986,395	-	-	25,734,033	(11,513,617)	5,852,742	40,013,153	650,000	41,531,650	378
(% of PW Cost)			1.2%	0.9%	2.1%	2.3%	45.7%	0.0%	0.0%	62.0%	-27.7%	14.1%	96.3%	1.6%	100.0%	

Abitibi Snowflake Economic Analysis — Case 2 — Add 2nd Scrubber w/Upgraded FGD

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	SO2 Control Cost ($/Ton SO2 Rem.)
0																
1	2008	9,916,320	90,998	84,204	175,202	170,530	3,395,285	-	-	4,601,946	(1,400,085)	640,312	7,407,987	2,116,631	9,699,820	901
2	2009	9,916,320	93,272	86,309	179,582	173,940	3,463,190	-	-	4,693,985	(1,428,087)	659,521	7,562,550	2,116,631	9,858,763	916
3	2010	9,916,320	95,604	88,467	184,071	177,419	3,532,454	-	-	4,787,865	(1,456,648)	679,307	7,720,396	2,116,631	10,021,099	931
4	2011	9,916,320	97,994	90,678	188,673	180,967	3,603,103	-	-	4,883,622	(1,485,781)	699,686	7,881,597	2,116,631	10,186,901	946
5	2012	9,916,320	100,444	92,945	193,390	184,587	3,675,165	-	-	4,981,294	(1,515,497)	720,677	8,046,226	2,116,631	10,356,247	962
6	2013	9,916,320	102,955	95,269	198,224	188,278	3,748,668	-	-	5,080,920	(1,545,807)	742,297	8,214,357	2,116,631	10,529,213	978
7	2014	9,916,320	105,529	97,651	203,180	192,044	3,823,642	-	-	5,182,539	(1,576,723)	764,566	8,386,068	2,116,631	10,705,879	995
8	2015	9,916,320	108,167	100,092	208,260	195,885	3,900,115	-	-	5,286,189	(1,608,257)	787,503	8,561,435	2,116,631	10,886,325	1,011
9	2016	9,916,320	110,872	102,594	213,466	199,803	3,978,117	-	-	5,391,913	(1,640,423)	811,128	8,740,538	2,116,631	11,070,635	1,029
10	2017	9,916,320	113,643	105,159	218,803	203,799	4,057,679	-	-	5,499,751	(1,673,231)	835,462	8,923,460	2,116,631	11,258,894	1,046
11	2018	9,916,320	116,484	107,788	224,273	207,875	4,138,833	-	-	5,609,746	(1,706,696)	860,526	9,110,284	2,116,631	11,451,188	1,064
12	2019	9,916,320	119,397	110,483	229,880	212,032	4,221,610	-	-	5,721,941	(1,740,829)	886,342	9,301,095	2,116,631	11,647,606	1,082
13	2020	9,916,320	122,382	113,245	235,627	216,273	4,306,042	-	-	5,836,380	(1,775,646)	912,932	9,495,980	2,116,631	11,848,238	1,101
14	2021	9,916,320	125,441	116,076	241,517	220,598	4,392,163	-	-	5,953,108	(1,811,159)	940,320	9,695,029	2,116,631	12,053,178	1,120
15	2022	9,916,320	128,577	118,978	247,555	225,010	4,480,006	-	-	6,072,170	(1,847,382)	968,529	9,898,333	2,116,631	12,262,519	1,139
PW Cost			769,032	711,619	1,480,651	1,402,352	27,921,169	-	-	37,844,166	(11,513,617)	5,562,715	61,216,786	15,650,000	78,347,437	485
(% of PW Cost)			1.0%	0.9%	1.9%	1.8%	35.6%	0.0%	0.0%	48.3%	-14.7%	7.1%	78.1%	20.0%	100.0%	

Abitibi Snowflake Economic Analysis — Case 3 — OFA Using Existing Fan

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	25,740	-	25,740	-	-	-	-	-	3,118,229	74,685	3,192,914	2,705	3,221,359	3,713
2	2009	9,916,320	26,384	-	26,384	-	-	-	-	-	3,180,594	76,926	3,257,519	2,705	3,286,608	3,788
3	2010	9,916,320	27,043	-	27,043	-	-	-	-	-	3,244,205	79,234	3,323,439	2,705	3,353,187	3,865
4	2011	9,916,320	27,719	-	27,719	-	-	-	-	-	3,309,090	81,611	3,390,700	2,705	3,421,124	3,943
5	2012	9,916,320	28,412	-	28,412	-	-	-	-	-	3,375,271	84,059	3,459,330	2,705	3,490,447	4,023
6	2013	9,916,320	29,122	-	29,122	-	-	-	-	-	3,442,777	86,581	3,529,358	2,705	3,561,185	4,104
7	2014	9,916,320	29,851	-	29,851	-	-	-	-	-	3,511,632	89,178	3,600,811	2,705	3,633,366	4,187
8	2015	9,916,320	30,597	-	30,597	-	-	-	-	-	3,581,865	91,854	3,673,719	2,705	3,707,020	4,272
9	2016	9,916,320	31,362	-	31,362	-	-	-	-	-	3,653,502	94,609	3,748,111	2,705	3,782,178	4,359
10	2017	9,916,320	32,146	-	32,146	-	-	-	-	-	3,726,572	97,447	3,824,020	2,705	3,858,870	4,447
11	2018	9,916,320	32,949	-	32,949	-	-	-	-	-	3,801,104	100,371	3,901,475	2,705	3,937,129	4,538
12	2019	9,916,320	33,773	-	33,773	-	-	-	-	-	3,877,126	103,382	3,980,508	2,705	4,016,986	4,630
13	2020	9,916,320	34,617	-	34,617	-	-	-	-	-	3,954,668	106,483	4,061,152	2,705	4,098,474	4,723
14	2021	9,916,320	35,483	-	35,483	-	-	-	-	-	4,033,762	109,678	4,143,440	2,705	4,181,628	4,819
15	2022	9,916,320	36,370	-	36,370	-	-	-	-	-	4,114,437	112,968	4,227,405	2,705	4,266,480	4,917
PW Cost			217,532	-	217,532	-	-	-	-	-	25,642,799	648,830	26,291,629	20,000	26,529,161	2,038
(% of PW Cost)			0.8%	0.0%	0.8%	0.0%	0.0%	0.0%	0.0%	0.0%	96.7%	2.4%	99.1%	0.1%	100.0%	

Abitibi Snowflake Economic Analysis — Case 4 — New Low-NOx Burners (LNB)

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	84,221	-	84,221	-	-	-	-	-	3,118,229	-	3,118,229	197,735	3,400,185	2,078
2	2009	9,916,320	86,327	-	86,327	-	-	-	-	-	3,180,594	-	3,180,594	197,735	3,464,655	2,118
3	2010	9,916,320	88,485	-	88,485	-	-	-	-	-	3,244,205	-	3,244,205	197,735	3,530,425	2,158
4	2011	9,916,320	90,697	-	90,697	-	-	-	-	-	3,309,090	-	3,309,090	197,735	3,597,522	2,199
5	2012	9,916,320	92,964	-	92,964	-	-	-	-	-	3,375,271	-	3,375,271	197,735	3,665,971	2,241
6	2013	9,916,320	95,288	-	95,288	-	-	-	-	-	3,442,777	-	3,442,777	197,735	3,735,800	2,283
7	2014	9,916,320	97,671	-	97,671	-	-	-	-	-	3,511,632	-	3,511,632	197,735	3,807,038	2,327
8	2015	9,916,320	100,112	-	100,112	-	-	-	-	-	3,581,865	-	3,581,865	197,735	3,879,713	2,371
9	2016	9,916,320	102,615	-	102,615	-	-	-	-	-	3,653,502	-	3,653,502	197,735	3,953,853	2,416
10	2017	9,916,320	105,180	-	105,180	-	-	-	-	-	3,726,572	-	3,726,572	197,735	4,029,488	2,463
11	2018	9,916,320	107,810	-	107,810	-	-	-	-	-	3,801,104	-	3,801,104	197,735	4,106,649	2,510
12	2019	9,916,320	110,505	-	110,505	-	-	-	-	-	3,877,126	-	3,877,126	197,735	4,185,366	2,558
13	2020	9,916,320	113,268	-	113,268	-	-	-	-	-	3,954,668	-	3,954,668	197,735	4,265,671	2,607
14	2021	9,916,320	116,100	-	116,100	-	-	-	-	-	4,033,762	-	4,033,762	197,735	4,347,597	2,657
15	2022	9,916,320	119,002	-	119,002	-	-	-	-	-	4,114,437	-	4,114,437	197,735	4,431,174	2,708
PW Cost			711,763	-	711,763	-	-	-	-	-	25,642,799	-	25,642,799	1,462,020	27,816,582	1,133
(% of PW Cost)			2.6%	0.0%	2.6%	0.0%	0.0%	0.0%	0.0%	0.0%	92.2%	0.0%	92.2%	5.3%	100.0%	

Abitibi Snowflake Economic Analysis — Case 5 — New LNB w/OFA Modifications

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	109,284	-	109,284	-	-	-	-	-	3,118,229	-	3,118,229	282,479	3,509,992	1,627
2	2009	9,916,320	112,016	-	112,016	-	-	-	-	-	3,180,594	-	3,180,594	282,479	3,575,089	1,658
3	2010	9,916,320	114,817	-	114,817	-	-	-	-	-	3,244,205	-	3,244,205	282,479	3,641,501	1,688
4	2011	9,916,320	117,687	-	117,687	-	-	-	-	-	3,309,090	-	3,309,090	282,479	3,709,255	1,720
5	2012	9,916,320	120,629	-	120,629	-	-	-	-	-	3,375,271	-	3,375,271	282,479	3,778,379	1,752
6	2013	9,916,320	123,645	-	123,645	-	-	-	-	-	3,442,777	-	3,442,777	282,479	3,848,901	1,785
7	2014	9,916,320	126,736	-	126,736	-	-	-	-	-	3,511,632	-	3,511,632	282,479	3,920,847	1,818
8	2015	9,916,320	129,904	-	129,904	-	-	-	-	-	3,581,865	-	3,581,865	282,479	3,994,248	1,852
9	2016	9,916,320	133,152	-	133,152	-	-	-	-	-	3,653,502	-	3,653,502	282,479	4,069,133	1,887
10	2017	9,916,320	136,481	-	136,481	-	-	-	-	-	3,726,572	-	3,726,572	282,479	4,145,532	1,922
11	2018	9,916,320	139,893	-	139,893	-	-	-	-	-	3,801,104	-	3,801,104	282,479	4,223,475	1,958
12	2019	9,916,320	143,390	-	143,390	-	-	-	-	-	3,877,126	-	3,877,126	282,479	4,302,995	1,995
13	2020	9,916,320	146,975	-	146,975	-	-	-	-	-	3,954,668	-	3,954,668	282,479	4,384,122	2,033
14	2021	9,916,320	150,649	-	150,649	-	-	-	-	-	4,033,762	-	4,033,762	282,479	4,466,890	2,071
15	2022	9,916,320	154,415	-	154,415	-	-	-	-	-	4,114,437	-	4,114,437	282,479	4,551,331	2,110
PW Cost			923,573	-	923,573	-	-	-	-	-	25,642,799	-	25,642,799	2,088,600	28,654,973	886
(% of PW Cost)			3.2%	0.0%	3.2%	0.0%	0.0%	0.0%	0.0%	0.0%	89.5%	0.0%	89.5%	7.3%	100.0%	

Abitibi Snowflake Economic Analysis — Case 6 — New LNB w/ OFA & HERT SNCR

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	119,841	1,802	121,643	499	-	347,270	-	-	3,118,229	3,472	3,469,470	377,667	3,968,779	1,582
2	2009	9,916,320	122,837	1,847	124,684	509	-	357,688	-	-	3,180,594	3,576	3,542,367	377,667	4,044,717	1,612
3	2010	9,916,320	125,908	1,893	127,801	519	-	368,418	-	-	3,244,205	3,683	3,616,827	377,667	4,122,294	1,643
4	2011	9,916,320	129,056	1,941	130,996	530	-	379,471	-	-	3,309,090	3,794	3,692,884	377,667	4,201,547	1,675
5	2012	9,916,320	132,282	1,989	134,271	540	-	390,855	-	-	3,375,271	3,908	3,770,574	377,667	4,282,512	1,707
6	2013	9,916,320	135,589	2,039	137,628	551	-	402,581	-	-	3,442,777	4,025	3,849,934	377,667	4,365,228	1,740
7	2014	9,916,320	138,979	2,090	141,069	562	-	414,658	-	-	3,511,632	4,146	3,930,998	377,667	4,449,733	1,774
8	2015	9,916,320	142,453	2,142	144,595	574	-	427,098	-	-	3,581,865	4,270	4,013,806	377,667	4,536,068	1,808
9	2016	9,916,320	146,015	2,196	148,210	585	-	439,911	-	-	3,653,502	4,398	4,098,396	377,667	4,624,273	1,843
10	2017	9,916,320	149,665	2,250	151,915	597	-	453,108	-	-	3,726,572	4,530	4,184,807	377,667	4,714,389	1,879
11	2018	9,916,320	153,407	2,307	155,713	609	-	466,701	-	-	3,801,104	4,666	4,273,080	377,667	4,806,459	1,916
12	2019	9,916,320	157,242	2,364	159,606	621	-	480,702	-	-	3,877,126	4,806	4,363,255	377,667	4,900,528	1,953
13	2020	9,916,320	161,173	2,423	163,596	633	-	495,123	-	-	3,954,668	4,950	4,455,375	377,667	4,996,638	1,992
14	2021	9,916,320	165,202	2,484	167,686	646	-	509,977	-	-	4,033,762	5,099	4,549,483	377,667	5,094,836	2,031
15	2022	9,916,320	169,332	2,546	171,878	659	-	525,276	-	-	4,114,437	5,252	4,645,624	377,667	5,195,169	2,071
PW Cost			1,012,792	15,229	1,028,021	4,106	-	3,016,907	-	-	25,642,799	30,163	28,693,974	2,792,400	32,514,395	864
(% of PW Cost)			3.1%	0.0%	3.2%	0.0%	0.0%	9.3%	0.0%	0.0%	78.9%	0.1%	88.3%	8.6%	100.0%	

Abitibi Snowflake Economic Analysis — Case 7 — Mobotec ROFA

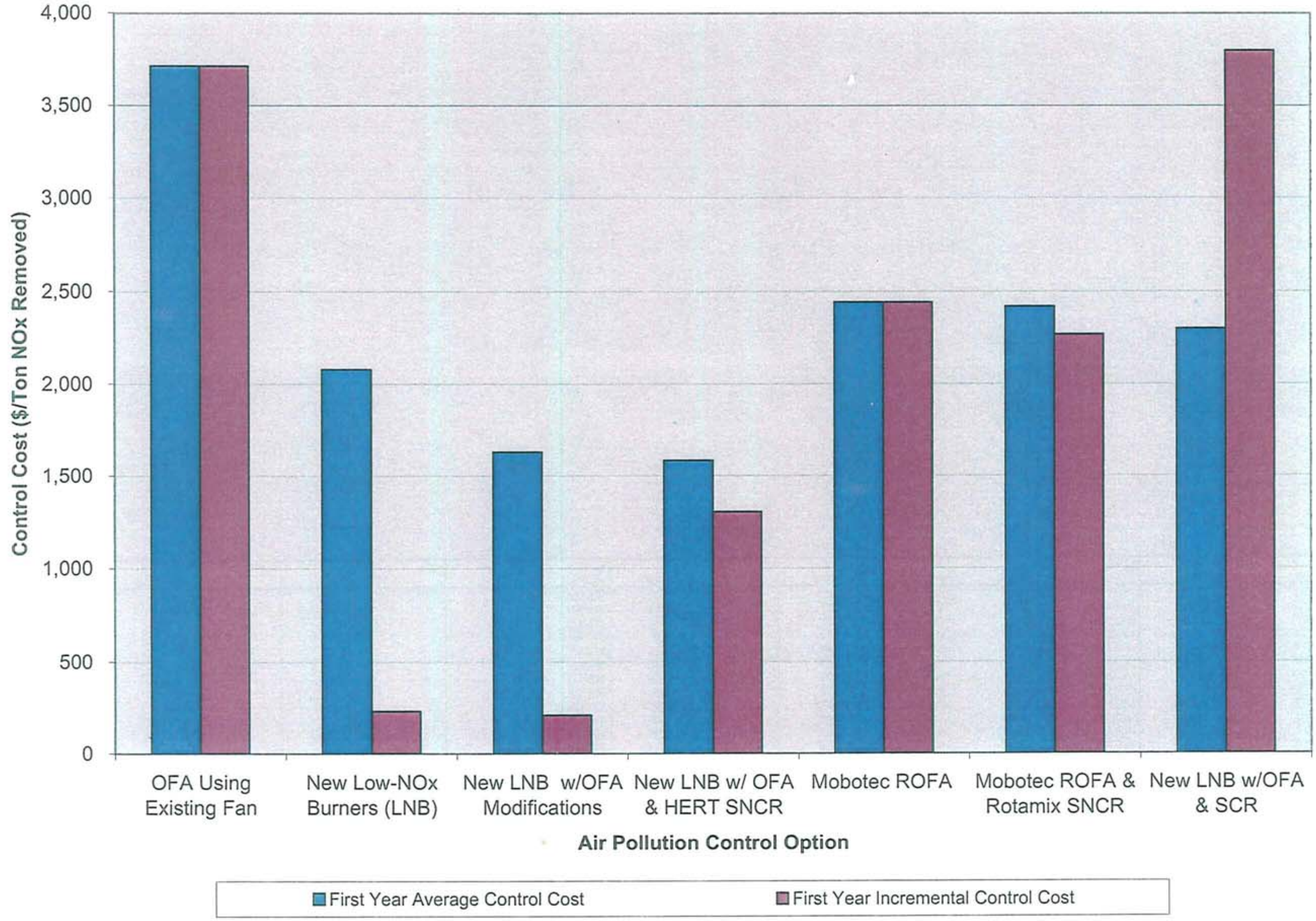
Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	207,185	-	207,185	-	-	-	-	-	3,118,229	323,637	3,441,866	613,502	4,262,553	2,442
2	2009	9,916,320	212,365	-	212,365	-	-	-	-	-	3,180,594	333,346	3,513,939	613,502	4,339,806	2,487
3	2010	9,916,320	217,674	-	217,674	-	-	-	-	-	3,244,205	343,346	3,587,552	613,502	4,418,727	2,532
4	2011	9,916,320	223,116	-	223,116	-	-	-	-	-	3,309,090	353,646	3,662,736	613,502	4,499,354	2,578
5	2012	9,916,320	228,693	-	228,693	-	-	-	-	-	3,375,271	364,256	3,739,527	613,502	4,581,723	2,625
6	2013	9,916,320	234,411	-	234,411	-	-	-	-	-	3,442,777	375,184	3,817,960	613,502	4,665,873	2,673
7	2014	9,916,320	240,271	-	240,271	-	-	-	-	-	3,511,632	386,439	3,898,071	613,502	4,751,844	2,723
8	2015	9,916,320	246,278	-	246,278	-	-	-	-	-	3,581,865	398,032	3,979,897	613,502	4,839,677	2,773
9	2016	9,916,320	252,435	-	252,435	-	-	-	-	-	3,653,502	409,973	4,063,475	613,502	4,929,412	2,824
10	2017	9,916,320	258,746	-	258,746	-	-	-	-	-	3,726,572	422,272	4,148,845	613,502	5,021,092	2,877
11	2018	9,916,320	265,214	-	265,214	-	-	-	-	-	3,801,104	434,941	4,236,044	613,502	5,114,761	2,931
12	2019	9,916,320	271,845	-	271,845	-	-	-	-	-	3,877,126	447,989	4,325,115	613,502	5,210,461	2,985
13	2020	9,916,320	278,641	-	278,641	-	-	-	-	-	3,954,668	461,428	4,416,097	613,502	5,308,239	3,041
14	2021	9,916,320	285,607	-	285,607	-	-	-	-	-	4,033,762	475,271	4,509,033	613,502	5,408,142	3,099
15	2022	9,916,320	292,747	-	292,747	-	-	-	-	-	4,114,437	489,529	4,603,966	613,502	5,510,215	3,157
PW Cost			1,750,947	-	1,750,947	-	-	-	-	-	25,642,799	2,811,595	28,454,395	4,536,126	34,741,468	1,327
(% of PW Cost)			5.0%	0.0%	5.0%	0.0%	0.0%	0.0%	0.0%	0.0%	73.8%	8.1%	81.9%	13.1%	100.0%	

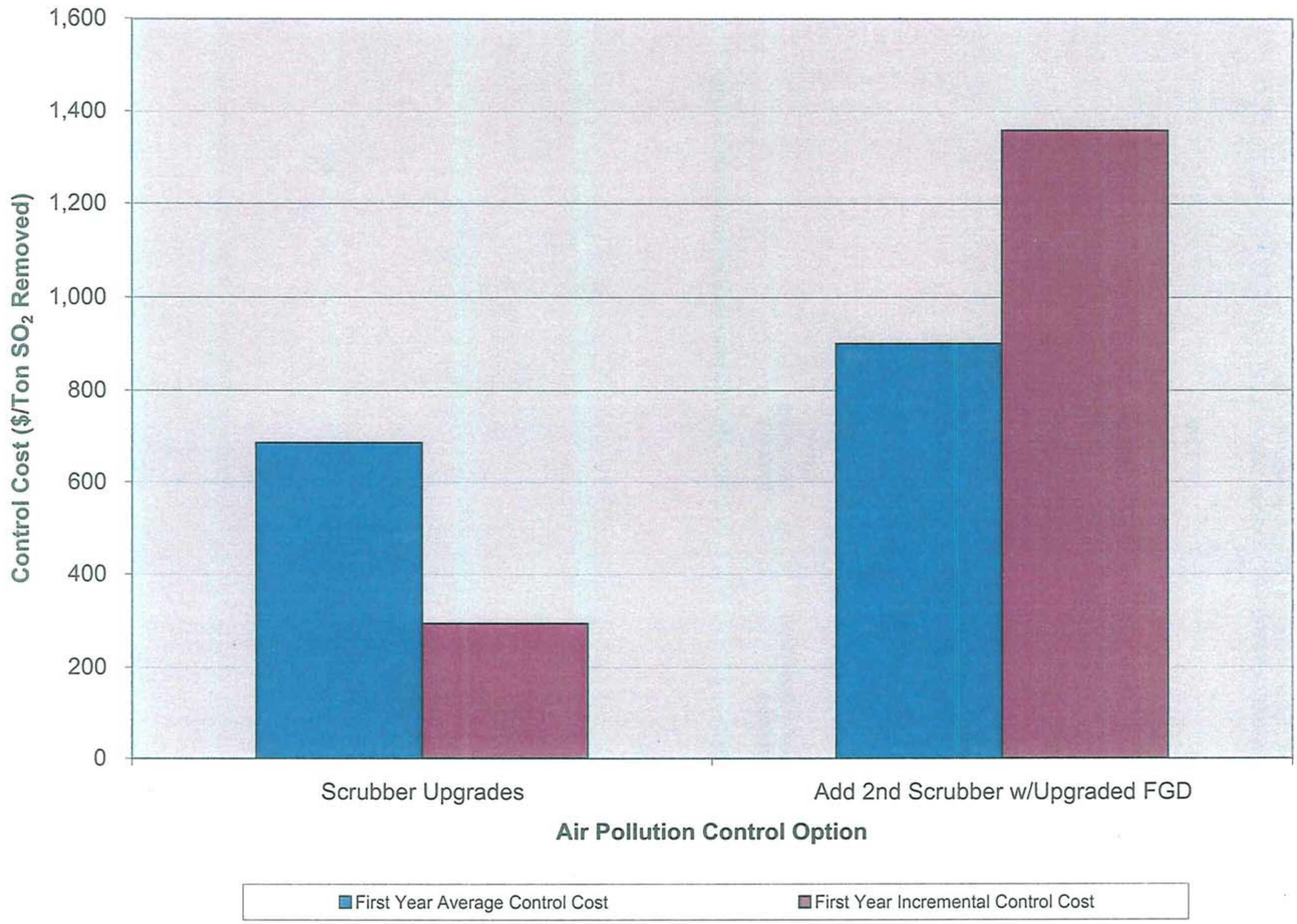
Abitibi Snowflake Economic Analysis — Case 8 — Mobotec ROFA & Rotamix SNCR

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Urea Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	228,616	1,802	230,418	4,322	-	416,723	-	-	3,118,229	327,109	3,866,383	806,733	4,903,534	2,418
2	2009	9,916,320	234,331	1,847	236,178	4,409	-	429,225	-	-	3,180,594	336,922	3,951,149	806,733	4,994,060	2,463
3	2010	9,916,320	240,190	1,893	242,083	4,497	-	442,102	-	-	3,244,205	347,029	4,037,834	806,733	5,086,649	2,508
4	2011	9,916,320	246,194	1,941	248,135	4,587	-	455,365	-	-	3,309,090	357,440	4,126,482	806,733	5,181,349	2,555
5	2012	9,916,320	252,349	1,989	254,338	4,678	-	469,026	-	-	3,375,271	368,164	4,217,139	806,733	5,278,210	2,603
6	2013	9,916,320	258,658	2,039	260,697	4,772	-	483,097	-	-	3,442,777	379,208	4,309,854	806,733	5,377,283	2,652
7	2014	9,916,320	265,124	2,090	267,214	4,867	-	497,590	-	-	3,511,632	390,585	4,404,674	806,733	5,478,621	2,702
8	2015	9,916,320	271,753	2,142	273,895	4,965	-	512,517	-	-	3,581,865	402,302	4,501,649	806,733	5,582,277	2,753
9	2016	9,916,320	278,546	2,196	280,742	5,064	-	527,893	-	-	3,653,502	414,371	4,600,830	806,733	5,688,305	2,805
10	2017	9,916,320	285,510	2,250	287,761	5,165	-	543,730	-	-	3,726,572	426,802	4,702,270	806,733	5,796,763	2,859
11	2018	9,916,320	292,648	2,307	294,955	5,269	-	560,041	-	-	3,801,104	439,607	4,806,020	806,733	5,907,708	2,913
12	2019	9,916,320	299,964	2,364	302,328	5,374	-	576,843	-	-	3,877,126	452,795	4,912,137	806,733	6,021,198	2,969
13	2020	9,916,320	307,463	2,423	309,887	5,482	-	594,148	-	-	3,954,668	466,379	5,020,676	806,733	6,137,296	3,026
14	2021	9,916,320	315,150	2,484	317,634	5,591	-	611,972	-	-	4,033,762	480,370	5,131,695	806,733	6,256,062	3,085
15	2022	9,916,320	323,028	2,546	325,575	5,703	-	630,332	-	-	4,114,437	494,781	5,245,253	806,733	6,377,560	3,145
PW Cost			1,932,064	15,229	1,947,292	35,543	-	3,620,288	-	-	25,642,799	2,841,758	32,140,388	5,964,840	40,052,521	1,317
(% of PW Cost)			4.8%	0.0%	4.9%	0.1%	0.0%	9.0%	0.0%	0.0%	64.0%	7.1%	80.2%	14.9%	100.0%	

Abitibi Snowflake Economic Analysis — Case 9 — New LNB w/OFA & SCR

Year	Date	Annual Boiler Heat Input (MMBtu/Yr)	Fixed O&M	Non-Fuel Variable O&M	TOTAL O&M COST	Makeup Water Cost	Alkali Reagent Cost	Ammonia Cost	SCR Catalyst Cost	Scrubber Waste Disposal Cost	Fly Ash Disposal + Lost Fly Ash Sales	Electric Power Cost	TOTAL CONSUMABLES COST	DEBT SERVICE	TOTAL ANNUAL COST	NOx Control Cost ($/Ton NOx Rem.)
0																
1	2008	9,916,320	246,973	-	246,973	-	-	87,485	435,717	-	3,118,229	189,122	3,830,553	3,104,010	7,181,536	2,299
2	2009	9,916,320	253,147	-	253,147	-	-	90,109	448,788	-	3,180,594	194,796	3,914,287	3,104,010	7,271,445	2,328
3	2010	9,916,320	259,476	-	259,476	-	-	92,812	462,252	-	3,244,205	200,640	3,999,910	3,104,010	7,363,396	2,357
4	2011	9,916,320	265,963	-	265,963	-	-	95,597	476,119	-	3,309,090	206,659	4,087,465	3,104,010	7,457,438	2,387
5	2012	9,916,320	272,612	-	272,612	-	-	98,465	490,403	-	3,375,271	212,859	4,176,998	3,104,010	7,553,620	2,418
6	2013	9,916,320	279,427	-	279,427	-	-	101,419	505,115	-	3,442,777	219,245	4,268,555	3,104,010	7,651,993	2,450
7	2014	9,916,320	286,413	-	286,413	-	-	104,461	520,269	-	3,511,632	225,822	4,362,184	3,104,010	7,752,607	2,482
8	2015	9,916,320	293,573	-	293,573	-	-	107,595	535,877	-	3,581,865	232,597	4,457,933	3,104,010	7,855,517	2,515
9	2016	9,916,320	300,913	-	300,913	-	-	110,823	551,953	-	3,653,502	239,575	4,555,853	3,104,010	7,960,776	2,549
10	2017	9,916,320	308,435	-	308,435	-	-	114,148	568,512	-	3,726,572	246,762	4,655,993	3,104,010	8,068,439	2,583
11	2018	9,916,320	316,146	-	316,146	-	-	117,572	585,567	-	3,801,104	254,165	4,758,407	3,104,010	8,178,564	2,618
12	2019	9,916,320	324,050	-	324,050	-	-	121,099	603,134	-	3,877,126	261,790	4,863,149	3,104,010	8,291,209	2,654
13	2020	9,916,320	332,151	-	332,151	-	-	124,732	621,228	-	3,954,668	269,643	4,970,272	3,104,010	8,406,433	2,691
14	2021	9,916,320	340,455	-	340,455	-	-	128,474	639,865	-	4,033,762	277,733	5,079,833	3,104,010	8,524,299	2,729
15	2022	9,916,320	348,966	-	348,966	-	-	132,328	659,061	-	4,114,437	286,065	5,191,891	3,104,010	8,644,867	2,768
PW Cost			2,087,201	-	2,087,201	-	-	760,024	3,785,293	-	25,642,799	1,643,002	31,831,118	22,950,507	56,868,826	1,870
(% of PW Cost)			3.7%	0.0%	3.7%	0.0%	0.0%	1.3%	6.7%	0.0%	45.1%	2.9%	56.0%	40.4%	100.0%	


4,000
3,500
3,000
2,500
2,000
1,500
1,000
500
0
Control Cost ($/Ton NOx Removed)
OFA Using Existing Fan
New Low-NOx Burners (LNB)
New LNB w/OFA Modifications
New LNB w/ OFA & HERT SNCR
Mobotec ROFA
Mobotec ROFA & Rotamix SNCR
New LNB w/OFA & SCR
Air Pollution Control Option
First Year Average Control Cost
First Year Incremental Control Cost


1,600
1,400
1,200
1,000
800
600
400
200
0
Control Cost ($/Ton SO_2 Removed)
Scrubber Upgrades
Add 2nd Scrubber w/Upgraded FGD
Air Pollution Control Option
First Year Average Control Cost
First Year Incremental Control Cost

Abitibi BART SCR

USEPA. Cost of Selective Catalytic Reduction (SCR) Application for NOx Control on Coal-Fired Boilers (EPA-600/R-01-087). October 2001.

Plant Data		
B = Inlet NOx (lb/MMBTU)	0.265	
NOx outlet (lb/MMBTU)	0.07	
C = NOx removal efficiency (%)	73.6	
A = Plant capacity (KW)	102909	
Annual operating hours	8760	
Plant Capacity Factor	1	
Andydrous NH3 cost ($/ton)	225	
Heat Input (MMBTU/hr)	1132	
Electric Power Cost $/kWh	0.037	
Capital adjustment factor (2000-2007)	2	
Cost of auxiliary power/unit of generation	0.0055	constant
Total Capital Investment (end of 2007) ($)	$20,861,907	
Fixed O&M Cost ($/yr)	$137,689	
NH3 Use Cost ($/yr)	$84,937	
Annual Catalyst Replacement Cost ($/yr)	$423,026	
Energy Requirement Cost ($/yr)	$183,452	
Variable O&M Costs ($/yr)	$691,415	NH3 use + catalyst replacement + energy

Terms of Payment
Progress payments will be submitted when project milestones are completed.

Validity

This budget proposal is valid for acceptance for ninety (90) days.

COMBUSTION IMPROVEMENT
Mobotec
MULTI-POLLUTANT REDUCTION

Abitibi Unit #2
Budget Pricing & Estimates

October 23, 2007

Mobotec USA
Ph: 925.935.2500
Fax: 925.935.2583

Physical Address:
2540 Camino Diablo Boulevard, Suite 200
Walnut Creek, California 94597-3933

Mailing Address:
Post Office Box 2025
Orinda, California 94563

ABITIBI
ROFA 2007 Estimate
FOR NOx CONTROL

Capital Cost Factors

DIRECT COSTS	Cost Factors				
(1) Purchased Equipment					
(a) Basic Equipment and auxiliaries					
Capital Cost of ROFA System				= $	2,171,850
Total Capital Cost				= $	2,171,850
(b) Instruments and controls [0.1 * (a)]	0.1	*	(a)	= $	217,185
(c) Taxes [0.03(a)]	0.03	*	(a)	= $	65,156
(d) Freight [0.05(a)]	0.05	*	(a)	= $	108,593
Total Equipment Cost (TEC)				= $	2,562,783
(2) Construction Costs					
(a) Foundations and supports	0	*	(TEC)	= $	-
(b) Handling and Erection	0.14	*	(TEC)	= $	358,790
(c) Electrical	0.04	*	(TEC)	= $	102,511
(d) Piping	0	*	(TEC)	= $	-
(e) Insulation	0.01	*	(TEC)	= $	25,628
(f) Painting	0	*	(TEC)	= $	-
Total Construction Costs (TCC)				= $	486,929
Total Direct Costs (TDC)	(TEC)	+	(TCC)	= $	3,049,712
INDIRECT COSTS					
(3) Engineering and supervision	0.2	*	(TEC)	= $	512,557
(4) Construction and field expenses	0.05	*	(TEC)	= $	128,139
(5) Construction fee	0.1	*	(TEC)	= $	256,278
(6) Start-up	0.02	*	(TEC)	= $	51,256
(7) Performance test	0.01	*	(TEC)	= $	25,628
(8) Contingency	0.2	*	(TEC)	= $	512,557
TOTAL INDIRECT COSTS (TIC)				= $	1,486,414
TOTAL INSTALLED CAPITAL COSTS (TICC)				= $	4,536,126

ABITIBI
ROFA 2007 Estimate
FOR NOx CONTROL

Annualized Cost Factors

DIRECT COSTS			Cost Factors			
(1) Operating Labor:	180	hours/year	*	$45	= $	8,100
(2) Supervisory Labor		15%	of	(1)	= $	1,215
(3) Maintenance Labor:	365	hours/year	*	$45	= $	16,425
(4) Parts and Materials					= $	-
(5) Utilities						
Power needs:			*		= $	-
Assume cost of power is $.037 per kw						
Power needed =	0	kw			= $	-
(6) Replacement Catalyst						
Catalyst Cost *Capital Recovery Factor, Assuming 3 -year life and 7% interest						
Catalyst Cost =	$ -					
Capital Recovery Factor = $[I(1+I)^m]/(1+I)^m-1]$				0.381	= $	-
I=interest rate and m=equipment life						
(7) Freight for Catalyst Return for Recovery						
0.05*Catalyst Cost*Capital Recovery Factor					= $	-
TOTAL DIRECT COSTS (TDAC)					= $	25,740
INDIRECT COSTS						
(6) Overhead	Included in $/hour used		in	(1) + (2) + (3)	= $	-
(7) Property Tax		1%	of	(TICC)	= $	45,361
(8) Insurance		1%	of	(TICC)	= $	45,361
(9) G&A Charges		2%	of	(TICC)	= $	90,723
(10) Capital Recovery		0.135	*	(TICC)	=	
TOTAL INDIRECT COSTS (TIAC)					= $	181,445
TOTAL ANNUALIZED COSTS					= $	207,185

Cost factors - from OAQPS Control Cost Manual, Chapter 3
Based on lowest cost estimate from four other projects

Capital Recovery Factor for System - Based on a 15-year equipment life and10.5% interest rate,
base cost excludes cost of catalyst because equipment life will be less than 20 years

ABITIBI
Operating Existing OFA Fan 2007 Estimate
FOR NOx CONTROL

Capital Cost Factors

DIRECT COSTS	**Cost Factors**				
(1) Purchased Equipment					
(a) Basic Equipment and auxiliaries					
Capital Cost of LNB System				= $	-
Total Capital Cost				= $	-
(b) Instruments and controls [0.1 * (a)]	0.1	*	(a)	= $	-
(c) Taxes [0.03(a)]	0.03	*	(a)	= $	-
(d) Freight [0.05(a)]	0.05	*	(a)	= $	-
Total Equipment Cost (TEC)				= $	-
(2) Construction Costs					
(a) Foundations and supports	0	*	(TEC)	= $	-
(b) Handling and Erection	0.14	*	(TEC)	= $	-
(c) Electrical	0.04	*	(TEC)	= $	-
(d) Piping	0	*	(TEC)	= $	-
(e) Insulation	0.01	*	(TEC)	= $	-
(f) Painting	0	*	(TEC)	= $	-
Total Construction Costs (TCC)				= $	-
Total Direct Costs (TDC)	(TEC)	+	(TCC)	= $	-
INDIRECT COSTS					
(3) Engineering and supervision	0.2	*	(TEC)	= $	-
(4) Construction and field expenses	0.05	*	(TEC)	= $	-
(5) Construction fee	0.1	*	(TEC)	= $	-
(6) Start-up	0.02	*	(TEC)	= $	-
(7) Performance test	0.01	*	(TEC)	= $	-
(8) Contingency	0.2	*	(TEC)	= $	-
TOTAL INDIRECT COSTS (TIC)				= $	-
TOTAL INSTALLED CAPITAL COSTS (TICC)				= $	-

ABITIBI
Operating Existing OFA Fan 2007 Estimate
FOR NOx CONTROL

Annualized Cost Factors

DIRECT COSTS			Cost Factors			
(1) Operating Labor:	180	hours/year	*	$45	= $	8,100
(2) Supervisory Labor		15%	of	(1)	= $	1,215
(3) Maintenance Labor:	365	hours/year	*	$45	= $	16,425
(4) Parts and Materials					= $	-
(5) Utilities						
Power needs:			*		= $	-
Assume cost of power is $.037 per kw						
Power needed =	0	kw			= $	-
(6) Replacement Catalyst						
Catalyst Cost *Capital Recovery Factor, Assuming 3 -year life and 7% interest						
Catalyst Cost =	$	-				
Capital Recovery Factor = $[I(1+I)^m]/(1+I)^m-1]$				0.381	= $	-
I=interest rate and m=equipment life						
(7) Freight for Catalyst Return for Recovery						
0.05*Catalyst Cost*Capital Recovery Factor					= $	-
TOTAL DIRECT COSTS (TDAC)					= $	25,740
INDIRECT COSTS						
(6) Overhead	Included in $/hour used		in	(1) + (2) + (3)	= $	-
(7) Property Tax		1%	of	(TICC)	= $	-
(8) Insurance		1%	of	(TICC)	= $	-
(9) G&A Charges		2%	of	(TICC)	= $	-
(10) Capital Recovery		0.135	*	(TICC)	=	
TOTAL INDIRECT COSTS (TIAC)					= $	-
TOTAL ANNUALIZED COSTS					= $	25,740

Cost factors - from OAQPS Control Cost Manual, Chapter 3
Based on lowest cost estimate from four other projects

Capital Recovery Factor for System - Based on a 15-year equipment life and10.5% interest rate,
base cost excludes cost of catalyst because equipment life will be less than 20 years

ABITIBI

Low NOx Burner w/ OFA 2007 Estimate
FOR NOx CONTROL

Capital Cost Factors

DIRECT COSTS	**Cost Factors**				
(1) Purchased Equipment					
(a) Basic Equipment and auxiliaries					
Capital Cost of LNB System				= $	1,000,000
Total Capital Cost				= $	1,000,000
(b) Instruments and controls [0.1 * (a)]	0.1	*	(a)	= $	100,000
(c) Taxes [0.03(a)]	0.03	*	(a)	= $	30,000
(d) Freight [0.05(a)]	0.05	*	(a)	= $	50,000
Total Equipment Cost (TEC)				= $	1,180,000
(2) Construction Costs					
(a) Foundations and supports	0	*	(TEC)	= $	-
(b) Handling and Erection	0.14	*	(TEC)	= $	165,200
(c) Electrical	0.04	*	(TEC)	= $	47,200
(d) Piping	0	*	(TEC)	= $	-
(e) Insulation	0.01	*	(TEC)	= $	11,800
(f) Painting	0	*	(TEC)	= $	-
Total Construction Costs (TCC)				= $	224,200
Total Direct Costs (TDC)	(TEC)	+	(TCC)	= $	1,404,200
INDIRECT COSTS					
(3) Engineering and supervision	0.2	*	(TEC)	= $	236,000
(4) Construction and field expenses	0.05	*	(TEC)	= $	59,000
(5) Construction fee	0.1	*	(TEC)	= $	118,000
(6) Start-up	0.02	*	(TEC)	= $	23,600
(7) Performance test	0.01	*	(TEC)	= $	11,800
(8) Contingency	0.2	*	(TEC)	= $	236,000
TOTAL INDIRECT COSTS (TIC)				= $	684,400
TOTAL INSTALLED CAPITAL COSTS (TICC)				= $	2,088,600

ABITIBI
Low NOx Burner w/ OFA 2007 Estimate
FOR NOx CONTROL

Annualized Cost Factors

DIRECT COSTS			**Cost Factors**			
(1) Operating Labor:	180	hours/year	*	$45	= $	8,100
(2) Supervisory Labor		15%	of	(1)	= $	1,215
(3) Maintenance Labor:	365	hours/year	*	$45	= $	16,425
(4) Parts and Materials					= $	-
(5) Utilities						
Power needs:			*		= $	-
Assume cost of power is $.037 per kw						
Power needed =	0	kw			= $	-
(6) Replacement Catalyst						
Catalyst Cost *Capital Recovery Factor, Assuming 3 -year life and 7% interest						
Catalyst Cost =	$	-				
Capital Recovery Factor = $[I(1+I)^{n}]/(1+I)^{m}-1]$				0.381	= $	-
I=interest rate and m=equipment life						
(7) Freight for Catalyst Return for Recovery						
0.05*Catalyst Cost*Capital Recovery Factor					= $	-
TOTAL DIRECT COSTS (TDAC)					= $	25,740
INDIRECT COSTS						
(6) Overhead	Included in $/hour used		in	(1) + (2) + (3)	= $	-
(7) Property Tax		1%	of	(TICC)	= $	20,886
(8) Insurance		1%	of	(TICC)	= $	20,886
(9) G&A Charges		2%	of	(TICC)	= $	41,772
(10) Capital Recovery		0.135	*	(TICC)	=	
TOTAL INDIRECT COSTS (TIAC)					= $	83,544
TOTAL ANNUALIZED COSTS					= $	109,284

Cost factors - from OAQPS Control Cost Manual, Chapter 3
Based on lowest cost estimate from four other projects

Capital Recovery Factor for System - Based on a 15-year equipment life and10.5% interest rate,
base cost excludes cost of catalyst because equipment life will be less than 20 years

ABITIBI
Low NOx Burner 2007 Estimate
FOR NOx CONTROL

Capital Cost Factors

DIRECT COSTS	Cost Factors				
(1) Purchased Equipment					
(a) Basic Equipment and auxiliaries					
Capital Cost of LNB System				= $	700,000
Total Capital Cost				= $	700,000
(b) Instruments and controls [0.1 * (a)]	0.1	*	(a)	= $	70,000
(c) Taxes [0.03(a)]	0.03	*	(a)	= $	21,000
(d) Freight [0.05(a)]	0.05	*	(a)	= $	35,000
Total Equipment Cost (TEC)				= $	826,000
(2) Construction Costs					
(a) Foundations and supports	0	*	(TEC)	= $	-
(b) Handling and Erection	0.14	*	(TEC)	= $	115,640
(c) Electrical	0.04	*	(TEC)	= $	33,040
(d) Piping	0	*	(TEC)	= $	-
(e) Insulation	0.01	*	(TEC)	= $	8,260
(f) Painting	0	*	(TEC)	= $	-
Total Construction Costs (TCC)				= $	156,940
Total Direct Costs (TDC)	(TEC)	+	(TCC)	= $	982,940
INDIRECT COSTS					
(3) Engineering and supervision	0.2	*	(TEC)	= $	165,200
(4) Construction and field expenses	0.05	*	(TEC)	= $	41,300
(5) Construction fee	0.1	*	(TEC)	= $	82,600
(6) Start-up	0.02	*	(TEC)	= $	16,520
(7) Performance test	0.01	*	(TEC)	= $	8,260
(8) Contingency	0.2	*	(TEC)	= $	165,200
TOTAL INDIRECT COSTS (TIC)				= $	479,080
TOTAL INSTALLED CAPITAL COSTS (TICC)				= $	1,462,020

ABITIBI
Low NOx Burner 2007 Estimate
FOR NOx CONTROL

Annualized Cost Factors

DIRECT COSTS			Cost Factors			
(1) Operating Labor:	180	hours/year	*	$45	= $	8,100
(2) Supervisory Labor		15%	of	(1)	= $	1,215
(3) Maintenance Labor:	365	hours/year	*	$45	= $	16,425
(4) Parts and Materials					= $	-
(5) Utilities						
Power needs:			*		= $	-
Assume cost of power is $.037 per kw						
Power needed =	0	kw			= $	-
(6) Replacement Catalyst						
Catalyst Cost *Capital Recovery Factor, Assuming 3 -year life and 7% interest						
Catalyst Cost =	$ -					
Capital Recovery Factor = $[I(1+I)^m]/(1+I)^m-1]$				0.381	= $	-
I=interest rate and m=equipment life						
(7) Freight for Catalyst Return for Recovery						
0.05*Catalyst Cost*Capital Recovery Factor					= $	-
TOTAL DIRECT COSTS (TDAC)					= $	25,740
INDIRECT COSTS						
(6) Overhead	Included in $/hour used		in	(1) + (2) + (3)	= $	-
(7) Property Tax		1%	of	(TICC)	= $	14,620
(8) Insurance		1%	of	(TICC)	= $	14,620
(9) G&A Charges		2%	of	(TICC)	= $	29,240
(10) Capital Recovery		0.135	*	(TICC)	=	
TOTAL INDIRECT COSTS (TIAC)					= $	58,481
TOTAL ANNUALIZED COSTS					= $	84,221

Cost factors - from OAQPS Control Cost Manual, Chapter 3
Based on lowest cost estimate from four other projects

Capital Recovery Factor for System - Based on a 15-year equipment life and10.5% interest rate,
base cost excludes cost of catalyst because equipment life will be less than 20 years

Capital Cost Factors for an SNCR Aplication

Cost	**EPA Cost Control Manual**	**ACT - HERT**	**Mobotec Rotamix**	
Boiler Size (MMBTU/Hr)	1132			
NOx Removal Efficiency	0.229			
Cost Year	2007			
Total Capacity Factor				
Total Direct Capital Cost	$1,409,441	$500,000	$1,015,000	vendor quotes
Indirect Installation Costs				
General Facilities	$70,472	$25,000	$50,750	
Engineering & Home Office Fees	$140,944	$50,000	$101,500	
Process Contingency	$70,472	$25,000	$50,750	
Total Indirect Installation Costs	$281,888	$100,000	$203,000	
Project Contingency	$253,699	$90,000	$182,700	
Total Plant Cost	$1,945,028	$690,000	$1,400,700	
Alowance for Funds During Construction	$0			
Royalty Allowance	$0			
Preproduction Cost	$38,901	$13,800	$28,014	
Inventory Capital	$2,531	$0	$0	
Initial Catalyst and Chemicals	$0			
Total Capital Investment	$1,986,460	$703,800	$1,428,714	

Annual Cost Calculations for SNCR

	Cost Control Manual	ACT - HERT	Mobotec Rotamix	
Toatal Capital Investment	$1,986,460	$703,800	$1,428,714	
Annual Maintenance cost $/yr	$29,797	$10,557	$21,431	
Annual Reagent Cost $/yr	$65,999			included in BART spreadsheet
Annual Electricity Cost $/yr	$3,485			included in BART spreadsheet
Annual Water Cost $/yr	$491			included in BART spreadsheet
Annual Coal Cost $/yr	$15,938	$15,938	$15,938	
Annual Ash Cost $/yr	$1,034	$1,034	$1,034	
Total Variable cost	$86,946	$16,971	$16,971	
Total Direct Annual Cost	$116,743	$27,528	$38,402	
Capital Recovery Factor	0.13525			
Indirect Annual Cost	$268,665			
Total Annual Cost	$385,408			
NOx Removed tons/yr	218.158192			
Cost Effectiveness $/ton	1767			

Abitibi SNCR - Plant Design Data

Plant Capacity MW	
Plant Heat rate Btu/kw	
Fuel High Heating Value Btu/lb	9200
Maximum Fuel Consumption rate lb/hr	123043
Annual Fuel Consuption MMBtu/yr	
Average annual Fuel Consumption lb/yr	1.078E+09
Number of SNCR operating days	365
Uncontrolled NOx concentration lb/MMBtu	0.192
Desired Outlet concentration lb/MMBtu	0.148
Fuel Ash Content % by weight	17.9
Stored Urea Concentration %	50
Injected Urea Concentration %	10
Number of days of storage for Urea	14
Cost year	2007
Equipment life years	15
Annual Interest rate	10.5
Coal Cost $/MMBtu	2.67
Ash Disposal Cost $/ton	17.8
50% Urea Cost $/gal	0.85
Water Consumption Cost $/gal	0.00139
Maximum Fuel Consuption Rate MMBTU/hr	1131.9956
Capacity Factor	1
SNCR Capacity Factor	1
Total Capacity Factor	1
NOx Removal Efficiency	0.2291667
Normalized Stoichiometric Ratio	1.2938368
Reagent Utilization	0.1771218
Reagent Mass Flow Rate lb/hr	42.061041
Flow Rate for diluted Solution lb/hr	84.122082
Solution Volume Flow Rate gal/hr	8.8636238
Reagent Tank Volume gal	2978.1776
Power Consumption kW	10.752767
Water Consumption lb/hr	40.322148
Additional Coal required lb/hr	0.6813889
Additional Ash lb/hr	13.257457

ALSTOM

Power
Customer Services Division
Boiler & Environmental Plant Services

Budgetary Proposal/Report No. 43081212

October 21, 2006

Ref: Abitibi Snowflake Mill, Arizona, Budgetary Proposal/Report No. 43081212

Subject: APC Equipment Status and Recommendations.

The following reports were reviewed along with various e-mails in support of the present report and recommendation. This interim report is developed for further discussion with Abitibi.

- MoDo Scrubber and Precipitator Evaluation Report of June 19, 2006 to June 29, 2006, by Don Champion
- MoDo Scrubber Internal Inspection Report dated September 20, 2006, by Don Champion
- E-Mail report dated October 3, 2006, by Arthur Swift

As a recap, I will restate what I believe to be the objective associated with this work effort.

1. Scrubber suffers from continual plugging of the mist eliminators and build up on the vessel walls leading to performance and reliability problems.
2. Both ESP's appear to suffer from "back corona" issues that affect the particulate output from the ESP's thus exacerbating the problems in the Scrubber
3. Abitibi is changing the coal source for the boiler unit, thus requiring an evaluation of whether the existing scrubber can handle the new levels of gas flow, gas volume, SO_2 and particulate.

The present coal being used is McKinley with the following characteristics:

0.54% Sulphur per lb
9280 Btu/lb
1.1 lbs SO2/MBTU

Plan is to go to Lee Ranch Coal, which has:
0.90% Sulphur per lb
9800 Btu/lb
1.88 lbs SO2/MBTU

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Initial Conclusion from Data, Reports and Inspections

From the Scrubber standpoint, the SO_2 removal performance based upon the original design parameters should accommodate this change of coal. The real issue is whether an increase in gas flow due to this change will result in an increase in gas velocity through the scrubber in excess of 12 ft/sec. It is not known at this time what the velocity through the scrubber is using the McKinley coal. More than likely it is in the 9.5-10 ft/sec range and therefore can accommodate a small increase and still achieve the original design performance. At this time we cannot accurately predict what the performance would be without testing and operation of the system in good condition to allow review of all parameters.

While it is entirely possible and probable that the Scrubber can meet the performance requirements caused by the change in coal, other elements of its operation will preclude it from doing so unless action is taken by the Customer.

The most critical problem is associated with the continual plugging problem of the ME's and trays and the continual plugging of the nozzles.

All of these issues tend to be caused by the particulate carryover from the ESP's and the lack of a clarifier to assist in the removal of solids prior to scrubbing. It was noted many years ago that the scrubber has no provisions for solids removal, therefore the ash and scale circulate until they plug a nozzle or line. The pumps also scale inside and on all the valves.

It is noted that the clarifier is not working at this time after being abandoned many years ago due to troublesome operation. The sizing was very small as it was only for blowdown.

Upon review of past reports in the early 1990's relating to issues with the scrubber, it was noted several times that the particulate carryover from the ESP's is a major cause of operational problems.

Several recommendations to assist in resolving some of these issues are included in this report.

They involve maintenance, repair and power supply upgrades to the ESP's in an attempt to enhance performance removal and opacity reduction of the hot side units, and the installation of a clarifier for all return flows to remove the large chunks, which contribute to the plugging problems.

Ideally, the addition of a second scrubber would allow redundancy an increase the reliability of the overall APC system and its operation. This is always and option based upon funding approval.

Following this section is some budgetary pricing associated with these recommendations

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Recommendations with Budgetary Pricing

MoDo Scrubber

From the referenced report it is evident that the scrubber is suffering from an excess of particulate input above the original design conditions.

This is evidenced by the continuing plugging of the ME's and build up of scale on the walls of the scrubber vessel. It is noted that the clarifier is not a functioning system at this time, which leads to a reduction in particulate removal effect of the system.

It is also noted that there are several different nozzles in use and it is highly likely that the nozzles in use today are worn and cause for further plugging problems by not producing an efficient spray pattern as required by the original design of the scrubber.

A further inspection and report was developed by Don Champion on September 20, 2006. From that report, Don's recommendations revolved around evaluation of the nozzle sizes for the Recycle Spray, Quench, and ME wash section. ALSTOM has no reason to believe that differently sized nozzles could be required for your systems.

What is recommended is that the Recycle Branch Lines From the suction Side of the Recycle pumps, Discharge lines from the Recycle Pumps, Recycle Tank, absorber Drain line, Absorber Spray Section main 10" header recycle line. Absorber Spray section Recycle Branch lines, Absorber Section Nozzles, Absorber Inlet Duct Quench Line and Nozzles be thoroughly cleaned. As included in the report, the following areas should also be cleaned. The Perforated Blade section, underside and topside. Vessel Side wall casing, the Chevron Section should be cleaned along with the upper split finger ducts and vertical bypass section of the Scrubber on the Duct floor, at the Back upper turning vanes and Upper stack entry point.

Items that require further development and discussion are:

- All missing Instruments and Control loops need to be addressed, including the possibility of replacement of the flow monitoring and control devices
- Consideration of a Ring header systems where Nozzles can be easily removed while Vessel is in operation has been requested with access platforms
- Design means to clean the Spray Header section piping more efficiently.
- Determine whether an agitator can be installed in the Recycle tank.

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The budgetary pricing for labor and materials that would bring the scrubber to a clean and operable level without making any changes that would resolve present issues is…….. **$650,000.00**

Clarifier Option

Budgetary price for materials and labor to install a new clarifier

Clarifier for solids removal…………………………………………….… $325,000.00 materials

Labor and Installation……………………………………………………. $550,000.00 labor

Budgetary Total for Clarifier…………………………………………… **$875,000.00 Total**

For the Southern Environmental ESP

From the report dated June 19 – June 29, 2006 a scope of work was developed to return the ESP to an acceptable operating condition along with items that would improve the performance and possibly reduce emissions.

The scope of supply for repair is shown in the table below

Description (SEI ESP)	Labor	Material Quantities	Budgetary Price
Mobilization	x	-	
Set up/ Material/Scaffolding	x	-	
Replace Rapper shoes on N. Unit	x	41	
Repair SE corner hot roof com wall	x	-	
Repair area in SE corner Hot Roof	x	-	
Repair and Replumb GD screens	x	-	
Clean and reconnect HV Buss	x	-	
Clean and regasket Access Doors	x	34	
Replace Rapper shoes on S. Unit	x	36	
Replumb MiGi's	x	77	
Clean Insulators	x	-	
Single Tapered adapter		100	
Double Tapered adapter		100	
Ground Straps		100	
Boot Seal Clamps		100	
Air load Checkout	x	-	
Cleanup & Demobilization	x	-	
	Budgetary Price		**$324,000.00**

The scope of supply for replacement equipment to assist in improving performance of the SEI ESP is shown in the following table

Description (SEI ESP)	Quantity	Price
70kv, 800mA SIR's (Switched Integrated Rectifiers) Includes controls and mechanical interfaces	8	
Ground switches and bus duct interfaces	8	
Budgetary Price, Material & Labor		**$362,000.00**

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For the Koppers ESP

From the report generated by Arthur Swift at the recent inspection, the foloowing scope of work has been developed to return ther unit to a better perfrominig condition. Following is the cost associated with upgrading the power supplies to assist in preventing the back corona conditions that are prevalent and allow more power into the ESP to enhance performance

Description (Koppers ESP)	Labor	Material Quantities	Budgetary Price
Mobilization	x	-	
Set up/ Material/Scaffolding	x	-	
Correct alignment or Rappers	x	5	
Replace support insulators	x	2	
Repair broken CE panel clips	x	2	
Repair GD screens	x	1	
Clean and reconnect HV bus	x	2	
Replace rapper shafts on Koppers Unit	x	22	
Inspect all CE panel clips	x	-	
Air load Checkout	x	-	
Cleanup & Demobilization	x	-	
Budgetary Price, Material & Labor			**$108,500.00**

The scope of supply for replacement equipment to assist in improving performance of the Koppers ESP is shown in the following table

Description (Koppers ESP)	Quantity	Price
70kv, 800mA SIR's (Switched Integrated Rectifiers)	8	
Includes controls and mechanical interfaces		
Ground switches and bus duct interfaces	8	
Budgetary Price		**$362,000.00**

Optional Budgetary Pircing for a Second Scrubber

Budget Scope:

Description- Additional MoDo Scrubber	Quantity	Price
MoDo Scrubber of similar size including accessories and controls to be installed in parallel to the existing unit	1	
Ductwork to accommodate equal flows through each with crossover ductwork with dampers etc. allowing one Scrubber to be removed from service for maintenance	lot	
Scrubber Budgetary Price, Materials Only		$4,650,000.00
Scrubber Budgetary Erection Pricing		$6,850,000.00
Total Scrubber Budgetary Turnkey Pricing		**$11,500,000.00**

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I hope that the above information is helpful in assisting Abitibi in determining the future plans for the work to be done on-site and in the coal conversion operation.

I apologize for the delay in providing this information and hope that in the future we can discuss in more detail the options outlined.

If I can assist in any other manner, pleae do not hesitate to contac me or Charlie Hart.

Sincerely,

Colin Tonks
Business Development Manager
ALSTOM Power Inc.
865-671-5929 (office direct)
865-603-4665 (mobile)

cc.	Charlie Hart	ALSTOM
	Randy Cook	ALSTOM
	Mark Fiedler	ALSTOM ECS
	Jim Sutton	ALSTOM BEPS

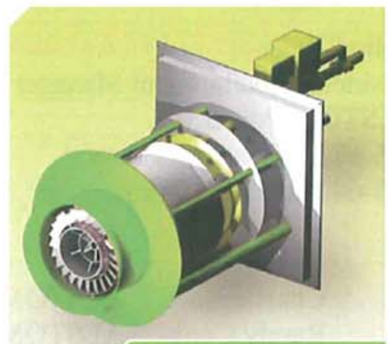
ACT
ADVANCED COMBUSTION TECHNOLOGY, INC

A Comprehensive Design, Engineering and Installation Resource

Ultra Low NOx Burners

ULTRA LOW NOx — HIGH VALUE WALL FIRED SOLUTION

Advanced Combustion Technology, Inc (ACT) Ultra Low NOx coal burners provide industrial and boiler owners with the ultimate solution to their NOx compliance needs. Each system application is specifically designed to maximize NOx reduction without sacrificing combustion performance or unit operation.


Ultra Low NOx Coal Burner

HOW ACT'S ULTRA LOW NOx COAL BURNERS REDUCES NOx EMISSIONS

Fuels being fired range from sub-bituminous through low and high sulfur eastern bituminous coals. NOx reductions exceeding 50% from baseline levels are achieved across the load range with minimal increases in unburned carbon.


Ultra Low NOx Coal Burner

Features include:

- Ease of operation
- Patent pending five (5) zone burner
- Balanced perimeter airflow
- Homogeneous coal flow
- "Clean release" coal nozzle
- Accurate secondary airflow measurement

ULTRA LOW NOx BURNERS

- State of the Art Components
- NOx Reductions Exceeding 50% From Baseline Levels Achieved Across Load Range

ADVANCED COMBUSTION TECHNOLOGY, INC

ULTRA LOW NOx — HIGH VALUE WALL FIRED SOLUTIONS

Ultra Low NOx Coal Burner

THE HARDWARE

ACT Ultra Low NOx coal burners provide the lowest possible NOx control while maintaining optimum combustion. State of the art components provide control over the following:

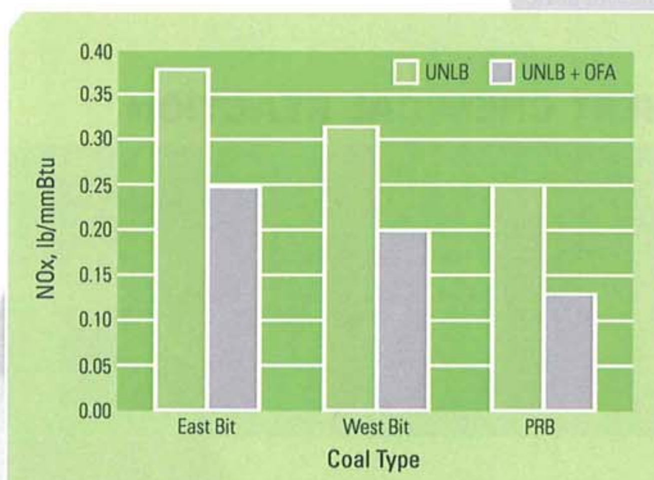
- NOx Emissions
- Flame Shaping
- CO Emissions
- Burner Eyebrows
- Flyash LOI
- Furnace Slagging

Ultra Low NOx Coal Burner

MECHANICAL ATTRIBUTES

- Refactory Lined Inlet Elbow
- Ceramic Lined Coal Barrel with 309 SS tip
- Venturi Low NOx Register Assembly with Flow Control
- Ceramic Lined Coal Distribution Disk
- Ultra Low NOx Swirler
- Ultra Low NOx Coal Nozzle
- Insulated Front Plate

ACT'S ULTRA LOW NOx PERFORMANCE



ADVANCED COMBUSTION TECHNOLOGY, INC

A Comprehensive Design, Engineering and Installation Resource

HERT - High Energy Reagent Technology

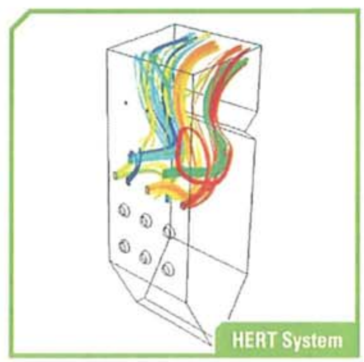
OPTIMUM NOx CONTROL FOR UTILITY AND LARGE INDUSTRIAL BOILERS

Over Fire Air (OFA) is coupled with Urea or Ammonia injection to control nitrogen oxide emissions. The Hert System can achieve up to 65% NOx reductions. The OFA system stages combustion for an initial reduction. A high energy chemical agent follows the OFA into the proper temperature window to optimize the NOx conversion. Fewer injectors are required than a typical SNCR system. Installed cost range from \$3 to \$5 per kw.

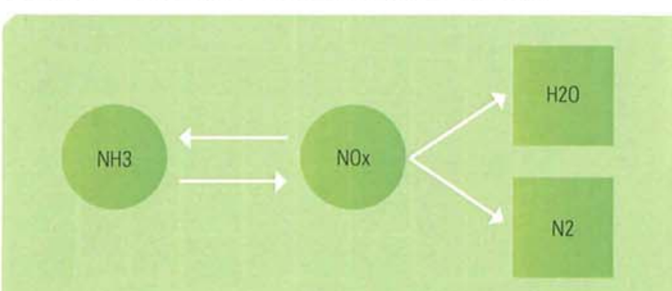

HERT System Skid

HOW ACT'S HERT SYSTEM REDUCES NOx EMISSIONS

OFA reduces NOx by staging combustion. Urea breaks down to NH3 and reacts with NOx in the proper temperature window, 1600° F to 2100° F, to form H20 and N2. Multi-level injection scheme controls NH3 slip below 5 ppm.


HERT System

HERT CHEMICAL REACTION




HERT System Injector

ACT

ADVANCED COMBUSTION TECHNOLOGY, INC

HERT - NOx CONTROL

- Up to 65% NOx Reduction
- Substantially Reduce NOx on Utility and Industrial Coal Fired Boilers

OPTIMUM NOx CONTROL FOR UTILITY AND LARGE INDUSTRIAL BOILERS

THE FIRST STEP

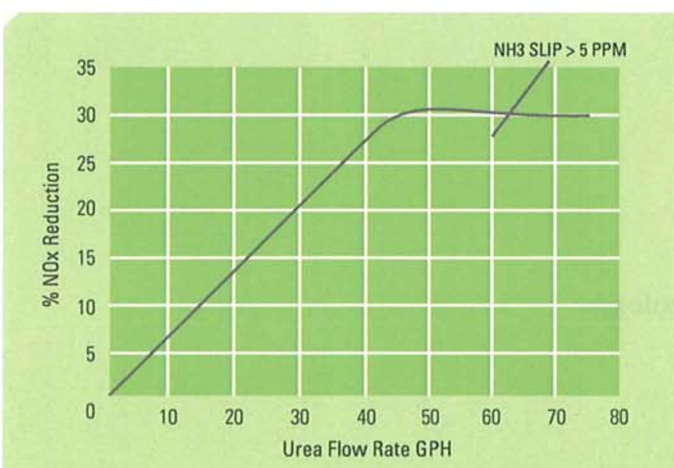
Computational Fluid Dynamics (CFD) modeling is used in conjuction with test data to design the OFA system and predict NOx reduction and NH3 slip levels.

THE HARDWARE

Large wall injection coupled with a high momentum OFA injection stage combustion produces an optimum chemical agent coverage at the furnace outlet. The skid mounted control system meters urea from the storage tank to injectors throughout the load range. Optimum chemical usage with minimal ammonia slip is maintained.


HERT System Storage

HERT SYSTEM REDUCTION POTENTIAL AND NH3 SLIP



NOx REDUCTION POTENTIAL

Boiler Type	NOx Reduction
Wall Fired	40% – 60%
Cyclone Wall Fired	55% – 65%
Tangential Fired	45% – 65%

ADVANCED COMBUSTION TECHNOLOGY, INC

ABITIBI

POWER BOILER # 2

BUDGET PROPOSAL FOR

LOW NOx BURNERS, OVER FIRE AIR & HERT

NOx REDUCTION TECHNOLOGIES

ACT Proposal No. 2007-128
October 24, 2007

Prepared by:

Dan Smolens

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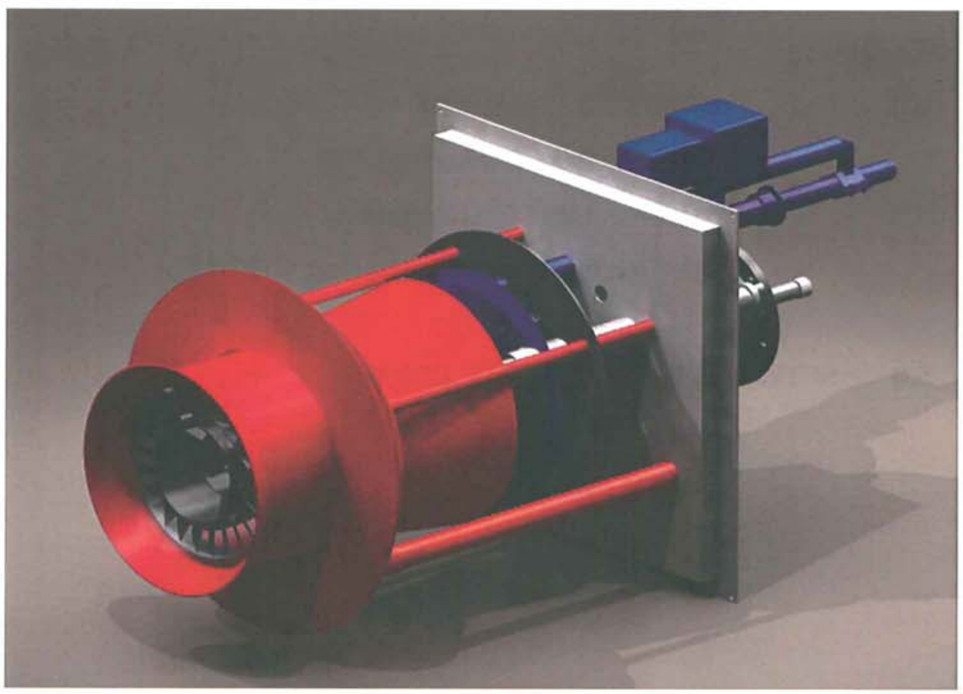
1106 Hooksett RD
Hooksett, NH 03106
PH (805) 985-3366

TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

Abitibi has a recycle paper mill in Snowflake, AZ and is considering NOx control on their No. 2 Power Boiler. Unit 2 is a B&W boiler wall fired boiler, installed in 1975. The boiler has a capacity of: approximately 830,000 lb/hr steam flow at 1200 psi steam outlet, at 1132 MMBtu rated heat input. There are four pulverizers, each feeding three burners. There are twelve burners – six rows of two.

The boiler has an overfire air fan that has never been used, and no other NOx controls. The NOx emission limit in the present permit is 0.7 lb/MMBtu. The average of actual NOx emissions as measured by most recent 7 years of source testing is 0.52 lb/MMBtu (range = 0.43-0.59). Target NOx emissions are 0.23 lb/MMBtu (presumptive BART limit for dry-bottom wall-fired unit burning subbituminous coal)



ACT Ultra Low NOx Burner

2.0 OBJECTIVES

The goal of the Low NOx program is as follows:

- Reduce NOx Emissions
- Limit slagging in the upper furnace
- Reduce ash throughout the boiler
- Maintain the furnace exit flue gas temperature below the ash deformation temperature

A reduction in NOx and improved combustion can be achieved as part of a multi step program. It is unlikely simply installing new components will achieve the goal of the program. A detailed program can be established following a site visit and initial Computational Fluid Dynamics (CFD) modeling. It is anticipated that several steps in the program will be as follows:

- Balanced airflow to each burner to within +-5% of the boiler mean
  - The burners can be balanced using a combustion air probe inserted in each burner and testing at 24 points around the perimeter
  - Once the balance position is determined the zone disks should not be moved

- Balanced coal flow to each burner to within +-10% of the mill mean
  - ASME primary air and coal flow testing can be conducted to determine the current balance
  - Orifice plates can be used to balance the coal flow

- Balanced airflow around the perimeter of the burner
  - Based on the combustion air test results baffles may be required in the windbox to ensure balanced airflow around the burner.
  - A secondary air swirler should be added in the burner to control the secondary air swirl and improve the distribution

- Homogeneous coal flow at the outlet of each burner
  - A new barrel section with internal baffles will produce balanced coal flow at the burner outlet

- Secondary air swirl with a burner swirl number in the range of 0.6 to 0.8
  - A secondary air swirler will provide the proper amount of swirl and prevent over swirling the burner

- Burner exit primary air velocity of 70 ft/s
    - The new barrel section will be designed for the ideal velocity

- OFA port designed with balance airflow around the perimeter
    - CFD model of the furnace region will aide in locating the ports on the furnace walls

- OFA port locations to effectively cover the upper furnace region with an injection velocity 4 times the furnace upward velocity
    - OFA port design should be venturi shaped

- Post combustion NOx control
    - Urea injection in the upper furnace for additional NOx control (HERT System)
    - Allows increased NOx reduction with no impact on combustion performance

<u>The recommended steps for the unit is as follows:</u>

- Site visit, review of operating history
- Collection of baseline data
- CFD model of boiler and burners to match current operation
- CFD model of boiler with new ULNB
- Presentation of model results to Abitibi
- Design of new ULNB
- Addition of OFA
- Addition of Urea Injection (HERT System)
- Fabrication of components
- Installation of components
- Unit startup and optimization

The Over Fire Air (OFA) can be designed to enhance Unit performance. It is assumed that parts of the existing OFA ducting can be reused. Our pricing includes completely new OFA Ports.

It is anticipated the NOx levels will be as shown in Table 2.

Table 2
ABITIBI
NOx Technology and Predicted NOx Reduction

Unit ID	Technology	Predicted NOx Reduction
2	ULNB	50%
2	ULNB & OFA	65%
2	ULNB, OFA & HERT	78%

UNLB – Ultra Low NOx burners with five (5) zones stages NOx to the lowest possible level.

OFA – Over Fire Air diverts a portion of the combustion air to the upper furnace for additional combustion staging and NOx control.

HERT – High Energy Reagent Technology system is a patent means of injecting urea into a portion of the OFA stream for post combustion SNCR control. It is anticipated that Unit 2 will use approximately 45 gph of urea at full load operation. This is anticipated to provide NOx control at less than $1,000 per ton of operation.

3.0 PRICING

Pricing for the NOx reductions program, as anticipated, is listed below. These prices are estimates as the first stage of the program, i.e. Site Visit and Baseline CFD modeling must be completed to determine what NOx reduction goals are realistic.

All prices are quoted FOB delivery and do not include installation. All prices are quoted exclusive of state and local sales, excise, use or any other taxes. Such taxes, if applicable, will be in addition to the above prices and will be charged to your account. Any taxes assessed to ACT at a later date will be charged to your account. If the above items are tax-exempt, the applicable tax exemption certificate is to be sent to ACT with your purchase order.

Program Pricing –

Low NOx Program 1st Stage:

Site Visit and Collection of Baseline data	$50,000.
Baseline CFD Modeling and Preliminary Design of Components	$75,000.
<u>ULNB</u> New ultra low NOx burners, engineering, installation technical support and boiler optimization and testing	$575,000.
<u>Over Fire Air System</u> Four (4) Sets of OFA components consisting of duct work, OFA nozzle, bent tube openings, engineering & optimization	$300,000.
<u>High Energy Reagent Technology</u> HERT system consisting of storage tank, recirculation skid, dilution water skid, blower skid, injectors and optimization	$500,000.

4.0 SYSTEM DESCRIPTION

Unit 2's wall fired burners will be replaced with ACT's Ultra Low NOx, four (4) zone, VH600K series burners. The VH Series burner utilizes a fixed bladed Ultra Low NOx Swirler (ULNS) in conjunction with a flow control Venturi register and coal nozzle to develop alternating axial and swirling secondary air zones. Combustion is staged for optimum Low NOx performance. Features of the VH Series Burner are as follows:

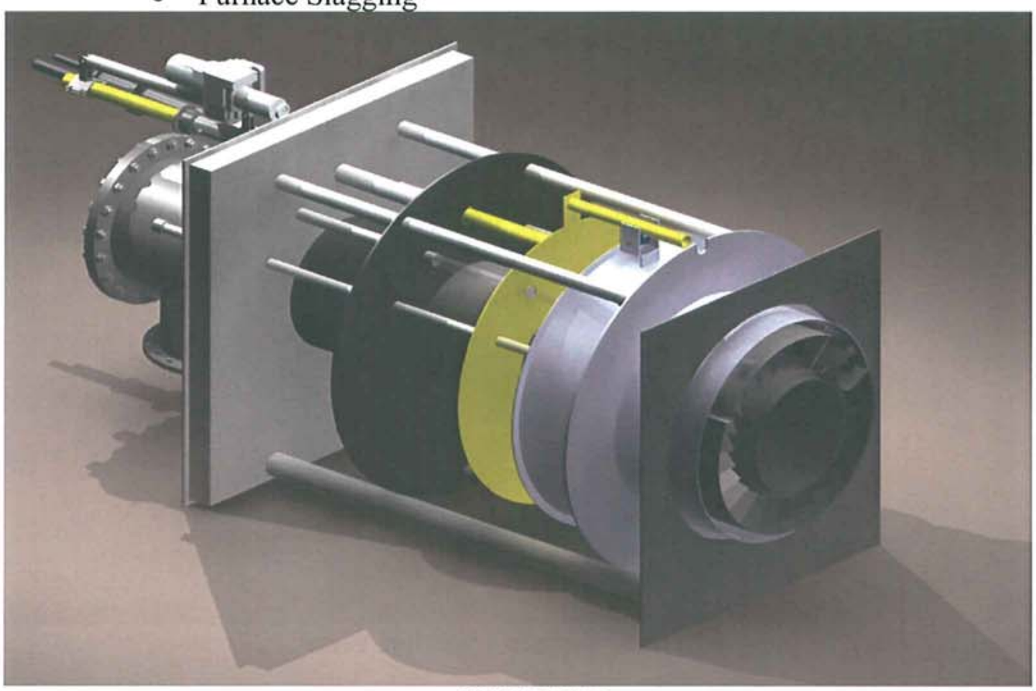
- Refractory lined components in the coal head for long life
- Precise secondary air control over the boiler load range
- Homogeneous coal flow at the burner outlet to limit impact on fly ash LOI

- Balanced air/fuel ratio in each burner

NEW ULTRA LOW NOX BURNERS (ULNB)

The ACT VH600K ULNB provides the lowest possible NOx emissions while maintaining optimum combustion efficiency. ACT's patent pending register design maintains strict burner dynamics throughout the load range. The basis for flame shape control is the Low NOx nozzle adjustment that will be locked in place following tuning. State of the art robust components provide control over the following:

- NOx Emissions
  Lowest Possible Levels
- CO Emissions
  Optimized Combustion
- Fly ash LOI
  Minimal Impact
- Flame Shaping
  Control of Flame Envelope with the furnace boundary
- Furnace Slagging

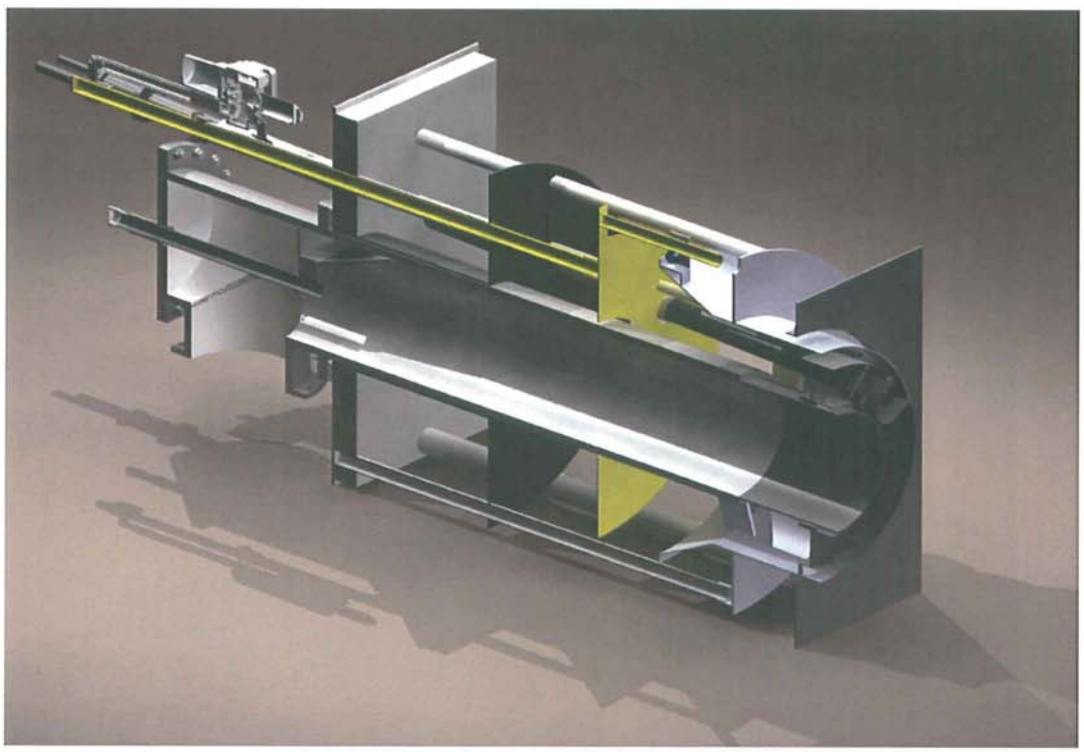


VH600K Burner

Mechanical attributes of the burner are as follows:

- Refractory Lined Inlet Coal Head

- Carbon Steel Coal Pipe with 310 SS tip
- Ceramic Coated Coal Distribution Disk
- Venturi Low NOx Register Assembly with Beck Axial Zone Disk Assembly
- Ultra Low NOx, Four (4) Zone Design
- Ultra Low NOx Coal Nozzle
- Carbon Steel Insulated Front Plate
- Windbox Burner Support Assembly
- Plug In design with no pressure part modifications



VH600K Burner - Section View

COMBUSTION AIR TEST

This proposal contains a Combustion Air Test (CAT) to balance the secondary airflow between burners to within ± 5% of the boiler mean. To ensure Low NOx combustion with minimal impact on combustion, ACT will measure the airflow in each burner with its CAT probe. The airflow to each burner will be balanced to within ± 5% of the boiler mean.

The CAT will be performed with the unit off line and the Forced Draft fans operating at full capacity. Zone disk will be set to the wide-open position. This will simulate the airflow through the windbox and burners during full load operation. ACT's CAT probe will be inserted down the burner centerline and raised up to measure the secondary airflow through the burners. Secondary airflow velocity is measured at twelve (12) points around the burner perimeter to determine the burner mean airflow. Burner deviation is determined by comparing the burner airflow to the average of all burners. Burner shrouds are adjusted to balance all burners to within +-5% of the boiler mean. Testing duration is 6 hours.

COMPUTATIONAL FLUID DYNAMICS (CFD) MODELING

ACT performs all the required CFD modeling inhouse. A three-dimensional CFD model will be constructed of the burners and furnace region. The CFD model will use boiler design data and current operating data to determine the present performance of the Unit. The new burners will be incorporated into the model to determine the impact. The model will be run to determine the expected impact different variable.

The CFD model works by solving heat transfer and species reactions to simulate combustion interaction within the furnace for the existing configuration and then with the advanced ULNB. Several scenarios will be simulated to determine the combustion gas and air mixing rate and products leaving the furnace. The CFD model outputs will be used as the basis for the design of the ULNB system.

OFA SYSTEM

A new Over Fire Air System will be supplied to divert air from the top of the OFA air duct to new Over Fire Air Ports on the front wall located above the top elevation of burners. Diverting air away from the main combustion zone reduces the peak flame temperature and thermal NOx formation.

The system includes a complete four port OFA system with components as listed below:

OFA port openings, including tube bends and seal box
Beck drives for OFA control damper, each with 4 -20 ma control and position feedback
OFA control dampers, approx. 3' x 3'
Yokogawa local pressure gauges to measure OFA pressure
Expansion joints
System Design and CFD Modeling
Duct Work - material will be carbon steel in the main runs and 310 SS near the ports.
System Optimization
Insulation and Lagging

Damper setting will be characterized based on boiler steam flow.

HIGH ENERGY REAGENT TECHNOLOGY

HERT is an ACT patented system for post combustion NOx control. Urea is vaporized in a portion of the OFA stream and mixed into the furnace. The urea breaks down to NH_3 that reacts with NOx in the flue gas stream to form N_2 and H_2O. System components are as follows:

- 5,000 gallon storage tank
- Urea Recirculation skid
- Dilution water skid
- Blower Skid
- Injectors
- PLC Based control system

4.0 SCHEDULE , PAYMENT TERMS & EXCEPTIONS

Program Schedule

The lead-time for the burner upgrades, ULNB and OFA is fourteen (14) weeks from receipt of your company's purchase order.

Appendix B
Additional BART Modeling Results

FIGURE B-1
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Mazatzal Wilderness
AbitibiBowater No. 2 Power Boiler

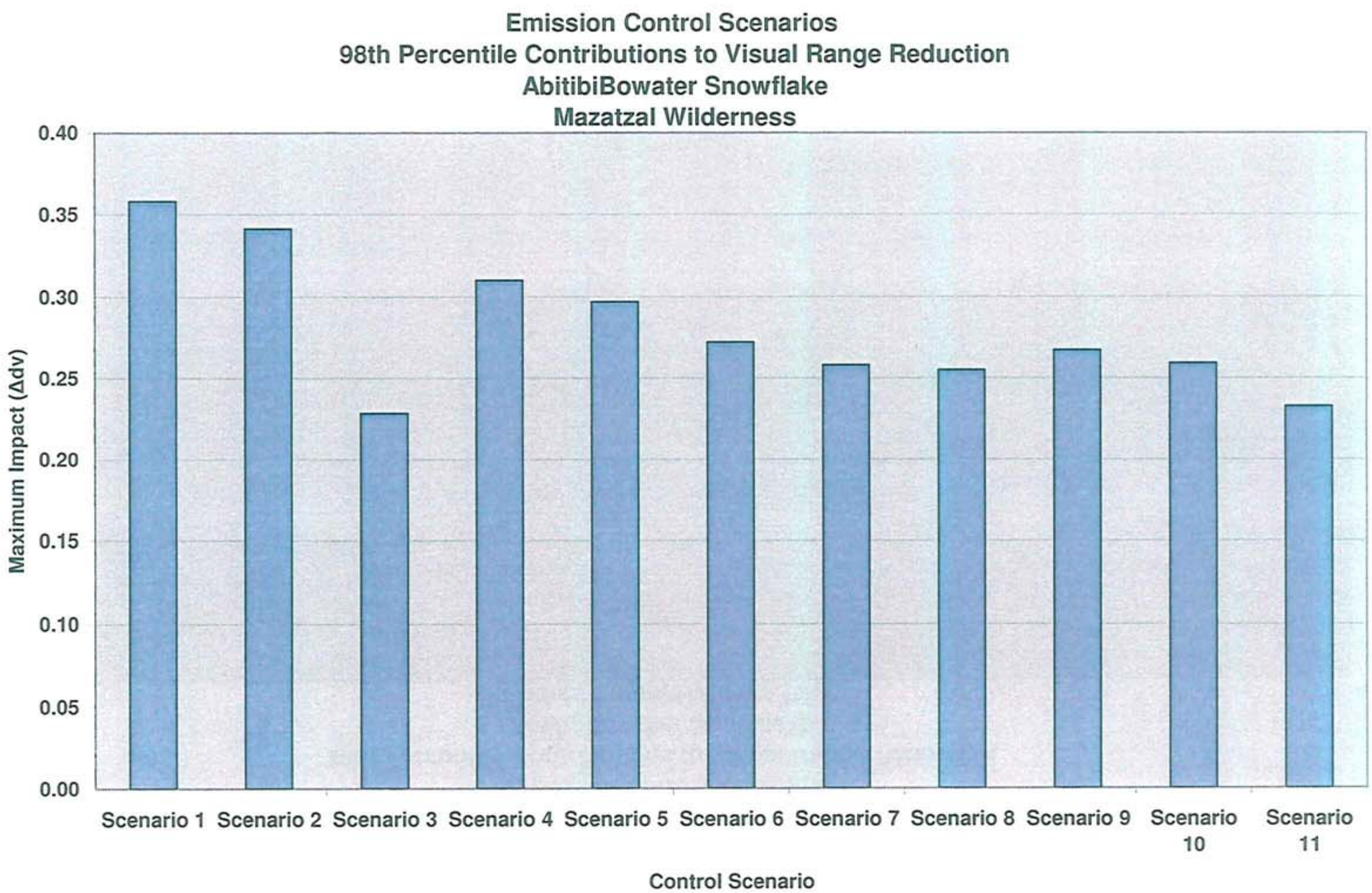


FIGURE B-2
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Petrified Forest National Park
AbitibiBowater No. 2 Power Boiler

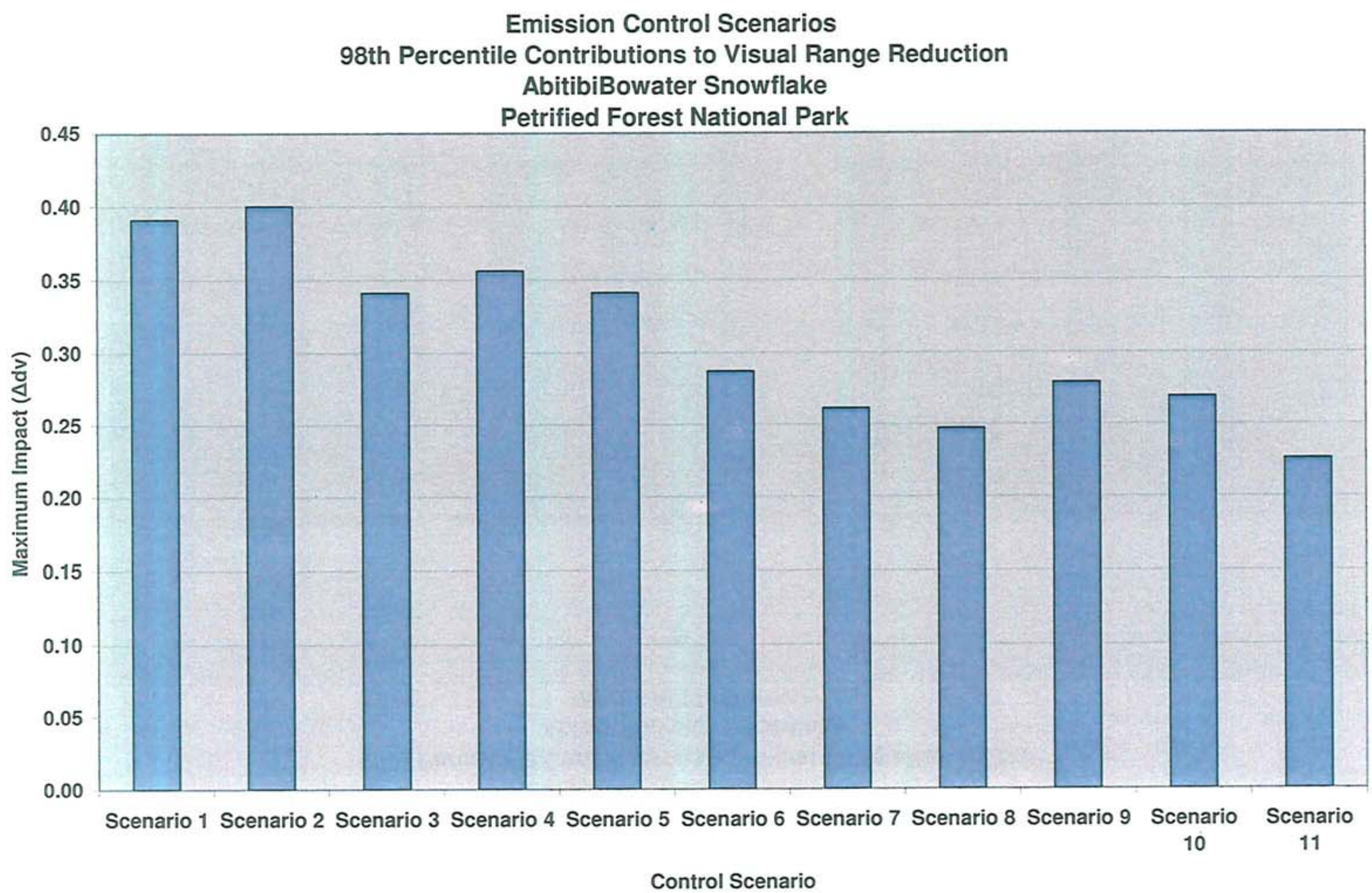


FIGURE B-3

NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Sierra Ancha Wilderness

AbitibiBowater No. 2 Power Boiler

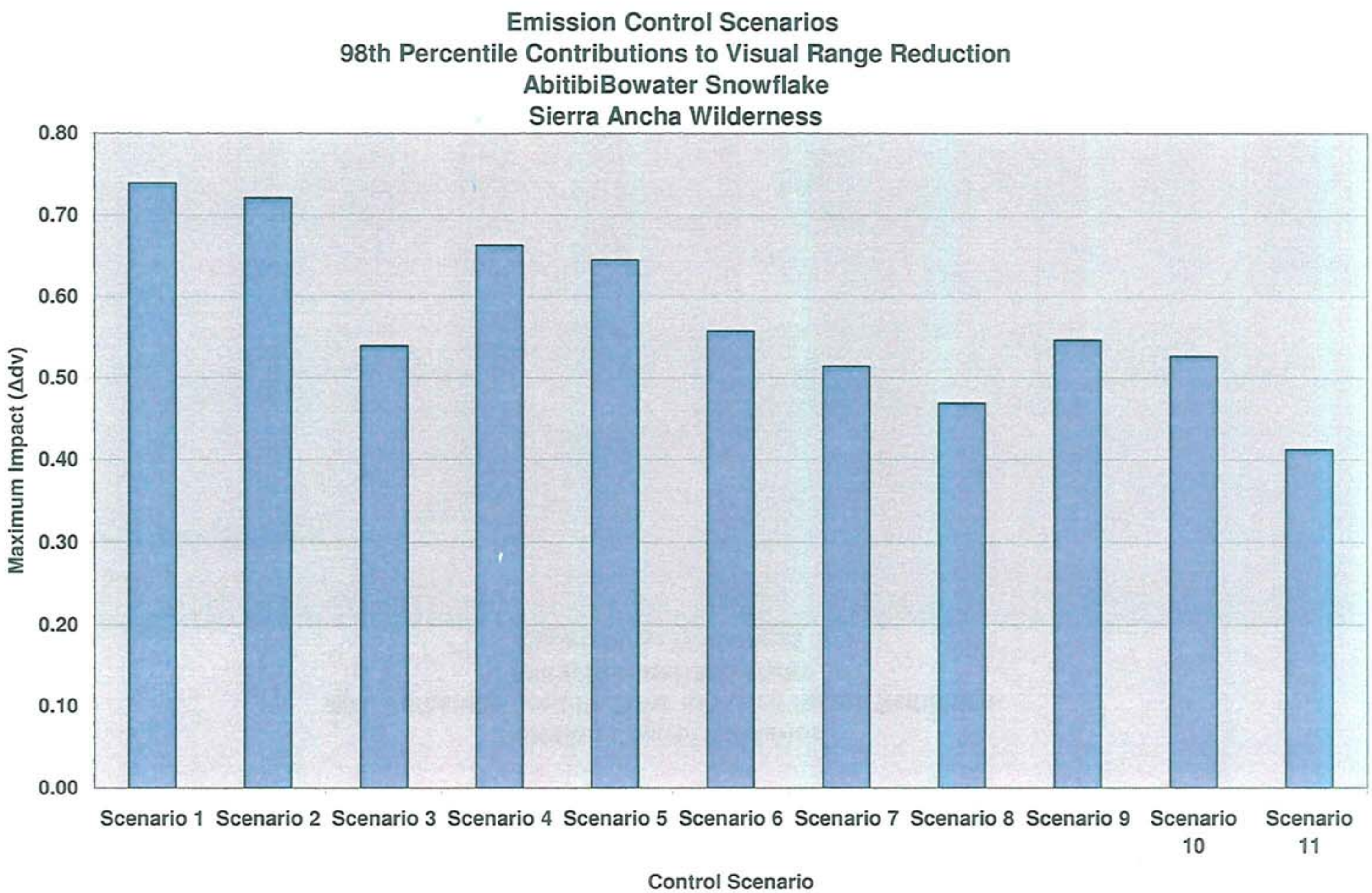


FIGURE B-4
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Superstition Wilderness
AbitibiBowater No. 2 Power Boiler

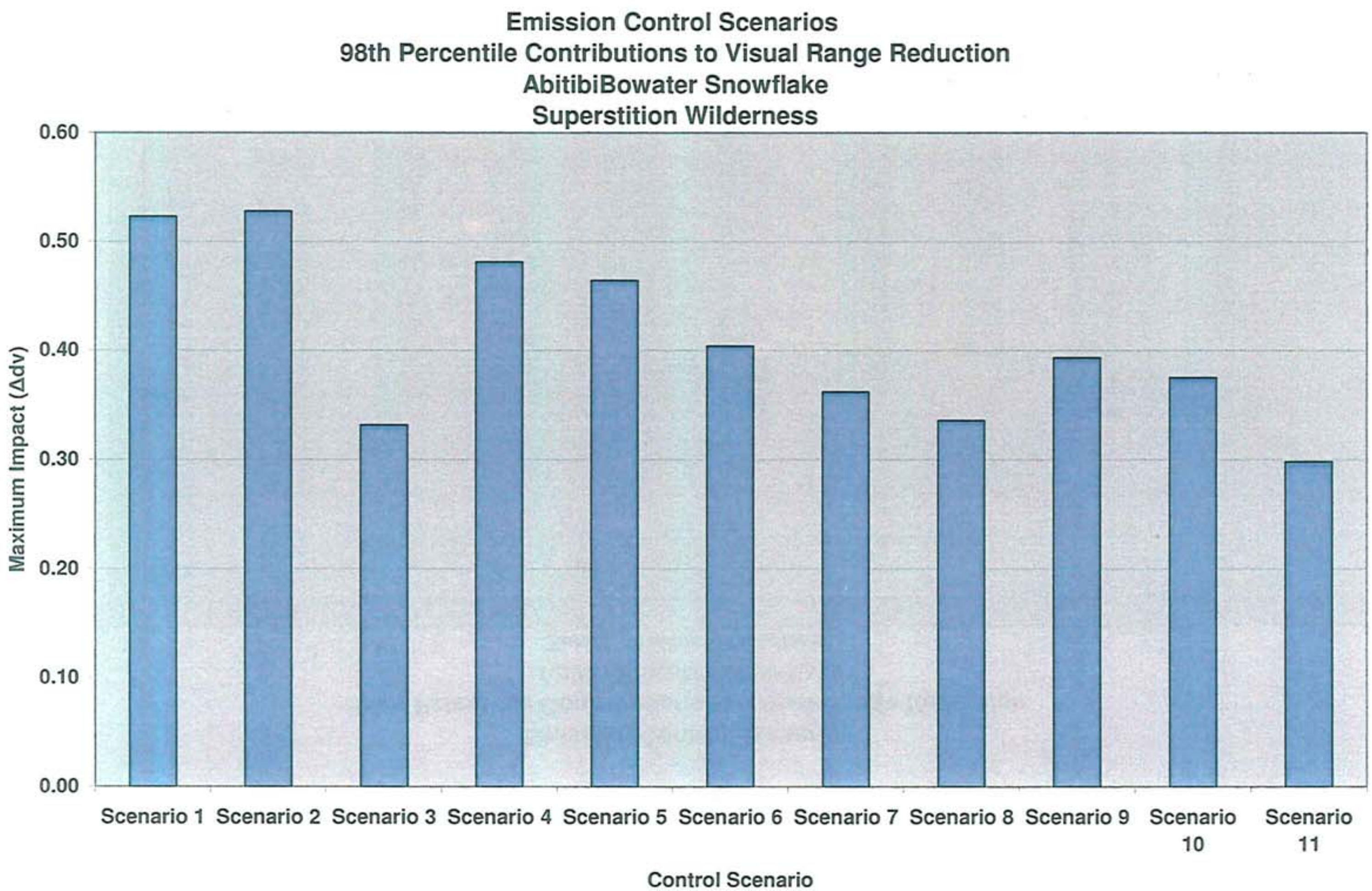


FIGURE B-5
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Chiricahua National Monument
Abitibi Unit 2

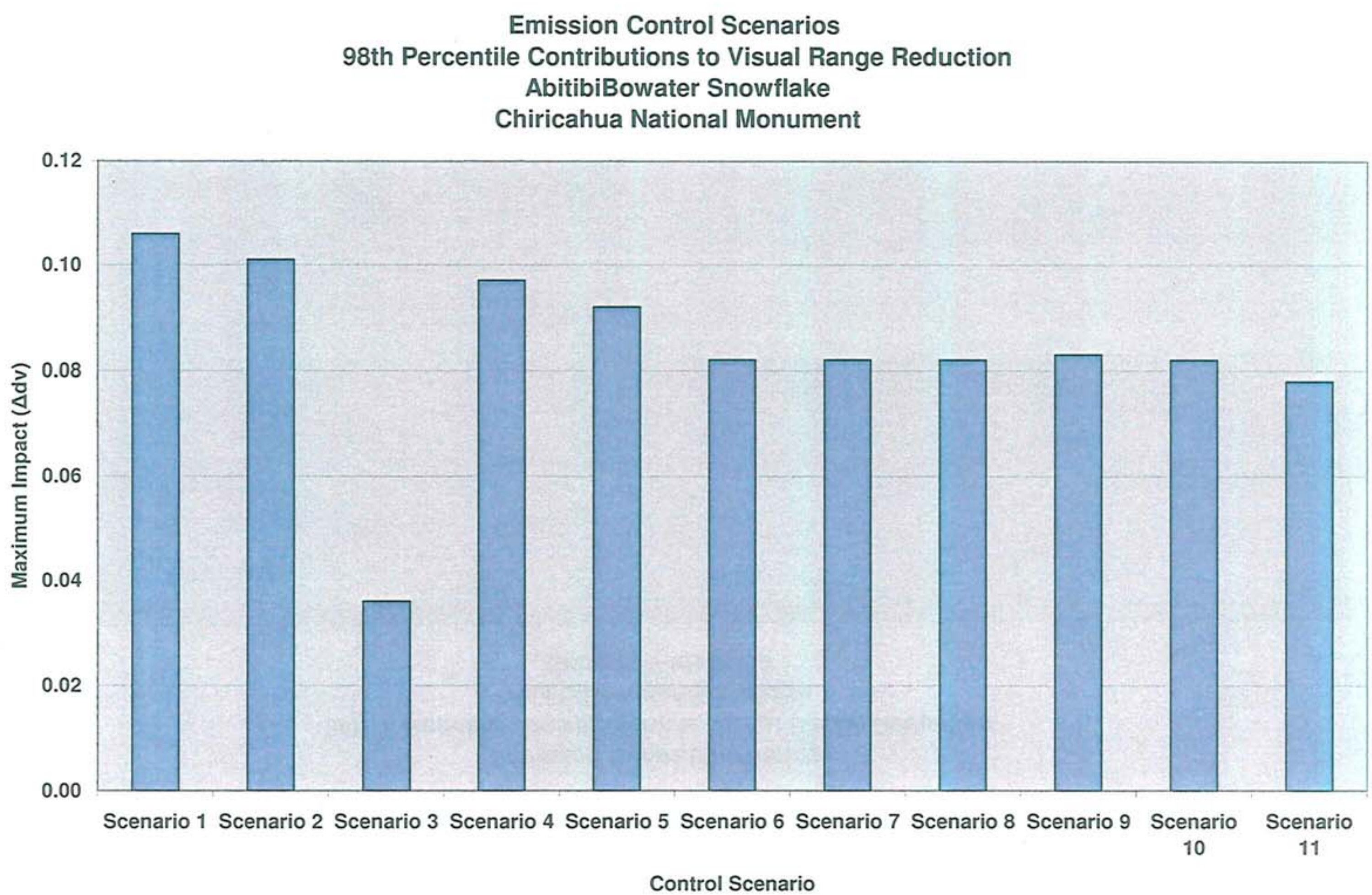


FIGURE B-6
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Galiuro Wilderness
Abitibi Unit 2

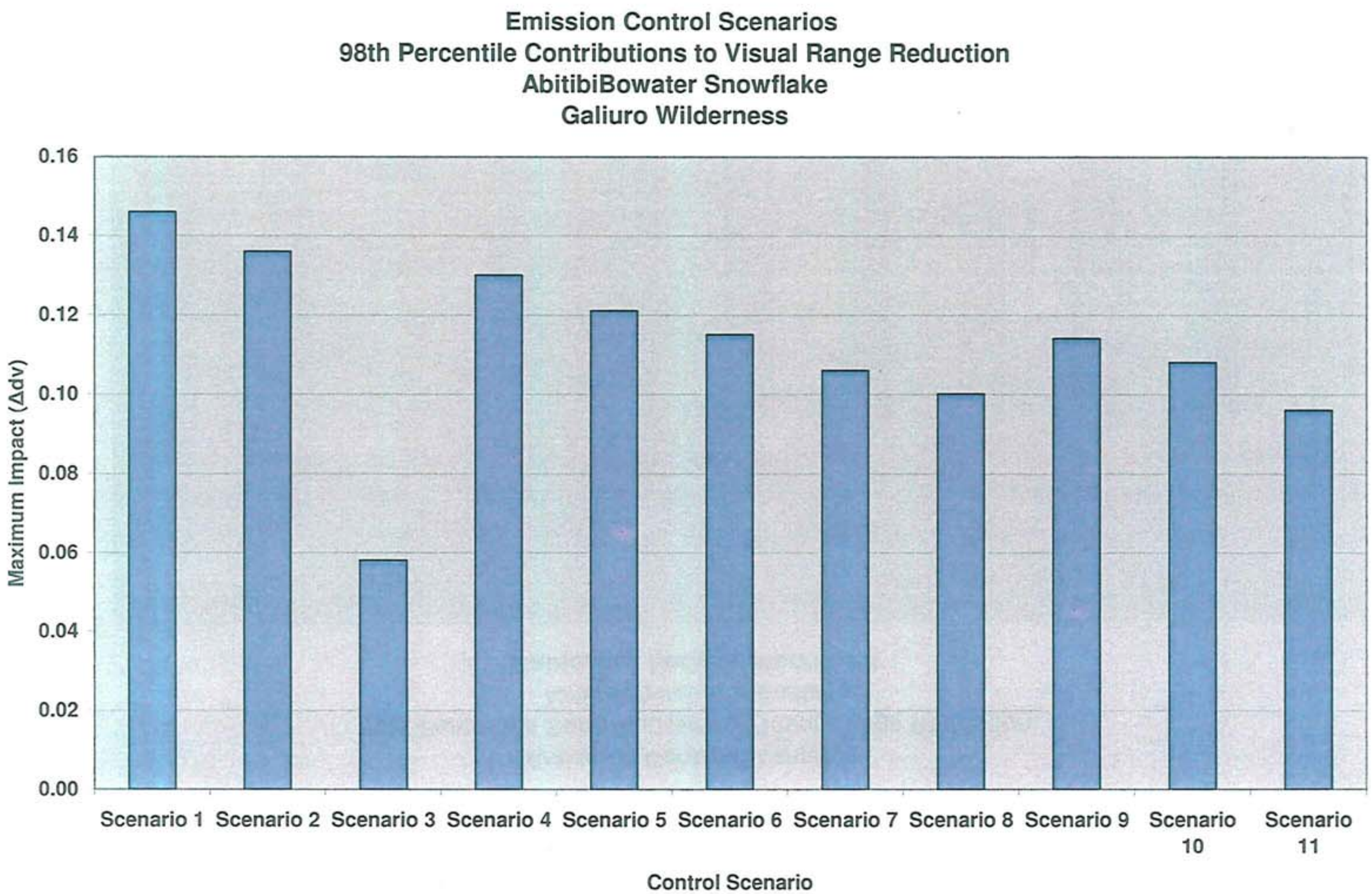


FIGURE B-7
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Gila Wilderness
Abitibi Unit 2

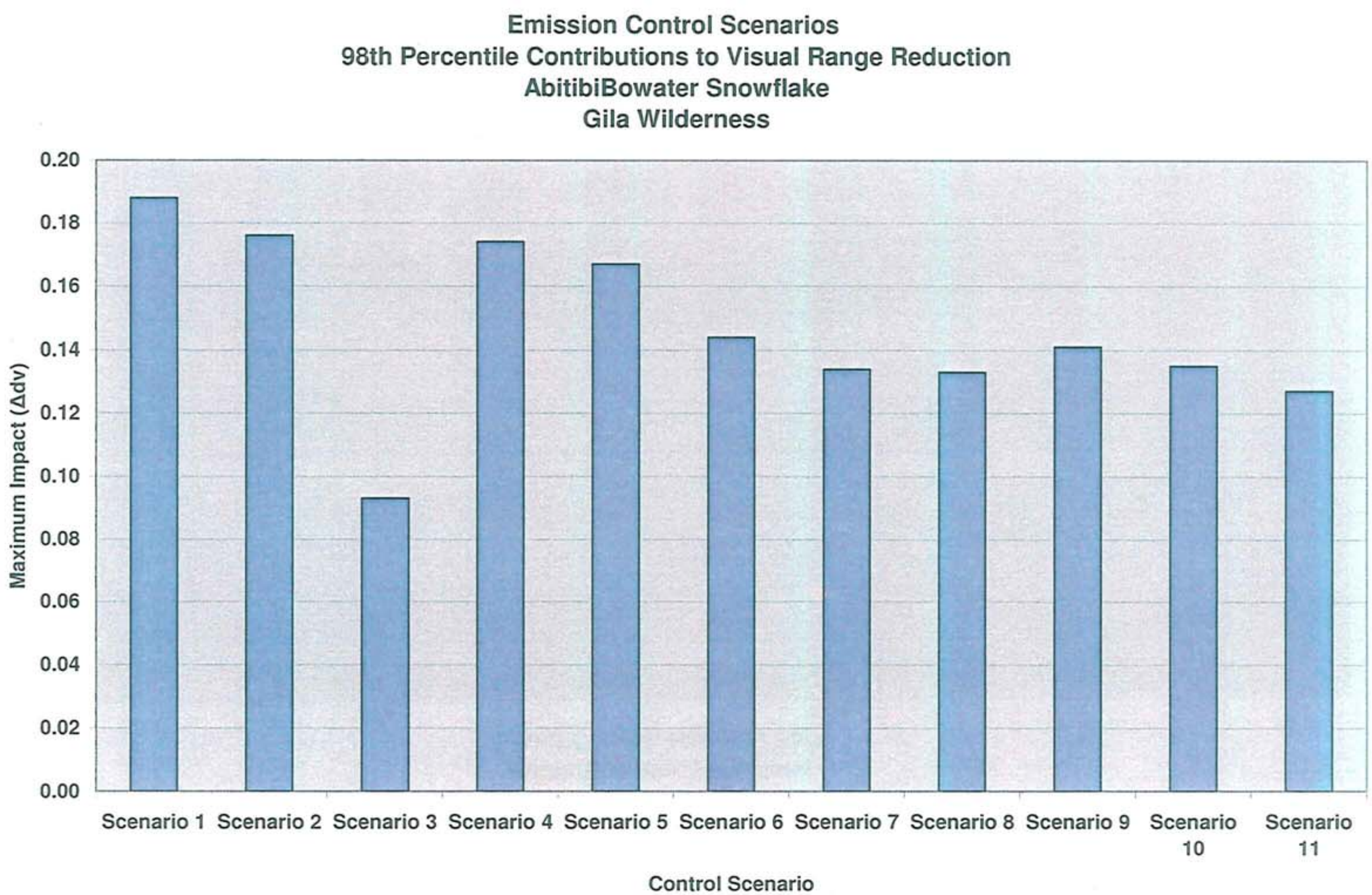


FIGURE B-8
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Grand Canyon National Park
Abitibi Unit 2

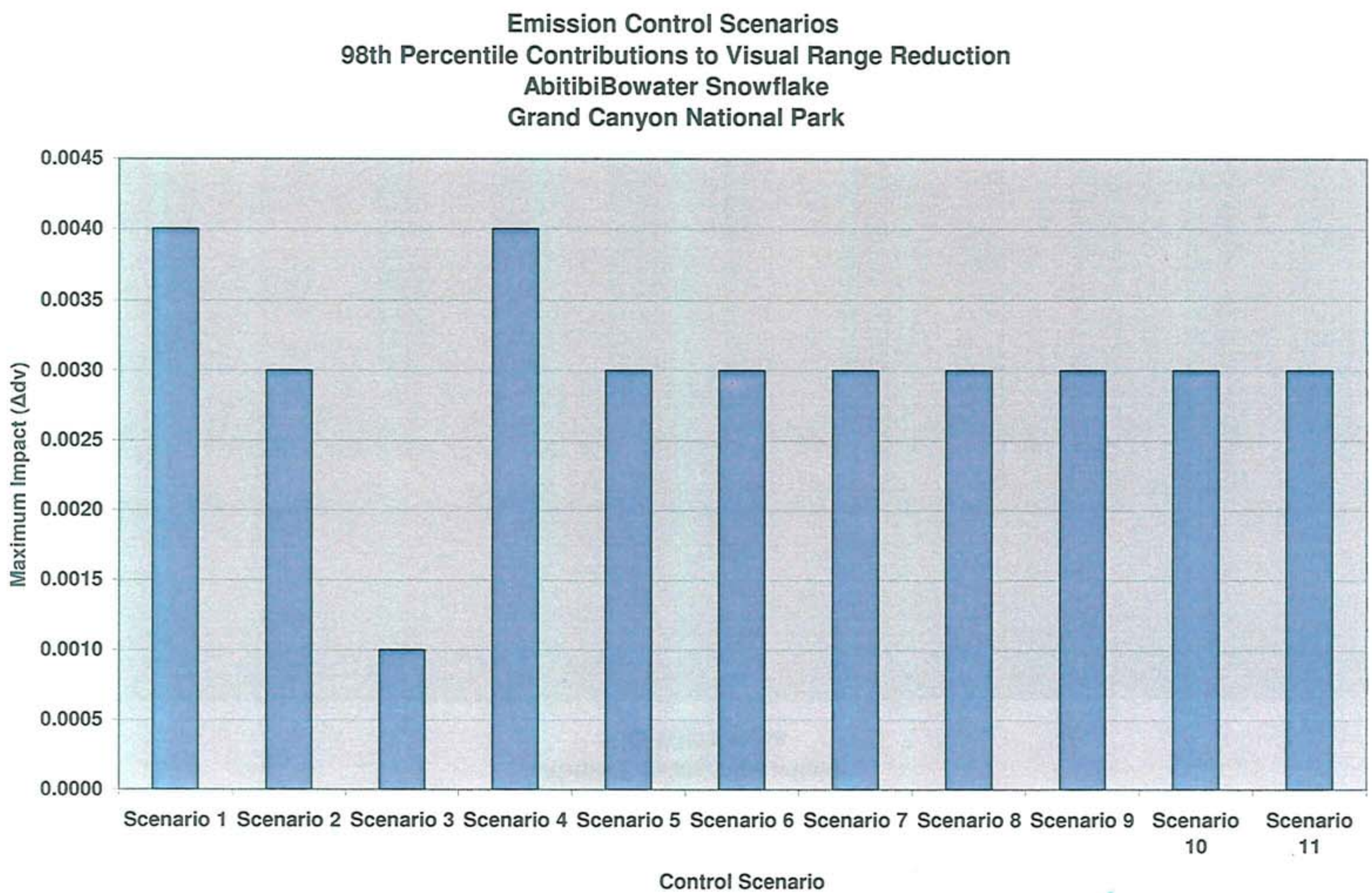


FIGURE B-9
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Mount Baldy Wilderness
Abitibi Unit 2

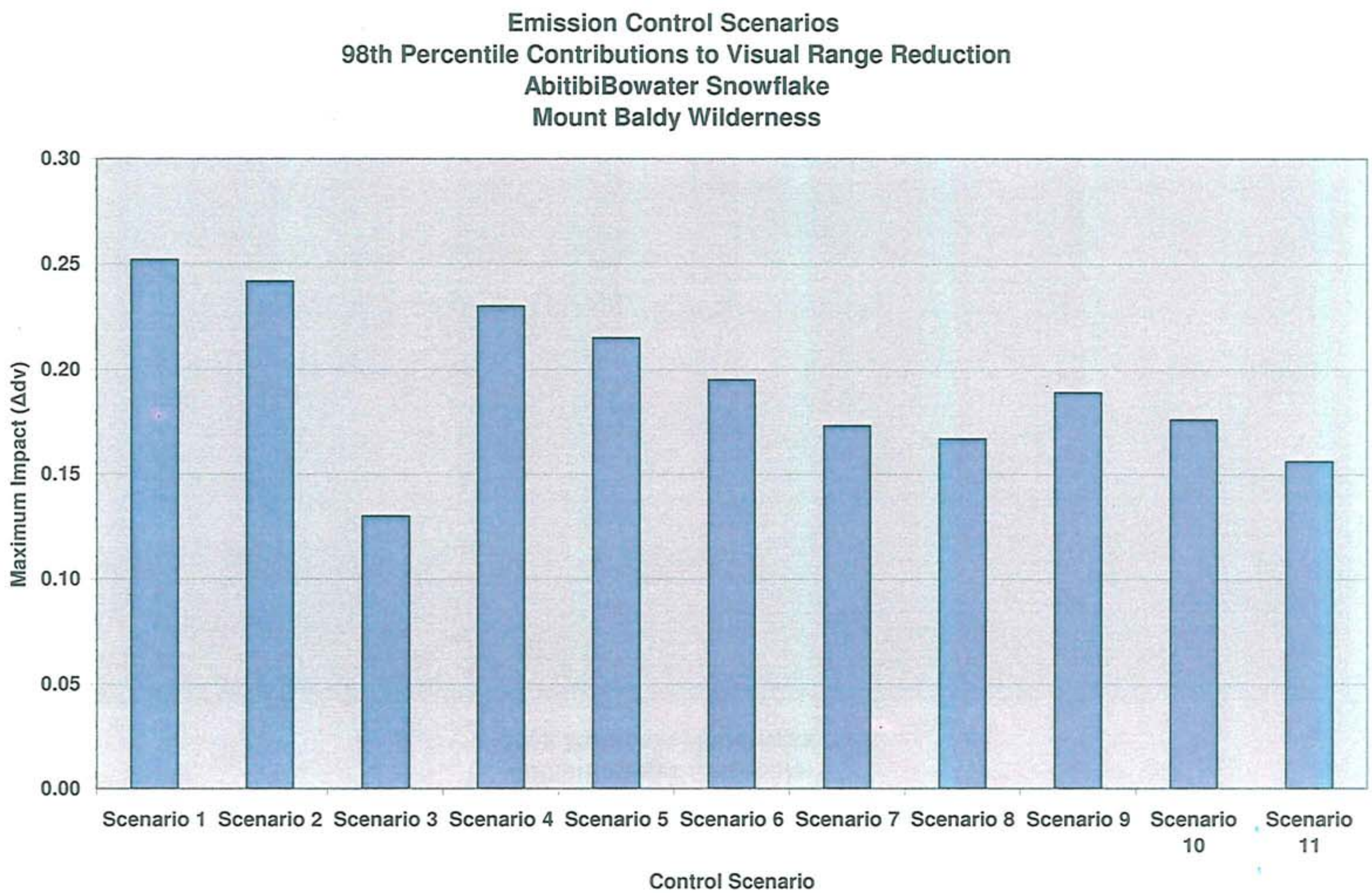


FIGURE B-10

NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Pine Mountain Wilderness

Abitibi Unit 2

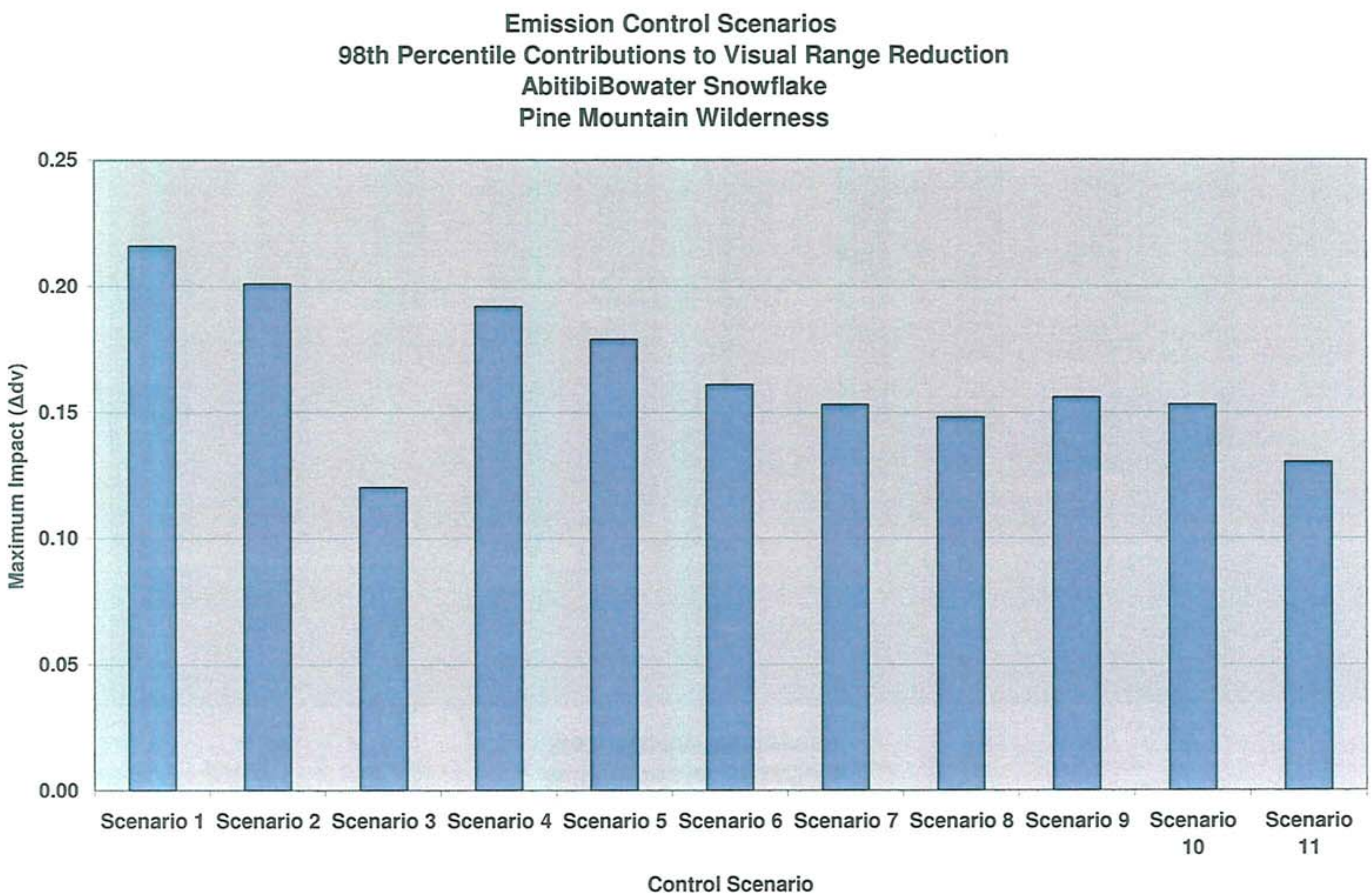


FIGURE B-11
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Saguaro National Park
Abitibi Unit 2

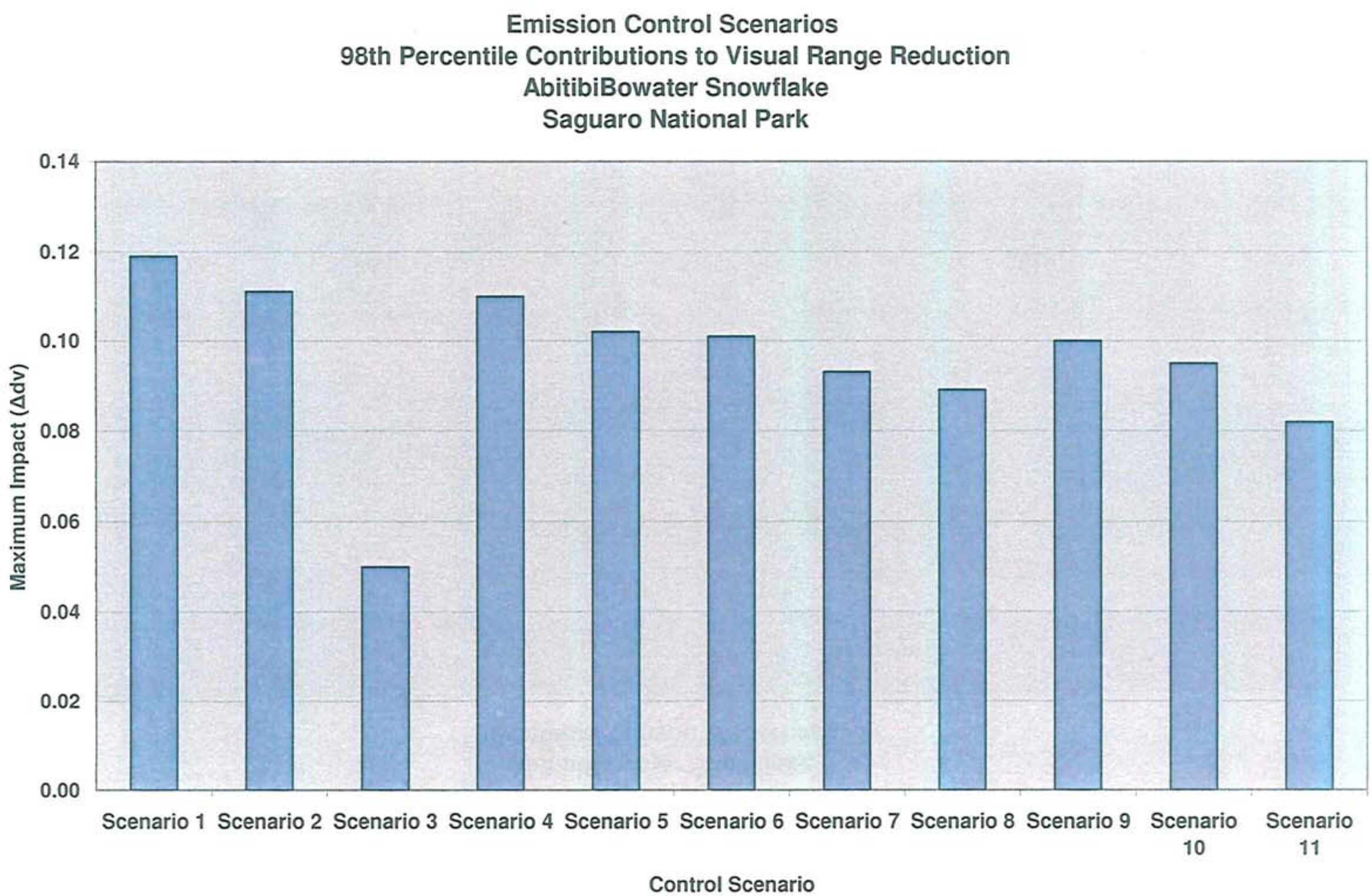


FIGURE B-12
NO_x and SO_2 Control Scenarios—Maximum Contributions to Visual Range Reduction at Sycamore Canyon Wilderness
Abitibi Unit 2

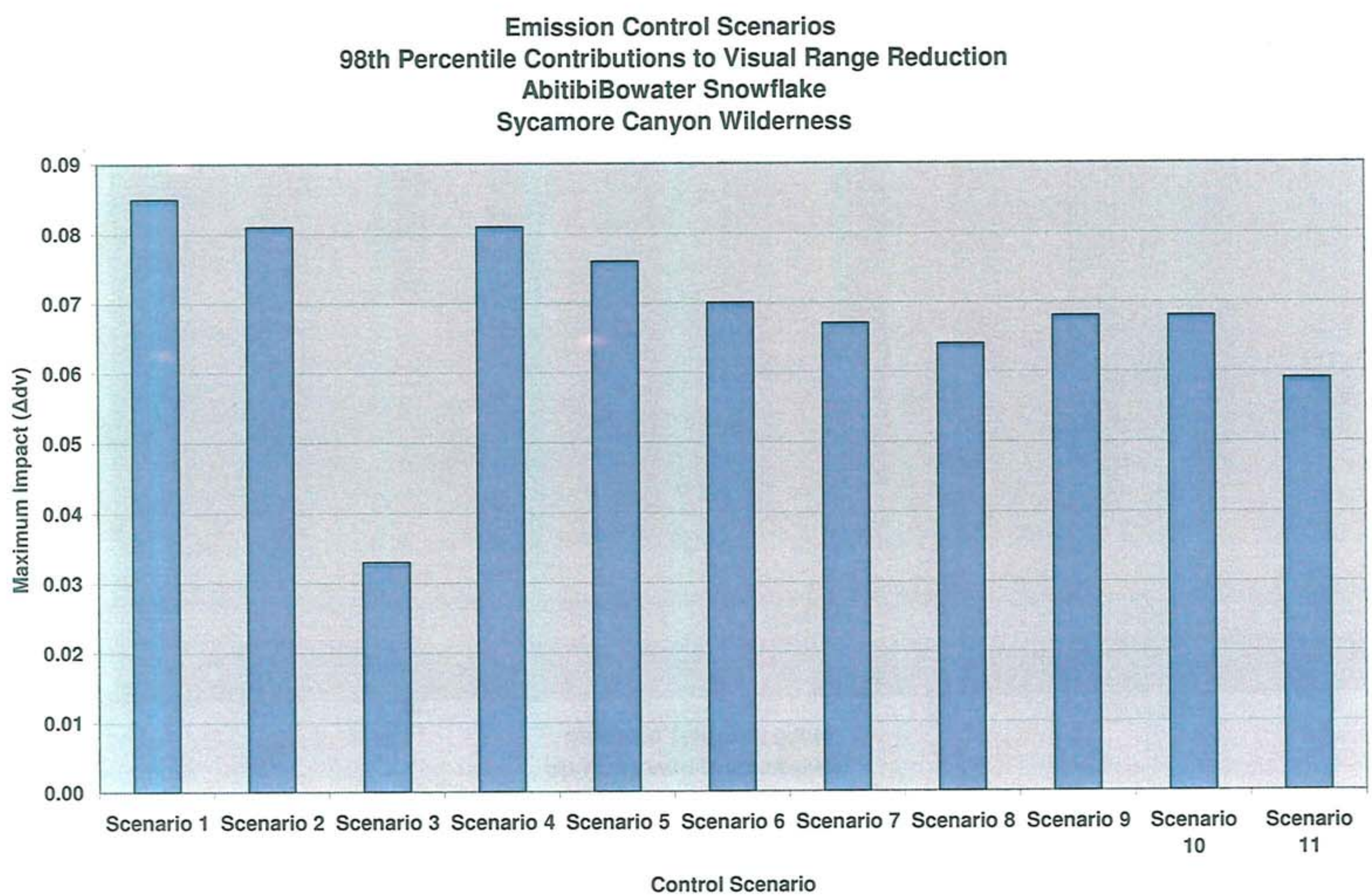


TABLE B-1
NO_x and SO_2 Control Scenario Results for Mazatzal Wilderness
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	6	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	5	0.017	9.949	9.949	585.224
3	Add 2nd Scrubber w/Upgraded Scrubber	2	0.130	14.630	3.658	112.541
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	3	0.048	8.152	2.717	169.829
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	3	0.061	8.240	2.747	135.077
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	3	0.086	8.419	2.806	97.890
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.100	8.528	1.421	85.284
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.103	8.987	1.498	87.254
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	3	0.091	9.281	3.094	101.988
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	2	0.099	9.922	2.480	100.221
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.126	12.212	2.035	96.919

TABLE B-2

NO_x and SO_2 Control Scenario Results for Petrified Forest National Park

AbitibiBowater No. 2 Power Boiler

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	6	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	8	-0.009	9.949	-4.974	-1105.424
3	Add 2nd Scrubber w/Upgraded Scrubber	4	0.050	14.630	7.315	292.605
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	5	0.035	8.152	8.152	232.909
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	4	0.050	8.240	4.120	164.794
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	3	0.104	8.419	2.806	80.948
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	2	0.130	8.528	2.132	65.603
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	1	0.144	8.987	1.797	62.411
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	3	0.112	9.281	3.094	82.865
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	2	0.122	9.922	2.480	81.327
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	1	0.165	12.212	2.442	74.011

TABLE B-3

NO_x and SO_2 Control Scenario Results for Sierra Ancha Wilderness

AbitibiBowater No. 2 Power Boiler

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	19	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	19	0.018	9.949	NA	552.712
3	Add 2nd Scrubber w/Upgraded Scrubber	9	0.200	14.630	1.463	73.151
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	16	0.076	8.152	2.717	107.261
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	15	0.094	8.240	2.060	87.657
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	12	0.182	8.419	1.203	46.256
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	9	0.225	8.528	0.853	37.904
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	8	0.270	8.987	0.817	33.286
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	12	0.193	9.281	1.326	48.088
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	9	0.213	9.922	0.992	46.582
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	5	0.327	12.212	0.872	37.345

TABLE B-4
NO_x and SO_2 Control Scenario Results for Superstition Wilderness
AbitibiBowater No. 2 Power Boiler

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	13	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	14	-0.005	9.949	-9.949	-1989.766
3	Add 2nd Scrubber w/Upgraded Scrubber	7	0.191	14.630	2.438	76.598
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	12	0.042	8.152	8.152	194.091
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	11	0.059	8.240	4.120	139.656
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	6	0.119	8.419	1.203	70.744
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	5	0.161	8.528	1.066	52.971
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	2	0.187	8.987	0.817	48.060
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	6	0.130	9.281	1.326	71.392
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	6	0.148	9.922	1.417	67.040
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	2	0.225	12.212	1.110	54.274

TABLE B-5

NO_x and SO_2 Control Scenario Results for Chiricahua National Monument

Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	0	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	0	0.005	9.949	NA	1989.766
3	Add 2nd Scrubber w/Upgraded Scrubber	0	0.070	14.630	NA	209.004
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	0	0.009	8.152	NA	905.758
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	0	0.014	8.240	NA	588.552
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	0	0.024	8.419	NA	350.773
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.024	8.528	NA	355.348
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.024	8.987	NA	374.464
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	0	0.023	9.281	NA	403.518
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0	0.024	9.922	NA	413.413
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.028	12.200	NA	435.711

TABLE B-6
NO_x and SO_2 Control Scenario Results for Galiuro Wilderness
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	0	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	0	0.010	9.949	NA	994.883
3	Add 2nd Scrubber w/Upgraded Scrubber	0	0.088	14.630	NA	166.253
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	0	0.016	8.152	NA	509.488
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	0	0.025	8.240	NA	329.589
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	0	0.031	8.419	NA	271.566
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.040	8.528	NA	213.209
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.046	8.987	NA	195.373
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	0	0.032	9.281	NA	290.029
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0	0.038	9.922	NA	261.103
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.050	12.200	NA	243.998

TABLE B-7
NO_x and SO_2 Control Scenario Results for Gila Wilderness
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	1	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	1	0.012	9.949	NA	829.069
3	Add 2nd Scrubber w/Upgraded Scrubber	0	0.095	14.630	14.630	154.003
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	1	0.014	8.152	NA	582.273
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	1	0.021	8.240	NA	392.368
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	0	0.044	8.419	8.419	191.331
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.054	8.528	8.528	157.933
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.055	8.987	8.987	163.403
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	0	0.047	9.281	9.281	197.466
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0	0.053	9.922	9.922	187.206
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.061	12.200	12.200	199.998

TABLE B-8
NO_x and SO_2 Control Scenario Results for Grand Canyon National Park
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	0	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	0	0.001	9.949	NA	9948.820
3	Add 2nd Scrubber w/Upgraded Scrubber	0	0.003	14.630	NA	4876.758
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	0	0.000	8.152	NA	NA
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	0	0.001	8.240	NA	8239.725
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	0	0.001	8.419	NA	8418.551
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.001	8.528	NA	8528.357
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.001	8.987	NA	8987.145
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	0	0.001	9.281	NA	9280.917
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0	0.001	9.922	NA	9921.898
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.001	12.200	NA	12199.901

TABLE B-9
NO_x and SO_2 Control Scenario Results for Mount Baldy Wilderness
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	3	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	3	0.010	9.949	NA	994.882
3	Add 2nd Scrubber w/Upgraded Scrubber	2	0.122	14.630	14.630	119.920
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	3	0.022	8.152	NA	370.537
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	3	0.037	8.240	NA	222.695
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	2	0.057	8.419	8.419	147.694
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	1	0.079	8.528	4.264	107.954
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.085	8.987	2.996	105.731
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	2	0.063	9.281	9.281	147.316
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	1	0.076	9.922	4.961	130.551
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.096	12.200	4.067	127.082

TABLE B-10
NO_x and SO_2 Control Scenario Results for Pine Mountain Wilderness
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	1	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	1	0.015	9.949	NA	663.255
3	Add 2nd Scrubber w/Upgraded Scrubber	1	0.096	14.630	NA	152.399
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	1	0.024	8.152	NA	339.659
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	1	0.037	8.240	NA	222.695
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	1	0.055	8.419	NA	153.065
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	1	0.063	8.528	NA	135.371
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.068	8.987	8.987	132.164
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	1	0.060	9.281	NA	154.682
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	1	0.063	9.922	NA	157.490
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.086	12.200	12.200	141.859

TABLE B-11
NO_x and SO_2 Control Scenario Results for Saguaro National Park
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	0	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	0	0.008	9.949	NA	1243.603
3	Add 2nd Scrubber w/Upgraded Scrubber	0	0.069	14.630	NA	212.033
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	0	0.009	8.152	NA	905.757
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	0	0.017	8.240	NA	484.690
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	0	0.018	8.419	NA	467.697
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.026	8.528	NA	328.014
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.030	8.987	NA	299.572
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	0	0.019	9.281	NA	488.469
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0	0.024	9.922	NA	413.412
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.037	12.200	NA	329.727

TABLE B-12
NO_x and SO_2 Control Scenario Results for Sycamore Canyon Wilderness
Abitibi Unit 2

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (Million$/Day Reduced)	Cost per ΔdV Reduction (Million$/dV Reduced)
1	Existing Wet Soda Ash Scrubber	0	0.000	9.861	NA	NA
2	Upgraded Wet Soda Ash Scrubber	0	0.004	9.949	NA	2487.205
3	Add 2nd Scrubber w/Upgraded Scrubber	0	0.052	14.630	NA	281.351
4	Operate Existing Over Fire Air Fan - Existing Wet Soda Ash Scrubber	0	0.004	8.152	NA	2037.953
5	Operate Existing Over Fire Air Fan - Upgraded Wet Soda Ash Scrubber	0	0.009	8.240	NA	915.525
6	New Low-NOx Burners - Upgraded Wet Soda Ash Scrubber	0	0.015	8.419	NA	561.237
7	New LNB w/Over Fire Air Modifications - Upgraded Wet Soda Ash Scrubber	0	0.018	8.528	NA	473.798
8	New LNB w/ Over Fire Air & HERT SNCR - Upgraded Wet Soda Ash Scrubber	0	0.021	8.987	NA	427.959
9	Mobotec Rotating Over Fire Air - Upgraded Wet Soda Ash Scrubber	0	0.017	9.281	NA	545.937
10	Mobotec Rotating Over Fire Air & Rotamix SNCR - Upgraded Wet Soda Ash Scrubber	0	0.017	9.922	NA	583.641
11	New LNB w/Over Fire Air & SCR - Upgraded Wet Soda Ash Scrubber	0	0.026	12.200	NA	469.227

TABLE B-13
NO_x and SO_2 Control Scenario Incremental Analysis Data for Mazatzal Wilderness
AbitibiBowater No. 2 Power Boiler

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.013	0.088	NA	6.762
Scenario 5 vs Scenario 6	0	0.025	0.179	NA	7.153
Scenario 6 vs Scenario 7	3	0.014	0.11	0.037	7.843
Scenario 7 vs Scenario 11	0	0.026	3.683	NA	141.669
Scenario 11 vs Scenario 3	-2	0.004	2.419	-1.209	604.635

TABLE B-14
NO_x and SO_2 Control Scenario Incremental Analysis Data for Petrified Forest National Park
AbitibiBowater No. 2 Power Boiler

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 6	2	0.069	0.267	0.133	3.866
Scenario 6 vs Scenario 7	1	0.026	0.11	0.11	4.223
Scenario 7 vs Scenario 8	1	0.014	0.459	0.459	32.77
Scenario 8 vs Scenario 11	0	0.021	3.225	NA	153.552

TABLE B-15

NO_x and SO_2 Control Scenario Incremental Analysis Data for Sierra Ancha Wilderness

AbitibiBowater No. 2 Power Boiler

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 6	4	0.106	0.267	0.067	2.516
Scenario 6 vs Scenario 7	3	0.043	0.11	0.037	2.554
Scenario 7 vs Scenario 8	1	0.045	0.459	0.459	10.195
Scenario 8 vs Scenario 11	3	0.057	3.225	1.075	56.572

TABLE B-16

NO_x and SO_2 Control Scenario Incremental Analysis Data for Superstition Wilderness

AbitibiBowater No. 2 Power Boiler

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 7	7	0.119	0.377	0.054	3.164
Scenario 7 vs Scenario 8	3	0.026	0.459	0.153	17.646
Scenario 8 vs Scenario 11	0	0.038	3.225	NA	84.858

TABLE B-17
NO_x and SO_2 Control Scenario Incremental Analysis Data for Chiricahua National Monument
Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.005	0.088	NA	17.582
Scenario 5 vs Scenario 6	0	0.010	0.179	NA	17.883
Scenario 6 vs Scenario 3	0	0.046	6.212	NA	135.037

TABLE B-18
NO_x and SO_2 Control Scenario Incremental Analysis Data for Galiuro Wilderness
Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.009	0.088	NA	9.768
Scenario 5 vs Scenario 7	0	0.015	0.289	NA	19.242
Scenario 7 vs Scenario 8	0	0.006	0.459	NA	76.465
Scenario 8 vs Scenario 3	0	0.042	5.643	NA	134.360

TABLE B-19
NO_x and SO_2 Control Scenario Incremental Analysis Data for Gila Wilderness
Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 6	1	0.030	0.267	0.267	8.891
Scenario 6 vs Scenario 7	0	0.010	0.110	NA	10.981
Scenario 7 vs Scenario 3	0	0.041	6.102	NA	148.827

TABLE B-19

NO_x and SO_2 Control Scenario Incremental Analysis Data for Gila Wilderness

Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 6	1	0.030	0.267	0.267	8.891
Scenario 6 vs Scenario 7	0	0.010	0.110	NA	10.981
Scenario 7 vs Scenario 3	0	0.041	6.102	NA	148.827

TABLE B-20

NO_x and SO_2 Control Scenario Incremental Analysis Data for Grand Canyon National Park

Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.001	0.088	NA	87.911
Scenario 5 vs Scenario 3	0	0.002	6.391	NA	3195.275

TABLE B-21

NO_x and SO_2 Control Scenario Incremental Analysis Data for Mount Baldy Wilderness

Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.015	0.088	NA	5.861
Scenario 5 vs Scenario 7	2	0.042	0.289	0.144	6.872
Scenario 7 vs Scenario 8	1	0.006	0.459	0.459	76.465
Scenario 8 vs Scenario 3	-2	0.037	5.643	-2.822	152.517

TABLE B-22
NO_x and SO_2 Control Scenario Incremental Analysis Data for Pine Mountain Wilderness
Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.013	0.088	NA	6.762
Scenario 5 vs Scenario 6	0	0.018	0.179	NA	9.935
Scenario 6 vs Scenario 7	0	0.008	0.110	NA	13.726
Scenario 7 vs Scenario 8	1	0.005	0.459	0.459	91.757
Scenario 8 vs Scenario 11	0	0.018	3.213	NA	178.486
Scenario 11 vs Scenario 3	-1	0.010	2.430	-2.430	243.037

TABLE B-23
NO_x and SO_2 Control Scenario Incremental Analysis Data for Saguaro National Park
Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.008	0.088	NA	10.989
Scenario 5 vs Scenario 7	0	0.009	0.289	NA	32.070
Scenario 7 vs Scenario 8	0	0.004	0.459	NA	114.697
Scenario 8 vs Scenario 3	0	0.039	5.643	NA	144.696

TABLE B-24
NO_x and SO_2 Control Scenario Incremental Analysis Data for Sycamore Canyon Wilderness
Abitibi Unit 2

Options Compared	Incremental Reduction in Days Above 0.5 ΔdV (Days)	Incremental ΔdV Reductions (dV)	Incremental Cost (Million$)	Incremental Cost Effectiveness (Million$/Day)	Incremental Cost Effectiveness (Million$/dV)
Scenario 4 vs Scenario 5	0	0.005	0.088	NA	17.582
Scenario 5 vs Scenario 6	0	0.006	0.179	NA	29.804
Scenario 6 vs Scenario 7	0	0.003	0.110	NA	36.602
Scenario 7 vs Scenario 8	0	0.003	0.459	NA	152.929
Scenario 8 vs Scenario 3	0	0.031	5.643	NA	182.036

FIGURE B-13
NO_x and SO_2 Control Scenarios—Least-Cost Envelope Chiricahua National Monument —98th Percentile Reduction
Abitibi Unit 2

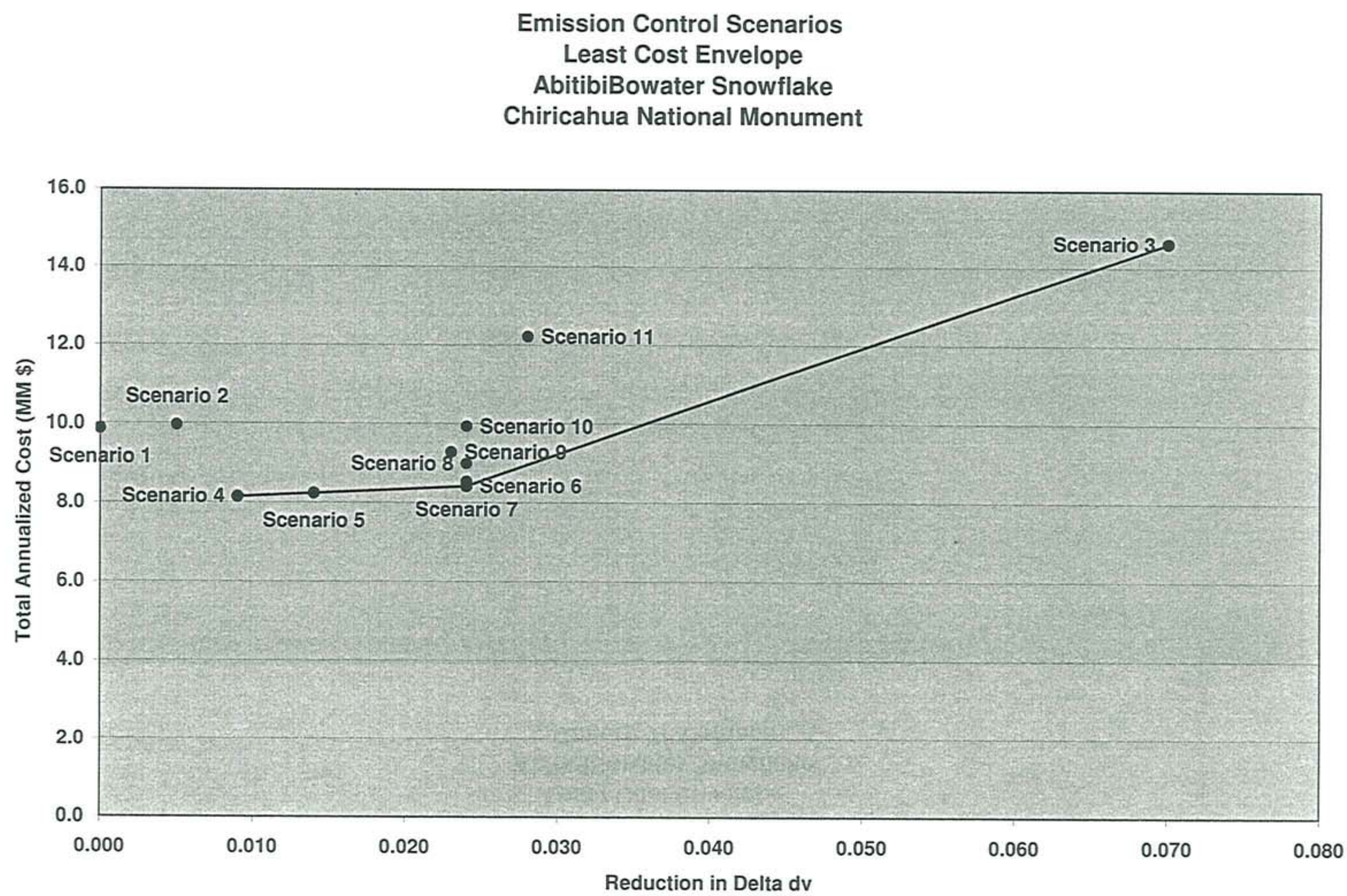


FIGURE B-14
NO_x and SO_2 Control Scenarios—Least-Cost Envelope Galiuro Wilderness —98th Percentile Reduction
Abitibi Unit 2

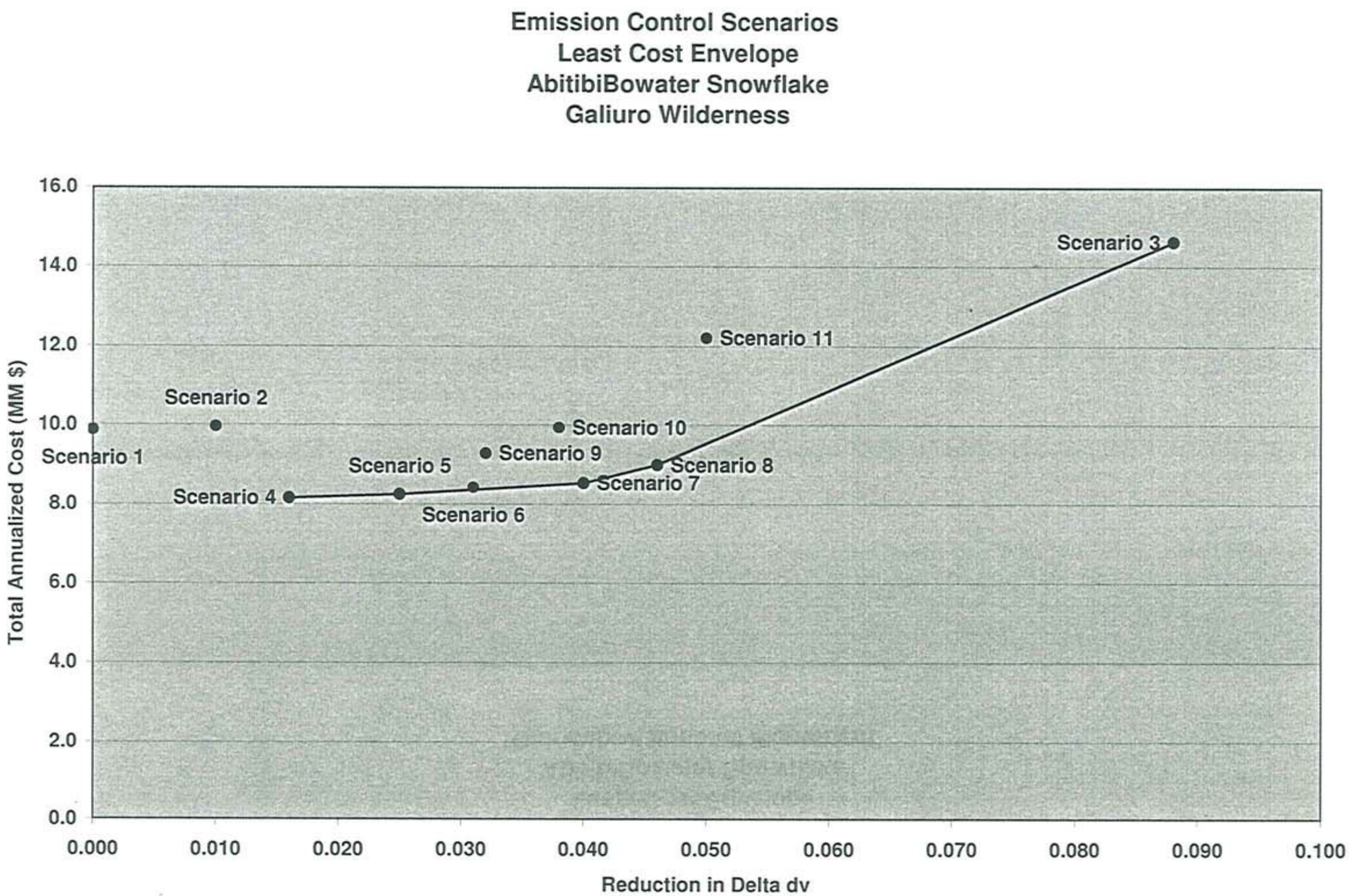


FIGURE B-15
NO_x and SO_2 Control Scenarios—Least-Cost Envelope Gila Wilderness —98th Percentile Reduction
Abitibi Unit 2

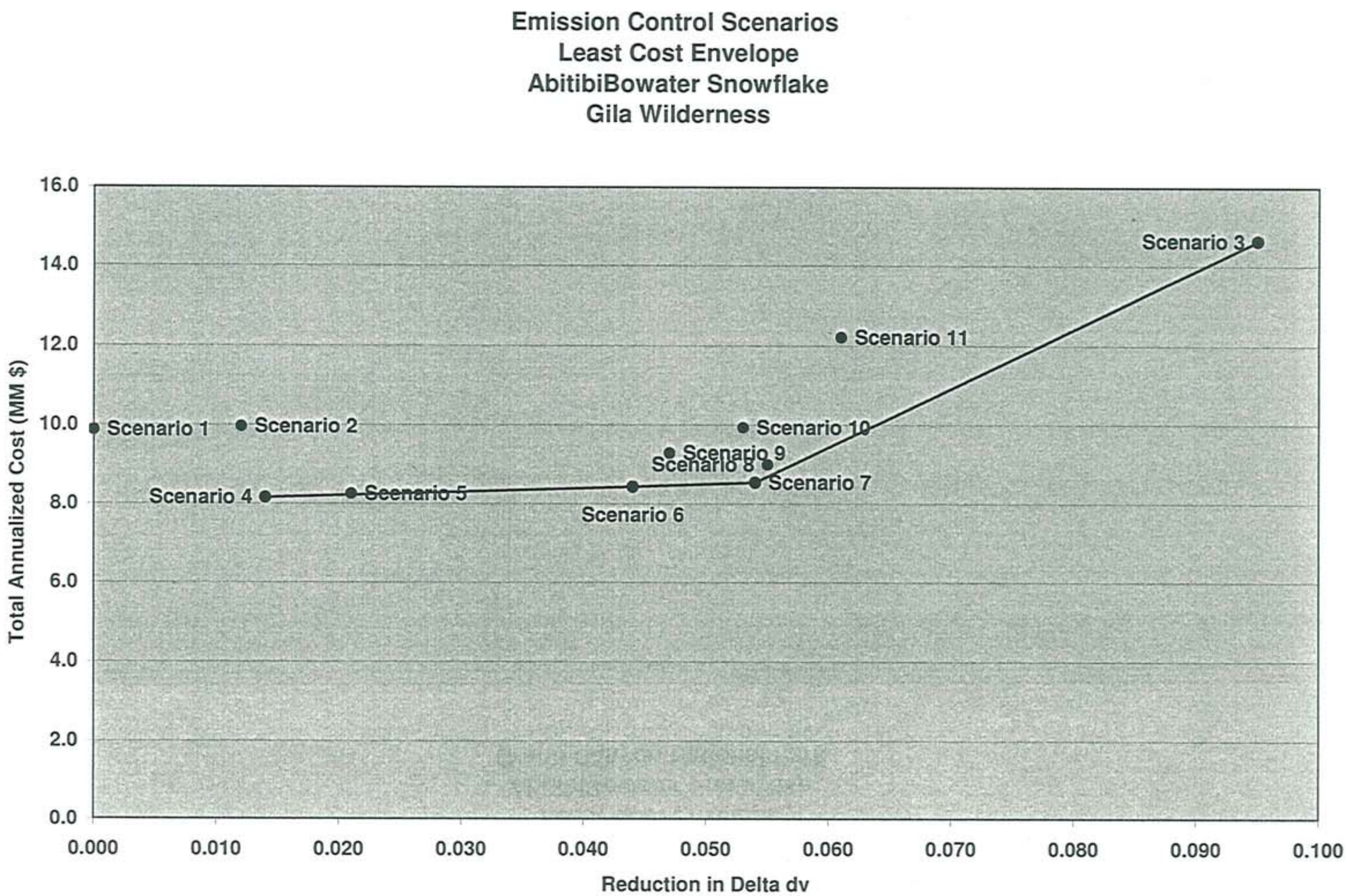


FIGURE B-16
NO_x and SO_2 Control Scenarios—Least-Cost Envelope Grand Canyon National Park —98th Percentile Reduction
Abitibi Unit 2

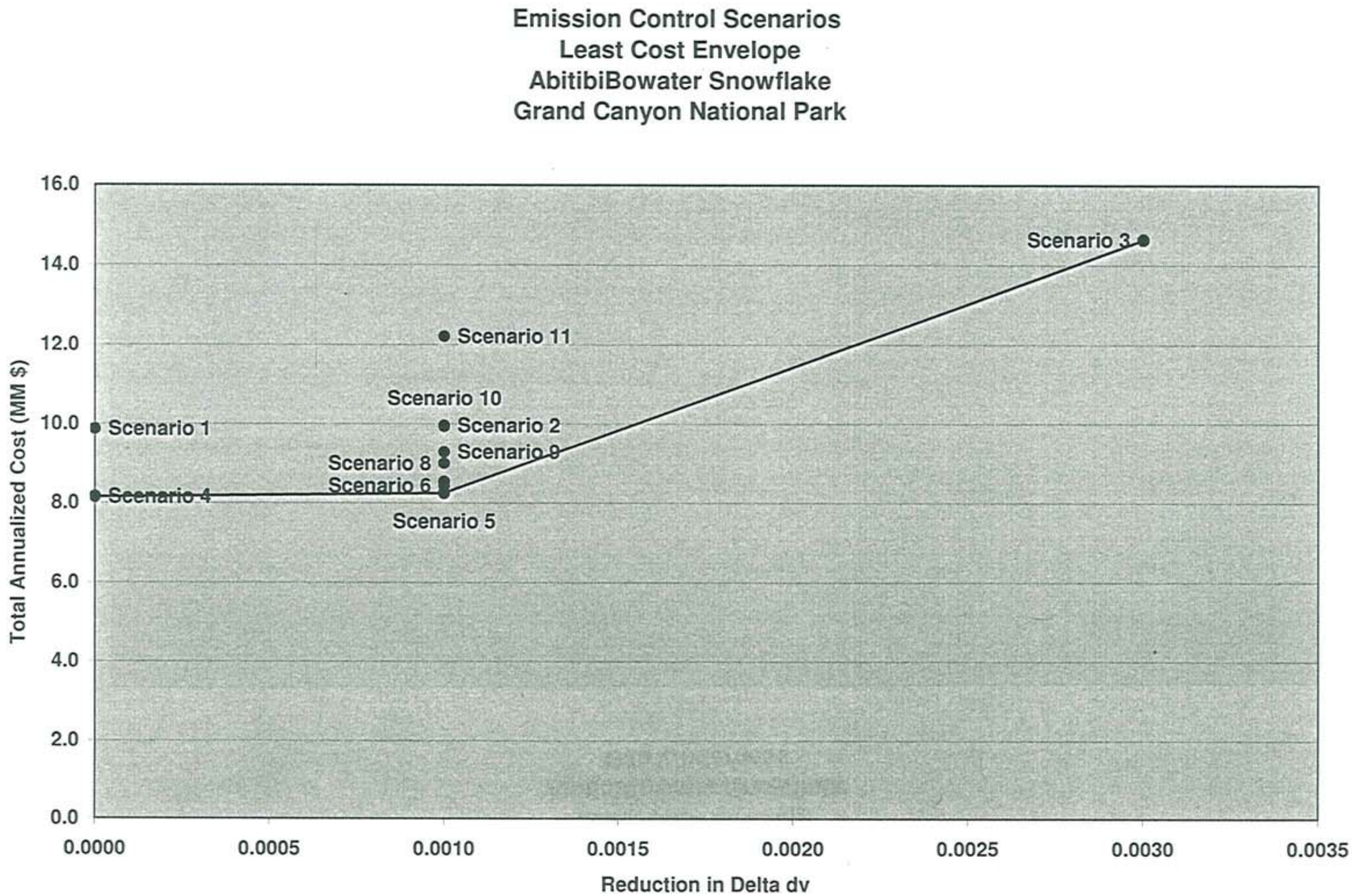


FIGURE B-17

NO_x and SO_2 Control Scenarios—Least-Cost Envelope Mount Baldy Wilderness —98th Percentile Reduction

Abitibi Unit 2

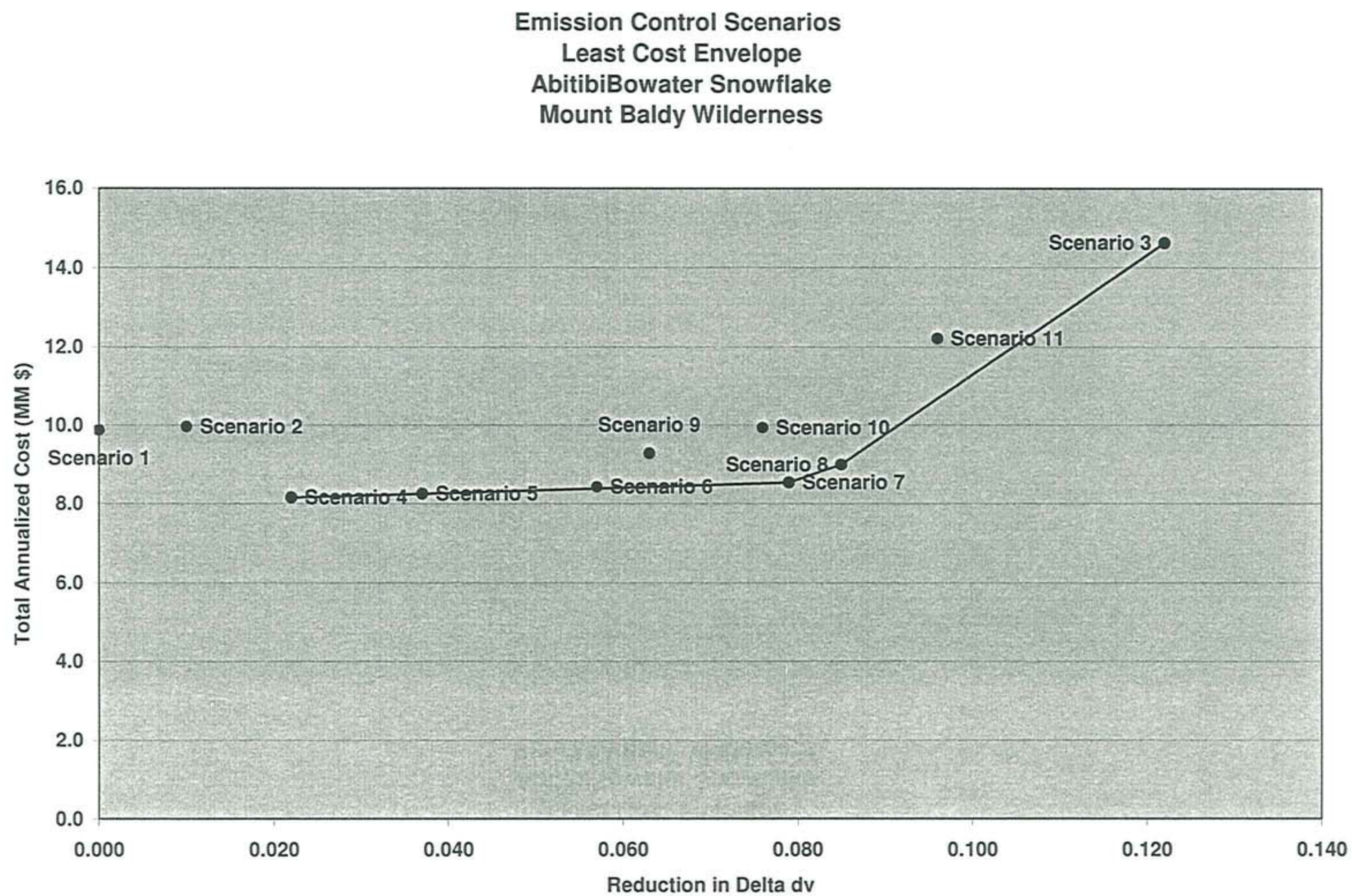


FIGURE B-18

NO_x and SO_2 Control Scenarios—Least-Cost Envelope Pine Mountain Wilderness —98th Percentile Reduction

Abitibi Unit 2

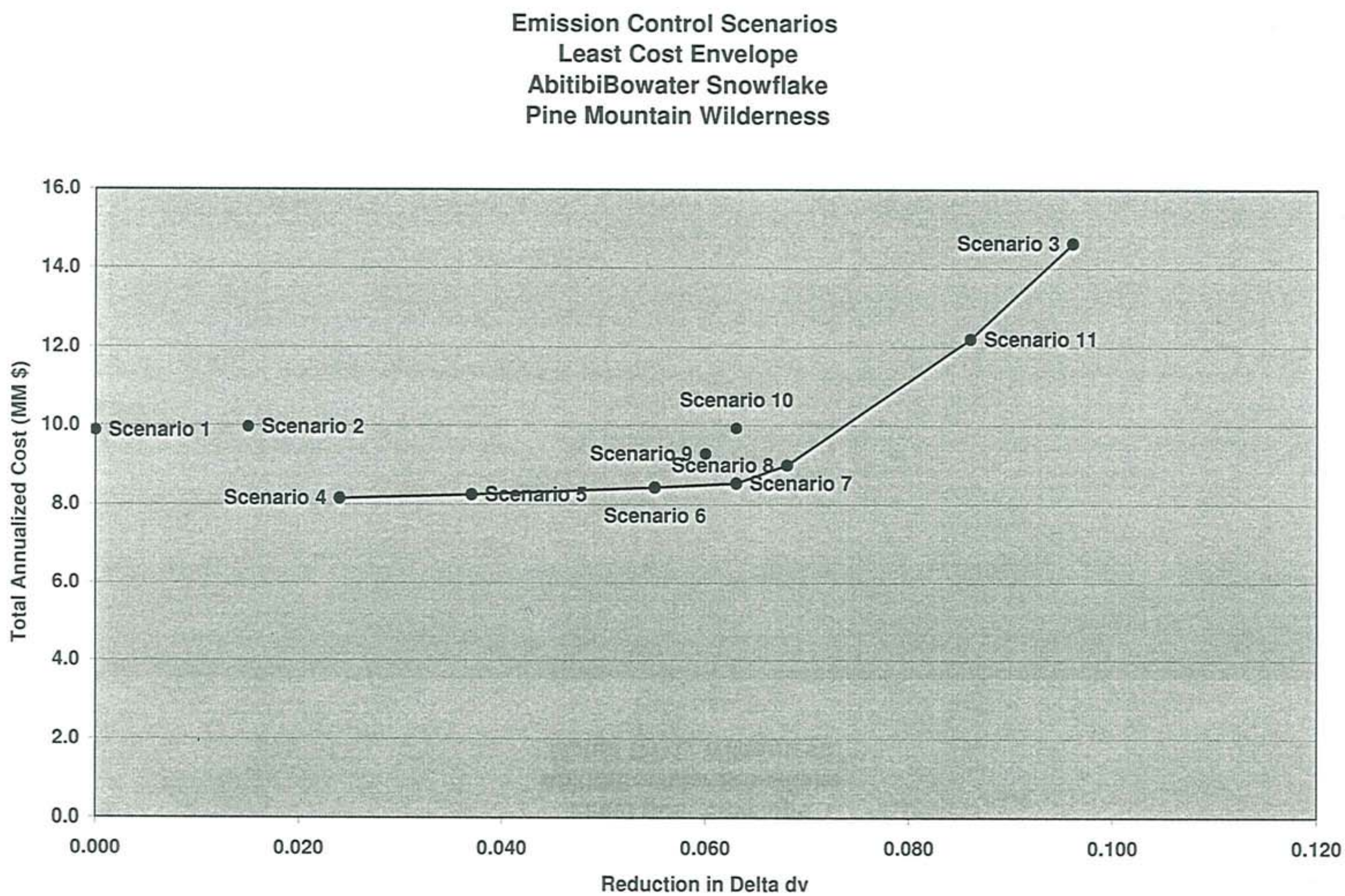


FIGURE B-19
NO_x and SO_2 Control Scenarios—Least-Cost Envelope Saguaro National Park —98th Percentile Reduction
Abitibi Unit 2

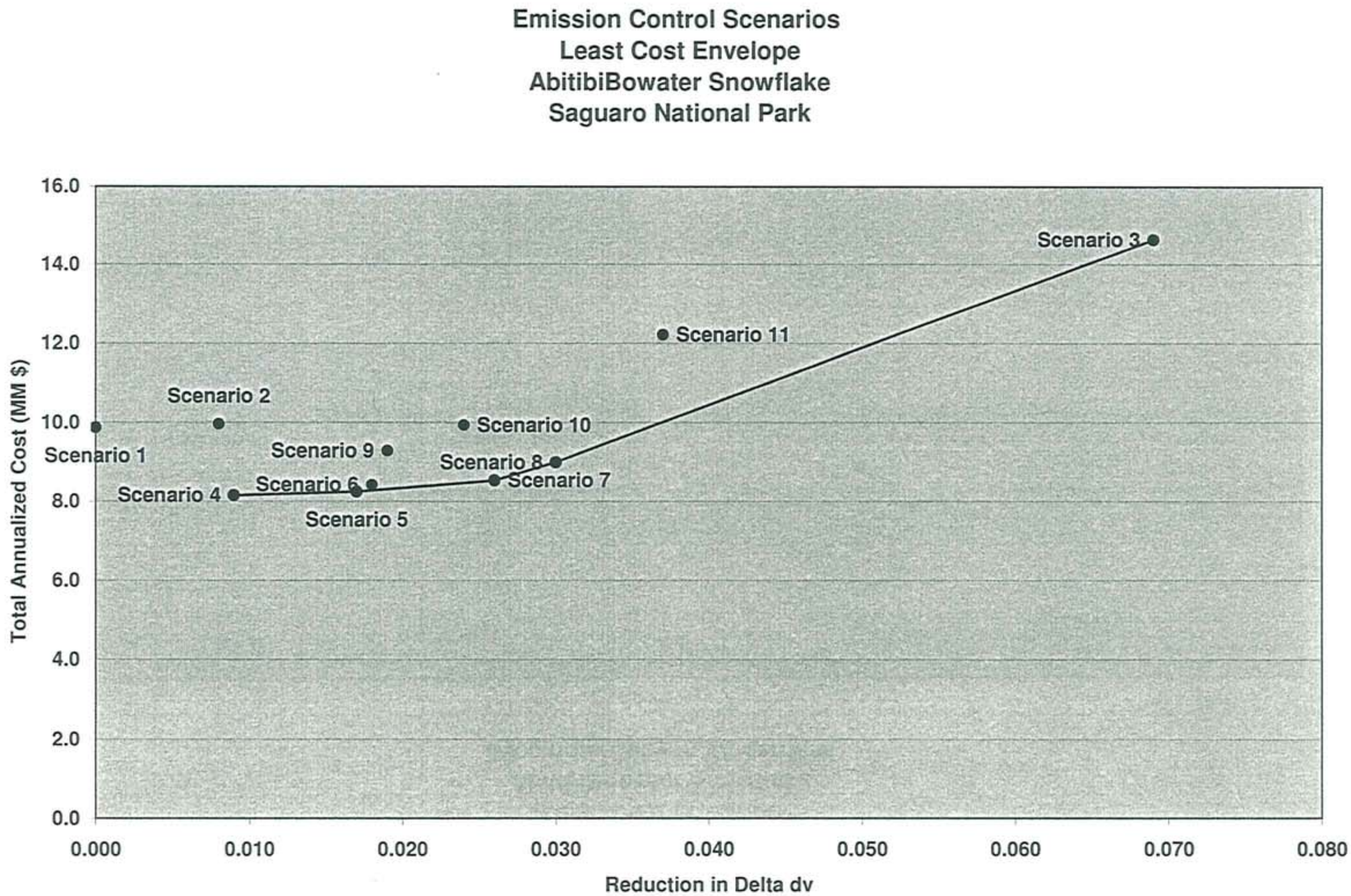


FIGURE B-20
NO_x ans SO_2 Control Scenarios—Least-Cost Envelope Sycamore Canyon Wilderness —98th Percentile Reduction
Abitibi Unit 2