BART DETERMINATION STUDY

for

Leland Olds Station Unit 1 and 2

Basin Electric Power Cooperative

Final Draft

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Basin Electric Power Cooperative
Leland Olds Station
Units 1 and 2
Best Available Retrofit Technology Analysis

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EXECUTIVE SUMMARY

On July 6, 2005, the U.S. EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations. The final regulations require eligible sources to be analyzed to determine a BART emission limit for nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM). The North Dakota Department of Health (NDDH) reviewed the operational history of North Dakota sources and determined which sources were BART eligible and provided a state specific modeling protocol for use in the analysis. Basin Electric Power Cooperative's (BEPC's) Units 1 and 2 at the Leland Olds Station (LOS) were determined to be BART eligible by the NDDH. As discussed in the analysis, small emission units at LOS produce emissions in levels anticipated to be too small to affect visibility in Class 1 areas and were excluded from further consideration in the study. This BART determination was conducted in accordance with the eligibility conclusion made by NDDH and follows the steps outlined in the guidelines and the NDDH protocol.

The BART determination process has five predefined steps. Steps 1 through 3 include identifying and evaluating feasible control technologies. Steps 4 and 5 involve a technical evaluation of the impacts related to each control technology. The evaluation reviews multiple impacts including economics and visibility impairment in Class 1 areas. The result of conducting this five step analysis is a list of control technologies for regulated pollutants that provides a cost effective system of emission reduction and visibility impact reduction. This technology list, including control efficiencies, is then translated into an emission rate constituting BART that must be achieved by the eligible source. Although the impacts requiring analysis are explicitly stated within the guideline, no methodology is provided for using the impacts to select a control technology. Thus, every BART analysis will have a certain level of subjectivity based upon source characteristics, reviewed technologies, and background information used to perform the evaluation.

This analysis used several reference works, including the RACT/BACT/LAER Clearinghouse (RBLC), to identify which control technologies to evaluate. The technologies were then reviewed for feasibility and systematically eliminated by analyzing the impacts provided in the guidelines. Specifically, the control technologies were ranked by control efficiency and removed from the list based upon the cost per ton of removal and the reduction in visibility impairment impact. Based upon that evaluation, the BART recommendations are made for each pollutant and are summarized in the tables below.

Leland Olds Station Unit 1 Recommended BART

Pollutant	Percent Removal %	Emission Rate lb/MMBtu
SO_2	90	0.34
NO_X	-	0.29
PM(1)	NA	0.10

(1) - Filterable PM only.

Leland Olds Station Unit 2 Recommended BART

Pollutant	Percent Removal %	Emission Rate lb/MMBtu
SO_2	95	0.17
NO_X	54.5	0.304
PM(1)	NA	0.10

(1) - Filterable PM only.

The rates provided in these tables are based upon the control efficiency of a recommended BART control technology applied to each unit at the Maximum Continuous Rating (MCR) burning 100% lignite fuel. However, because the accuracy of the cost estimate is ± 30% and in some cases is greater than the differences between the estimated costs of feasible control alternatives, the technology used to meet the BART recommendation may change. These rates are not provided as recommended permit conditions. The guidelines suggest that emission limits be developed on a 30-day rolling average for Electric Generating Units (EGUs). Unfortunately, the guidelines do not provide a methodology to calculate the limit for permitting purposes and only state that an enforceable limit that reflects BART requirements must be established.

To develop recommended permit conditions for each pollutant, emissions calculations were performed using an increased Boiler Heat Input and coal sulfur content. Historical variability in plant operations show that the boiler design capacity Heat Input rate was exceeded 10.6% and 7.6% of the operating time for Unit 1 and Unit 2 respectively. Normal plant operation includes exceeding the original boiler design capacity Heat Input rate, which has an impact on hourly emissions variability. Short-term increases of heat input can raise hourly emissions, which can have a significant impact on short-term emission averages. To take into account the influence that an average heat input rate higher-than-nameplate boiler design heat input capacity rating would have on baseline emissions over a 30-day averaging period, a 5% increase in heat input was used for developing a recommended 30-day emission limit for each pollutant for permitting purposes.

Sulfur content of the coal was the primary constituent of concern because SO_2 emissions are directly related to the amount of sulfur in the coal and are not as related to equipment design. A forty year mining plan was analyzed to determine the future maximum annual sulfur content to be used in the BART analysis. The results indicated that future delivered coal will have a maximum annual average sulfur content of approximately 1.13% with a standard deviation of 0.12%. A 30-day rolling average SO_2 emission rate was calculated using the maximum sulfur content plus 1 standard deviation (i.e., 1.25% S).

As previously stated, selection of BART for control of the major pollutants of interest needs to be translated into an emission rate limit, which is not a fixed percent reduction from baseline. The post-control emission rate is influenced by the unit pre-control baseline emission rate and the effectiveness of BART selected for the particular pollutant. Boiler Heat Input is the single most important variable affecting the NO_X emissions rate. The pre-control baseline NO_X emission rate is influenced by the variability of the hourly boiler heat input rate over the duration of the averaging period selected. For LOS Unit 1, the recommended BART 30-day rolling average unit NO_X emission rate is 0.29 lb/mmBtu (presumptive level). A recommended BART 30-day rolling average unit NO_X emission rate of 0.35 lb/mmBtu for LOS Unit 2 results from applying a 54.5 percent reduction to the unit NO_X pre-control baseline emission rate of 0.77 lb/mmBtu that reflects the higher Boiler Heat Input rate. A provisional operating period of one year of operational experience is recommended in conjunction with the recommended BART 30-day rolling average NO_X permit emission rate to allow BEPC to demonstrate the actual control system capabilities of Unit 2's boiler. At the end of that period, it is recommended that the NO_X BART permit limits be reviewed considering the demonstrated operating history.

To account for the higher heat input and higher future sulfur content, a representative SO_2 emission rate was calculated based upon a 5% higher heat input and the maximum annual average sulfur content plus 1 standard deviation (i.e., 1.25% S). The resulting recommended 30-day rolling average SO_2 permit limit for LOS Unit 1 is 0.39 lb SO_2/mmBtu. Similarly, the resulting SO_2 permit limit for LOS Unit 2 is 0.19 lb SO_2/mmBtu.

Emission evaluated rates for particulate matter are based upon the design of the existing electrostatic precipitator and the heat input. The resulting recommended 30-day rolling average PM permit limits for both Unit 1 and 2 are 0.10 lb PM/mmBtu. Using the methodologies discussed for each pollutant, recommended emission limits for each pollutant are tabulated below.

Recommended 30-Day Rolling Average BART Emission Limits for LOS Unit 1

Pollutant	Emission Rate(1) lb/MMBtu
SO_2	0.39
NO_X	0.29
PM	0.10

(1) - 30-day rolling average, based upon an average boiler heat input rate of 2,622 * 1.05 = 2,753 mmBtu/hr and percent removal compared to pre-control baseline emission levels. NO_X pre-control baseline emission rate for this recommended limit is 0.29 lb/mmBtu. Note that the recommended PM emissions are not a 30-day rolling average.

Recommended 30-Day Rolling Average BART Emission Limits for LOS Unit 2

Pollutant	Emission Rate(1) lb/MMBtu
SO_2	0.19
NO_X	0.35
PM	0.10

(1) - 30-day rolling average, based upon an average boiler heat input rate of 5,130 * 1.05 = 5,387 mmBtu/hr and percent removal compared to pre-control baseline emission levels. NO_X pre-control baseline emission rate for this recommended limit is 0.77 lb/mmBtu. Note that the recommended PM emissions are not a 30-day rolling average.

Although the emission limits presented above for each unit are recommended for permitting purposes, this analysis also recommends discussing an alternative compliance method as suggested in the BART Guidelines. The guidelines provide that states, "should consider allowing sources to ''average'' emissions across any set of BART-eligible emission units within a fenceline, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute a BART-eligible source." (70 FR 39172) During the process of developing enforceable permit conditions, the opportunity to apply a plant-wide limit using an "averaging" or "bubbling" strategy should be considered.

1.0 INTRODUCTION

The U.S. EPA finalized the Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations[1] in the Federal Register on July 6, 2005 (70 FR 39104). BART is defined as "an emission limitation based on the degree of reduction achievable through the application of the best system of continuous emission reduction for each pollutant which is emitted by a BART-eligible source. The emission limitation must be established, on a case-by-case basis, taking into consideration the technology available, the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). This document presents the BART analysis for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Basin Electric Power Cooperative's (BEPC's) Leland Olds Station (LOS) Units 1 and 2 located in Stanton, North Dakota.

A BART eligible source is one that meets three criteria identified by EPA in the guidelines for the determination of BART. A source is BART eligible if operations fall within one of 26 specifically listed source categories (70 FR 39158), the source entered into service between August 7, 1962 and August 7, 1977, and the source has the potential to emit 250 tons per year or more of a visibility-impairing air pollutant (SO_2, NO_X or PM). The North Dakota Department of Health (NDDH) reviewed the operational history of sources within North Dakota and independently determined which sources are BART eligible. The NDDH classified the electric generating units (EGUs) at Leland Olds Station as BART eligible. For the purposes of this report, the NDDH's determination will be used and Units 1 and 2 at LOS are assumed to be subject to a BART analysis.

Where a particular source is determined to be eligible, the general steps for determining BART for each pollutant are as follows (70 FR 39164):

STEP 1 - Identify all available retrofit control technologies (within the BART Guidelines).
STEP 2 - Eliminate technically infeasible options.
STEP 3 - Evaluate control effectiveness of remaining control technologies.

[1] "Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations"; Environmental Protection Agency; Federal Register, Volume 70, No. 128; July 6, 2005.

STEP 4 - Evaluate the following impacts for each feasible control technology and document results: (70 FR 39166).

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

STEP 5 – Evaluate the visibility impacts.

Basin Electric Power Cooperative retained Burns & McDonnell to assist in the completion of the Best Available Retrofit Technology analysis for Leland Olds Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services to the power industry since the 1970s. As a result of their long history providing these services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis.

This report includes steps 1 through 5 of the BART Determination for emissions from Units 1 and 2 at LOS. Section 1 of the report quickly summarizes the plant conditions, provides the parameters used in the analysis and discusses the approach to the BART Determination. The true BART analysis begins with Sections 2 through 5. Each section contains the analysis for each major pollutant (NO_X, SO_2 and PM). Within the section for each pollutant, the results of each step of the BART analysis are summarized for each unit. Separate summaries for each unit are provided at the end of the report to communicate the results of each step in the analyses, combine results obtained for each pollutant and develop permit limit recommendations based upon a 30 day rolling average.

1.1 BACKGROUND

Basin Electric Power Cooperative operates the Leland Olds Station in Stanton, North Dakota. Leland Olds Station is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) wall-fired, dry-bottom, pulverized coal-fired boiler serving a turbine generator with a nameplate rating of 220 MW. Particulate control is provided by a Research Cottrell electrostatic precipitator (ESP) rated at 99.5% control. Unit 1 has no sulfur dioxide (SO_2) control system and exhausts to a 350 foot tall, concrete stack with a brick liner. Unit No. 2 is a B&W cyclone-fired unit burning crushed coal, with a turbine-generator name plate rating of 440 MW. Particulate control for

Unit 2 is provided by two parallel Joy Manufacturing precipitators rated at 99.1% control. Unit 2 does not have a flue gas desulfurization system and exhausts to a 500 foot tall, concrete stack with a brick liner. Unit 1 began commercial operation in 1966 and Unit 2 in 1976. Due to their designation by the NDDH, both units are subject to the requirements for BART analysis under the Regional Haze Rule.

1.2 BART ANALYSIS PARAMETERS

Table 1.2-1 contains the design parameters for LOS Unit 1 and Unit 2 used in the analysis. Typical coal parameters used in the BART analysis are provided in Table 1.2-2. The economic factors were specified by BEPC for this study and are presented in Table 1.2-3.

Table 1.2-1 – Unit Design and Operating Parameters

Design Unit Operating Characteristics(1)	**Unit 1 Design**	**Unit 2 Design**
Boiler Type	Wall-Fired	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,622	5,130
Unit Nameplate Generator Output Capacity, MW_g (gross)	216	440
Unit Nominal Full Load (NFL) Output, MW_g (gross)	220	440
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,468	4,846
Boiler Excess O_2, % (all cases)	3	3
Boiler Excess Air, % (all cases)	20	20
Fly Ash Portion of Total Ash, % (all cases)	70	30
Air Heater Leakage, % (all cases)	5	12
Average Boiler Heat Input for NO_X period, mmBtu/hr	2,443	4,478
Average Gross Unit Output for NO_X period, MW_g	217.8	406.5
Average Capacity Factor for NO_X period, % of Unit NFL	99	92.4
NO_X Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	0.29	0.67
lb/hr	697	2,987
Average Boiler Heat Input for SO_2 period, mmBtu/hr	2,468	4,846
Average Capacity Factor for SO_2 period, % of Unit NFL	90	85
Coal Flow Rate for Historic SO_2 Case, lb/hr	352,375	691,900
Flue Gas Conditions at the air heater outlet		
Flue Gas Temperature, F	375	395
Flue Gas Pressure, in. wg	-14.80	-14.80
Flue Gas Mass Flow Rate, lb/hr	2,670,000	5,590,000
Flue Gas Volumetric Flow Rate, acfm	972,600	2,085,000
SO_2 Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	2.76	2.76
lb/hr	6,817	13,380

Table 1.2-1 – Unit Design and Operating Parameters (cont.)

Design Unit Operating Characteristics	Unit 1 Design	Unit 2 Design
Future Potential-to-Emit (PTE) Conditions	**Design**	**Design**
Capacity Factor, %	100	100
PTE Case Boiler Heat Input, mmBtu/hr	2,622	5,130
NO_X Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	0.29	0.67
lb/hr	760	3,422
Coal Flow Rate for PTE Case , lb/hr	398,700	780,000
Flue Gas Conditions at the air heater outlet		
Flue Gas Temperature, F	375	395
Flue Gas Pressure, in. wg	-14.80	-14.80
Flue Gas Mass Flow Rate, lb/hr	2,838,000	5,921,000
Flue Gas Volumetric Flow Rate, acfm	1,034,000	2,210,000
SO_2 Concentrations at the air heater outlet	**Typical**	**Typical**
lb/mmBtu	3.43	3.43
lb/hr	9,001	17,609

(1) – Averages based upon highest actual 24-month rolling summation for each specific pollutant, years 2000-2004. Boiler heat input and unit generating output are specific to the actual 24-month period for each specific pollutant.

Table 1.2-2 – Coal Parameters

Ultimate Coal Analysis (% by mass):	PRB Typical	Lignite Typical	Typical Blended Coal[(1)]	Future Coal Case (Lignite)[(2)]
Moisture	32.00	37.25	36.88	37.25
Carbon	47.88	38.26	38.93	38.26
Hydrogen	3.10	2.69	2.72	2.69
Nitrogen	0.70	0.67	0.67	0.67
Chlorine	0.01	0.01	0.01	0.01
Sulfur	0.43	0.96	0.92	1.13
Ash	5.20	8.45	8.22	8.45
Oxygen	10.69	11.70	11.63	11.70
Total	100.01	99.99	99.99	100.16
Higher Heating Value, Btu/lb	8,000	6,577	6,677	6,548
Ash Mineral Analysis (% by mass):				
Silica	28.11	29.09		29.09
Alumina	15.57	13.06		13.06
Titania	1.31	0.51		0.51
Calcium Oxide	24.60	21.14		21.14
Magnesium Oxide	6.53	7.39		7.39
Sodium Oxide	1.60	7.55		7.55
Iron Oxide	6.01	4.96		4.96
Sulfur Trioxide	12.22	6.20		6.20
Potassium Oxide	0.23	1.20		1.20
Phosphorus Pentoxide	0.60	0.21		0.21
Strontium Oxide	not reported	not reported		not reported
Barium Oxide	not reported	1.49		1.49
Manganese Oxide	not reported	not reported		not reported
Total	96.78	92.80		92.80

(1) - Typical blend of 93% North Dakota lignite and 7% Powder River Basin (PRB) subbituminous coal on an annual basis.
(2) - A forty year mining plan was analyzed to determine the future maximum annual sulfur content to be used in the BART analysis. The mining plan data used in the analysis is presented in Appendix B2.

Table 1.2-3 – Economic Factors[(1), (2)]

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Conversion Tax (in lieu of property tax)	(see footnote 3)
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2%
Fuel (coal and natural gas) Escalation	2%
Auxiliary Electric Power Cost, $/MW-hr	$38.00
Fly Ash Disposal Cost ($/ton)	$5.51
Bottom Ash Disposal ($/ton)	$2.10
Operating Labor Rate (fully burdened), $/hr	$40.60
Administrative or Supervisory Overheads	30%
Lime Cost ($/ton delivered) [(4)]	$60.50
Limestone Cost ($/ton delivered) [(4)]	$25.00
Urea Cost, ($/ton delivered)	$380.00
Ammonia Cost ($/ton delivered)	$304.45
Natural Gas ($/mmBtu)	$7.98

(1) - All costs in the table were provided by BEPC.
(2) - All costs are in 2005 dollars unless noted otherwise.
(3) - Conversion tax is provided in the economics for each pollutant control technology.
(4) - Lime and limestone costs are in 2006 dollars.

1.3 APPROACH

The purpose of the Regional Haze Rule is to address visibility impairment in mandatory Class 1 areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The visibility impact of VOCs and ammonia are considered negligible for a BART analysis, according to the NDDH's November 2005 modeling protocol[2], and are not addressed further in this report. Before the actual BART analysis can begin, a basis must be defined for establishing emission rates to be used by eligible sources. The NDDH requested companies use the same basis that is used for the Prevention of Significant Deterioration (PSD) program which is to determine the hourly averages from the highest 24-month rolling summation emissions within the

[2] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota"; North Dakota Department of Health, Division of Air Quality; November, 2005.

previous 5-year operating period. BEPC reviewed its operating data for 2000 through 2004 to obtain historical emission rates presented in Table 1.3-1.

Table 1.3-1 – Leland Olds Station Historical Emissions for BART Analysis

Pollutant	Unit 1		Unit 2	
	lb/h(1)	tpy(2)	lb/h(1)	tpy(2)
SO_2	4,280	18,749	7,899	34,596
NO_X	697	2,967	2,987	12,023
PM (3)	68.68	263.9	153.32	577.2

(1) - Pounds per hour (lb/h) for SO_2 and NO_X for these historic pre-control baseline emission rates determined as actual 24-month highest rolling summation tons x 2000 lb/ton divided by actual 24-month operating hours for the same time period.

(2) - Tons per year (tpy) for SO_2 and NO_X calculated as the 24 month highest rolling summation tons divided by 2.

(3) - PM emissions calculated from actual 24-month highest rolling summation heat input (mmBtu) divided by actual 24-month operating hours for the same time period multiplied by the average PM total lb/mmBtu from particulate matter tests performed annually.

The historical emission rates are averages based upon operating at partial capacity and burning specific types of coal. Due to the narrow operational characteristics that are a result of past coal quality from which these emission rates were obtained, they are considered not representative for performing a BART analysis at LOS that accurately reflects future coal quality. BEPC discussed an alternative method to obtain acceptable emission rates with the NDDH and obtained approval to use different rates in the LOS BART analysis. The alternative rates are based upon each unit operating at 100% capacity and burning lignite with higher sulfur content. A forty year mining plan was analyzed to determine the future annual average lignite sulfur content used in the BART analysis. The alternative baseline emission rates for the future coal case scenario are labeled "PTE Emissions" and are presented in Table 1.3-2.

Table 1.3-2 – Leland Olds Station Future PTE Emissions for BART Analysis

Pollutant	Unit 1		Unit 2	
	lb/h(1)	tpy(2)	lb/h(1)	tpy(2)
SO_2	9,001	39,424	17,610	77,132
NO_X	760	3,330	3,422	14,989
PM	73	320	169	740

(1) - Pounds per hour (lb/h) for these future PTE pre-control baseline emission rates determined from assumed unit emission rates (lb/mmBtu) multiplied by boiler design capacity heat input rating (mmBtu/hr) provided in Table 1.2-1.

(2) - Tons per year (tpy) calculated from the average hourly unit emission rates multiplied by 8,760 hours per year of possible operation.

In Part IV of the Guidelines for BART Determination, and discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The format of this report follows these basic steps. The approach used to complete each step is summarized below.

1.3.1 IDENTIFICATION OF RETROFIT CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit control technologies. In order to identify the applicable control technologies, several reference works are consulted. A preliminary list of control technologies and their estimated capabilities is developed.

1.3.2 FEASIBILITY ANALYSIS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology.

A control technology is considered available, "if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" or "if it has reached the stage of licensing and commercial availability." On the contrary, a control technology is not considered available, "in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type." (70 FR 39165) "A technology that is available and applicable is technically feasible." (70 FR 39165)

1.3.3 EVALUATE TECHNICALLY FEASIBLE CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency is reviewed and presented with the description of each technology. The evaluation of the technically feasible BART alternatives concludes with the alternatives ranked in descending order of control effectiveness.

1.3.4 IMPACT ANALYSIS

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis. The BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

The first three of the four factors considered in the impact analysis are discussed in the associated pollutant section. The remaining useful life of the source is included as part of the cost of compliance. Due to the complexity involved with estimating costs, additional discussion is provided below.

1.3.5 METHODOLOGY FOR ESTIMATED COSTS

The economic evaluations of each control alternative are presented together for each pollutant in the respective sections of the report. Capital and O&M cost estimates for each control alternative are presented. The Levelized Total Annual Cost (LTAC) and Unit Control Costs for the control alternatives are calculated and presented. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, again in current (2005) dollars. As a minimum, the design life for any alternative was taken to be that recommended by "The EPA Air Pollution Control Cost Manual", Sixth Edition, January 2002, EPA/452/B-02-001.

The LTAC is also used to calculate the average annual and incremental cost effectiveness of each alternative. The LTAC represents an annual payment in current day dollars sufficient to finance the project over its entire life.

In determining the LTAC a Capital Recovery Factor and an O&M Levelization Factor were calculated from the project economic conditions and then applied separately to the estimated capital and O&M costs. The equation used is shown below.

$$LACC / NPV = \left(\frac{i(1+i)^n}{(1+i)^n - 1} \right) = CRF$$

Where,
LACC = Levelized Annual Capital Cost
NPV = Net Present Value of the capital investments required.
i = discount rate
n = design life in years
CRF = Capital Recovery Factor

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table 1.2-3 the Capital Recovery Factor was calculated to be 0.08718.

In determining the levelized annual O&M cost the estimated annual O&M cost, the inflation rate, the discount rate, and the equipment life are taken into account. The O&M Levelization Factor (OMLF) was calculated as follows.

$$LAOMC / A_1 = \left(\frac{1+i_d}{1+i_i} - 1 \right) \left(\frac{i_d (1+i_d)^n}{(1+i_d)^n - 1} \right) = OMLF$$

Where,
A = Levelized Annual O&M Cost (LAOMC)
A_1 = Total annual O&M cost in current dollars
i_d = discount rate
i_i = inflation rate
n = design life in years

Therefore:

LAOMC = OMLF x A_1

For the economic conditions described in Table 1.2-3 the Operating and Maintenance Levelization Factor was calculated to be 1.19314.

The Levelized Total Annual Cost, or LTAC is the sum of the levelized capital cost and the levelized O&M cost. Therefore:

$$LTAC = LACC + LAOMC = (CRF \text{ x } NPV) + (OMLF \text{ x } A_1) = 0.08718 \text{ x } P + 1.19314 \text{ x } A_1$$

The differences between alternatives are also presented graphically in the form of a plot of the LTAC versus the annual emissions reduction (tpy) for each alternative. This form of plot graphically depicts the cost effectiveness (in $/ton of pollutant reduction) of each alternative relative to all of the others. The cost effectiveness is also referred to as the Unit Control Cost and defined as the LTAC divided by the annual emissions reduction (ton/yr). The area on the plot indicated by the various data points represents the cost effectiveness envelope for the alternatives under consideration. A smooth line is drawn on this plot connecting the rightmost points (those with the lowest cost for a given level of emissions reduction). This line is referred to as the Dominant Control Curve (DCC). The DCC defines the right hand boundary of the envelope encompassing all of the alternatives considered. The DCC is used as a screening tool between considered alternatives. Those alternatives whose plotted position is above and/or to the left of the DCC are not as cost effective as those forming the line and thus can be eliminated from further analysis if desired.

In order to compare various pollutant control alternatives, the Unit Control Cost and the incremental Unit Control Cost of each alternative were also calculated and tabulated for comparison purposes. The Unit Control Cost compares control technologies on a basis of dollars expended per ton of pollutant reduced ($/ton). This relationship is graphically depicted in the DCC chart.

To more accurately compare between alternatives with different costs and control efficiencies, the incremental cost effectiveness is also determined for those alternatives on the DCC. The incremental cost effectiveness is defined as the LTAC of a given control option minus the LTAC of an alternative, divided by the difference between the annual emissions reduction (tpy) of the given control option and the alternative being evaluated. The combination of these two economic analyses can be used as an argument for the elimination of control technologies with significantly greater marginal control costs than the given case. The equation used for the incremental cost effectiveness is shown below.

$$ICF = \frac{(LTAC_1 - LTAC_2)}{(AE_1 - AE_2)}$$

Where,

ICF = Incremental cost effectiveness ($/incremental ton removed)
$LTAC_1$ = Levelized Total Annual Cost of control alternative No. 1 ($/yr)
$LTAC_2$ = Levelized Total Annual Cost of control alternative No. 2 ($/yr)
AE_1 = Control option No. 1 Annual Emissions Reduction (ton/yr)
AE_2 = Control option No. 2 Annual Emissions Reduction (ton/yr)
(The higher cost, more effective control option is subscript 1 in this equation.)

The economic analyses presented in this report not only include the estimated capital and O&M costs for each alternative, but also the LTAC for economic comparison of the various alternatives. In addition, the Unit Control Cost or cost effectiveness is presented for each alternative. Finally, a comparison between alternatives, in the form of the incremental cost effectiveness, is presented in both numerical and graphical form. Thus a comprehensive comparison of the economic impacts of each alternative, as well as the differences in economic impact between alternatives is clearly presented.

1.3.6 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

In the BART Determination Guidelines, and discussed in Section 1.0 of this report, the EPA provides five basic steps for a case-by-case BART analysis. The fifth step involves evaluating visibility impacts utilizing dispersion modeling. Visibility impairment impacts for modeled pre-control and post-control emission levels and visibility improvements are to be assessed in deciViews (dV). The BART guidelines describe the thresholds for visibility impairment as:

> "A single source that is responsible for a 1.0 dV change or more should be considered to "cause" visibility impairment; a source that causes less than a 1.0 dV change may still contribute to visibility impairment..... any threshold that you (the States) use for determining whether a source "contributes" to visibility impairment should not be higher than 0.5 dV." (70 FR 39161)

The NDDH BART protocol does not distinguish between a source that "causes" or "contributes" to visibility impairment but follows the EPA's Regional Haze Rule threshold recommendations. Thus, 0.5 dV is the deminimis threshold level of visibility impairment impact for an otherwise BART-eligible source under the NDDH BART protocol. In other words, a BART-eligible source for which modeling predicts a visibility impairment impact of greater than 0.5 dV is deemed to have a visibility impairment impact and thus is subject to a BART analysis under this the NDDH BART protocol. A BART-eligible source for which the modeling predicts less than a 0.5 dV impact would be deemed to not have a visibility impairment impact, and thus could be exempted from BART on that basis. Most noticeably, the EPA refrains from addressing the question of whether or not a difference in visibility impairment impact improvement of less than 0.5 dV between two BART alternatives would constitute equivalency under the visibility analysis, or if any difference in the model results, no matter how slight, should be interpreted as ranking one solution over the other.

The approach taken in the BART analysis for LOS incorporates the visibility analysis results as part of the decision making process. Thus, when ranking a particular BART alternative during the selection process, the visibility improvement associated with the implementation of that particular alternative is included in the ranking. If two alternatives have an identical potential for visibility improvement, the remaining criteria identified for consideration as part of the impact analysis are then used to differentiate between the two alternatives. Where similar visibility improvement potentials are identified for two or more alternatives, the incremental cost to achieve the slightly greater visibility improvement is determined and evaluated against incremental costs for the next most stringent alternative. This approach identifies the more effective BART alternative in terms of regional haze considerations, not in terms of the most stringent control alternative, as would happen if a strictly top-down approach had been implemented.

1.3.7 ADDITIONAL APPROACH METHODS

In addition to the steps discussed above, there are two subjects within the guidelines which warrant mention due to their effects on the contents of the report. The first subject deals with the presumptive limits and their application to power plants smaller than 750 MW in size. The Guidelines for BART Determination include the following statement with regard to presumptive BART for SO_2 (70 FR 39171):

> "You (meaning States) must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/MMBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. For a currently uncontrolled EGU

greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost effective and could be used in your BART determination….."

Similarly for NO_X, the EPA states (70 FR 39171):

> "For coal-fired EGUs greater than 200 MW located at greater than 750 MW power plants and operating without post-combustion controls, we have provided presumptive NO_X limits differentiated by boiler design and type of coal burned. You may determine that an alternative control level is appropriate based on a careful consideration of the statutory factors. For coal-fired EGUs greater than 200 MW located at power plants 750 MW or less in size and operating without post-combustion controls, you should likewise presume that these same levels are cost-effective."

For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X control. However, for power plants smaller than 750 MW in size, the presumptive limits are described as being "cost-effective" but not set as a minimum performance requirement. Thus, BART for EGUs at power plants smaller than 750 MW in size, like LOS, is not required to meet the presumptive limits. This BART analysis for LOS will evaluate potential control options that can attain presumptive limits on typical EGUs. Consequently, based upon the feasibility analysis, the recommended control options may not achieve the EPA's presumptive BART limits for specific pollutants from certain units.

The second part of the guideline that should be addressed relates to which emission units are subject to BART for a particular pollutant. The guideline states that:

> "Once you determine that a source is subject to BART for a particular pollutant, you must establish BART for that pollutant. The BART determination must address air pollution control measures for each emissions unit or pollutant emitting activity subject to review." (70 FR 39163)

According to this statement, the BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2, PM) regardless of size. The BART analysis for LOS will review control options for the main boilers for Unit 1 and Unit 2. However, smaller emissions sources at the facility are anticipated to provide negligible contribution to visibility impacts from LOS in Class 1 areas. Smaller sources at LOS are discussed in Section 1.3.8 through 1.3.10.

1.3.8 SMALL SOURCE EMISSION UNITS

The BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2, PM) regardless of size. However, smaller emissions sources at the facility are anticipated to provide negligible contributions to visibility impairment in Class 1 areas. The nearest Class 1 area is Theodore Roosevelt National Park located approximately 145 km to the west. Although technically eligible, smaller source emissions units were not reviewed because they have limited hours of operation and consequentially their emissions are too small to affect visibility in Class 1 areas. Table 1.3-3 lists emission units at Leland Olds Station that have very low operating hours due to the function of the equipment.

Table 1.3-3 – Leland Olds Station Limited Operation Emissions Units(1)

Emission Unit	Fuel	Rating	Operating Hours	NO_X (tons/yr)	SO_2 (tons/yr)	PM (tons/yr)
Auxiliary Boiler	Fuel Oil	51.6 mmBtu/hr	3.6	0.0128	0.0257	0.0013
Emergency Fire Pump	Fuel Oil	255 hp	4.3	0.00015	0.00030	0.00001

(1) - Emissions are based upon amount of fuel used, sulfur content of the fuel oil, AP-42 emission factors and actual average plant operations for the period of 2000 – 2004.

1.3.9 MATERIAL HANDLING EMISSIONS

Table 1.3-4 lists the emission rates for the material handling units at Leland Olds Station. The majority of the material handling units are associated with the totally enclosed coal delivery system. Since the system is totally enclosed, there would normally be no emissions associated with the equipment. However, the original equipment included air handling systems to reduce fire and explosions hazards caused by build-up of coal dust. The air handling systems used either rotoclones or baghouses for particulate control.

Table 1.3-4 – Leland Olds Station Material Handling Emissions Units

Emission Unit	Unit ID	PM Emissions (tons/yr) (1)
Rotoclone Transfer Tower G	M1	0(2)
Rotoclone Reclaim Tunnel	M2	0(2)
Rotoclone Crusher House (E)	M3	0(2)
Rotoclone Crusher House (W)	M4	0(2)
Rotoclone Transfer Tower	M5	0(2)
Rotoclone Unit 1 Bunker House	M6	0(2)
Rotoclone Unit 2 E. Bunker	M7	4.38
Rotoclone Unit 2 W. Bunker	M8	4.38
Rotoclone Unit 2 W. Trans. Conveyor	M9	4.38
Rotoclone E. Trans. Conveyor	M10	4.38
Baghouse Fabric Filter Main Fly Ash Silo	M11	0.95
Baghouse Fabric Filter 100 Ton Fly Ash Silo	M12	0.01
Baghouse Fabric Filter Coal Unloading	M13	12.39
Baghouse Fabric Filter Agglomerator	M14	0.04
Rotoclone Unit 1 Coal Bunker	M15	0(2)
Baghouse Fabric Filter Coal Unloading Silo	M16	0.19

(1) - Emissions are based upon manufacturers design emission rate and Units 1 and 2 operating at 100% capacity for 8760 hours. Hours of operation were maximized to account for variations in service and resulting annual emissions variation.
(2) - A fogging system was installed in 2003 to replace rotoclones used for fire suppression. The system uses totally enclosed transfer points and does not have any emissions.

In 2003, a water based fogging system was installed in the coal delivery system to provide a higher level of coal dust suppression inside the enclosed system. The existing air handling equipment with the rotoclones were placed in a stand-by mode thereby eliminating associated emissions. As shown in Table 1.3-4, the emission points currently using the fogging system do not have emissions. A search of the RACT/BACT/LAER database for coal handling sources showed that baghouses are currently recognized as the most effective control available for material handling sources emitting PM. No further BART analysis was conducted for baghouse controlled sources listed in Table 1.3-4 because the most effective control technology is already in use on these sources. Materials handling units at LOS using controls produce emissions in levels anticipated to be too small to affect visibility in the nearest Class 1 area located approximately 145 km away and were excluded from further consideration in the study.

1.3.10 FUGITIVE DUST

The primary source of fugitive dust is from the outside coal storage area and other plant activities normally found at a coal-fired electrical generating facility. The coal stockpile, access roads and plant activities are performed and maintained with good operating practices. On the coal stockpile and on other applicable fugitive sources, dust suppression is achieved through the use of water sprays or surfactants.

The level of fugitive PM emissions are not expected to affect the visibility in Class 1 areas based upon the approximate 145 km distance to the nearest Class 1 area, the large particle size and relatively small emission rates. As such, fugitive sources were not evaluated in this BART analysis for LOS.

1.4 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The proposed BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. The EPA interpreted the statutory provision of Section 169A of the Clean Air Act to require that a BART-eligible source is one that is "reasonably anticipated to cause or contribute" to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area (70 FR 39161). A Class I area, as listed by the EPA, is an area of the country with pristine air quality that is sensitive to changes in visibility. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility. CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to access long-range transport of pollutants. Two Class 1 areas have been identified for inclusion in the visibility analysis for LOS. These are the Theodore Roosevelt National Park (TRNP), and the Lostwood National Wildlife Refuge (Lostwood NWR), which are approximately 145 and 160 km (90 and 100 miles), from Leland Olds Station, respectively.

The NDDH modeling protocol confirmed that the two Class I areas to be considered for visibility impairment analysis are the TRNP and Lostwood NWR. However, the three units or areas of the TRNP are to be treated as separate Class I areas for the analysis.

1.4.1 CALPUFF MODELING METHODOLOGY

Visibility impairment is caused by a combination of particles and gases in the atmosphere. Some particles and gases scatter light, others absorb light. The combined effect of scattering and absorption is called "light extinction" which is most commonly seen as haze. This haziness is measured in deciView (dV) units, and is related to light extinction coefficient by the following equation:

$$dV = 10 \ln(b_{ext}/10)$$

Where b_{ext} is light extinction coefficient in inverse megameters.

Visibility impairment is a function of light extinction. Light extinction occurs when light energy is either scattered or absorbed by particles in the air. The amount of moisture in the air also plays a role in light extinction. Certain gases combine with moisture in the air to form small light scattering particles. These gases, most notably SO_2 and NO_X, are significant components of coal-fired power plant emissions. Particulate Matter (PM) also contributes to light extinction. In the BART Determination Guidelines, the EPA states that "You may use PM_{10} as an indicator for particulate matter. We do not recommend the use of Total Suspended Particulates (TSP). As emissions of PM_{10} include the components of $PM_{2.5}$ as a subset, there is no need to have separate 250 ton thresholds for PM_{10} and $PM_{2.5}$; 250 tons of PM_{10} represents at most 250 tons of $PM_{2.5,}$ and at most 250 tons of any individual particulate species such as elemental carbon, crustal material, etc." (70 FR 39160). The NDDH modeling protocol states that particulate matter emissions should be specified as either course (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$). The distinction between course and fine particulate occurs in the modeling.

The NDDH modeling protocol recommends a specific version of the CALPUFF modeling system as modified by the NDDH to specifically address terrain, climate, and emission characteristics of LOS. (CALMET and CALPUFF were recompiled by the NDDH while the CALPOST executable used for this visibility analysis was the EPA guideline executable). Along with the CALPUFF modeling system, the NDDH also provided the RUC2-MM5 gridded wind field data (2000-2002), surface, upper air, and precipitation files, and CALMET and CALPUFF input files. The input files contained the specific coordinate grid points, wind field options, terrain, dispersion options, receptor coordinates and plume characteristics and other model parameters that the NDDH has determined best represents the region. The NDDH version of CALPUFF was used for modeling.

In order to predict the change in light extinction at TRNP and Lostwood NWR areas, SO_2, NO_X, and PM were modeled with CALPUFF using pre-control and post-control emission scenarios. A variety of post-control scenarios were used to determine the reduction in visibility impact for each control technology. The NDDH identified 104 receptors allocated over both TRNP and Lostwood NWR. These receptors are location points for which CALPUFF was used to perform a visibility calculation.

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios.

The comparison should be made for the 98th percent days (70 FR 39170). The NDDH modeling protocol provides additional clarification about BART applicability by stating, "…the context of the 98th percentile 24-hour delta-deciView prediction is with respect to days of the year, and is not receptor specific. A 24-hour prediction greater than 0.5 delta-deciView at any receptor in a Class I area would constitute a day of exceedance, and up to 7 days of exceedance would be allowed per year per Class I area (i.e., the 98th percentile is approximated by the eighth-highest daily prediction)." In other words, visibility impacts should be compared on an annual basis using the eighth highest day for comparison (365 * (1-.98) ~ 7 days of acceptable exceedance). However, NDDH subsequently advised that the delta-deciView comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

1.4.2 MODELING SCENARIOS

Since a BART analysis is based on the degree of reduction achieved by the application of control technologies, the CALPUFF analysis examined multiple operating scenarios based upon the feasible control technologies identified for each pollutant. These scenarios represent the emissions of SO_2, NO_X, and PM under the following conditions:

- Pre-Control NDDH BART Modeling Protocol historical emissions
- Post-Control emissions based upon future coal data, PTE conditions and control technologies

The removal efficiencies modeled in each scenario are presented in Table 1.4-1.

Table 1.4-1 – Leland Olds Station Emissions Modeling Scenarios

Scenario	Unit 1		Unit 2	
	NO_X	SO_2	NO_X	SO_2
Screening	Uncontrolled	Uncontrolled	Uncontrolled	Uncontrolled
1$^{(1)}$	Presumptive$^{(2)}$	90.0%	60.3%	95.0%$^{(3)}$
2$^{(1)}$	Presumptive$^{(2)}$	93.0%	54.5%	95.0%$^{(3)}$
3$^{(1)}$	Presumptive$^{(2)}$	95.0%$^{(3)}$	28.0%	95.0%$^{(3)}$
4$^{(1)}$	20.7%	90.0%		
5$^{(1)}$	20.7%	93.0%		
6$^{(1)}$	20.7%	95.0%$^{(3)}$		

(1) - Percentages for emission reductions for future PTE post-control (future coal scenario) cases were applied to future PTE baseline average hourly unit emission rates and correspond to control options evaluated in this analysis.
(2) - Presumptive BART NO_X emissions for dry-bottom, wall-fired boilers burning lignite for LOS Unit 1.
(3) - Presumptive BART SO_2 emissions.

These scenarios represent the range of emissions evaluated to date for consideration in making a BART analysis. The removal efficiencies presented in Table 1.4-1 correspond to control options evaluated in this analysis. The pre-control scenario from the NDDH BART modeling protocol is based on the historical, maximum 24-hour emission rates for LOS between 2000 and 2002. These rates were supplied to the NDDH by BEPC, but were based upon emissions from burning specific types of coal. Due to analyses performed on future coal reserves, BEPC has determined that these historic rates are not representative of future maximum 24-hour emissions and has requested NDDH to allow the use of an alternative baseline. NDDH agreed to the alternative baseline. The alternative baseline and post-control scenarios are based upon various control technology emission reductions being applied to emissions from burning future coal at a heat input equal to the 100% of the boiler design capacity rating. Due to the number of variations involved for each pollutant, the scenarios are discussed in the section related to the controlled pollutant.

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2.0 NO_X BART EVALUATION

A summary of the BART analysis, steps 1 through 5, for NO_X emissions from Leland Olds Station Unit 1 and Unit 2 are described in this section. A review and discussion of the EPA's presumptive BART NO_X emission limits for dry bottom, wall-fired boilers and cyclone-fired boilers burning lignite is presented. Technical descriptions of LOS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. NO_X control technologies are identified, evaluated for feasibility and control capability, then ranked according to effectiveness. The impacts analysis for cost of compliance are summarized, with the estimated capital costs, and operating and maintenance (O&M) costs, for remaining feasible NO_X control alternatives. Remaining useful life impact analysis is included in the calculations for estimated annual costs of the feasible alternatives. Following the cost estimates, the cost effectiveness for selected feasible NO_X control technologies are plotted, and those that comprise the Dominant Control Curve are identified. The energy, non-air quality environmental, and visibility impacts are developed and summarized.

The NO_X BART evaluations for LOS Units 1 and 2 were combined for this part of the BART analysis due to similar control technologies (e.g., both EGUs include coal-fired boilers burning North Dakota lignite), with unit-specific cost-effectiveness and impacts analysis developed for each boiler.

Leland Olds Unit 1 is a Babcock and Wilcox pulverized coal-fired steam generator installed in 1966 (RB-412). The unit includes a pulverized coal-fired subcritical steam-generating boiler using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.570 million lbs/hr at 2,475 psi. The boiler is fired by 20 second-generation low-NO_x burners, consisting of two rows of four burners each arranged within compartmented windboxes across the back wall, and opposed by three rows of four burners across the front wall of the furnace. Four close-coupled, windbox/register-style overfire air ports are arranged across each of the front and rear walls of the furnace just above the top rows of burners. The unit has a tubular air heater installed between the boiler and the ductwork leading to the electrostatic precipitator (ESP) for preheating primary air to promote coal drying and conveying through the ten pulverizers to the burners. Compartmented windboxes are supplied with main combustion air (secondary air) preheated by two rotary regenerative (Ljungstrom) air heaters arranged in parallel. These secondary combustion air heaters (SCAHs) cool the flue gases prior to admission to the ESP. Exhaust gases leave the air heaters and pass through an ESP for particulate collection and removal prior to the two induced draft (ID) fans (installed in parallel) which discharge to the stack. Design nameplate output rating is 216 MW.

LOS Unit 1 does not currently employ post-combustion NO_X emission reduction technology. A summary of the identified NO_X emission control technologies is summarized in Section 2.1.

Leland Olds Station Unit 2 is a Babcock and Wilcox cyclone-fired steam generator first placed into commercial operation in 1975 (RB-489). The unit includes a subcritical steam-generating boiler using balanced-draft and assisted natural circulation. Original unit design steam generating capacity is 3.075 million lbs/hr at 2,620 psi. The boiler is fired by twelve 10-foot diameter cyclone burners, arranged "3 over 3" on front and rear walls of the lower furnace. The unit has a tubular air heater, installed for preheating primary air for coal drying and conveying, and secondary combustion air. The air preheater is located between the boiler and the flue gas ductwork leading to the pair of electrostatic precipitators (ESPs) installed in parallel. Exhaust gases leave the air heater and pass through the two parallel ESPs for particulate collection and removal prior to the two induced draft fans (installed in parallel) which discharge to the stack. Design nameplate output rating is 440 MW.

LOS Unit 2 does not currently employ post-combustion NO_X emission reduction technology. A summary of the identified NO_X emission control technologies is discussed in Section 2.1.

2.0.1 DISCUSSION OF BART GUIDELINES FOR NO_X BART CONTROL ALTERNATIVES AT LELAND OLDS STATION

EPA's final Guidelines for BART Determinations (BART Guidelines), and the Preamble to the final rule, established presumptive emission limits for nitrogen oxides for coal-fired electric generating units (EGUs), including wall-fired dry bottom, pulverized coal boilers burning lignite[1] [70 FR 39172, 39135]. According to the final BART Guidelines, "States, as a general matter, must require owners and operators of greater than 750 MW power plants to meet these BART emission limits" [70 FR 39131]. However, the EPA also recognized that:

> "A State may establish different requirements if the State can demonstrate that an alternative determination is justified based on a consideration of the five statutory factors. In addition, while States are not required to follow these guidelines for EGUs located at power plants with a generating capacity less than 750 MW, based on our analysis…the States will find these same presumptive controls to be highly cost-effective, and to result in a significant degree of visibility improvement, for most EGUs greater than 200 MW, regardless of the size of the plant at which they are located. A State is free to reach a different conclusion if the State

> believes that an alternative determination is justified based on a consideration of the five statutory factors" [70 FR 39131].

The EPA further states in the BART Guidelines that:

> "For sources without post-combustion controls (i.e. SCRs and SNCRs), we [the EPA] are establishing a presumption as to the appropriate BART limits for coal-fired units based on boiler design and coal type. These presumptions apply to EGUs greater than 200 MW at power plants with the generating capacity greater than 750 MW and are based on control strategies that are generally cost-effective for all such units" [70 FR 39134].

Also in the BART Guidelines is the statement:

> "both cost effectiveness and post-control rates for NO_X do depend largely on boiler design and type of coal burned. Based on these analyses, we [the EPA] believe that States should carefully consider the specific NO_X rate limits for different categories of coal-fired utility units, differentiated by boiler design and type of coal burned, set forth below as likely BART limits" [70 FR 39134].

2.0.1.1 PRESUMPTIVE BART NO_X LIMITS FOR PULVERIZED COAL-FIRED BOILERS

According to the BART Guidelines, there are a total of 491 BART-eligible coal-fired EGUs. Of those EGUs, 121 are dry-bottom, wall-fired units greater than 200 MW output. There are 44 dry-bottom, wall-fired units greater than 200 MW output located at power plants with less than 750 MW total output capacity [70 FR 39134, Table 1]. Unit 1 at Leland Olds Station satisfies this criterion.

According to the EPA, for "all types of boilers other than cyclone units, the limits … are based on the use of current combustion control technology. Current combustion control technology is generally, but not always, more cost-effective than post-combustion controls such as SCRs" [70 FR 39134]. Also, "the types of current combustion control technology options assumed [in the EPA's analysis] include low NO_X burners, over-fire air, and coal reburning" [70 FR 39134]. Furthermore, the EPA "assumed that coal-fired EGUs would have the space available to install separated over-fire air" [70 FR 39134].

In the BART Guidelines, the EPA lists the presumptive NO_X emission limits for BART-eligible coal-fired units, distinguished by unit type, and coal type. For dry-bottom, wall-fired EGUs burning lignite coal, the NO_X presumptive limit is 0.29 lb/mmBtu [70 FR 39135, Table 2]. The analysis performed by the EPA for establishing the presumptive limits for NO_X emissions from pulverized coal-fired EGUs assumed only the application of low-NOx burners and overfire air combustion controls.

The actual highest 24-month rolling NO_X summation total from 2000-2004 divided by the actual 24-month rolling summation unit heat input for the same time period for Unit 1 at Leland Olds Station meets the presumptive BART NO_X emission limits stated above. The future PTE case also meets presumptive BART NO_X emission limits. The requirements of performing a NO_X BART analysis on a BART-eligible coal-fired unit with a nameplate capacity greater than 200 MW at a powerplant less than 750 MW that has a unit NO_X emission rate that meets the EPA's presumptive BART NO_X emission limit is not apparent in the BART Guidelines. However, this BART analysis presents a NO_X control technology feasibility evaluation, with impact analysis for NO_X control alternatives. This includes the four prescribed impact criteria plus the impact assessment for visibility impairment improvement for a separated overfire air alternative following the general procedures of the BART Guideline.

2.0.1.2 PRESUMPTIVE BART NO_X LIMITS FOR CYCLONE-FIRED BOILERS

EPA's presumptive limit for emissions of nitrogen oxides from cyclone-fired boilers was established in the final BART Guidelines and the Preamble to the final rule [70 FR 39172]. In discussing NO_X controls for EGUs, there are two somewhat distinct approaches to reducing NO_X at existing sources. One approach is to use combustion controls. The other approach is removal technology applied to the flue gas stream (such as SCRs and SNCRs).

For NO_X emissions control, the EPA analyzed:

> "the installation of SCRs at BART-eligible EGUs, applying SCR to each unit and fuel type. The cost-effectiveness was generally higher than for current combustion control technology except for one unit type, cyclone units. Because of the relatively high NO_X emission rates of cyclone units, SCR is more cost-effective than the use of current combustion control technology for these units. The use of SCRs at cyclone units burning bituminous coal, sub-bituminous coal, and lignite should enable the units to cost-effectively meet NO_X rates of 0.10 lbs/mmBtu. As a result, [the EPA] are establishing a presumptive NO_x limit of 0.10 lbs/mmBtu based on the use of SCR for coal-fired cyclone units greater than 200 MW located at 750 MW power plants. As with other presumptive limits established in this guideline, [the

States] may determine that an alternative level of control is appropriate based on [the States'] consideration of the relevant statutory factors. For other cyclone units, [the States] should review the use of SCR and consider whether these post-combustion controls should be required as BART"[1] [70 FR 39172].

Also, for cyclone boilers,

"SCRs were found to be more cost-effective than current combustion control technology [which the EPA established in their analysis as coal reburning]; thus the NO_X limits for cyclone units are set based on using SCRs" [70 FR 39134].

The EPA identified a population of 56 BART-eligible coal-fired cyclone boilers used in their cost-effectiveness analysis for applying SCRs for NO_X control [70 FR 39134 Table 1]. Of the 56 cyclones, 35 are units larger than 200 MW, and 19 are units larger than 200 MW located at 750 MW plants [70 FR 39134]. Conversely, there are 16 cyclone-fired units greater than 200 MW output located at power plants with less than 750 MW total output capacity. Unit 2 at Leland Olds Station fits this criterion.

The EPA's Technical Support Document[2] published in the Edocket (EPA's internet website) for the BART Guidelines describes the cost-effectiveness analysis that resulted in the establishment of SCR as the presumptive NO_X control technology for BART-eligible cyclone-fired coal EGUs. For such cyclone EGUs, the analysis assumed that the unit capacity capital cost factor was \$100/kW and 90 percent of the boiler outlet NO_X concentration was removed by SCR technology. The EPA's cost-effectiveness analysis assumed presumptive BART emission rates for the cyclone-fired EGU at Leland Olds Station as 0.07 lb/mmBtu, based on a pre-control emission rate of 0.7 lb/mmBtu. This is approximately 60 percent lower than the lowest BART NO_X presumptive limit (0.17 lb/mmBtu) for dry-bottom, tangentially-fired boilers that burn pulverized lignite coal.

In the EPA's setting of presumptive NO_X limits for coal-fired EGUs larger than 200 MW at power plants greater than 750 MW total gross output rating, the EPA also recognizes that:

"because of differences in individual boilers, however, there may be situations where the use of such controls would not be technically feasible and/or cost-effective…As noted, the NO_X limits set forth here today are presumptions only; in making a BART determination, States have the ability to consider specific characteristics of the source at issue and to find that the presumptive limits would not be appropriate for that source" [70 FR 39134].

This BART analysis presents a NO_X control technology feasibility evaluation of pre-combustion, combustion, and post-combustion controls, including SCR, separated overfire air, SNCR, and coal reburn for Leland Olds Station Unit 2. This includes the four prescribed impact criteria plus the impact assessment for visibility impairment improvement following the general procedures of the BART Guideline.

2.0.1.3 TECHNOLOGY AVAILABILITY AND APPLICABILITY FOR EMISSION CONTROLS

The second step of the BART process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible. The final BART Guidelines states that "two key concepts [are] important in determining whether a technology could be applied: "availability" and "applicability" [70 FR 39165].

As explained in more detail in the final BART Guidelines:

> "a technology is considered "available" if the source owner may obtain it through commercial channels, or it is otherwise available in the common sense meaning of the term" [70 FR 39165].

For the purposes of this analysis, the term "commercial" is further defined to mean "capable of establishing a full contractual agreement with commercial and performance guarantees supported by appropriate financial backing" for the implementation of full-scale, full-time systems of the technique or technology application.

Also per the BART Guidelines:

> "An available technology is "applicable" if it can be reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible" [70 FR 39165].

A control technique is considered available "if it has reached the stage of licensing and commercial availability" [70 FR 39165]. "Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible" [70 FR 39165]. Also, "vendor guarantees may provide an indication of commercial availability and technical feasibility of a control technique and contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances" [70 FR 39165]. Furthermore, the EPA does "not consider a vendor guarantee alone as sufficient justification that a control option will work.

Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option is technically infeasible" [70 FR 39165]. [A State agency] "should make decisions about technical feasibility based on chemical, and engineering analyses, as discussed above, in conjunction with information about vendor guarantees" [70 FR 39165]. The EPA also does not "expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently [a State agency] would not consider technologies in the pilot scale stages of development as "available" for the purposes of a BART review" [70 FR 39165]. This would appear to apply to many emerging technologies in the bench, pilot-scale, or "proof-of-concept" testing phases of development, so these were eliminated from the list of potential controls included in subsequent sections of this analysis.

Also in the EPA's final BART Rule is a qualification of "applicability" for technical feasibility, as described by the statement:

> "[a State agency] need[s] to exercise technical judgment in determining whether a control alternative is applicable to the source type under consideration. Where [a State agency] conclude[s] that a control option identified in Step 1 is technically infeasible, [the State agency] should demonstrate that the option is either commercially unavailable, or that specific circumstances preclude its application to a particular emission unit. Generally, such a demonstration involves an evaluation of the characteristics of the pollutant-bearing gas stream and the capabilities of the technology. Alternatively, a demonstration of technical infeasibility may involve a showing that there are unresolvable technical difficulties with applying the control to the source (e.g. size of the unit, location of the proposed site, operating problems related to specific circumstances of the source, space constraints, reliability, and adverse side effects on the rest of the facility)" [70 FR 39165].

2.0.1.4 TECHNOLOGY EVALUATION FOR CONTROL EFFECTIVENESS

The third step in a BART evaluation is to evaluate the remaining control technologies for control effectiveness. The purpose is to establish a level of control effectiveness of the remaining feasible control technologies compared to baseline emission levels so that a suitable basis for estimating cost effectiveness can be determined. In order to determine control and cost effectiveness, "the degree of control using a metric [units] that ensures an "apples to apples" comparison of emissions performance levels among options" [70 FR 39166] is one of the two key issues that must be addressed in a BART analysis. For fossil fuel-fired boilers associated with steam-electric generating units, pounds of nitrogen oxides per unit of fuel heat input (i.e. lb/mmBtu), is a common means of comparing and calculating NO_X emissions.

The second key issue in the evaluation of technically feasible control alternatives is giving appropriate treatment and consideration of control techniques that can operate over a wide range of emission performance levels. Many control techniques, including both add-on controls and inherently lower polluting processes, can perform over a wide range of levels. To clarify this concept:

> "It is not the [EPA's] intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options. It is important, however, that in analyzing a technology [the States] take into account the most stringent emission control level that the technology is capable of achieving. [The States] should consider recent regulatory decisions and performance data (e.g. manufacturer's data, engineering estimates, and the experience of other sources) when identifying emissions performance level or levels to evaluate" [70 FR 39166].

2.0.1.5 IMPACT EVALUATION FOR FEASIBLE CONTROLS

The fourth step in a BART evaluation is to evaluate BART-specific impacts of remaining feasible control technologies. This consists of four parts:

- Impact analysis part 1: Costs of compliance.
- Impact analysis part 2: Energy impacts.
- Impact analysis part 3: Non-air quality environmental impacts.
- Impact analysis part 4: Remaining useful life of the source.

The purpose of the impacts evaluation is to determine if the remaining useful life of the source or any energy, economic, and non-air quality environmental reasons would eliminate the remaining control technologies from consideration.

Section 1.2 includes information pertinent to the cost analysis for part 1 of the impacts, involving several basic subtasks as prescribed by the BART Guidelines:

1. Identify the emissions units being controlled;
2. Identify design parameters for emissions controls; and
3. Develop cost estimates based upon those design parameters.

According to the BART Guidelines:

> "The part of the plant being evaluated for control costs must be clearly identified and well defined. The analysis should provide a clear summary list of equipment and the associated control costs. Specifying the control system design parameters, and the values selected for those parameters, should ensure that the control option will achieve the level of emission control being evaluated. Once the control technology alternatives and achievable emissions performance levels have been identified, estimated capital and annual costs are developed. The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor or by a referenced source (such as the OAQPS Control Cost Manual, latest edition), with the latter preferred where possible. The cost analysis should also take into account any site-specific design or other conditions identified above that affect the cost of a particular BART technology option" [70 FR 39166].

2.0.1.6 VISIBILITY IMPACT EVALUATION FOR FEASIBLE CONTROLS

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source. In order to predict the change in light extinction at the nearest Class 1 areas (TRNP and LNWR), hourly average SO_2, NO_X, and particulate matter emission rates were modeled with CALPUFF using pre-control baselines and different emission control scenarios. Other pollutants are emitted during coal combustion, but the BART guidelines focus on these three. The BART visibility impairment impact analysis was based on:

- NDDH BART protocol screening analysis emission rates (historic highest 24-hour pre-control average)[3]; and
- Potential-To-Emit (PTE) emission rates for the future PTE case (post-control).

A BART visibility impact analysis calculates the change in modeled visibility impairment predicted for the pre-control emissions rates (baseline) compared to the visibility impairment predicted from modeled post-control emissions rates over the days with the highest 90% and 98% visibility impacts above natural background levels at each receptor. Since visibility is a 24-hour averaged analysis, each receptor was tabulated for each day and the visibility impairment impact predicted for the worst 7 days (98th percentile) or worst 36 days (90th percentile). Results from the three-year modeling period included the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area (100th percentile). The visibility impairment impact (dVs) predicted for the 98th percentile and 90th percentile levels were also included with model results. This data is shown in Section 2.4 for LOS Unit 1, and Section 2.5 for LOS Unit 2, with additional details in Appendix D1.

The modeled visibility impact scenarios represent the range of emissions evaluated for consideration in making a BART analysis. The LOS boilers' heat inputs for the future PTE case are from the current NDDH Title V operating permit for LOS dated 7/27/98. The BART guidelines specify "presumptive BART" as 95% SO_2 control and NO_X levels of 0.29 lb/mmBtu for dry-bottom, wall-fired boilers burning pulverized lignite. These conditions were applied to the emissions for one run of visibility modeling of the post-control future PTE case for LOS Unit 1. Additional modeling runs for LOS Unit 1 were performed for various high levels of SO_2 control with a NO_X emission level expected to result from the next highest cost NO_X control alternative, i.e. achieving below the presumptive BART NO_X level using separated overfire air. The emissions for the post-control future PTE case for LOS Unit 2 include a presumptive BART level of 95% SO_2 control along with various alternative levels of NO_X control presented in Table 1.4-1.

2.0.1.7 BASIS FOR NO_X BART ANALYSIS AT LOS - UNIT 1

For LOS Unit 1, control and cost-effectiveness were evaluated at the historic highest 24-consecutive month average NO_X emission rate during the calendar years 2000-2004. This pre-control NO_X emission rate averaged 247 tons per month for the period ending on the last day of August 2004. This is equivalent to 2,967 tons of NO_X per year, and corresponds to an average hourly NO_X emission rate of 697 lbs per hour of actual operation. The historic 24-month average hourly NO_X emission rate for LOS Unit 1 is based upon an annual average unit operation of 8,510 hrs/yr corresponding to the same time period. This annual unit operation is equivalent to a 97.2% plant availability factor relative to 8,760 hrs/yr. An equivalent 24-month average NO_X emission rate of 0.285 lb/mmBtu was derived for this period of operation. An average gross unit output of 217.8 MW and average gross fuel heat input rate of 2,443 mmBtu/hr correspond to this same historic 24-month operating period. Compared to an average gross fuel heat input rate of 2,468 mmBtu/hr corresponding to a nominal 220 MW gross unit output, this historic highest 24-month operation resulted in an average running plant capacity factor (RPCF) of 99.0 percent during this same time period. The availability factor of 97.2% and the running plant capacity factor were used to calculate an overall capacity factor of 96.2 percent. LOS Unit 1's nameplate capacity of 216 MW (gross) output was used for the basis of controls design for BART determination purposes according to the EPA's Technical Support Document – Methodology for Developing BART NO_X Presumptive Limits[2]. This nameplate capacity also served as the assumed number for calculating capital costs based on $/kW unit capacity capital cost factors.

For LOS Unit 1, control and cost-effectiveness were also evaluated at the post-control basis for the maximum future PTE case. This analysis assumed an hourly average gross fuel heat input rate equal to the boiler design capacity rating of 2,622 mmBtu/hr for 8,760 hours per year of operation for LOS Unit 1's boiler.

The BART Guidelines specify presumptive BART levels for NO_X emissions from a dry bottom, wall-fired EGU burning pulverized lignite as 0.29 lb NO_X/mmBtu. The equivalent 24-month highest historic average NO_X emission rate was 0.285 lb /mmBtu during the calendar years 2000-2004. If the EPA's presumptive BART level were applied to LOS Unit 1's NO_X emissions, this would indicate that LOS Unit 1 already complies on a historic long-term average basis. Maintaining an average NO_X emission rate of 0.29 lb /mmBtu for the future PTE case for LOS Unit 1 also complies with the EPA's presumptive BART NO_X emission level for dry-bottom wall-fired boilers burning pulverized lignite in power plants greater than 750 MW.

2.0.1.8 BASIS FOR NO_X BART ANALYSIS AT LOS - UNIT 2

For LOS Unit 2, the highest 24-consecutive month average NO_X emission rate during the calendar years 2000-2004 averaged 1,002 tons per month, for the period ending on the last day of February 2003. This pre-control NO_X emission rate is equivalent to 12,023 tons/yr, and corresponds with an average NO_X emission rate of 2,987 lbs per hour of actual operation. The historic 24-month average hourly NO_X emission rate for LOS Unit 2 is based upon an annual average unit operation of 8,050 hrs/yr corresponding to the same time period. This annual unit operation is equivalent to a 91.9% plant availability factor relative to 8,760 hrs/yr. An equivalent 24-month average NO_X emission rate of 0.667 lb /mmBtu was derived for this period of operation. An average gross unit output of 406.5 MW and average gross fuel heat input rate of 4,478 mmBtu/hr correspond to this same historic 24-month operating period. Compared to an average gross fuel heat input rate of 4,846 mmBtu/hr corresponding to a nominal 440 MW gross unit output, this historic highest 24-month operation resulted in an average running plant capacity factor (RPCF) of 92.4% during this same time period. LOS Unit 2's nameplate capacity of 440 MW (gross) output was used for the basis of controls design for BART determination purposes according to the EPA's Technical Support Document –

Methodology for Developing BART NO_X Presumptive Limits[2]. This nameplate capacity also served as the assumed number for calculating capital costs based on $/kW unit capacity capital cost factors.

For LOS Unit 2, control and cost-effectiveness were also evaluated at the post-control basis for the future PTE case. This analysis assumed an hourly average gross fuel heat input rate equal to the boiler design capacity rating of 5,130 mmBtu/hr for 8,760 hours per year of operation for LOS Unit 2's boiler.

2.1 IDENTIFICATION OF RETROFIT NO_X CONTROL TECHNOLOGIES

The first step in the BART evaluation for nitrogen oxides emissions following determination of BART eligibility is to identify potentially applicable retrofit control alternatives. A comprehensive literature search was performed, with sources including technical papers and presentations made by parties involved with design, construction, and testing of NO_X control techniques at conferences sponsored by nationally-recognized technical organizations, plus hardware supplier experience lists.

Uncontrolled NO_X emissions from a coal-fired electric generating unit are highly dependent on type of firing method, amount of solid fuel fired per unit time and furnace volume, and the fuel's basic combustion properties and elemental composition. The methods for reduction of such emissions:

- either prevent pollution, i.e. use inherently lower-emitting processes/practices which produce fewer NO_X emissions during the power generation process; or
- involve improvements to, or provide new add-on controls that, reduce emissions after they are produced before they are emitted from the facility; or
- are combinations of inherently lower-emitting processes and add-on controls.

There are three basic categories of NO_X emission control alternatives:

- Pre-combustion controls;
- Combustion controls; and
- Post-Combustion controls.

A significant number of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent installations i the United States for five years or more.

A summary of the potentially available alternatives identified for NO_X emissions control on coal-fired steam-electric generating units is shown in Table 2.1-1.

TABLE 2.1-1 – Potentially Available NO_X Control Alternatives Identified for BART Analysis

Control Technology
Pre-Combustion Controls
Fuel Blending/Switching/Cleaning
Combustion Controls
Basic Combustion Control Improvements
Low NO_X Burners (LNB)
Separated Overfire Air (SOFA) / Boosted SOFA
Flue Gas Recirculation
Fuel Reburn
Oxygen-enhanced Combustion (OEC)
Water/steam Injection (Combustion Tempering)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)[(1)]
Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)[(2)]

Notes: these are basic forms of the identified techniques.
Not all variations or combinations are included.
(1) – SNCR technologies include Rich Reagent Injection, and Hydrocarbon-enhanced SNCR, commercially available as "NO_XStar™".
(2) – Multi-pollutant control technology currently under commercial development by Powerspan Corp.

Pre-combustion controls, such as fuel switching, fuel blending, and fuel cleaning, have been practiced and performed at numerous utility power plants, typically for sulfur dioxide and nitrogen oxide emissions control reasons.

Combustion controls, such as low-NO_X burners (LNBs) and overfire air systems, are very commonly applied to pulverized coal and gaseous or liquid fuel-fired boilers. Flue gas recirculation (FGR) has been applied and practiced at numerous natural gas and fuel oil-fired utility and industrial power plants for NO_X emissions control. FGR has been applied to large coal-fired utility boilers, primarily for steam temperature control purposes, not for emissions control. Conventional Gas Reburn (CGR) with overfire air has been placed in commercial operation on several cyclone-fired boilers, primarily in the eastern region of the United States. Coal Reburn (CR) with overfire air has been successfully demonstrated on two cyclone-fired boilers and commercially installed on three pulverized coal-fired boilers in the United States.

Selective Catalytic Reduction (SCR) and Selective Non-Catalytic Reduction (SNCR) are post-combustion technologies that have been applied mostly on eastern or midwestern bituminous coal-fired boilers. Others, mostly comprised of a combination of available control technologies, are often referred to as "hybrid" or "layered" control technologies. Variations of SNCR, such as recently developed "Rich Reagent Injection" (RRI) technology with and without SNCR, have only been demonstrated on a limited number of cyclone-fired boilers. Other layered NO_X emission control technologies, such as Fuel Lean Gas Reburn with SNCR, hydrocarbon-enhanced SNCR (commercially available as NO_XStar™), and oxygen-enhanced combustion have only been demonstrated and/or installed on a limited number of pulverized coal-fired power plants.

Emerging post-combustion multi-pollutant control technologies, such as Powerspan's Electro-Catalytic Oxidation (ECO®), which include NO_X control, were also identified. These are typically in the pilot-scale commercial development phase, and have not been successfully demonstrated on a full scale basis on any pulverized coal, cyclone, or circulating fluidized bed boilers.

In most of the "layered" control combination and emerging control cases, the NO_X control technology has been demonstrated to be capable of controlling the targeted pollutant(s) on either:

- a full-scale basis, but only with temporary equipment; or
- a full-scale basis, with permanent equipment but in a limited number of installations; or
- a commercial development basis with less than full-scale and full-time application.

The predominant method employed for control of NO_X emissions on dry bottom, wall-fired pulverized coal boilers is the application of low-NO_X burners (LNBs) and separated overfire air systems. Section 2.2 includes a summary of these control technologies available for potential use on LOS Unit 1, which uses existing low-NO_X burners and close-coupled overfire air. LOS Unit 1 appears to meet the current EPA BART presumptive NO_X emission level for dry bottom, wall-fired boilers burning pulverized lignite.

There are a number of coal-fired cyclone boilers around the country that have implemented or are planning to implement modifications to reduce NO_X emissions. Table 2.1-2 summarizes the various NO_X emission control system installations currently installed, or that have been demonstrated on a full-scale, short-term basis, in response to Acid Rain requirements, EPA's NO_X SIP call and local regulations, or a utility investigating the technology. The following section also includes a summary of these control technologies potentially available and applicable for use on LOS Unit 1 and Unit 2

TABLE 2.1-2 – Identified NO_X Control System Retrofits on Pulverized Coal and Cyclone Coal-Fired Boilers

No. of Units[(1)]	NO_X Control Technology Description[(1)]
	Pulverized Coal-Fired Boiler NO_X Control Technology Description
100+	Pulverized coal Low-NO_X Burners, w/ and w/o Separated Overfire Air (SOFA)
28	Selective Non-Catalytic Reduction, w/ and w/o Low NO_X Burners & SOFA
50+[(2),(3)]	High-dust or low-dust SCR, with or without other technologies
0[3]	Tail-gas SCR, with or without other technologies
8	Conventional fuel reburn (coal, gas, oil, orimulsion), w/ and w/o Low- NO_X Burners
1	Fuel lean gas reburn (FLGR), w/ and w/o Low- NO_X Burners
5	Amine-enhanced FLGR, w/ and w/o Low- NO_X Burners
2	Oxygen-enhanced combustion, w/ and w/o Low- NO_X Burners
	Cyclone Coal-Fired Boiler NO_X Control Technology Description
39[(4)]	Separated Overfire Air (SOFA)
22[(3)]	High-dust or low-dust SCR, with or without other technologies
1[(3)]	Tail-gas SCR, with or without other technologies
7[(5)]	Conventional fuel reburn (pulverized or micronized coal, gas), w/ SOFA
1[(6)]	Fuel lean gas reburn, with or without SOFA
2 2[(7)]	Selective Non-Catalytic Reduction, with or without SOFA Rich Reagent Injection, with SOFA

(1) – This list of known NO_X control retrofit installations is primarily focused on units in the United States. There may be other installations that are similar but were not identified. Includes boilers retrofit for full-scale temporary demonstration testing and permanent installations. Does not include Powerspan's ECO™ multi-pollutant control pilot plant (commercial demonstration unit, or CDU) at FirstEnergy's R.E. Burger Station Units 4&5.

(2) – At least 85 existing SCRs have been installed on BART-eligible EGUs in the US, mostly on coal-fired boilers burning eastern bituminous fuels. No examples of boilers located in the United States that were retrofit for full-scale, permanent TG SCR installations were found. PSE&G's Mercer Station Units 1 & 2 have low-dust SCRs with flue gas reheat, but they do not have flue gas desulfurization systems upstream of the SCR reactor inlets. See Technical Literature Reference list and Appendix A for further details

(3) – High-dust SCR technology has been retrofitted on sixteen U.S. cyclone-fired boilers, all believed to have SOFA. Low-dust SCRs in U.S. have only been installed on pulverized coal-fired boilers, none on cyclones. One tail-gas SCR installation on a coal-fired cyclone boiler found in Germany; none in the U.S. See technical literature references in Appendix A1 and A3 for details.

(4) – Installed for NO_X control without fuel reburn. A list of known cyclone boiler SOFA installations is included in Appendix A3.

(5) – Several conventional coal and gas reburn retrofits have discontinued reburn demonstration or routine operation. See Technical Literature Reference list and Appendix A3 for further details.

(6) – Only one example of fuel lean gas reburn retrofit (without OFA) on a cyclone-fired boiler has been demonstrated. This system was installed for short-term reburn testing and has since been removed.

(7) – RRI has only been demonstrated with temporary equipment for testing. See Technical Literature Reference List and Appendix A3 for further details.

A more detailed description of the various NO_X control technology retrofits and their technical feasibility is included in Appendix A1, with the associated references for technical literature. A summary of several U.S. NO_X retrofit projects and their claimed emission control effectiveness are included in Appendix A3, with the associated technical literature references for the selected NO_X control projects' listed in Appendix A4.

2.2 TECHNICAL DESCRIPTIONS AND FEASIBILITY ANALYSIS OF NO_X CONTROL TECHNOLOGIES

The second step of the BART process is to evaluate the control processes that have been identified. The following paragraphs summarize the evaluation of the processes for technical feasibility for Leland Olds Station Unit 1 and Unit 2 NO_X controls.

2.2.1 FEASIBILITY OF PRE-COMBUSTION NO_X CONTROLS

Pre-combustion controls involve technologies that are usually applied to the fuel and occur prior to entering the boiler. Pre-combustion controls include:

- Fuel switching,
- Fuel blending, and
- Fuel cleaning.

These techniques have been practiced and performed at numerous utility power plants, typically for operational and sulfur emissions control reasons. These methods are feasible, but considering the current use of lower cost lignite fuel and approximately equal combustion performance, they are not expected to produce lower NO_X emissions, and were eliminated from further consideration for NO_X control at Leland Olds Station. These techniques were not included in the NO_X control cost-effectiveness analysis. For more details, refer to the technical feasibility description included in Appendix A1.

2.2.2 FEASIBILITY OF COMBUSTION NO_X CONTROLS AT LOS

2.2.2.1 COMBUSTION NO_X CONTROLS - UNIT 1

Combustion controls include technologies that are applied to a pulverized fuel-fired boiler. These are summarized as follows:

- Basic combustion control improvements such as low-NO_X burners and separated overfire air are feasible, primarily involving improvements to measuring and controlling fuel feed and combustion air distribution. Basic combustion control improvements and improved operating techniques have already been implemented on the Unit 1 boiler to lower NO_X emissions, so no significant further reductions are expected without being incorporated into another feasible alternative, such as separated overfire air. Basic combustion control improvements alone were eliminated from consideration for additional NO_X reduction at Leland Olds Station.
- Low-NO_X burners (LNBs) are commonly installed in place of original equipment provided prior to 1990. These are often, but not always, installed with some form of overfire air to allow for air-staged or "starved air" combustion to lower NO_X emissions. LOS Unit 1 already has second-generation replacement low NO_X burners suitable for good combustion performance and low NO_X emissions with pulverized lignite fuel. Installing the latest multi-zone LNBs would not significantly lower NO_X emissions without adverse operational consequences, such as unstable flame patterns and raising unburned carbon levels in the emitted flyash. Using the latest LNB technology was eliminated from consideration for additional NO_X reduction at LOS for Unit 1.
- Separated overfire air (SOFA) systems are very commonly applied to pulverized coal-fired boilers for combustion NO_X control. SOFA systems typically divert approximately 15-20% of the hot secondary combustion air admitted to the boiler through the burners to dedicated ports located at higher elevations of the furnace, above the top row of burners. The overall amount of excess air admitted to the boiler is not substantially different than prior to implementation of a SOFA system. SOFA systems are often installed and operated with low-NO_X burners to provide lower carbon monoxide (CO) emissions and unburned carbon (UBC) levels in flyash during air-staged burner operation for effective NO_X emissions control. Booster fans may use ambient or hot secondary combustion air to supply the SOFA ports for higher velocity air injection, which promotes better mixing with the furnace gases for lower CO emissions and flyash UBC content than may be achieved with diverted secondary air on boilers with low windbox air pressure.

- Unit 1 at LOS already has close-coupled overfire air (CCOFA) and is capable of modest levels of additional NO_X emissions reduction by eliminating CCOFA and adding SOFA. Using SOFA was included in the control effectiveness analysis for additional NO_X reduction at LOS for Unit 1.
- "Rotating Opposed Fired Air" (ROFA) is feasible for dry-bottom, wall-fired pulverized coal boilers such as LOS Unit 1. It is different than basic SOFA in that it includes a hot air booster fan and injects the high-pressure overfire air into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row[9].
  - ROFA does not offer a significantly greater NO_X control reduction advantage compared with conventional SOFA to compensate for the higher costs of supplying, installing, and operating the booster fan for LOS Unit 1. This technology is subject to the same operating limitations as conventional air-staged or fuel-staged pulverized coal burners burning North Dakota lignite. (See Appendix A1 for details).
  - Alternatives with boosted overfire assume the installation of ROFA in the control effectiveness and cost evaluation for the Unit 1 boiler at Leland Olds Station.

- Fuel reburn, with and without overfire air:
  - Conventional gas reburn (CGR) and conventional pulverized or micronized coal reburn (PCR or MCR) have been installed and demonstrated as effective for NO_X control on pulverized coal boilers [10,11,12,13,15,16]. CGR or PCR/MCR replaces around 15-30% of total boiler fuel heat input with reburn fuel injected downstream of burners and upstream of SOFA, with or without air-staging the burners. CGR or PCR/MCR would likely involve operation with fewer active pulverized coal main burners.
    - Although LOS currently has no direct high volume supply of gaseous fossil fuels, conventional gas reburn is otherwise considered technically feasible for NO_X control at LOS. Compared with other similarly-effective NO_X controls, conventional gas reburn's expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make gas-consuming alternatives economically unattractive for application at LOS. Conventional gas reburn alternatives were not evaluated further for consideration as NO_X control options for LOS Unit 1.
    - Powerhouse site space constraints would require dedicated buildings and grinding equipment for coal reburn fuel preparation for LOS Unit 1. PCR/MCR would require improvements to increase PM collection efficiency for LOS Unit 1 to prevent higher particulate matter emissions (described in more detail in Appendix A1).

    - Conventional pulverized/micronized coal reburn alternatives were included in the control effectiveness and cost evaluation for the Unit 1 boiler at Leland Olds Station.
  - Fuel-lean gas reburn (FLGR™) has been permanently installed on only a few dry-bottom, pulverized coal-fired boilers. FLGR™ replaces around 6-7% of total boiler fuel heat input with natural gas injection downstream of burners and overfire air, with or without air-staging the burners below stoichiometric ratio.
    - FLGR™ is considered technically feasible for application on LOS Unit 1, but compared with other equally-effective NO_X controls, the expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive for application at LOS.
    - With much higher installation and operating costs compared with SOFA, FLGR™ alternatives were not evaluated further for consideration as NO_X control options for LOS Unit 1.
- Oxygen-enhanced combustion (OEC) has only been demonstrated and/or installed on a limited number of small pulverized coal-fired power plants[19,20].
  - OEC has not been demonstrated and does not have permanently installed experience on pulverized coal boilers in the same output range as LOS Unit 1. Compared with other equally-effective NO_X controls, expected high on-going oxygen costs make this alternative economically unattractive for application at LOS.
  - OEC was considered infeasible for NO_X control application at LOS on Unit 1.
- Flue gas recirculation (FGR) has been applied and practiced at numerous natural gas and fuel oil-fired utility and industrial power plants for NO_X emissions control. No examples of flue gas recirculation applied to dry-bottom wall-fired pulverized coal boilers for NO_X control were found. FGR has been applied to large coal-fired utility boilers, primarily for steam temperature control purposes, but not for emissions control. Lacking demonstrated experience on pulverized coal boilers for NO_X control purposes, FGR was considered infeasible for application at LOS on Unit 1
- Water/steam injection has been retrofit and intermittently practiced on older natural gas and oil-burning wall-fired utility boilers. This technique was not found to be permanently installed and continuously practiced on dry-bottom wall-fired pulverized coal boilers, especially those that fire high-moisture lignite or western subbituminous coals. Thus, water/steam injection was considered infeasible for permanent, full-time, long-term application for NO_X control on Unit 1.

2.2.2.2 COMBUSTION NO_X CONTROLS - UNIT 2

Combustion controls include technologies that are applied to a cyclone-fired boiler. These are summarized as follows:

- Basic combustion control improvements and improved operating techniques have already been implemented on the Unit 2 boiler to lower NO_X emissions, so no significant further reductions are expected without being incorporated into another feasible alternative, such as separated overfire air. Basic combustion control improvements were eliminated from consideration for additional NO_X reduction at LOS for the Unit 2 boiler.
- Low-NO_X burners (LNBs) are not applicable as replacements of cyclones for combustion NO_X control [4]. This alternative was considered infeasible for application at LOS for the Unit 2 boiler.
- Separated overfire air (SOFA) systems have been retrofit to many cyclone boilers[4,5,6,7,8] for combustion NO_X control. The amount of secondary combustion air diverted from the burners and function of a SOFA system applied to a cyclone boiler is generally the same as for a pulverized coal boiler. Supplying a booster fan for raising the pressure of the separated overfire air on a cyclone boiler is unnecessary, since cyclone boilers inherently require higher pressure combustion air than pulverized coal boilers.
    - "Advanced" SOFA (ASOFA) offers the highest performing version of this technology for lignite-fired cyclone boilers, and includes relocating lignite drying system vent ports and flue gas recirculation ports. Using ASOFA was included in the control effectiveness analysis for additional NO_X reduction at LOS for Unit 2. Such NO_X control improvements at LOS Unit 2 will be limited by potential adverse impacts on cyclone operation associated with air-staged (sub-stoichiometric air/fuel) cyclone operation, which are described in Appendix A1.
    - ROFA has not been demonstrated or permanently installed and operated on any cyclone boiler.
        - ROFA is subject to the same operating limitations as conventional air-staged or fuel-staged cyclones burning North Dakota lignite. (See Appendix A1).
        - Since a booster fan typically supplied with this technology is not necessary for cyclone boilers, ROFA does not appear to offer significant advantages for improved NO_X control performance on LOS Unit 2 compared to conventional SOFA.
        - Although it may be possible to install some aspects of ROFA on a cyclone boiler, such as high-velocity offset overfire air ports without a booster fan, the lack of experience on cyclone boiler applications makes this alternative infeasible for LOS Unit 2. ROFA was not evaluated further for the Unit 2 boiler at Leland Olds Station.

- Fuel reburn, with and without overfire air:
  - Conventional gas reburn (CGR) and conventional pulverized or micronized coal reburn (PCR or MCR) have been installed and demonstrated as effective for NO_X control on cyclone boilers[10,11,12,13,14,15,16].
    - CGR or PCR/MCR replaces around 15-30% of total boiler fuel heat input with reburn fuel injected downstream of the cyclones and upstream of SOFA, with or without air-staging the cyclones.
    - CGR or PCR/MCR would likely involve operation with fewer active cyclones.
    - Operation of CGR or PCR/MCR with fewer active cyclones with limited use of advanced SOFA on LOS Unit 2 potentially avoids some adverse operational impacts and impairments associated with fuel- and air-staging cyclones burning North Dakota lignite.
    - Compared with other similarly-effective NO_X controls, conventional gas reburn's expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make gas-consuming alternatives economically unattractive for application at LOS. CGR with ASOFA was not evaluated further for LOS Unit 2.
    - Powerhouse site space constraints would require dedicated buildings and grinding equipment for coal reburn fuel preparation for LOS Unit 2. PCR/MCR would require improvements to increase PM collection capacity additions for LOS Unit 2, for preventing higher particulate matter emissions (described in more detail in Appendix A1).
    - These conditions will make conventional PCR/MCR with basic or advanced versions of SOFA more expensive to install, operate, and maintain at LOS compared to previous retrofit coal reburn applications on existing cyclone-fired boilers. The conventional PCR/MCR with ASOFA alternative is the highest performing version considered technically feasible for NO_X control at Leland Olds Station, and was evaluated for LOS Unit 2.
  - Fuel-lean gas reburn (FLGR™) has not been permanently installed and operated on any cyclone-fired boilers. FLGR™ replaces around 6-7% of total boiler fuel heat input with natural gas injection downstream of cyclones and overfire air, with or without air-staging the cyclones below stoichiometric ratio.
    - For cyclone boilers, FLGR™ has only been demonstrated during a single short-term test[17,18] on a cyclone boiler without a SOFA system. This technology appears to offer limited NO_X control potential on cyclone boilers burning North Dakota lignite, especially for the current configuration of lignite drying system vent ports and flue gas recirculation

ports in the lower furnace where the gas injectors would be located (described in more detail in Appendix A1).

  - FLGR™ may be technically feasible to be installed with an advanced form of SOFA on cyclone boilers designed to burn North Dakota lignite, however the expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive for application at LOS. FLGR™ was not evaluated further as a combustion control option for LOS Unit 2 NO_X reduction.

- Oxygen-enhanced combustion (OEC) has not been demonstrated and/or installed on a cyclone-fired boiler. Lacking demonstrated experience on cyclone boilers, OEC was considered infeasible for NO_X control application at LOS on Unit 2.
- Flue gas recirculation (FGR) has been applied and practiced at numerous natural gas and fuel oil-fired utility and industrial power plants for NO_X emissions control. No examples of flue gas recirculation applied to coal-fired cyclone boilers for NO_X control were found. FGR has been applied to large coal-fired utility boilers, primarily for steam temperature control purposes, not for emissions control.
  - FGR is installed and practiced at LOS on Unit 2 for operational reasons, not for NO_X control. However, the advanced version of SOFA applied to cyclone boilers designed to burn North Dakota lignite using lignite drying systems would relocate the existing lower furnace FGR ports to minimize disruption of the in-furnace NO_X reduction process (described in more detail in Appendix A1). Due to the lack of use on cyclone boilers, using FGR alone for NO_X control at LOS Unit 2 was eliminated from further consideration.
- Water/steam injection has been retrofit and intermittently practiced on older natural gas wall-fired utility boilers, and at one natural gas-fired cyclone boiler[21]. Although it has been tested on eastern or midwestern bituminous coal-fired cyclone boilers[4], this technique was not found to be permanently installed and continuously practiced on coal-fired cyclone boilers, especially those that fire high-moisture lignite or western subbituminous coals. Thus, water/steam injection was considered infeasible for permanent, full-time, long-term application for NO_X control on lignite-fired boilers at LOS.

2.2.3 FEASIBILITY OF POST-COMBUSTION NO_X CONTROLS

2.2.3.1 POST-COMBUSTION NO_X CONTROLS - UNIT 1

Post-combustion controls involve technologies that are usually applied to the flue gas exiting the boiler. These are summarized as follows:

- Selective Non-Catalytic Reduction (SNCR) and variations for NO_X control at LOS Unit 1:
  - Injects ammonia or urea reagent into the upper furnace zone with suitable temperature conditions.
  - Chemical reactions of amine and NO_X are insensitive to fuel and boiler type; excess unreacted reagent is emitted from the boiler as "ammonia slip" and can contribute to fouling of air heaters when combined with sulfates.
  - SNCR can be implemented with or without other combustion and in-furnace and downstream post-combustion controls.
  - SNCR has been applied and practiced on numerous pulverized coal utility boilers.
  - SNCR, in combination with the existing close-coupled overfire air (CCOFA), is considered feasible for modest NO_X control on the Unit 1 pulverized coal boiler at LOS.
  - Hydrocarbon-enhanced SNCR (commercially available as NO_XStar™) uses high temperature steam and ammonia vapor with small quantities of gaseous hydrocarbon fuel (natural gas or propane) and offers potentially higher NO_X control performance than conventional SNCR. NO_XStar™ has been demonstrated with the initial installation on one pulverized coal-fired boiler burning eastern coal, and commercially installed on another PC boiler burning eastern coal[25,26].
    - NO_XStar™ is susceptible to major impairment of permanently-installed injection lances attached to convective heat transfer surfaces of the boiler due to severe fouling expected from lignite ash deposits.
    - NO_XStar™ may be feasible for NO_X control on lignite-fired dry-bottom pulverized coal boilers such as LOS Unit 1. However, with much higher installation and operating costs compared with SOFA, and the lack of a experience on dry-bottom PC-fired boilers burning high fouling coals such as lignite, this alternative was considered infeasible as a NO_X control option for LOS Unit 1.
  - Rich Reagent Injection (RRI) injects aqueous urea into the high-temperature lower furnace zone and requires an "air-starved" atmosphere to avoid creating instead of reducing NO_X. RRI has not been developed nor demonstrated for NO_X control application on pulverized coal-fired boilers. This alternative is considered infeasible for LOS Unit 1.
- Selective Catalytic Reduction (SCR):
  - Injects ammonia reagent into the flue gas in a zone with suitable temperature conditions.
  - Chemical reactions of ammonia and NO_X in the presence of a catalyst are effective at much lower temperatures than SNCR, typically 600°F to 750°F. Very high NO_X control efficiencies are possible, with lower reagent consumption per ton of NO_X emission reduction

compared to SNCR. This technology has been applied to a variety of fuels and boiler types. Excess unreacted reagent is emitted from the boiler as "ammonia slip" and can contribute to fouling of air heaters when combined with sulfates.

- Conventional SCR technology has been widely applied to pulverized coal fired boilers in the United States for NO_X control, primarily in a "hot-side, high-dust" arrangement.
  - There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite.
  - An evaluation of impacts of ash on SCR plugging and blinding was performed, which included the use of SCR slipstream testing on a North Dakota lignite-fired powerplant. This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels.
  - North Dakota lignite produces ash with severe deposition characteristics that are not typical with other fuels. These deposition characteristics will result in deposits and pluggage of the catalyst. SCR performance and catalyst life will be severely impacted.
  - Success of SCR technology on an EGU firing North Dakota lignite is considered technically infeasible. This is explained in more detail in Appendix A1 and A5.
  - SCR alternatives were not evaluated further for consideration as options for LOS Unit 1.

- Electro-Catalytic Oxidation (ECO®) is an emerging multi-pollutant control technology for coal-fired boilers that uses a barrier reactor for NO_X control upstream of an ammonia scrubber. A slip-stream pilot-scale commercial demonstration of ECO® is currently undergoing field development on a pulverized coal-fired power plant in Ohio. ECO® has not been installed on a full-scale, full-time basis on any coal-fired EGU, and has no commercial demonstration experience on western subbituminous or lignite coals. Thus, ECO® was considered commercially unavailable and technically infeasible for NO_X control at LOS. For more details, refer to the technical feasibility evaluation included in Appendix A1.

2.2.3.2 POST-COMBUSTION NO_X CONTROLS - UNIT 2

Post-combustion controls involve technologies that are usually applied to the flue gas exiting the boiler. These are summarized as follows:

- Selective Non-Catalytic Reduction (SNCR) and variations for NO_X control at LOS Unit 2:
  - SNCR has been applied and practiced on several cyclone-fired boilers[22,23,24] since 1995.
  - SNCR is considered feasible for modest NO_X control on the Unit 2 cyclone boiler at LOS.

- SNCR without SOFA, with much higher installation and operating costs compared with SOFA alone, is not economically attractive for application at LOS Unit 2 and was eliminated from further consideration for control and cost-effectiveness.
- Hydrocarbon-enhanced SNCR (commercially available as NO_XStar™) has not been demonstrated on any cyclone-fired boilers. It is susceptible to major impairment of permanently-installed injection lances attached to convective heat transfer surfaces of the boiler due to severe fouling expected from lignite ash deposits. NO_XStar™ was considered infeasible for application on North Dakota lignite-fired cyclone boilers for NO_X control.
- Rich Reagent Injection (RRI) injects aqueous urea into the high-temperature lower furnace zone and requires an "air-starved" atmosphere to avoid creating instead of reducing NO_X. RRI has been developed and demonstrated with application intended only on cyclone boilers[27,28,29,30]. RRI but has not been permanently installed but is commercially available from two sub-licensees (Fuel Tech and Combustion Components Associates) of the technology licensed by EPRI to Reaction Engineering International, Inc..
    - RRI is susceptible to impairment due to fouling by ash slag deposits and heat-related damage of injection nozzles, located near the cyclones in the lower furnace.
    - RRI may be feasible for application at LOS for Unit 2's cyclone-fired boiler operating under substoichiometric conditions with modest air-staged cyclones using ASOFA for limited NO_X control. Because RRI in combination with ASOFA without SNCR is expected to be less effective for NO_X reduction and have higher reagent consumption than SNCR with ASOFA, RRI+ASOFA was not included in the control and cost effectiveness analysis in this evaluation for LOS Unit 2. (see Section 2.2.4)
    - Basic SOFA for North Dakota lignite cyclone boilers is incompatible with Rich Reagent Injection. Such combinations are technically infeasible, and thus were eliminated from further consideration for LOS Unit 2. For more details, refer to the technical feasibility evaluation included in Appendix A1.

- Selective Catalytic Reduction (SCR):
    - SCR technology has been installed on 22 cyclone-fired boilers in the U.S.[34], mostly applied in conventional "hot-side, high-dust" arrangements.
    - Catalyst is susceptible to fouling and deactivation from sodium and sulfur deposits, which are expected to be severe from the firing of North Dakota lignite in the LOS Unit 2 cyclone boiler. This conventional arrangement of SCR technology is considered technically infeasible for application at LOS for the Unit 2 cyclone boiler. For more details, refer to the technical feasibility evaluation included in Appendix A1.

- “Low-dust” SCR (LD-SCR) technology (hot-side or cold-side) has been installed on 10 pulverized coal-fired boilers, but no cyclone boilers, in the U.S.[34]. LD-SCRs are typically located downstream of a hot-side electrostatic precipitator. LD-SCR in a cold-side application requires flue gas reheat prior to the catalyst reactor, typically involving supplemental gaseous fuel firing and large regenerative gas-to-gas heat exchanger equipment. LD-SCR is also susceptible to catalyst fouling and deactivation from sodium and sulfur deposits not removed by the particulate matter control device upstream. This fouling is expected to be sufficient to cause significant impairment on ND lignite-fired cyclone boilers. LD-SCR was considered technically infeasible for application at LOS Unit 2. For more details, refer to the technical feasibility evaluation included in Appendix A1.
- “Tail gas” SCR (TG-SCR) technology has been installed on several coal-fired boilers in Europe, but not in the United States[34]. In such cases, TG-SCRs are located downstream of the air preheater, particulate matter control device and flue gas desulfurization (FGD) scrubber. This requires supplemental fuel or steam heat with a large gas-to-gas heat exchanger to reheat the flue gas to an appropriate temperature prior to the SCR reactor. There are serious concerns about the susceptibility of TG-SCR catalyst to fouling from sodium and sulfur deposits not removed by the particulate matter control device and FGD scrubber sufficient to cause significant impairment on ND lignite-fired cyclone boilers. TG-SCR technology was considered technically infeasible for application on Unit 2 at LOS. For more details, refer to the technical feasibility evaluation included in Appendix A1.

2.2.4 FEASIBILITY OF COMBINATIONS OF COMBUSTION AND POST-COMBUSTION NO_X CONTROLS

2.2.4.1 COMBUSTION AND POST-COMBUSTION NO_X CONTROLS - UNIT 1

Combination controls involve simultaneous use of multiple types of technologies that were described in Section 2.2.2 above. These are briefly summarized as follows:

- Separated Overfire Air + Selective Non-Catalytic Reduction (SNCR) and variations:
  - Basic or boosted SOFA + SNCR combinations are technically feasible for application on pulverized coal-fired boilers for NO_X control, and were included in the control and cost effectiveness analysis for LOS Unit 1.
  - Basic and boosted SOFA + Hydrocarbon-enhanced SNCR (commercially available as NO_XStar™) may be capable of NO_X control on lignite-fired dry-bottom pulverized coal boilers such as LOS Unit 1. However, with much higher installation and operating costs

compared with conventional SNCR, and the lack of a experience on dry-bottom PC-fired boilers burning high fouling coals such as lignite, this alternative was considered infeasible as a NO_X control option for LOS Unit 1.

- A version of SNCR combined with a boosted form of separated overfire air is currently being marketed commercially as "Rotating Mixing" (Rotamix, using ROFA or Rotating Opposed Fired Air). This has been applied only to pulverized coal-fired boilers. It is different than basic SOFA + SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects ammonia (or urea) reagent into the high-pressure overfire air stream which is introduced into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. At least eight tangentially-fired and five wall-fired pulverized coal utility boilers have been retrofitted with Rotamix, with results published for three "T"-fired boilers burning eastern bituminous coal or Illinois bituminous coal [31,32,33].
  - Since it uses ROFA, Rotamix technology is subject to the same operating limitations as conventional air-staged or fuel-staged pulverized coal burners firing North Dakota lignite. (See Appendix A1).
  - Use of Rotamix on some coal-fired boilers may not produce the levels of NO_X control capable of being achieved with separate SNCR and SOFA injection ports located to optimize each individual technique's performance. This applies to the Unit 1 boiler at LOS.
  - Rotamix is generally considered feasible for NO_X control on small to medium-sized dry-bottom wall-fired pulverized coal boilers.
  - The boosted overfire and SNCR NO_X control alternative assumes the installation of Rotamix in the control effectiveness and cost evaluations for the Unit 1 boiler at Leland Olds Station.

- Fuel Reburn + Selective Non-Catalytic Reduction (SNCR) and variations:
  - Fuel-lean gas reburn + SNCR with basic or boosted SOFA is considered technically feasible on dry-bottom, wall-fired pulverized coal boilers. However, with much higher installation and operating costs compared to other options with similar control effectiveness, such combinations of technologies were not evaluated for consideration as NO_X control options for LOS Unit 1.
  - Conventional Gas Reburn (CGR) + SNCR with basic SOFA combination has only been installed on one tangentially-fired pulverized coal boiler in the United States. This combination of technologies may be technically feasible for LOS Unit 1, but there have been

no commercial installations on dry-bottom, wall-fired pulverized coal boilers. Also, with much higher installation and operating costs compared to other options with similar control effectiveness, this alternative was not evaluated for consideration as a layered controls option for LOS Unit 1.

- Conventional pulverized / micronized coal reburn (PCR or MCR) + SNCR with basic or boosted SOFA combination may be technically feasible for LOS Unit 1, but has not been demonstration tested or commercially sold for a dry-bottom, wall-fired pulverized coal boiler application in the United States. A dedicated building with grinding equipment for coal reburn fuel preparation, and the need to control higher particulate matter emissions through increased collection efficiency improvements would be required to implement this alternative on LOS Unit 1. With a lack of demonstrated success and much higher installation and operating costs compared with other demonstrated combinations of NOx control technologies with similar control effectiveness, this option was eliminated from further consideration for NO_X control on LOS Unit 1.

The results of Step 2 of the NO_X BART Analysis for determining the technical feasibility of NO_X emission control technologies potentially applicable to lignite-fired pulverized coal-fired boilers are summarized in Table 2.2-1, and for cyclone boilers in Table 2.2-2 located in the following report section. Every possible combination of all the various techniques, i.e. "layered technologies", is not listed, in keeping with the EPA's BART Guidelines that they do not "expect a source owner to conduct extended trials to learn how to apply a technology" and "would not consider technologies in the pilot scale stages of development as "available" for the purposes of a BART review" [70 FR 39165]. Also, it "is not the [EPA's] intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options" and [the States] "should consider recent regulatory decisions and performance data (e.g. manufacturer's data, engineering estimates, and the experience of other sources) when identifying emissions performance level or levels to evaluate" [70 FR 39166].

TABLE 2.2-1 – Technical Feasibility of Potential NO_X Control Technologies for Leland Olds Station Unit 1

Control Technology[1]	In Permanent, Full-Scale Service on Existing Pulverized Coal-Fired Utility Boilers?	Technically Feasible on Leland Olds Station Unit 1 boiler?
Selective Catalytic Reduction (SCR) (high dust); Low-dust SCR; Tail-gas SCR	Yes[2] / Yes / Yes[3]	No. See discussion in text and footnote
Electro-Catalytic Oxidation (ECO®)	No	No; has not been demonstrated full-scale; See discussion in text and footnote[3].
SNCR	Yes[2]	Yes; can be combined w/ other technologies.
HE-SNCR (NO_XStar™)	Yes[4]	No[4]. See discussion in text and footnote[5].
Rich Reagent Injection (RRI)	No[6]	No[6]. Not applicable to pulverized coal-firing.
Rotamix (ROFA + SNCR)	Yes	Yes. See discussion in text and footnote.
Conventional Gas Reburn (CGR)	Yes[7]	Yes[7]; Requires SOFA. See discussion in text and footnote[5].
Conventional Gas Reburn + SNCR w/ SOFA	Yes[7]	Yes. Only one CGR w/ SNCR application on PC firing. See discussion in text and footnote[5].
Coal Reburn	Yes[8]	Yes[8]; Requires SOFA.
Coal Reburn + SNCR	No	No. Has not been demonstrated on PC-firing.
FLGR™	No[7]	Yes[7] (w/ or w/out SOFA). See discussion in text and footnote[5].
Fuel Lean Gas Reburn + SNCR (AEFLGR™)	Yes[7]	Yes. Five installations in PC-fired U.S. boilers. See discussion in text and footnote[5].
Boosted SOFA (or ROFA)	Yes[9],[10]	Yes[9]. See discussion in text and footnote.
Separated OFA (SOFA)	Yes[10]	Yes, commonly applied with LNBs.
Low NO_X Burners (LNBs)(latest technology)	Yes	Yes, commonly applied with CCOFA or SOFA. See discussion in text.
Combustion Improvements	Yes	Yes[11]; typically included with separated OFA.
OEC	No[12]	No[12]. See discussion in text and footnote.
Water Injection	No[13]	No[13]
Flue Gas Recirculation	Not for NO_X control	No[14]
Fuel Switching (from lignite to 100% PRB)	Yes	Yes[15] (not expected to reduce NO_X further)

See technical feasibility details in Appendix A1 and literature References in Appendix A3 for details.

1 – All potential combinations of technologies not listed. See discussion of "layered" technologies.

2 – Limited number of active installations on pulverized-fired boilers burning western subbituminous coal.

3 – No identified full-scale permanent installations operating continuously on coal-fired boilers in the United States.

4 – Hydrocarbon-enhanced SNCR has been demonstrated on two pulverized coal-fired boilers, but not on any boiler firing western subbituminous coal or lignite with severe fouling characteristics.

5 – Much higher installation and operation costs expected compared with other options with similar control effectiveness, this alternative was not evaluated for consideration as a NO_X control option for LOS Unit 1.

6 – Rich Reagent Injection has only been successfully demonstrated for brief periods with SOFA+SNCR at two cyclone power plants. It is not intended nor has it been successfully demonstrated on pulverized coal-fired boilers.

7 – No conventional gas reburn (CGR) demonstrations or installations on pulverized coal-fired boilers burning western subbituminous coal or lignite. No demonstrations or installations of FLGR™ have been performed on a pulverized coal-fired boiler burning western subbituminous coal or lignite. Only one installation of conventional gas reburn with SNCR on PC-fired boiler burning eastern bituminous coal. Several installations of FLGR™ with and without SNCR on PC-fired boilers burning eastern bituminous coal. Most conventional gas reburn and FLGR™ systems are not currently active.

8 – No conventional pulverized or micronized coal reburn (PCR/MCR) demonstrations or installations on pulverized coal-fired boilers burning western subbituminous coal or lignite. Three active coal reburn systems on PC-fired boilers burning eastern bituminous coal.
9 – Several active commercial installations of boosted SOFA on pulverized coal-fired boilers.
10 –No wall-fired PC boilers burning North Dakota lignite have installed separated OFA or boosted OFA.
11 –Considered part of SOFA installation for coal boilers without improved combustion controls for NO_X reduction.
12 – Oxygen-enhanced combustion has been applied on two modestly-sized pulverized coal-fired boilers firing bituminous coal, but has not been demonstrated on 100% western subbituminous coal or lignite-fired boilers.
13 – No permanently installed examples of using this technique continuously on coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.
14 – No examples of using recirculated flue gas on coal-fired boilers for NO_X emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 1.
15 – Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 1.

2.2.4.2 COMBUSTION AND POST-COMBUSTION NO_X CONTROLS - UNIT 2

Combination controls involve simultaneous use of multiple types of technologies that were described in Section 2.2.3 above. These are briefly summarized as follows:

- Separated Overfire Air + Selective Non-Catalytic Reduction (SNCR) and variations:
  - Because advanced SOFA + SNCR is the highest performing feasible form of this post-combustion NO_X control combination for North Dakota lignite cyclone boilers, it was evaluated for control and cost effectiveness on LOS Unit 2. Basic SOFA + SNCR together is a feasible combination but is not the highest performing version, and thus was eliminated from further consideration for LOS Unit 2.
  - Basic or advanced SOFA + Hydrocarbon-enhanced SNCR (commercially available as NO_XStar™) alternatives lack demonstrated experience on cyclone boilers. These combinations are susceptible to major impairment of permanently-installed reagent injection lances attached to convective heat transfer surfaces of the boiler due to severe fouling expected from lignite ash deposits. NO_XStar™ with basic or advanced SOFA combinations were considered infeasible for application on North Dakota lignite-fired cyclone boilers such as LOS Unit 2 for NO_X control.
  - Rich Reagent Injection may be technically feasible for application with and without SNCR combinations at LOS for Unit 2's cyclone-fired boiler operating under substoichiometric conditions with ASOFA, although the expected modest amount of cyclone air-staging will substantially reduce the NO_X control potential of RRI at LOS Unit 2. Because RRI + SNCR with advanced SOFA is the highest performing form of this post-combustion NO_X control combination, it was evaluated for control and cost effectiveness on LOS Unit 2.
  - RRI with advanced SOFA (without SNCR) is not the highest performing version, and thus was eliminated from further consideration for LOS Unit 2.

- Basic SOFA for North Dakota lignite cyclone boilers is incompatible with Rich Reagent Injection with SNCR, so this combination is technically infeasible, and thus was eliminated from further consideration for LOS Unit 2. For more details, refer to the technical feasibility evaluation included in Appendix A1.
- SNCR combined with a boosted form of separated overfire air is currently being marketed commercially as "Rotating Mixing" (Rotamix, using ROFA or Rotating Opposed Fired Air). This has been applied only to pulverized coal-fired boilers[31,32,33].
  - Since it uses ROFA, Rotamix technology is subject to the same operating limitations as conventional air-staged or fuel-staged cyclones burning North Dakota lignite. (See Appendix A1).
  - Use of Rotamix on some coal-fired boilers may not produce the levels of NO_X control capable of being achieved with separate SNCR and SOFA injection ports located to optimize each individual technique's performance. This applies to the LOS Unit 2 boiler.
  - There has been no Rotamix experience on cyclone-fired boilers. Rotamix also does not offer a significant performance advantage for cyclone NO_X control at LOS for Unit 2 compared to the levels of NO_X control capable of being achieved with separate SNCR and SOFA injection ports located to optimize each individual technique's performance. Although it may be possible to install some aspects of Rotamix on a cyclone boiler, such as high-velocity offset overfire air ports with SNCR but without a booster fan, the lack of experience on cyclone boiler applications makes this alternative infeasible for LOS Unit 2. Rotamix was not evaluated further for the LOS Unit 2 boiler.

- Fuel Reburn + Selective Non-Catalytic Reduction (SNCR) and variations:
  - FLGR™ + SNCR (with basic or advanced SOFA) has not been demonstrated or permanently installed and operated on a coal-fired cyclone boiler. This combination may be technically feasible but would appear to offer limited NO_X control potential on cyclone boilers burning North Dakota lignite (see Appendix A1). FLGR™'s expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive for application at LOS. FLGR™ + SNCR (with basic or advanced SOFA) were eliminated from further consideration for NO_X control on LOS Unit 2.
  - Conventional Gas Reburn (CGR) + SNCR with basic or advanced SOFA may be technically feasible for LOS Unit 2, but there have been no successfully demonstrated or commercial installations on cyclone boilers. This combination of technologies lacks

experience. Expected high capital costs for a natural gas supply pipeline and on-going natural gas costs make this alternative economically unattractive compared with similar NO_X reduction available with other demonstrated or commercially available controls. This combination was eliminated from further consideration on LOS Unit 2.

- Conventional pulverized / micronized coal reburn (PCR or MCR) + SNCR with basic or advanced SOFA combination may be technically feasible for LOS Unit 2, but has not been demonstration tested or commercially sold for a cyclone boiler application. A dedicated building with grinding equipment for coal reburn fuel preparation, and the need to control higher particulate matter emissions through increased PM collection capacity with flyash handling and storage capacity additions would be required to implement this alternative on LOS Unit 2. Since this combination of technologies lacks experience, PCR or MCR + SNCR with basic or advanced SOFA were eliminated from further consideration for NO_X control on LOS Unit 2.

TABLE 2.2-2 – Technical Feasibility of Potential NO_X Control Technologies for Leland Olds Station Unit 2

Control Technology[1]	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on Leland Olds Station Unit 2 boiler?
Selective Catalytic Reduction (SCR) (high dust); Low-dust SCR; Tail-gas SCR	Yes[2] / No / Yes[3]	No - Unresolvable fouling and catalyst deactivation problems expected. See discussion of SCR feasibility for ND lignite.
Electro-Catalytic Oxidation (ECO®)	No	No, has not been demonstrated full-scale; commercial availability not confirmed
SNCR	Yes[2]	Yes; can be combined with other technologies
HE-SNCR (NO_XStar™)(with or without SOFA or ASOFA)	No[4]	No[4]. Has not been demonstrated on cyclone.
Rich Reagent Injection (RRI) with ASOFA	No[5]	Yes[5]. Requires Advanced SOFA for lignite, can be combined w/ SNCR.
Rotamix (ROFA + SNCR)	No	No. Has not been demonstrated on cyclone.
Conventional Gas Reburn (ACGR) + SNCR	No[6]	No. Has not been demonstrated on cyclone. Would require ASOFA.
Conventional Gas Reburn	Yes[6]	Yes[7]; Requires ASOFA
Coal Reburn	Yes[8]	Yes[8]; Requires ASOFA
Coal Reburn + SNCR	No	No. Has not been demonstrated on cyclone.
FLGR™	No[6]	Yes[7] (w/ or w/out SOFA or ASOFA)
Fuel Lean Gas Reburn + SNCR (AEFLGR™)	No[6]	No. Has not been demonstrated on cyclone.
Advanced SOFA	No[9]	Yes[9]
Separated OFA (SOFA)	Yes[9]	Yes[9]
ROFA	No[10]	No[10]. No significant advantages over SOFA.
Combustion Improvements	Yes	Yes[11] ; typically included with separated OFA
OEC[12]	No[12]	No - has not been demonstrated on cyclone boiler
Water Injection	No[13]	No[13]
Flue Gas Recirculation	Not for NO_X control	Yes[14] (not expected to reduce NO_X further)
Fuel Switching (from lignite to 100% PRB)	Yes	Yes[15] (not expected to reduce NO_X further)
Low NO_X Burners	No	No – Not Feasible

See technical feasibility details in Appendix A1 and literature References in Appendix A3 for details.

1 – All potential combinations of technologies not listed. See discussion of "layered" technologies.

2 – Limited number of active installations on cyclone-fired boilers burning western subbituminous coal.

3 – No identified full-scale permanent installations operating continuously on coal-fired boilers in the United States.

4 – Hydrocarbon-enhanced SNCR has been demonstrated on two pulverized coal-fired boilers, but not on any boiler, including cyclones, firing western subbituminous coal or lignite with severe fouling characteristics.

5 – Rich Reagent Injection has only been successfully demonstrated for brief periods with SOFA+SNCR at two cyclone power plants. It is not intended nor has it been successfully demonstrated on pulverized coal-fired boilers.

6 – Limited number of conventional gas reburn (CGR) demonstrations or installations on cyclone-fired boilers burning western subbituminous coal. One demonstrations (no permanent installations) of FLGR™ have been performed on a cyclone-fired boiler. Only one installation of conventional gas reburn with SNCR on PC-fired boiler burning eastern bituminous coal. Several installations of FLGR™ with and without SNCR on PC-fired boilers burning eastern bituminous coal. Most conventional gas reburn and FLGR™ systems are not currently active.

7 – Much higher installation and operation costs expected compared with other options with similar control effectiveness, this alternative was not evaluated for consideration as a NO_X control option for LOS Unit 2.

8 – One conventional pulverized (PCR/MCR) demonstration on cyclone-fired boilers burning western subbituminous coal has been discontinued. Only one active micronized coal reburn system on cyclone boiler burning eastern bituminous coal. Three active coal reburn systems on PC-fired boilers burning eastern bituminous coal.

9 – No cyclone or wall-fired PC boilers burning North Dakota lignite have installed separated OFA or boosted OFA.

10 – Several active commercial installations of boosted SOFA (or ROFA) on pulverized coal-fired boilers, none on cyclone boilers.

11 –Considered part of SOFA installation for coal boilers without improved combustion controls for NO_X reduction.

12 – Oxygen-enhanced combustion has been applied on two modestly-sized pulverized coal-fired boilers firing bituminous coal, but has not been demonstrated on any cyclone boilers or 100% western subbituminous coal or lignite-fired PC boilers.

13 – This technique has been demonstrated but no permanently installed examples of using this technique continuously on cyclone coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.

14 – No examples of using recirculated flue gas on coal-fired boilers for NO_X emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 2. Potential NO_X reduction improvement on LOS Unit 2 considered part of "advanced" SOFA.

15 – Zero additional NO_X reduction potential expected from this technique alone for LOS Unit 2.

2.3 CONTROL EFFECTIVENESS EVALUATION OF NO_X CONTROL TECHNOLOGIES

Several feasible NO_X control alternatives previously listed in Tables 2.2-1 and 2.2-2 have been removed from the control effectiveness ranking in Tables 2.3-1 and 2.3-2 for LOS Unit 1, and Tables 2.3-3 and 2.3-4 for LOS Unit 2. This control option ranking approach recognizes that those feasible alternatives that appear to offer zero or very small control performance for a significant cost impact (e.g. fuel switching), should not be included in the control and cost effectiveness impact analysis. Alternatives that include natural gas firing, or are similar in predicted emission reduction percentage but are more expensive to install and operate, or have more substantial operational limitations compared to other feasible alternatives were also eliminated from further analysis.

The emission reduction (control effectiveness) percentages developed for ranking the feasible alternatives shown for LOS Unit 1 and LOS Unit 2 are estimates based upon engineering judgments with considerations of:

- the general combustion properties of North Dakota lignite;
- published and available emission reduction performance achieved at other similar utility power plants (dry-bottom pulverized coal and wet-bottom cyclone-fired boilers);
- computer-derived predictions; and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

These NO_X emission level and percent reduction estimates include adjustments of previously demonstrated or predicted performance that reflect differences between North Dakota lignite and eastern or midwestern bituminous and western subbituminous coals. The numbers assume the maximum short-term potential capability of the employed technique, demonstrated or installed elsewhere, is not achievable or sustainable long-term. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application.

2.3.1 CONTROL EFFECTIVENESS OF COMBUSTION NO_X CONTROLS – LOS UNIT 1

Only close-coupled overfire air with low NO_X burners have been previously installed for reducing NO_X emissions from the LOS Unit 1 boiler. NO_X emission control options considered feasible were evaluated for the LOS Unit 1 boiler, are listed in Table 2.3-1 and Table 2.3-2. The existing LNBs with a retrofit of separated overfire air in place of CCOFA were estimated to produce a modest NO_X control reduction for LOS Unit 1 beyond the presumptive BART NO_X level. Pre-retrofit levels of NO_X emissions for Leland Olds Station's Unit 1 boiler in Table 2.3-1 are relative to an equivalent unit emission baseline rate of 0.285 lb/mmBtu (historic highest 24-month average rate, years 2000-2004), with a corresponding average heat input rate of 2,443 mmBtu/hr for 8,510 hours per year. This is compared to the estimated post-control equivalent average NO_X unit emission rates (lb/mmBtu) for a boiler design capacity heat input rate of 2,622 mmBtu/hr for 8,760 hrs/yr operation under the future Potential To Emit (PTE) scenario.

Feasible, demonstrated pulverized coal-fired boiler NO_X controls which allow or enhance further reductions when separated overfire air is combined with other combustion or post-combustion control alternatives that did not involve gas-consuming technologies were evaluated.

Based upon Burns & McDonnell's experience, applying SOFA technology to LOS Unit 1 boiler is expected to produce a reduction percentage from the pre-control baseline NO_X emission rate approximately half as great as is typically achieved when PC-fired boilers burning western subbituminous coal implement SOFA and operate low-NO_X burners at fairly low burner air/fuel ratios (around 0.90). This reduction estimate relates to the pre-control baseline NO_X emission rate which reflects the modest amount of burner air-staging that is believed can be sustained when firing lignite at full unit output capacity when operating existing low-NO_X burners with SOFA.

Predictions of NO_X emission reduction percentages for incremental NO_X emission reductions from CCOFA-, and basic and boosted SOFA-controlled levels for SNCR alternatives were estimated from a vendor proposal of Selective Non-Catalytic Reduction[46].

Coal reburn with basic and boosted SOFA is estimated to reduce NO_X emissions around 60 percent, based upon estimated uncontrolled baseline NO_X levels and demonstrated coal-reburn retrofits on PC-fired boilers. The reduction estimates from pre-retrofit baseline levels of NO_X emissions for Leland Olds Station's Unit 1 boiler in Tables 2.3-1 and 2.3-2 reflect the modest amount of burner air-staging with existing LNBs and CCOFA that can be sustained when firing lignite at full unit output capacity.

TABLE 2.3-1 – Historic Baseline and Estimated Control Options' PTE NO_X Emission Rates Evaluated for LOS Unit 1 Boiler

Alt. No.(1)	NO_X Control Technique	LOS Unit 1 Emission Rate(2) (lb/mmBtu)	Control Percentage(2)	LOS Unit 1 Hourly Emission(2) (lb/hr)	LOS Unit 1 Annual Emission(2) (tons/yr)
G	Coal Reburn with boosted SOFA (future PTE case)	0.147	48.7	384	1,666
F	Coal Reburn with basic SOFA (future PTE case)	0.154	46.2	403	1,746
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	0.157	45.1	411	1,782
D	SNCR with basic SOFA (future PTE case)	0.166	42.0	434	1,883
C	SNCR with Close-Coupled OFA (future PTE case)	0.216	24.5	565	2,450
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	0.216	24.3	567	2,483
A	Separated Overfire Air (SOFA, basic), (future PTE case)	0.230	19.4	603	2,642
--	Baseline, based on annual operation at highest historic 24-mo average pre-control NO_X emission rate	0.285	--	697	2,967

1 – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
2 – Emissions are calculated from unit emission rates, control percentage, 2,443 mmBtu/hr hourly heat input rate, and 8,510 annual hrs/yr of operation at future PTE conditions compared to historic pre-control baseline.

Table 2.3-2 shows an average pre-control equivalent NO_X baseline unit emission rate of 0.29 lb/mmBtu and post-control unit emission rates (lb/mmBtu), each applied to the LOS Unit 1 boiler at a fuel heat input rate of 2,622 mmBtu/hr (boiler design capacity rating) for 8,760 hrs/yr of operation under steady-state operating conditions relative to the future PTE case. Note that the order of SNCR with CCOFA and Boosted SOFA (ROFA) are switched in the latter case versus historic baseline.

TABLE 2.3-2 – Pre-Control Presumptive BART Baseline and Estimated Control Options' NO_X Emission Rates Evaluated for Future PTE Scenario, LOS Unit 1 Boiler

Alt. No.(1)	NO_X Control Technique	LOS Unit 1 Emission Rate(2) (lb/mmBtu)	Control Percentage(2)	LOS Unit 1 Hourly Emission(2) (lb/hr)	LOS Unit 1 Annual Emission(2) (tons/yr)
G	Coal Reburn with boosted SOFA (future PTE case)	0.149	48.7	390	1,693
F	Coal Reburn with basic SOFA (future PTE case)	0.156	46.2	409	1,774
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	0.159	45.1	418	1,811
D	SNCR with basic SOFA (future PTE case)	0.168	42.0	441	1,913
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	0.215	25.9	564	2,469
B	SNCR with Close-Coupled OFA (future PTE case)	0.219	24.5	574	2,490
A	Separated Overfire Air (SOFA, basic), (future PTE case)	0.230	20.7	603	2,641
--	Baseline, based on annual operation at presumptive BART NO_X pre-control emission rate for future PTE scenario	0.290	--	760	3,330

1 – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
2 – Emissions are calculated from unit emission rates, control percentage, 2,622 mmBtu/hr hourly heat input rate, and 8,760 annual hrs/yr of operation at future PTE conditions compared to presumptive BART NO_X pre-control baseline.

2.3.2 CONTROL EFFECTIVENESS OF COMBUSTION AND POST-COMBUSTION NO_X CONTROLS – LOS UNIT 2

None of the remaining control options have been installed on cyclone-fired boilers burning North Dakota lignite. This is particularly pertinent to all control options that involve air-staged combustion associated with advanced forms of separated overfire air, reburn, and Rich Reagent Injection. RRI requires the hot furnace environment where the reagent is injected to be essentially devoid of free oxygen. Alternatives with the advanced form of SOFA are estimated to reduce NO_X emission levels more effectively from the LOS Unit 2 pre-control baselines than those which do not employ the use of cyclone air-staging and overfire air. Feasible, demonstrated cyclone boiler NO_X controls which allow or enhance further reductions when ASOFA is combined with other combustion or post-combustion control alternatives that did not involve gas-consuming technologies were evaluated.

Based upon Burns & McDonnell's experience, applying the advanced version of SOFA to the LOS Unit 2 cyclone boiler's pre-control baseline NO_X emission rate is estimated to produce a reduction percentage approximately half as great as is typically achieved when cyclone-fired boilers burning western subbituminous coal implement SOFA and operate at fairly low cyclone air/fuel ratios (around 0.90). This reduction estimate relates to the pre-control baseline NO_X emission rate which reflects the modest amount of cyclone air-staging that is believed can be sustained when firing lignite at full unit output capacity, and the additional amount of control potential available from operating with relocated lignite drying system vent ports and FGR ports associated with ASOFA.

Prediction of NO_X emission reduction percentage for Rich Reagent Injection (RRI) is based on engineering judgment with consideration of a recent demonstration testing performed at Ameren's Sioux Unit 1 cyclone boiler, and published computational fluid dynamics (CFD) modeling of the Sioux Unit 1 cyclones and furnace zones. A 2002 technical paper by Reaction Engineering International[28] showing the results of CFD modeling and field demonstration testing of RRI at the Sioux Unit 1 boiler with modest cyclone air/fuel ratios (close to 0.95 to 0.99) was used as guidance for estimating the NO_X emission reduction percentages assumed for LOS Unit 2.

Incremental NO_X emission reductions from ASOFA-controlled levels for SNCR, and SNCR+RRI alternatives were estimated from a vendor proposal of Selective Non-Catalytic Reduction[46] and information in a 2002 technical paper by Reaction Engineering International[28] for RRI testing and CFD modeling of the Sioux Unit 1 boiler.

Coal reburn with ASOFA is estimated to reduce NO_X emissions slightly more than 50 percent, based upon control levels demonstrated by previous coal-reburn retrofits on cyclone-fired boilers. This reduction estimate relates to the pre-control baseline NO_X emission rate which reflects the modest amount of cyclone air-staging that is believed can be sustained when firing lignite at full unit output capacity, and the additional amount of control potential available from operating with relocated lignite drying system vent ports and FGR ports associated with ASOFA.

The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated overfire air and Rich Reagent

Injection or coal reburn alternatives are expected to limit the amount of NO_X control potential possible from successful practice of the technique or technology.

A ranking of available NO_X emission control options considered feasible for Leland Olds Station Unit 2 boiler are listed in Table 2.3-3 and Table 2.3-4. Ranking of the alternatives in Table 2.3-4 assumes that the pre-retrofit level of NO_X emissions for the Leland Olds Station Unit 2 boiler is associated with the equivalent average unit emission rate of 0.67 lb/mmBtu. This baseline is based on the historic highest twenty-four consecutive months' summation between years 2000 and 2004, with a corresponding average heat input rate of 4,478 mmBtu/hr for 8,050 hours per year. The annual post-control estimated NO_X emissions are based on the stated percent reduction applied to the pre-control unit baseline emission rate (0.67 lb/mmBtu) and fuel heat input rate of 5,130 mmBtu/hr (boiler design capacity rating) for 8,760 hrs/yr operation for the future PTE scenario.

TABLE 2.3-3 – Historic Baseline and Estimated Control Options' NO_X Emission Rates Evaluated for Future PTE Scenario, LOS Unit 2 Boiler

Alt. No.(1)	NO_X Control Technique	LOS Unit 2 Emission Rate (lb/mmBtu)	Control Percentage(1)	LOS Unit 2 Hourly Emission(1) (lb/hr)	LOS Unit 2 Annual Emission(1) (tons/yr)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	0.265	60.3	1,359	5,895
C	SNCR (using urea) w/ ASOFA	0.304	54.5	1,557	6,762
B	Coal Reburn (conventional, pulverized) w/ ASOFA	0.32	51.8	1,649	7,115
A	Advanced Separated Overfire Air (ASOFA)	0.48	28	2,465	10,796
--	Baseline, based on annual operation at historic highest 24-month average pre-control NO_X emission rate	0.67	--	2,987	12,023

1 - Alternative designation assigned from highest to lowest unit NO_X emission rate. Emissions are calculated from unit emission rates, control percentage, hourly heat input rate of 4,478 mmBtu/hr, and 8,050 annual hrs/yr operation compared to pre-control baseline.

Table 2.3-4 shows NO_X emissions for a different pre-control baseline. The annual post-control maximum NO_X emissions are based on the stated percent reduction applied to the LOS Unit 2 boiler pre-control unit emission rate (0.67 lb/mmBtu) and 5,130 mmBtu/hr for 8,760 hrs/yr operation for the future PTE case.

TABLE 2.3-4 – Pre-Control Baseline and Estimated Control Options' NO_X Emission Rates Evaluated for Future PTE Scenario LOS Unit 2 Boiler

Alt. No.(1)	NO_X Control Technique	LOS Unit 2 Emission Rate (lb/mmBtu)	Control Percentage(1)	LOS Unit 2 Hourly Emission(1) (lb/hr)	LOS Unit 2 Annual Emission(1) (tons/yr)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	0.265	60.3	1,359	5,895
C	SNCR (using urea) w/ ASOFA	0.304	54.5	1,557	6,762
B	Coal Reburn (conventional, pulverized) w/ ASOFA	0.32	51.8	1,649	7,115
A	Advanced Separated Overfire Air (ASOFA)	0.48	28	2,465	10,796
--	Baseline, based on annual operation at future PTE scenario pre-control emission rate	0.67	--	3,422	14,989

1 - Alternative designation assigned from highest to lowest unit NO_X emission rate. Emissions are calculated from unit emission rates, control percentage, hourly heat input of 5,130 mmBtu/hr, and 8,760 annual hrs/yr operation compared to pre-control baseline.

Combinations of individual technologies for most alternatives in Tables 2.3-3 and 2.3-4 apply "advanced" SOFA, which is expected to have significantly lower NO_X emissions than a typical SOFA system as applied to the LOS Unit 2 cyclone boiler. The distinction that "advanced" separated overfire air has drastically different expected NO_X emissions than a typical SOFA system affects the NO_X emissions predicted from application of the highest performing form of overfire air combined with other various combustion-related and post-combustion techniques and technologies. These figures indicate the expected additional NO_X emission reduction potential from installation of various forms of SNCR, or coal reburn, in combination with existing cyclones and advanced separated overfire air systems for modest levels of "starved air" substoichiometric cyclone combustion.

2.4 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS – LOS UNIT 1

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the remaining control technologies from consideration for LOS Unit 1.

2.4.1 COST IMPACTS OF NO_X CONTROLS – LOS UNIT 1

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on LOS Unit 1 boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation a particular control technology. The results of this evaluation are summarized in Tables 2.4-1 through 2.4-6.

2.4.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 1

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor range and single point unit capital cost factor for the feasible NO_X emission reduction technologies evaluated for LOS Unit 1 is presented in Table 2.4-1.

TABLE 2.4-1 – Unit Capital Cost Factors of NO_X Control Options for LOS Unit 1

NO_X Control Technique	Range ($/kW)(1),(2)	Single Point Unit Capital Cost Factor(2), ($/kW) LOS Unit 1
SNCR (using urea) w/ boosted SOFA (Rotamix)	27-45(3),(4)	43.3(5)
SNCR (using urea) w/ basic SOFA	15-30(4)	28.9(5),(6)
SNCR (using urea) w/ CCOFA	10-20(4)	22.6(5)
Coal Reburn (conventional, pulverized) w/ boosted SOFA	42-75(3)	178.8(3),(7)
Coal Reburn (conventional, pulverized) w/ basic SOFA	30-60(3)	164.4(6),(7)
Boosted Separated Overfire Air (ROFA)	17-25(3)	20.7(4)
Separated Overfire Air (SOFA, basic)	5-10(4)	6.3(6)

(1) – Range based on published values or vendor proposals. Single point cost factor is a reasonable estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on MCR rating. In several cases, additional capital costs will be incurred that were not included in the published unit cost factors.
(2) – Unit capital cost factors of these individual technologies combined by simple addition. Actual costs may differ this due to positive or negative synergistic effects.
(3) – ROFA capital cost range from the 2005 WRAP Draft Report[44], posted at their website. See Appendix A for reference details
(4) – SNCR capital cost range from NESCAUM 2005 Technical Paper[43], posted at their website. See Appendix A for reference details.
(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech.
(6) – Burns & McDonnell internal database was used for the point capital cost estimates of basic SOFA.
(7) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper[43]; the single point cost estimate is based on the same factor assumed for cyclone boilers included in the 2005 WRAP Draft Report[44], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 72.9 $/kW. See Appendix A for reference details.

Annualized capital cost, which includes the time value of capital monies and its recovery, is determined from the estimated capital cost and the methodology described in Section 1. Table 2.4-2 shows the estimated installed capital cost and annualized capital cost values for the NO_X emission reduction technologies evaluated for LOS Unit 1. These were developed from multiplying the unit capital cost single point factor for the control option by the nameplate output capacity rating of the respective unit.

TABLE 2.4-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Options - LOS Unit 1

NO_X Control Alternative	Installed Capital Cost(1) ($1,000)	Annualized Capital Cost(2) ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	9,342	814
SNCR (using urea) w/ basic SOFA	6,234	544
SNCR (using urea) w/ CCOFA	4,871	425
Coal Reburn (conventional, pulverized) w/ boosted SOFA	38,617(3)	3,367(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	35,509	3,096
Boosted Separated Overfire Air (ROFA)	4,471	390
Separated Overfire Air (SOFA, basic)	1,363	119

(1) – Installed capital cost is estimated for determination of total capital cost for a control technology, based on nameplate unit output capacity rating of 216,000 kW. Installed capital cost figures in 2005 dollars.
(2) – Annualized capital cost = Installed capital cost x 0.08718 capital recovery factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $15,740,000 for installed capital cost, and $1,372,000/yr annualized capital cost.

2.4.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 1

The operation and maintenance costs to implement the NO_X control technologies evaluated for LOS Unit 1 were largely estimated from cost factors established in the EPA's Air Pollution Control Cost Manual (OAQPS), and from engineering judgment applied to that control technology. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.

- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.4-3 and Table 2.4-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the NO_X control options evaluated for LOS Unit 1. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors. The annual operating and maintenance costs of the control options in Table 2.4-3 is based on LOS Unit 1 operation with the control options at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit pre-control baseline operation at 0.285 lb/mmBtu for the highest 24-month NOx emission summation at 2,443 mmBtu/hr heat input for 8,510 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

TABLE 2.4-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

NO_X Control Alternative	Annual O&M Cost(1) ($1,000)	Levelized Annual O&M Cost(2) ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,157	2,574
SNCR (using urea) w/ basic SOFA	1,702	2,030
SNCR (using urea) w/ CCOFA	1,195	1,426
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072(3)	3,665(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420(3)	2,887(3)
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

The annual operating and maintenance costs of the control options in Table 2.4-4 are based on LOS Unit 1 operation with the control option at 2,622 mmBtu/hr heat input and 8,760 hrs/yr operation. These O&M costs are relative to unit baseline operation at 0.29 lb/mmBtu for the highest 24-month

NO_X emission summation at 2,622 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 1 with existing close-coupled overfire air and low-NO_X burners.

TABLE 2.4-4 – Estimated O&M Costs for NO_X Control Options (Relative to Presumptive BART Annual Emission Baseline – Future PTE Case) LOS Unit 1

NO_X Control Alternative	Annual O&M Cost(1) ($1,000)	Levelized Annual O&M Cost(2) ($1,000)
SNCR (using urea) w/ boosted SOFA (Rotamix)	2,157	2,574
SNCR (using urea) w/ basic SOFA	1,701	2,030
SNCR (using urea) w/ CCOFA	1,197	1,428
Coal Reburn (conventional, pulverized) w/ boosted SOFA	3,072(3)	3,665(3)
Coal Reburn (conventional, pulverized) w/ basic SOFA	2,420(3)	2,887(3)
Boosted Separated Overfire Air (ROFA)	626	747
Separated Overfire Air (SOFA, basic)	21	25
Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Annual O&M cost figures in 2005 dollars.
(2) – Levelized annual O&M cost = Annual O&M cost x 1.19314 O&M cost factor.
(3) – Costs for increased PM collection capacity included in coal reburn option are $901,000 for annual O&M cost, and $1,074,000/yr levelized annual O&M cost.

2.4.1.3 COST EFFECTIVENESS FOR NO_X CONTROLS – LOS UNIT 1

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART determination process, the basic methodology defined in the BART Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of each alternative, was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 for cost methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. There are two different NO_X emission baselines; the first assumes the highest historic 24-month average NO_X emission rate expressed in tons per year. The second baseline derives tons per year from the maximum future PTE case average NO_X emission rate. This approach results in two different average cost effectiveness values for the control options evaluated for LOS Unit 1. The annual NO_X emission reduction is the difference between the pre-control baseline and post-control emissions in tons per year. Average control cost for a particular technology is LTAC divided by annual tons of expected emission reduction. A summary of the annual emissions, reductions, control and levelized annual costs for the two LOS Unit 1 baselines are presented in Table 2.4-5 and 2.4-6.

TABLE 2.4-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
G	Coal Reburn with boosted SOFA (future PTE case)	1,666	1,301	7,032(5)	5,404(5)
F	Coal Reburn with basic SOFA (future PTE case)	1,746	1,221	5,983(5)	4,898(5)
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,782	1,185	3,388	2,860
D	SNCR with basic SOFA (future PTE case)	1,883	1,084	2,574	2,373
C	SNCR with Close-Coupled OFA (future PTE case)	2,450	517	1,851	3,582
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,483	484	1,137	2,347
A	Separated Overfire Air (SOFA, basic)	2,642	325	144	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	2,967	0	0	

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – NO_X emissions and control level reductions relative to the highest historic 24-month average pre-control annual baseline for LOS Unit 1.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,762/ton with boosted SOFA and $1,870/ton with basic SOFA.

TABLE 2.4-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Presumptive BART Annual Emission Baseline – Future PTE Case) LOS Unit 1

Alt. No.(1)	NO_X Control Alternative	Annual NO_X Emissions(2) Tons/yr	Annual NO_X Emissions Reduction(2) Tons/yr	Levelized Total Annual Cost(3),(4) $1,000	Average Control Cost(4) $/ton
G	Coal Reburn with boosted SOFA (future PTE case)	1,693	1,638	7,032(5)	4,293(5)
F	Coal Reburn with basic SOFA (future PTE case)	1,774	1,557	5,983(5)	3,844(5)
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	1,811	1,519	3,388	2,230
D	SNCR with basic SOFA (future PTE case)	1,913	1,417	2,574	1,816
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	2,469	862	1,137	1,298
B	SNCR with Close-Coupled OFA (future PTE case)	2,490	841	1,853	2,204
A	Separated Overfire Air (SOFA, basic)	2,641	689	144	208
	Baseline, based on annual operation at future PTE scenario pre-control emission rate	3,330	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

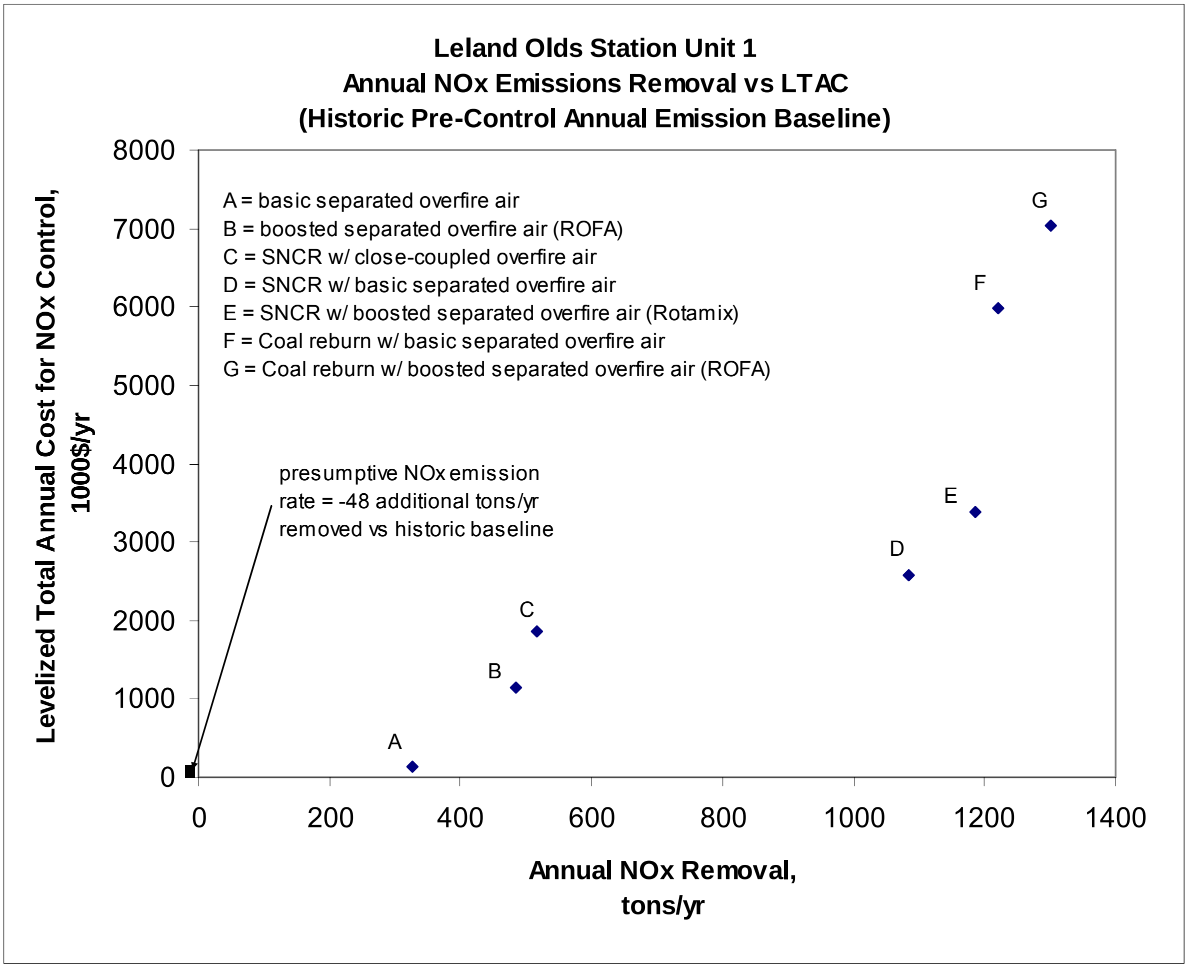
(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE scenario applied to LOS Unit 1.

(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #2 for Tables 2.4-2 and 2.4-4 for annualized cost factors.

(4) – Annualized cost figures in 2005 dollars.

(5) – LTAC for increased PM collection capacity included in coal reburn option are $1,372,000 for annualized capital cost plus $1,074,000 for annualized O&M cost, for a total of $2,446,000/yr. This results in an average control cost of $1,493/ton with boosted SOFA and $1,571/ton with basic SOFA.

Figure 2.4-1 – NO_X Control Cost Effectiveness – LOS Unit 1 (Historic Pre-Control Annual Emission Baseline)(1)



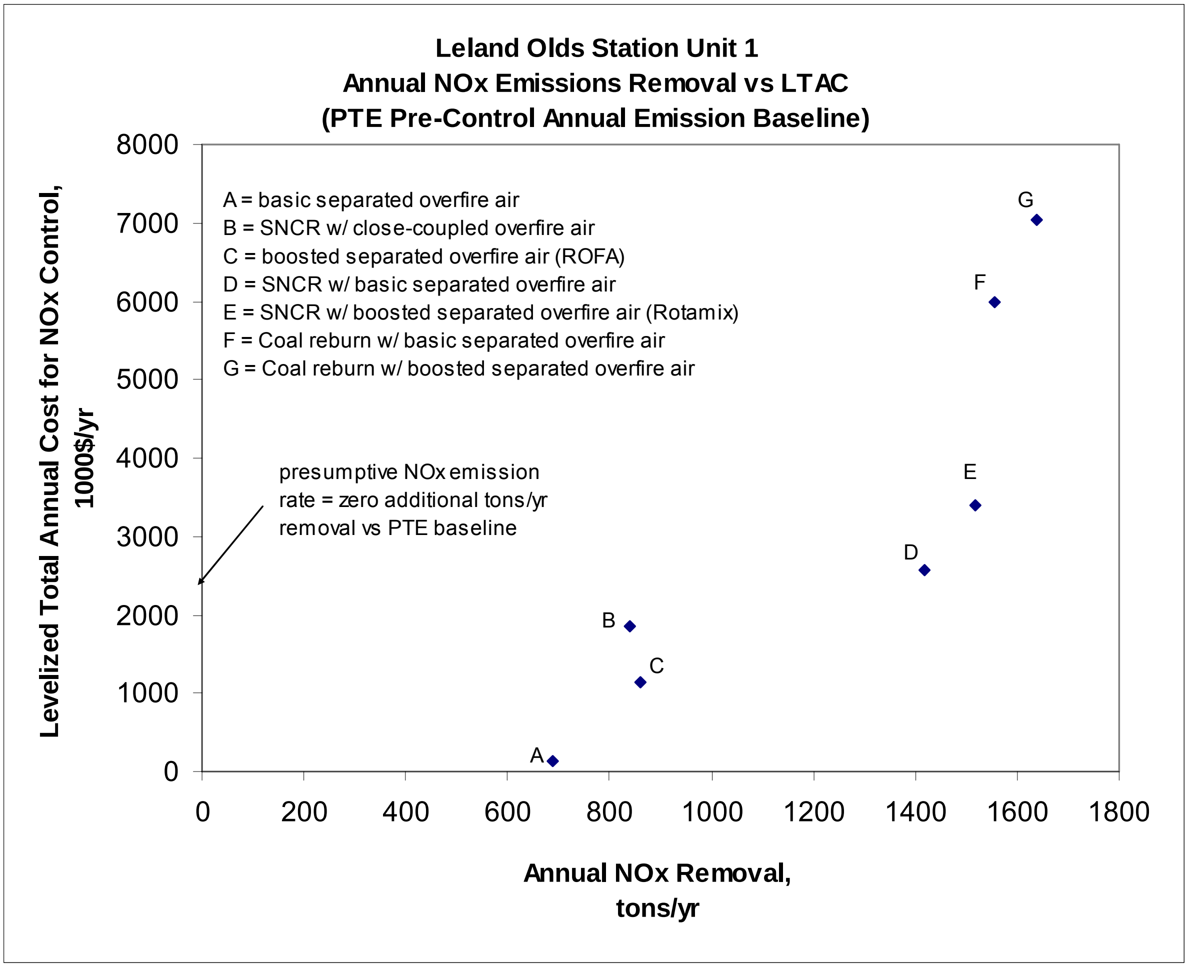
(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 1 relative to two different NO_X emission baselines was made and is shown in Figures 2.4-1 and 2.4-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.4-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 1 under the future PTE case.

Figure 2.4-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit ` under the future PTE case.

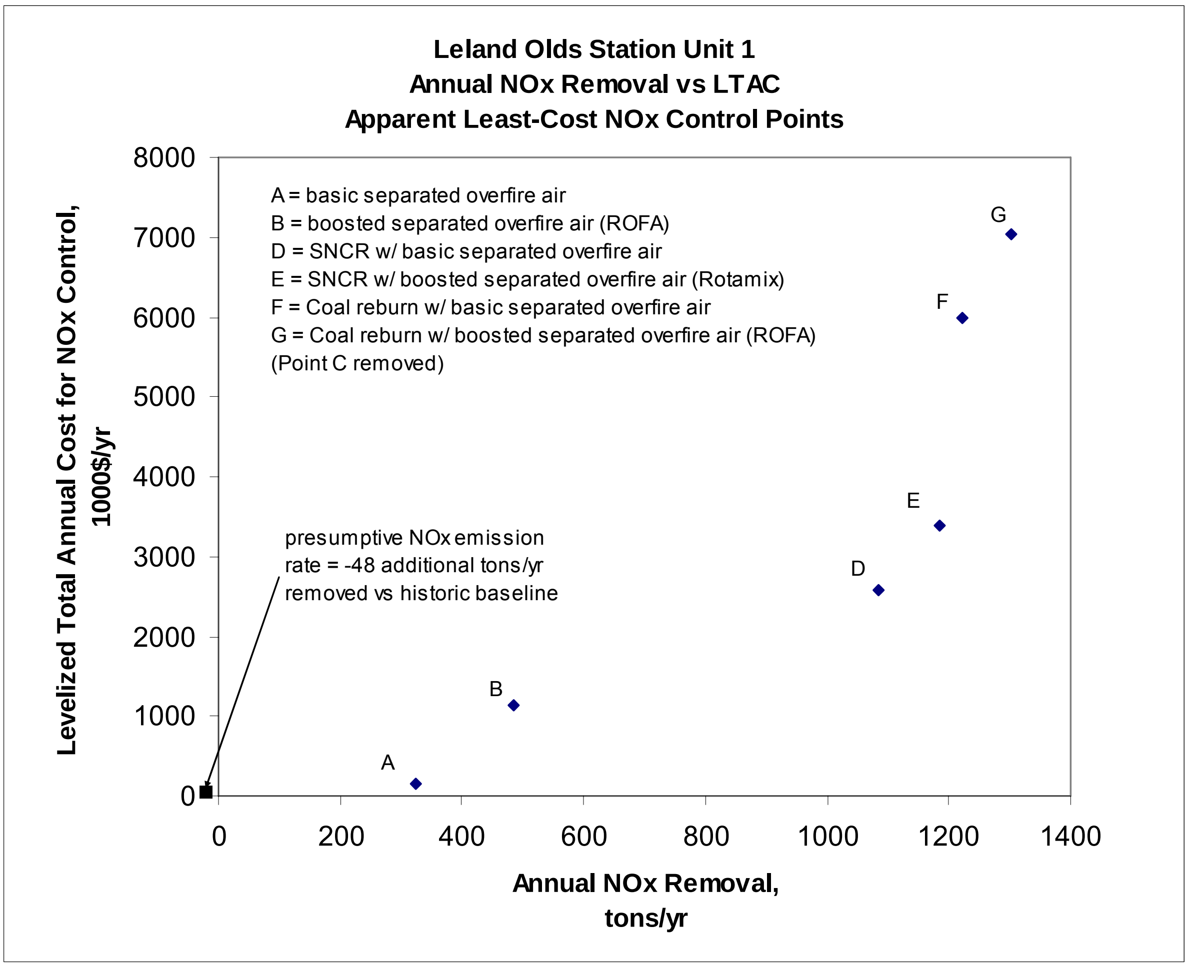
Figure 2.4-2 – NO_X Control Cost Effectiveness – LOS Unit 1 (PTE Pre-Control Annual Emission Baseline – Future PTE Case)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

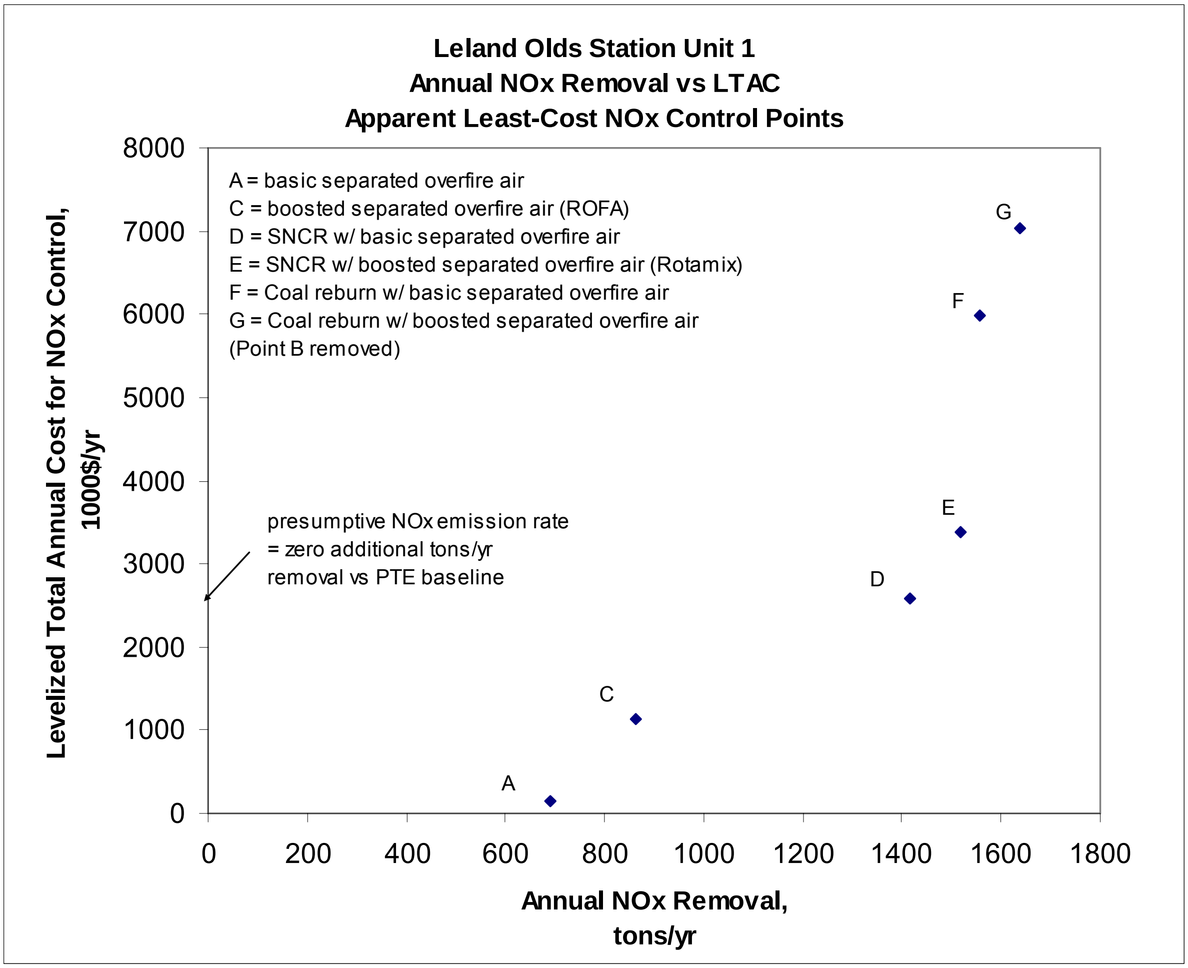
The purpose of Figures 2.4-1 and 2.4-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 1 NO_X control alternatives evaluated for cost-effectiveness, the data point for SNCR with close-coupled OFA is seen to be more costly for fewer tons of NO_X removed than for boosted separated overfire air (ROFA). SNCR with CCOFA appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis. Figures 2.4-3 and 2.4-4 show the revised least-cost control points without SNCR with CCOFA.

Figure 2.4-3 – NO_X Control Cost Effectiveness – LOS Unit 1
Apparent Least-Cost NOx Control Points
(Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-5.

Figure 2.4-4 – NO_X Control Cost Effectiveness – LOS Unit 1
Apparent Least-Cost NOx Control Points
(PTE Pre-Control Annual Emission Baseline – Future PTE Case)[(1)]



1 - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-6.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.4-5 and Figure 2.4-6 contain a repetition of the levelized total annual cost and NO_X control information from Figure 2.4-3 and Figure 2.4-4 with SNCR with CCOFA removed (Point C in Figure 2.4-1, and Point B in Figure 2.4-2), and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point.

TABLE 2.4-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1

Alt. No.(1)	**NO_X Control Technique**	**Levelized Total Annual Cost(2),(3) ($1,000)**	**Annual Emission Reduction(4) (Tons/yr)**	**Incremental Levelized Total Annual Cost(3),(5) ($1,000)**	**Incremental Annual Emission Reduction(4),(5) (Tons/yr)**	**Incremental Control Cost Effectiveness ($/ton)(3),(6)**
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	1,049	80	13,130
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,221	2,594	37	70,697
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,185	815	100	8,124
D	SNCR with basic SOFA (future PTE case)	2,574	1,084	1,437	600	2,394
B	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	484	993	159	6,249
A	Separated Overfire Air (SOFA, basic)	144	325	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

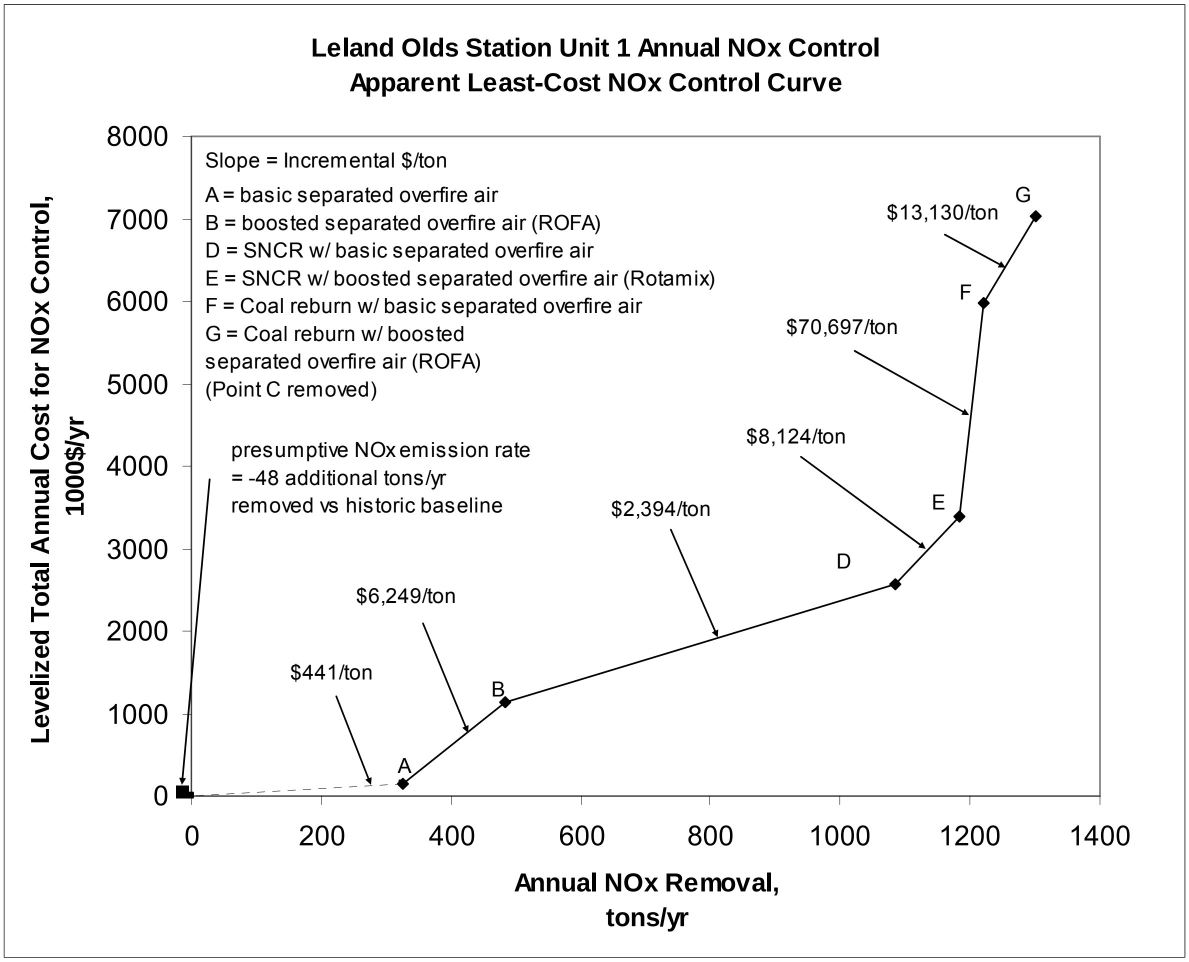
(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn options.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 1

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[2],[3] ($1,000)	Annual Emission Reduction[4] (Tons/yr)	Incremental Levelized Total Annual Cost[3],[5] ($1,000)	Incremental Annual Emission Reduction[4],[5] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3],[6]
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	1,049	81	12,921
F	Coal Reburn with basic SOFA (future PTE case)	5,983	1,557	2,594	37	69,573
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,519	815	102	7,994
D	SNCR with basic SOFA (future PTE case)	2,574	1,417	1,437	556	2,586
C	Boosted Separated Overfire Air (ROFA), (future PTE case)	1,137	862	993	172	5,763
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

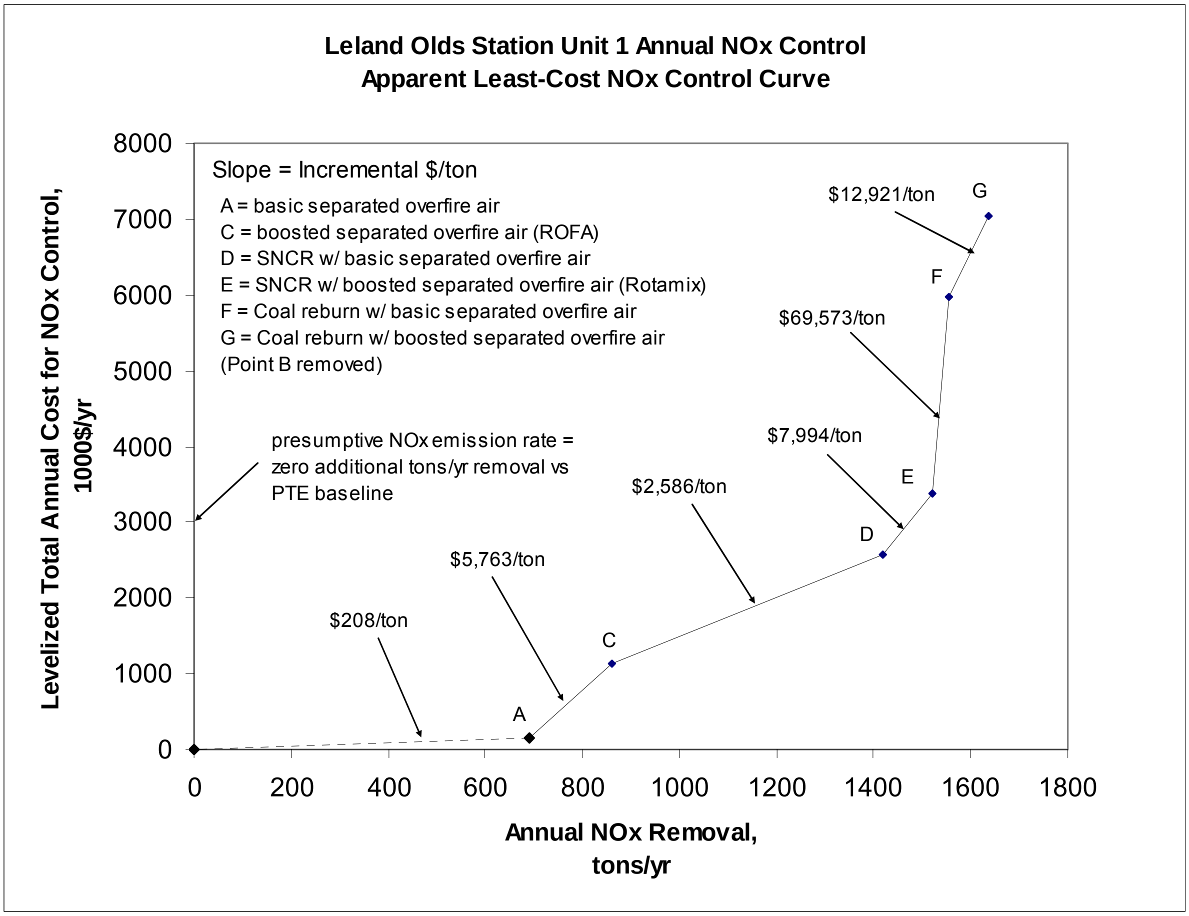
(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn options.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

Figure 2.4-5 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (Historic Pre-Control Annual Emission Baseline)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-7.

Figure 2.4-6 – NO_X Control Cost Effectiveness – LOS Unit 1 Apparent Least-Cost Controls Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)[(1)]

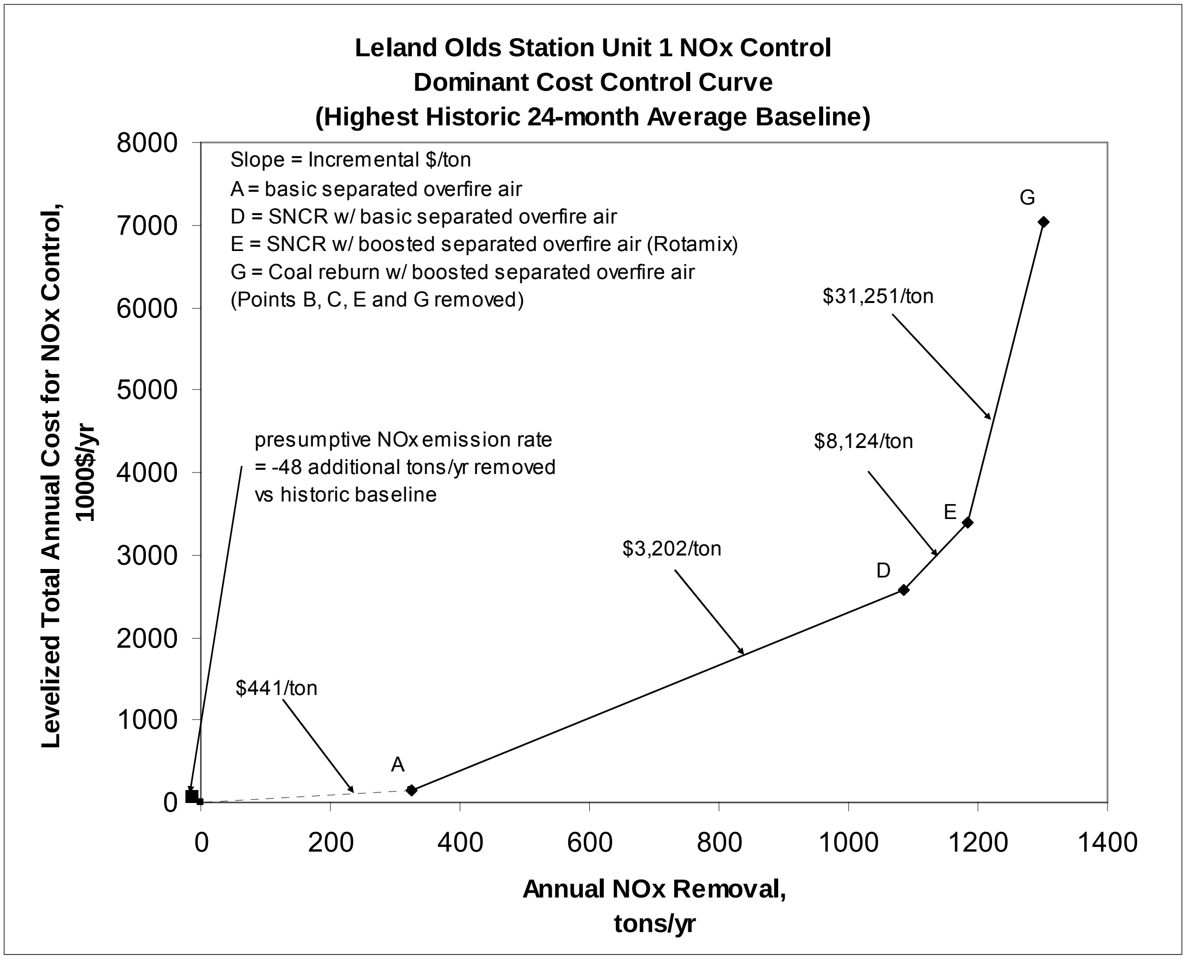


(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-8.

In the comparison displayed in Figure 2.4-5 and Figure 2.4-6, for the data shown in Table 2.4-7 and Table 2.4-8, the boosted SOFA (ROFA) NO_X control alternative (Point B in Figure 2.4-5, Point C in Figure 2.4-6) had a significantly higher incremental unit NO_X control cost (slope, $6,249/ton and $5,763/ton, respectively) compared against basic SOFA alternative (Point A) versus SNCR with basic SOFA (Points D) compared against ROFA. Also, Coal Reburn with basic SOFA (Points F) was significantly more incrementally expensive ($70,697/ton and $69,573/ton) compared against SNCR with boosted SOFA (Points E) versus Coal Reburn with boosted SOFA (Points G) compared against Coal Reburn with basic SOFA alternatives (Point F) ($13,130/ton and $12,921/ton). This indicates that Points C and Points F are inferior controls and do not occupy the Dominant Cost Control Curves.

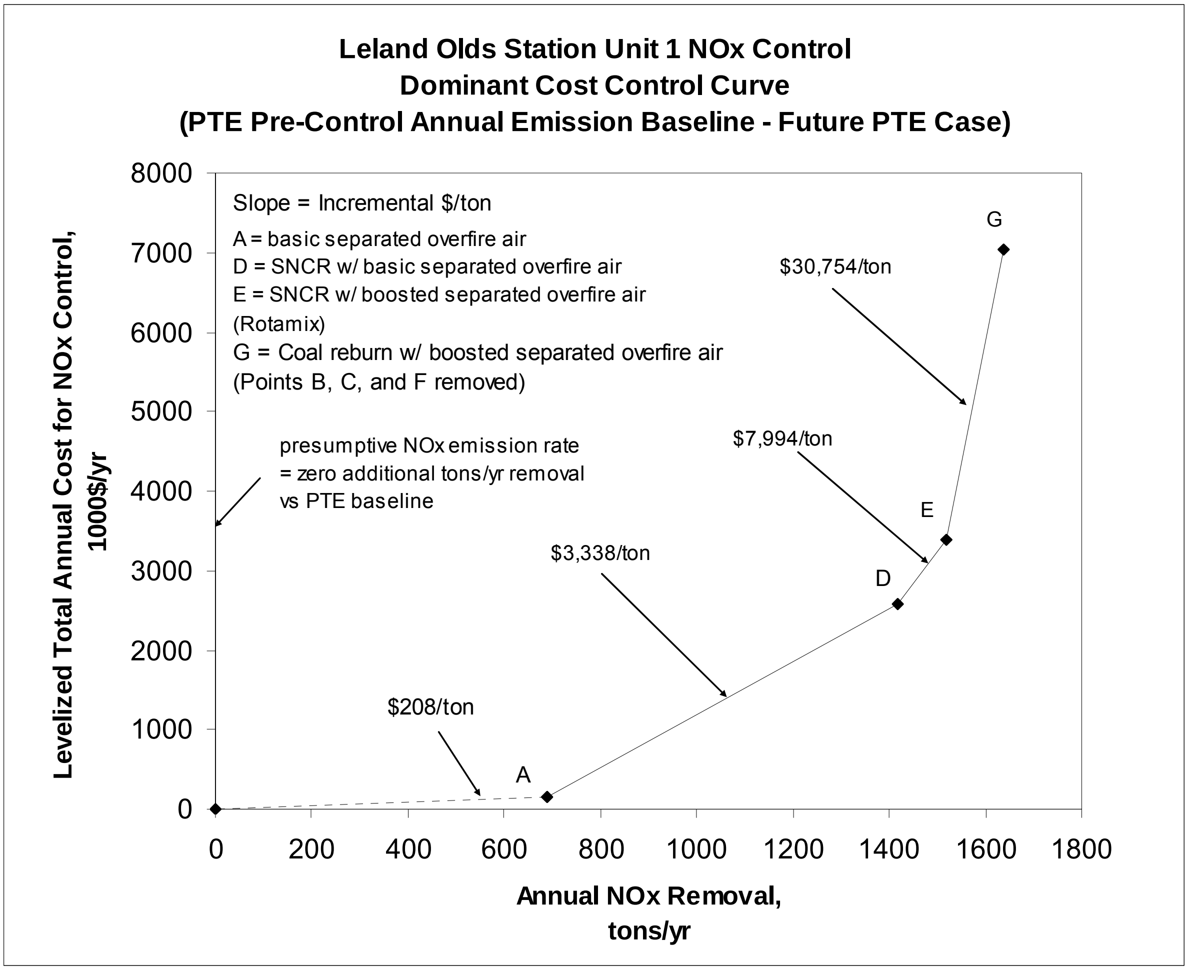
After removal of Points C and F, the modified least-cost controls curve is the Dominant Cost Control Curve for NO_X emissions alternatives for each of the LOS Unit 1 pre-control baselines evaluated.

Figure 2.4-7 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-9.

Figure 2.4-8 – NO_X Control Cost Effectiveness – LOS Unit 1 Dominant Cost Control Curve(1) (PTE Pre-Control Annual Emission Baseline – Future PTE Case)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.4-10.

TABLE 2.4-9 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 1 NO_X Control

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[(2),(3)] ($1,000)	Annual Emission Reduction[(4)] (Tons/yr)	Incremental Levelized Total Annual Cost[(3),(5)] ($1,000)	Incremental Annual Emission Reduction[(4),(5)] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[(3),(6)]
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,301	3,643	117	31,251
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,185	815	100	8,124
D	SNCR with basic SOFA (future PTE case)	2,574	1,084	2,430	759	3,202
A	Separated Overfire Air (SOFA, basic)	144	235	144	325	441
--	Baseline, based on annual operation at highest historic 24-mo average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest annual NO_X emissions.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

TABLE 2.4-10 – Estimated Incremental Annual Emissions and LTAC for Dominant Cost Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 1 NO_X Control

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
G	Coal Reburn with boosted SOFA (future PTE case)	7,032	1,638	3,643	118	30,754
E	SNCR with boosted SOFA (Rotamix) (future PTE case)	3,388	1,519	815	102	7,994
D	SNCR with basic SOFA (future PTE case)	2,574	1,417	2,430	728	3,338
A	Separated Overfire Air (SOFA, basic)	144	689	144	689	208
--	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.4-2 and 2.4-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 1.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

The cost impact analysis for historic and PTE baseline conditions identifies those control alternatives that are on the Dominant Controls Cost Curve. Those alternatives are scrutinized for cost-effectiveness on both relative and absolute bases. In the comparison displayed in Figure 2.4-7 and Figure 2.4-8, for the data shown in Table 2.5-9 and Table 2.5-10, the SNCR with basic SOFA NO_X control alternative (Points D) had a significantly higher incremental unit NO_X control cost (slope, $3,202/ton and $3,338/ton, respectively, for historic and PTE baseline conditions) compared against basic SOFA alternative (Point A) versus baseline ($441/ton and $208/ton, respectively). The incremental cost-effectiveness of the least-cost SNCR alternative on the Dominant Cost Control Curve is on the order of seven to sixteen times the magnitude of basic SOFA. SNCR with boosted SOFA (Point E) had a significantly higher incremental unit NO_X control cost compared against the

SNCR with basic SOFA alternative (Point D) ($8,124/ton and $7,994/ton, vs $3,202/ton and $3,338/ton respectively). Coal Reburn with boosted SOFA was even more incrementally costly. In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.4-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $441/ton to $5,404/ton. Table 2.4-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $208/ton to $4,293/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

Various combinations of NO_X control technologies evaluated for control and cost-effectiveness are considered to be technically feasible for LOS Unit 1, but have much higher installation and operating costs compared with basic SOFA alone. This confirms the analysis performed by the EPA for establishing the presumptive limits for BART NO_X emissions from pulverized coal-fired EGUs: that the application of current combustion control technology, [primarily low-NOx burners and overfire air] is generally, but not always, more cost-effective than post-combustion controls. Based on the cost impact analysis and the premise that LOS Unit 1's historic and PTE annual average baseline emissions already meet the presumptive BART NO_X level of 0.29 lb/mmBtu, only the least-cost alternative of basic separated overfire air was considered for further impact and visibility impairment evaluations for LOS Unit 1 NO_X emissions control.

The other elements of the fourth step of a BART analysis after the cost impact analysis include evaluating the following impacts:

- Energy impacts.
- Non-air quality environmental impacts.
- Remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the levelized annual cost impact estimates. The other impacts for the single LOS Unit 1 NO_X emissions control alternative chosen to be evaluated further are discussed in Section 2.4.2 and Section 2.4.3. Visibility impairment impacts for the single LOS Unit 1 NO_X emissions control are summarized in Section 2.4.4.

2.4.2 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 1

The single feasible NO_X control alternative was reviewed for significant or unusual energy penalties or benefits associated with its use. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

Separated overfire air was the only NOX control technology evaluated further for LOS Unit 1. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. To provide effective volumes and velocities of separated overfire air at the injection ports may require slightly higher forced draft fan power consumption resulting from higher fan discharge pressure. Combustion air damper actuators' electrical power demand would be an insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 1. Higher windbox pressure and ductwork pressure drop impacts of the SOFA system on the forced draft fans' and induced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Operation of a SOFA system may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged burner operation with SOFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion of the steel waterwall tubes by sulfur compounds in the furnace gases being created above the burners and below the SOFA injection ports. Due to the moderate sulfur content in the lignite and modest amount of air-staging during firing of the existing low-NO_X burners expected during SOFA operation, this potential change in corrosion rate of the boiler tubes is expected to be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

Table 2.4-11 summarizes the gross demand and usage of auxiliary electrical power estimated for the single NO_X control alternative evaluated for LOS Unit 1. This assumes annual operation for 8,760 hours at a heat input rate of 2,622 mmBtu/hr at the future PTE case conditions.

TABLE 2.4-11 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 1

Alt. No.	NO_X Control Technique	NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage		
		Aux. Power Demand (1) (kW)	Generation Reduction from Aux. Power Demand(2) (kW-hrs/yr)	Generation Reduction from Reduced Unit Availability(3) (kW-hrs/yr)
A	Separated OFA	1	8,760	0

(1) – The NO_X control equipment gross auxiliary electrical power demand is estimated.
(2) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(3) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

2.4.3 NON AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 1

Nitrogen oxides react with oxygen in the atmosphere to produce elemental nitrogen and ozone (O_3). This is one of the common causes of visible pollution in the atmosphere referred to as “smog”. Operation of the various NO_X control technologies considered for potential application at the Leland Olds Station impose direct and indirect impacts on the environment. The most pronounced environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility. This is discussed in detail in the Visibility Impacts section.

2.4.3.1 ENVIRONMENTAL IMPACTS OF SOFA

The amount of unburned carbon in the flyash produced by the boiler, collected for disposal or potentially emitted to the atmosphere, may increase by small increments due to operation of LOS Unit 1 using separated overfire air for NO_X emissions control. The potential changes in the annual amounts of flyash emissions and disposal rates are expected to be inconsequential, and have not been quantified.

The operation of a system using a basic form of separated overfire air for NO_X emissions control may increase carbon monoxide concentrations in the stack flue gas emitted from the LOS Unit 1 boiler.

This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

There were no other adverse or significant changes in non-air quality or other environmental impacts identified for LOS Unit 1 as a result of using separated overfire air for NO_X emissions control. Predicted visibility impacts are discussed in the next section.

2.4.4 VISIBILITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 1

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source.

For this BART analysis, there were two baseline NO_X emission rates modeled for LOS Unit 1 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the presumptive BART NO_X emission rate. The historic pre-control emission baseline was the 24-hour average actual NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH BART protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period.

The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 1 under the conditions stated above was 813 lb/hr. Visibility impact modeling was performed using the CALPUFF model with the difference between the impacts from historic pre-control baseline and post-control average hourly NO_X emission rates representing the visibility impairment impact reduction. Three CALPUFF model runs were conducted with the same presumptive BART NO_X emission baseline rate, constant PM emissions, and various levels of SO_2 control assuming the Potential-To-Emit (PTE) boiler design rating for heat input (2,622 mmBtu/hr). The presumptive BART unit NO_X emission baseline rate of 0.29 lb/mmBtu multiplied by the boiler PTE heat input rating of 2,622 mmBtu/hr yields 760 lb/hr for LOS Unit 1 under the future PTE case. The model used an average unit NO_X emission rate of 0.23 lb/mmBtu with the PTE boiler heat input rating to yield 603 lb/hr. This was the post-control hourly NO_X emission rate representing basic SOFA applied to the future PTE case for LOS Unit 1.

In keeping with the NDDH BART visibility impairment impact modeling protocol, the BART NO_X presumptive emission rate (760 lb/hr) and SOFA alternative both have a different boiler heat input basis than the historic highest 24-hour pre-control NO_X emission baseline (813 lb/hr). The post-control conditions both assume operation at the boiler PTE capacity rating (future PTE case).

The results of the historic pre-control baseline presumptive BART NO_X PTE baseline emission rate, and post-control SOFA-enhanced PTE NO_X emission rate, modeled with the PTE 90% sulfur emission control rate for LOS Unit 1 are shown in Table 2.4-12. The results of the visibility impairment modeling at the pre-control (protocol) baseline emission rate for LOS Unit 1 showed that Lostwood National Wildlife Refuge exceeded 0.5 deciView for the highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Average predicted visibility impairment impacts decreased significantly for the presumptive BART NO_X PTE baseline emission rate, and slightly more with post-control SOFA-enhanced PTE NO_X emission rates, modeled with any of the three PTE sulfur emission control rates for LOS Unit 1. The comparison of the incremental average visibility impairment impacts that are predicted for the three PTE sulfur emission control rates for LOS Unit 1 is shown in Section 3.4.4.

TABLE 2.4-12 – Average Visibility Impairment Impacts from NO_X Controls – LOS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1]		
	Historic Pre-Control (Protocol) Baseline (dV)	**Presumptive BART NO_X PTE Baseline[2] (dV)**	**PTE Emissions with SOFA NO_X Control[2] (dV)**
TRNP-South Unit	0.423	0.107	0.099
TRNP-North Unit	0.450	0.118	0.111
TRNP-Elkhorn Ranch	0.287	0.080	0.073
Lostwood NWR	0.639	0.171	0.153

(1) - Average predicted visibility impairment impacts (90th percentile) relative to background for years 2000-2002. Pre-control baseline impacts are from highest historic 24-hour NO_X, SO_2, and PM emission rates (NDDH BART protocol). Presumptive BART NO_X and SOFA NO_X impacts are from PTE heat input emission rates. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

The results of the visibility impairment modeling at the presumptive BART NO_X PTE emission rate (760 lb/hr) with the PTE 90% sulfur emission control rate for LOS Unit 1 again showed that Lostwood National Wildlife Refuge had the highest predicted improvement in visibility impairment compared to the pre-control (protocol) baseline levels. Average predicted visibility impairment reduction also increased with SOFA-enhanced post-control NO_X PTE emission rate from LOS Unit 1 for Lostwood NWR (approximately 0.5 deciView reduction). This is shown in Table 2.4-13.

TABLE 2.4-13 – Average Visibility Impairment Impact Reductions from NO_X Controls – LOS Unit 1 (Post-Control PTE Emissions vs Historic Baseline)

Federal Class 1 Area	Visibility Impairment Reductions[(1)]	
	Presumptive BART NO_X PTE Baseline[(2)] (dV)	PTE Emissions, SOFA NO_X Control[(2)] (dV)
TRNP-South Unit	0.316	0.323
TRNP-North Unit	0.332	0.339
TRNP-Elkhorn Ranch	0.207	0.214
Lostwood NWR	0.467	0.486

(1) - Average predicted visibility impairment impact reductions (90th percentile) relative to historic pre-control emission rates (NDDH BART protocol) for years 2000-2002. Presumptive BART NO_X and SOFA NO_X impacts are from PTE heat input emission rates.
(2) - SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case scenario.

This analysis includes a determination of the incremental control effectiveness of reducing the predicted visibility impairment impact for presumptive BART NO_X and SOFA alternatives' PTE emission levels evaluated for the future PTE case operation of LOS Unit 1. The average predicted visibility impairment reduction resulting from LOS Unit 1 NO_X PTE emissions expected to result from separated overfire air (SOFA) emissions versus presumptive BART NO_X levels for the future PTE case are shown in Table 2.4-14.

TABLE 2.4-14 –Visibility Impairment Reduction from NO_X Controls (vs Presumptive BART NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction(1) PTE Emissions, SOFA NO_X Control(2) (dV)
TRNP-South Unit	0.00733
TRNP-North Unit	0.00733
TRNP-Elkhorn Ranch	0.00733
Lostwood NWR	0.0183

(1) - Incremental average predicted visibility impairment impact reductions (90th percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002. SOFA NO_X impacts are from PTE heat input emission rates.
(2) - SO_2 emissions reduced by 90% over pre-control PTE heat input baseline for the future PTE case.

Table 2.4-14 shows that incremental visibility impairment improvements predicted to result from applying the SOFA alternative to the presumptive BART NO_X PTE emission rate for LOS Unit 1 are very small. The amount of visibility impairment predicted for natural background conditions is much greater in magnitude than the amount predicted from LOS Unit 1's contribution alone. The data also shows that reductions in predicted visibility impairment impacts that result from a combination of presumptive BART NO_X PTE emissions and SO_2 PTE emissions at the 90 percent (or better) control levels compared to the pre-control (protocol) emission conditions are much greater in significance than the incremental improvements of predicted visibility impairment from additional reductions in NO_X emissions.

This analysis also includes a determination of the incremental cost-effectiveness of reducing predicted visibility impairment impact for the SOFA alternative evaluated for LOS Unit 1. The estimated LTAC for reducing NO_X emissions from LOS Unit 1 expected to result from separated overfire air (SOFA) for the future PTE case are shown in Table 2.4-6. The comparison in Table 2.4-15 shows that the ratio of the estimated additional annualized costs of installing and operating SOFA with the future PTE case to the average predicted visibility impairment improvement relative to the presumptive BART NO_X PTE baseline emission rate for the future PTE case applied to LOS Unit 1 would result in millions of dollars per deciView of visibility impairment improvement.

TABLE 2.4-15 – Cost Effectiveness of Visibility Impairment Reduction from NO_X Controls (vs Presumptive NO_X Baseline Emissions) – LOS Unit 1

Federal Class 1 Area	Incremental Visibility Impairment Reduction Unit Cost PTE Emissions, SOFA NO_X Control(1),(2) ($/dV-yr)
TRNP-South Unit	19,640,000
TRNP-North Unit	19,640,000
TRNP-Elkhorn Ranch	19,640,000
Lostwood NWR	7,860,000

(1) - Average predicted visibility impairment impact reductions (90^{th} percentile) relative to presumptive BART NO_X PTE baseline emission rates for years 2000-2002. SOFA NO_X impacts are from PTE heat input emission rates. Control costs are levelized annual values for installed capital + O&M for SOFA NO_X control. All cost figures in 2005 dollars. See Table 2.4-6 for details.

(2) - SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case.

The number of days predicted to have visibility impairment due to LOS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) hourly NO_X, SO_2, and PM emission rates described previously in this Section. The results are summarized and presented in Table 3.4-15. Similarly, the same information for the post-control SO_2 and PM alternatives with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 3.5-16. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between presumptive BART NO_X emission rates versus SOFA-controlled NO_X emission rates with post-control SO_2 and PM alternatives are summarized and shown in Table 2.4-16.

The magnitude of predicted visibility impairment impacts and number of days predicted to have visibility impairment impact greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2000 for Lostwood NWR. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for both the pre-control and post-control model results is included in Section 3.4.

The post-control SO_2 and PM alternatives with SOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same post-control SO_2 and PM conditions with presumptive BART NO_X PTE emission rates. The number of days are presented in Appendix D. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the SOFA-controlled PTE emission rates compared to presumptive BART NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.4-9, 2.4-10, and 2.4-11.

2.4.5 SUMMARY OF IMPACTS OF LOS NO_X CONTROLS – UNIT 1

Table 2.4-17 summarizes the various quantifiable impacts discussed in Sections 2.4.1 through 2.4.4 for the single BART NO_X alternative evaluated for LOS Unit 1.

Table 2.4-16 – Visibility Impairment Reductions – SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

Class 1 Area	NO_X Control Technique(1)	Visibility Impairment Reduction(2) (ΔdV)	ΔDays(3) Exceeding 0.5 dV in 2000	ΔDays(3) Exceeding 0.5 dV in 2001	ΔDays(3) Exceeding 0.5 dV in 2002	ΔDays(3) Exceeding 1.0 dV in 2000	ΔDays(3) Exceeding 1.0 dV in 2001	ΔDays(3) Exceeding 1.0 dV in 2002	ΔConsecutive Days(3) Exceeding 0.5 dV 2000	ΔConsecutive Days(3) Exceeding 0.5 dV 2001	ΔConsecutive Days(3) Exceeding 0.5 dV 2002
TRNP South	SOFA	0.00733	1	0	0	0	0	0	0	0	0
TRNP North	SOFA	0.00733	2	3	2	0	0	0	0	1	0
TRNP Elkhorn	SOFA	0.00733	1	0	1	1	0	1	0	0	0
Lostwood NWR	SOFA	0.0183	0	0	2	0	2	0	0	0	0

1 - SO_2 emissions reduced by 90% over pre-control baseline for the future PTE case. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
2 - Average predicted visibility impairment reductions (90^{th} percentile) from all PTE emissions for SO_2 and PM post-control alternatives with SOFA NO_X control at 0.23 lb/mmBtu relative to presumptive NO_X emission level of 0.29 lb/mmBtu with PTE heat input emission rates (future PTE case), years 2000-2002.
3 - Difference in number of days is 100^{th} percentile level for predicted visibility impacts in Table 3.4-15.

Figure 2.4-9 – Days of Visibility Impairment Reductions – 0.5 dV
SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

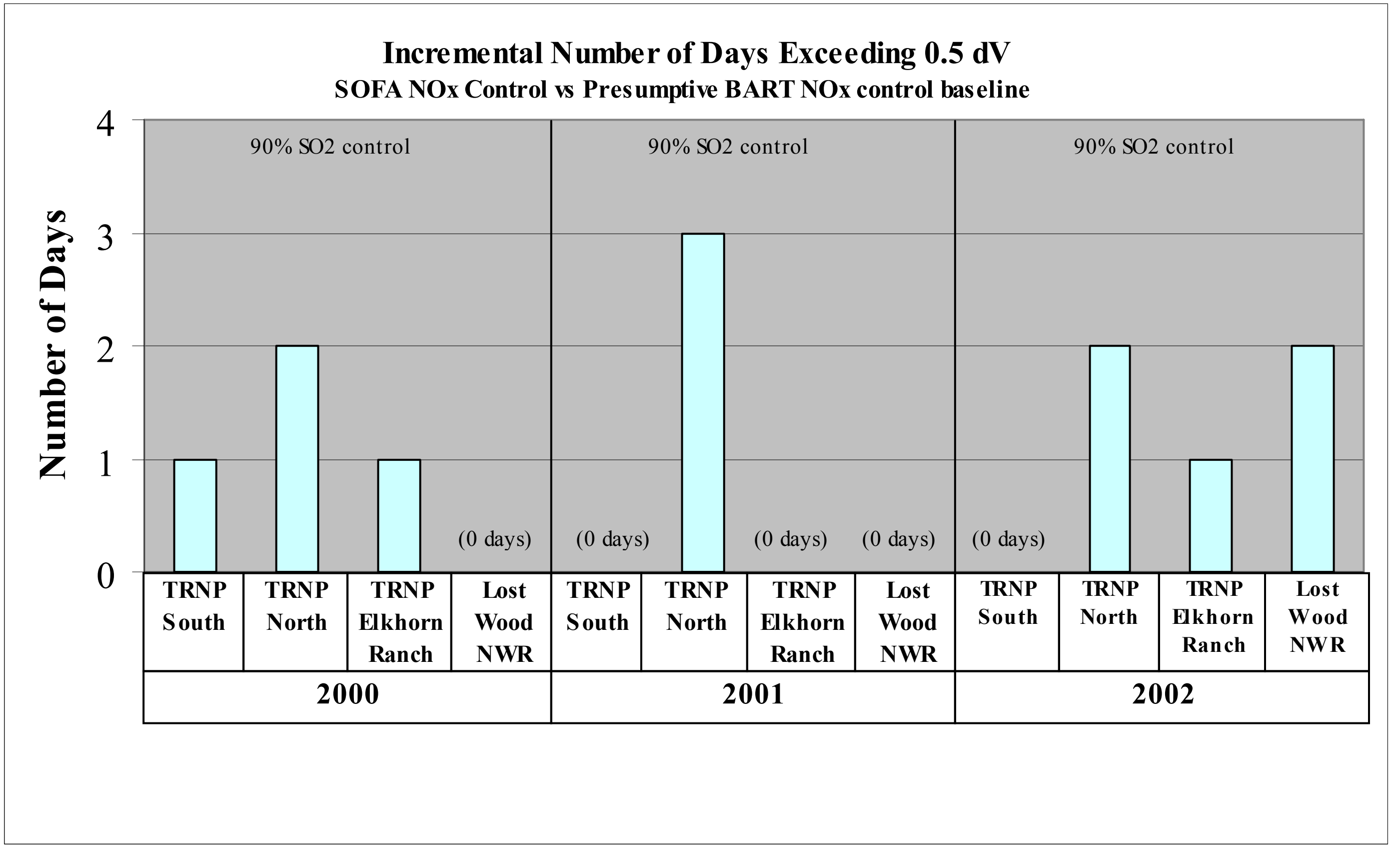


Figure 2.4-10 – Days of Visibility Impairment Reductions – 1.0 dV
SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls
LOS Unit 1

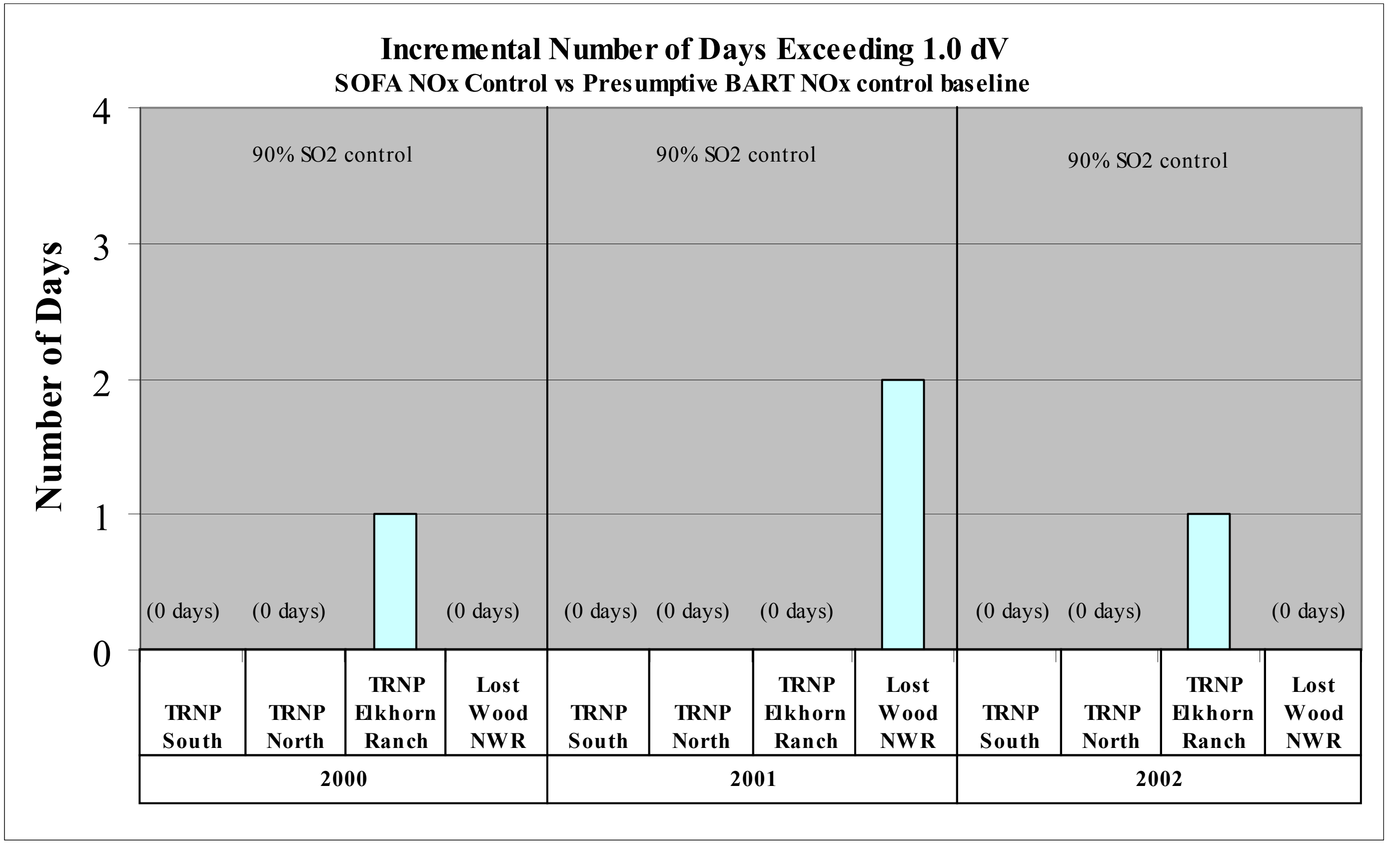


Figure 2.4-11 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV SOFA vs Presumptive BART NO_X Control with SO_2 and PM Controls LOS Unit 1

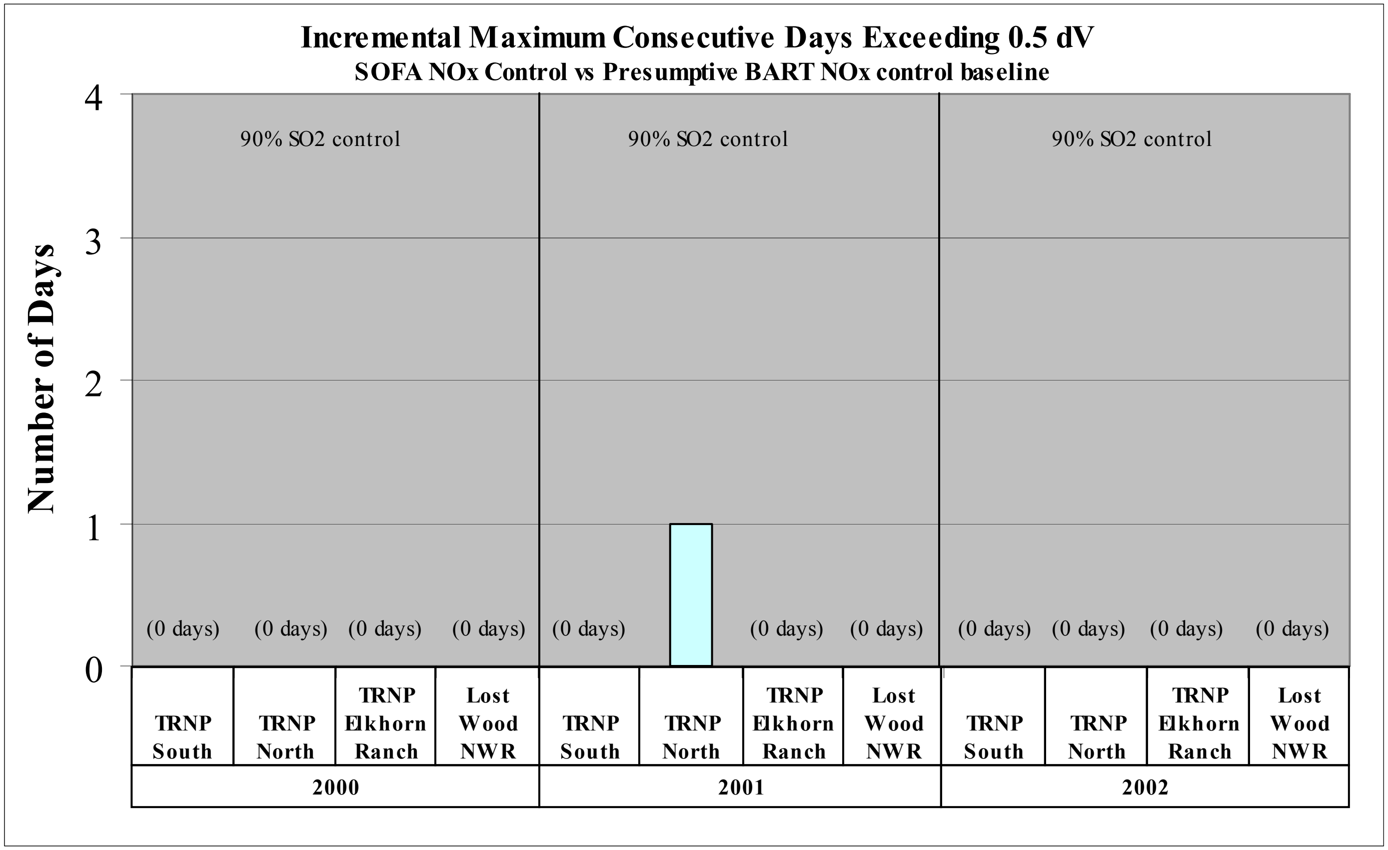


Table 2.4-17 – Impacts Summary for LOS Unit 1 NO_X Controls (vs Presumptive BART NO_X PTE Emissions)

NO_X Control Technique w/ SO_2 Control Level	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1),(3) ($/dV)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental(2) ΔdV			
SOFA w/ 90% SO_2 Control	20.7%	689	$144,000	$289	TRNP-S	0.00733	$19,640,000	1	Flyash unburned carbon increase
					TRNP-N	0.00733	$19,640,000		
					TRNP-Elk	0.00733	$19,640,000		
					LNWR	0.0183	$7,860,000		

(1) - All cost figures in 2005 dollars. See Table 2.4-6 for details.
(2) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) for years 2000-2002 relative to presumptive BART NO_X emission level of 0.29 lb/mmBtu for all SO_2 and PM post-control alternatives at PTE heat input emission rates (future PTE case). This case assumes 90% SO_2 control over pre-control baseline.
(3) - LTAC for SOFA NO_X control divided by Incremental ΔdV.

2.5 EVALUATION OF IMPACTS FOR FEASIBLE NO_X CONTROLS – LOS UNIT 2

The fourth step of a BART analysis is to evaluate the following impacts of feasible emission controls:

- The cost of compliance.
- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

The purpose of the impacts evaluation is to determine if there are any energy, economic, non-air quality environmental reasons, or aspects of the remaining useful life of the source, which would eliminate the control technologies from consideration for Leland Olds Station Unit 2.

2.5.1 COST IMPACTS OF NO_X CONTROLS – LOS UNIT 2

An evaluation was performed to determine the compliance costs of installing various feasible NO_X control alternatives on LOS Unit 2 boiler. This evaluation included estimates for:

- Capital costs;
- Fixed and variable operating and maintenance costs; and
- Levelized total annual costs

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 2.5-1 through 2.5-8. From Step 3 of the BART analysis, compared with other similarly-effective NO_X controls, conventional gas reburn alternatives would have high expected capital costs for a natural gas supply pipeline and on-going natural gas costs. Thus, otherwise technically feasible gas-consuming alternatives are considered economically unattractive for application at LOS on the Unit 2 boiler.

Although the BART Guidelines prescribes following a "top down" analysis approach for BART determination, the development of a least cost envelope with dominant controls[1] [70 FR 39168] clearly labels points with lower emissions reductions and total annual costs first, i.e. "A", "B", etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NO_X control technique alternative has followed this approach.

2.5.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROLS - LOS UNIT 2

The capital costs to implement the various NO_X control technologies were largely estimated from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. In the cases involving SNCR, preliminary vendor budgetary cost information was obtained and used in place of, or to adjust, the published unit output cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

A review of the unit capital cost factor range and single point unit capital cost factor for the feasible NO_X emission reduction technology evaluated for LOS Unit 2 are presented in Table 2.5-1.

TABLE 2.5-1 – Unit Capital Cost Factors of Feasible NO_X Control Options for LOS Unit 2

Alt. No. (1)	NO_X Control Technique	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) LOS Unit 2
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20 + ?(4)	46(4),(5),(6)
C	SNCR (using urea) w/ ASOFA	20-35(7)	38(5),(6)
B	Coal Reburn (conventional, pulverized) w/ ASOFA	30-60(7)	153(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	23(6)

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2005 dollars.
(4) – No published RRI unit capital cost factor was found in available technical literature. The installed capital costs for RRI are expected to be similar to SNCR. If both RRI and SNCR are installed together, capital cost of the RRI+SNCR portion was assumed to be 1.5x the capital cost of SNCR alone, due to commonality between the two systems sharing certain equipment and systems.
(5) – Estimated capital cost for SNCR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix A for details.
(6) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(7) – NESCAUM 2005 Technical Paper, posted at their website for basic SOFA. See Appendix A for details.
(8) – The single point unit capital cost factor shown for a coal reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in coal reburn options is 57.5 $/kW. See Appendix A for details.

Annualized capital cost, which includes the time value of capital monies and its recovery, is determined from the estimated capital cost and the methodology described in Section 1. Table 2.5-2 shows the estimated installed capital cost and annualized capital cost values for the highest-performing form of the various feasible NO_X emission reduction technologies applied to LOS Unit 2. These were developed by multiplying the unit capital cost single point factors for the control option by the nameplate output capacity rating of the respective unit. These are listed in order of control effectiveness, with the highest ranked options at the top.

TABLE 2.5-2 – Installed and Annualized Capital Costs Estimated for NO_X Control Alternatives - LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Installed Capital Cost(2) ($1,000)	Annualized Capital Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	20,200	1,760
C	SNCR (using urea) w/ ASOFA	16,800	1,470
B	Coal Reburn (conventional, pulverized) w/ ASOFA	67,400(4)	5,880(4)
A	Advanced Separated Overfire Air (ASOFA)	10,100	883
	Baseline	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Installed capital cost is estimated for determination of total capital cost for a control technology, assuming maximum unit output capacity is based on existing nameplate rating of 440,000 kW. Installed capital cost figures in 2005 dollars.
(3) – Annualized capital cost = Installed capital cost x 0.08718 Capital Recovery Factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $25,300,000 for installed capital cost, and $2,200,000/yr annualized capital cost.

2.5.1.2 OPERATING AND MAINTENANCE COST ESTIMATES FOR NO_X CONTROLS – LOS UNIT 2

The operation and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS), and from engineering judgment applied to that control technology. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's Levelized Total Annual Costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR and RRI alternatives; and
- Reagent dilution water consumption and unit cost for SNCR and RRI alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler equipment.
- Reductions in revenue expected to result from loss of unit availability, i.e. outages attributable to the control option, which reduce annual net electrical generation available for sale (revenue).

Table 2.5-3 and Table 2.5-4 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Section 1.3.5 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 2.5-3 – Estimated O&M Costs for NO_X Control Options (Relative to Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,000	13,100
C	SNCR (using urea) w/ ASOFA	6,570	7,830
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,730(4)	6,830(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

Annual operating and maintenance costs of the NO_X control options in Table 2.5-3 and Table 2.5-4 are based on LOS Unit 2 operation with the control option at 5,130 mmBtu/hr heat input and 8,760 hrs/yr operation. The Table 2.5-3 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the highest 24-month NO_X emission summation at 4,478 mmBtu/hr heat input for 8,050 hrs/yr operation of LOS Unit 2. The Table 2.5-4 O&M costs are relative to unit pre-control baseline operation at 0.667 lb/mmBtu for the maximum NO_X emissions associated with the future PTE case at 5,130 mmBtu/hr heat input for 8,760 hrs/yr operation of LOS Unit 2.

TABLE 2.5-4 – Estimated O&M Costs for NO_X Control Options (Relative to PTE Pre-Control Annual Emission Baseline – Future PTE Case) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual O&M Cost(2) ($1,000)	Levelized Annual O&M Cost(3) ($1,000)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	11,000	13,100
C	SNCR (using urea) w/ ASOFA	6,580	7,830
B	Coal Reburn (conventional, pulverized) w/ ASOFA	5,730(4)	6,830(4)
A	Advanced Separated Overfire Air (ASOFA)	152	182
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Annual O&M cost figures in 2005 dollars.
(3) – Levelized annual O&M cost = Annual O&M cost x 1.19314 Annualized O&M cost factor.
(4) – Costs for increased PM collection capacity included in coal reburn option are $1,740,000 for annual O&M cost, and $2,080,000/yr levelized annual O&M cost.

The majority of the annual operating and maintenance costs for the alternatives using chemical reagent injection (urea) for NO_X emissions control are for the delivered reagent and dilution water. Both RRI and SNCR are assumed to dilute the 50% aqueous urea solution as-received to a 10% aqueous urea concentration for direct injection into the targeted furnace areas. Higher than theoretical normalized (molar) stoichiometric ratios (NSRs) for the moles of equivalent reagent injected (urea) per mole of inlet NO_X emission were assumed for SNCR with ASOFA, and for RRI+SNCR with ASOFA due to inefficiencies inherent in their use. These annual costs reflect a significant increase in reagent consumption above the theoretical rates based on expected amounts of reagent utilization.

In order to compare a particular NO_X emission reduction alternative during the cost of compliance impact analysis portion of the BART selection process, the basic methodology defined in the BART

Guidelines was followed [70 FR 39167-39168]. The sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which in this analysis is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal incurred by implementing that alternative, was calculated. The LTAC for these NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Section 1.3.5 of this BART evaluation for methodology details).

The Average Cost Effectiveness (also called Unit Control Cost) was then determined as the LTAC divided by baseline annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The feasible control alternatives were also compared by calculating the change in LTAC per incremental ton of pollutant removed for the next most stringent alternative (incremental cost effectiveness). This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average LTAC increment compared with the pre-control baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted. These incremental and average control costs relative to the historic pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-5. The incremental and average control costs relative to the PTE pre-control annual NO_X emission baseline for LOS Unit 2 are shown in Table 2.5-6.

TABLE 2.5-5 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No. (1)	NO_X Control Alternative	Annual NO_X Emissions(2) (Tons/yr)	Annual NO_X Emissions Reduction(2) (Tons/yr)	Levelized Total Annual Cost(3),(4) ($1,000)	Average Control Cost(4) ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	6,128	14,900	2,430
C	SNCR (using urea) w/ ASOFA	6,762	5,261	9,300	1,770
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	4,908	12,700[5]	2,590[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	1,227	1,060	867
	Baseline, based on annual operation at historic 24-mo average pre-control emission rate	12,023	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in an average control cost of $873 per ton of NO_X removed.

TABLE 2.5-6 – Estimated Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 2

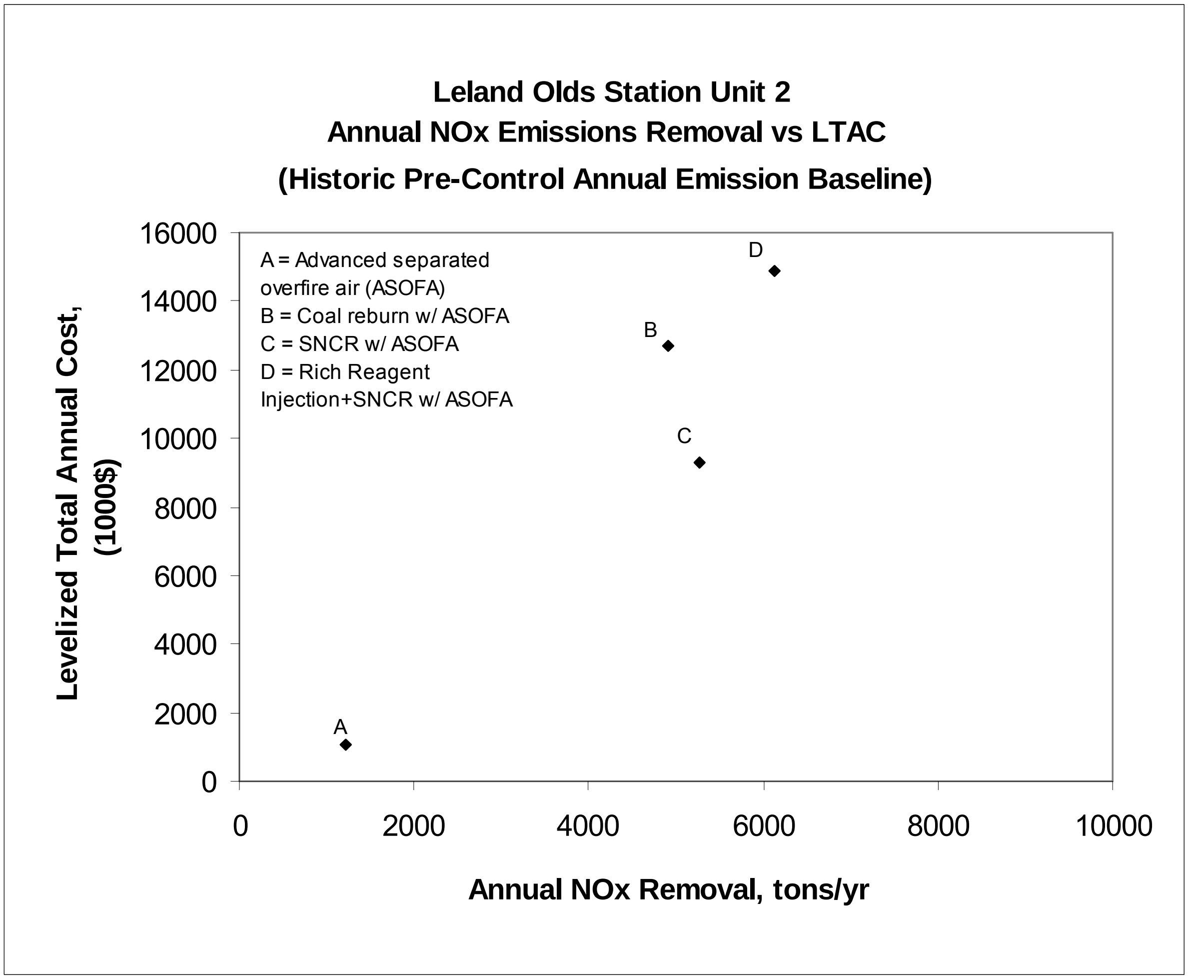
Alt. No. [(1)]	NO_X Control Alternative	Annual NO_X Emissions[(2)] (Tons/yr)	Annual NO_X Emissions Reduction[(2)] (Tons/yr)	Levelized Total Annual Cost[(3),(4)] ($1,000)	Average Control Cost[(4)] ($/ton)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	5,895	9,094	14,900	1,640
C	SNCR (using urea) w/ ASOFA	6,762	8,226	9,300	1,130
B	Coal Reburn (conventional, pulverized) w/ ASOFA	7,115	7,873	12,700[5]	1,610[5]
A	Advanced Separated Overfire Air (ASOFA)	10,796	4,193	1,060	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	14,989	0	0	

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.
(3) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-4 for annualized cost factors.
(4) – Annualized cost figures in 2005 dollars.
(5) – LTAC for increased PM collection capacity included in coal reburn option are $2,200,000 for annualized capital cost plus $2,080,000 for annualized O&M cost, for a total of $4,280,000/yr. This results in a average control cost of $544 per ton of NO_X removed.

The comparison of the cost-effectiveness of the control options evaluated for LOS Unit 2 relative to two different NO_X emission baselines was made and is shown in Figures 2.5-1 and 2.5-2. The estimated annual amount of NO_X removal (emission reduction) in tons per year is plotted on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis).

Figure 2.5-1 is for the control options evaluated relative to the baseline historic pre-control annual baseline, compared to the post-control maximum annual NO_X emissions for operation of LOS Unit 2 under the future PTE case.

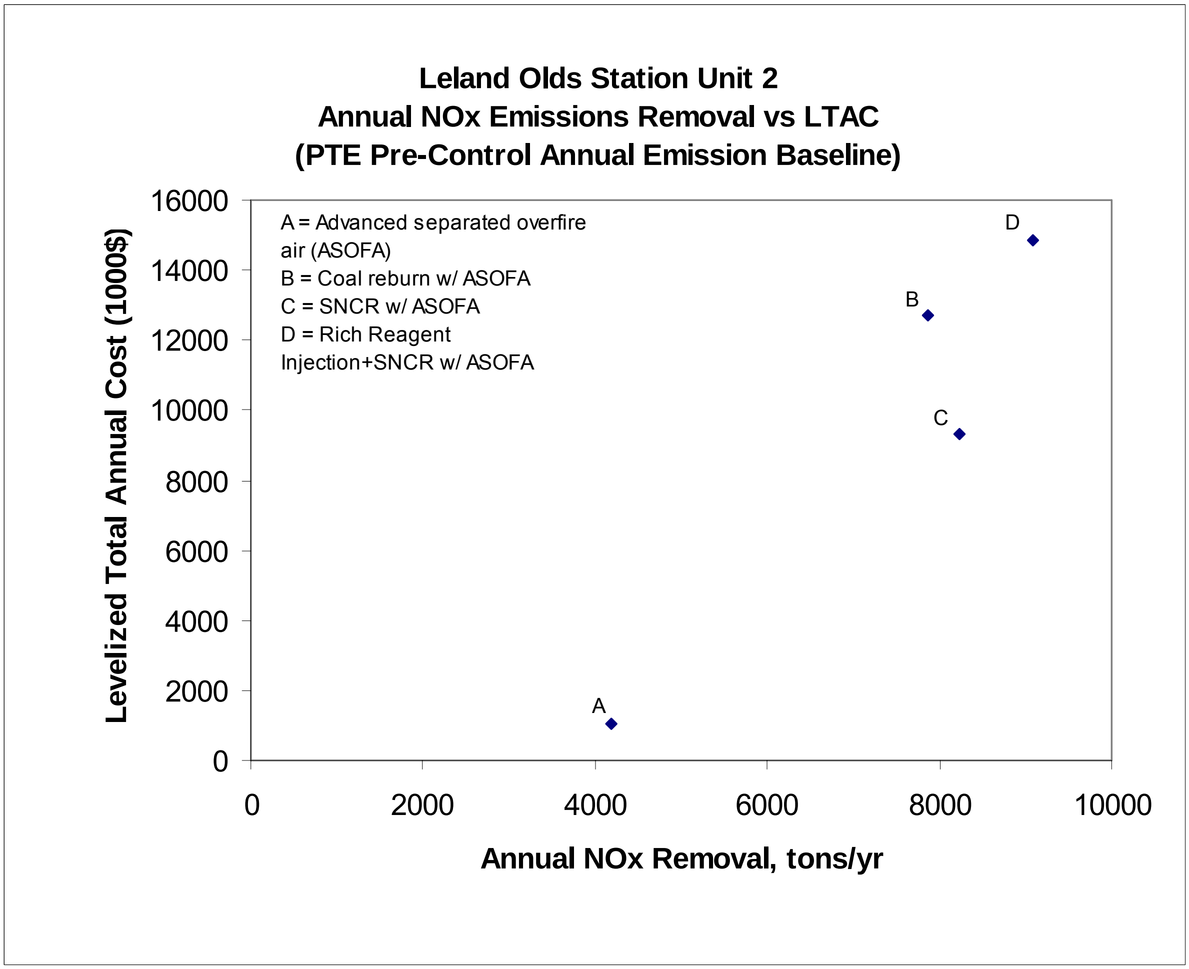
Figure 2.5-1 – NO_X Control Cost Effectiveness – LOS Unit 2 (Historic Pre-Control Annual Emission Baseline)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-5.

Figure 2.5-2 plots estimated levelized total annual costs versus estimated annual amount of NO_X removal (emission reduction) for the control options evaluated relative to the maximum pre-control annual baseline and future potential-to-emit post-control NO_X emissions for operation of LOS Unit 2 under the future PTE case.

Figure 2.5-2 – NO_X Control Cost Effectiveness – LOS Unit 2 (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-6.

The purpose of Figures 2.5-1 and 2.5-2 is to show the range of control and cost for the evaluated NO_X reduction alternatives and identify the least-cost controls so that the Dominant Controls Curve can be created. The Dominant Controls Curve is the best fit line through the points forming the lower rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual NO_X removal tonnage for the various remaining BART alternatives. Points distinctly to the left of and above this curve are inferior control alternatives per the BART Guidelines and BART Guidelines on a cost effectiveness basis. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope should be excluded from further analysis on a cost efficiency basis. Of the highest-performing versions of the technically feasible LOS Unit 2 NO_X control alternatives evaluated for cost-effectiveness, the data point for coal reburn with ASOFA is seen to be more costly for fewer tons of NO_X removed than for SNCR with ASOFA. This appears to be an inferior control, and thus should not be included on the least cost and Dominant Controls Curve boundary. Note that cost-effectiveness points for conventional gas reburn and fuel-lean gas reburn alternatives would be distinctly left and significantly above the least cost-control envelope, so these options were not included in the cost-effectiveness analysis.

The next step in the cost effectiveness analysis for the BART NO_X control alternatives is to review the incremental cost effectiveness between remaining least-cost alternatives. Figure 2.5-3 and Figure 2.5-4 contains a repetition of the levelized total annual cost and NO_X control information from Figure 2.5-1 and Figure 2.5-2 with Point B removed, and shows the incremental cost effectiveness between each successive set of least-cost NO_X control alternatives. The incremental NO_X control tons per year, divided by the incremental levelized annual cost, yields an incremental average unit cost ($/ton). This represents the slope of a line, if drawn, from one least-cost point as compared with another least-cost point. This modified least-cost controls curve is the Dominant Controls Cost Curve for NO_X emissions alternatives for each of the LOS Unit 2 pre-control baselines evaluated.

TABLE 2.5-7 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (Historic Pre-Control Annual Emission Baseline) – LOS Unit 2

Alt. No.[1]	NO_X Control Technique	Levelized Total Annual Cost[2],[3] ($1,000)	Annual Emission Reduction[4] (Tons/yr)	Incremental Levelized Total Annual Cost[3],[5] ($1,000)	Incremental Annual Emission Reduction[4],[5] (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)[3],[6]
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	14,900	6,128	5,570	867	6,420
C	SNCR (using urea) w/ ASOFA	9,300	5,261	8,240	4,034	2,040
A	Advanced SOFA (ASOFA)	1,060	1,227	1,060	1,227	867
	Baseline, based on annual operation at historic 24-month average pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors. Costs for increased PM collection efficiency are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the historic pre-control annual baseline for LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

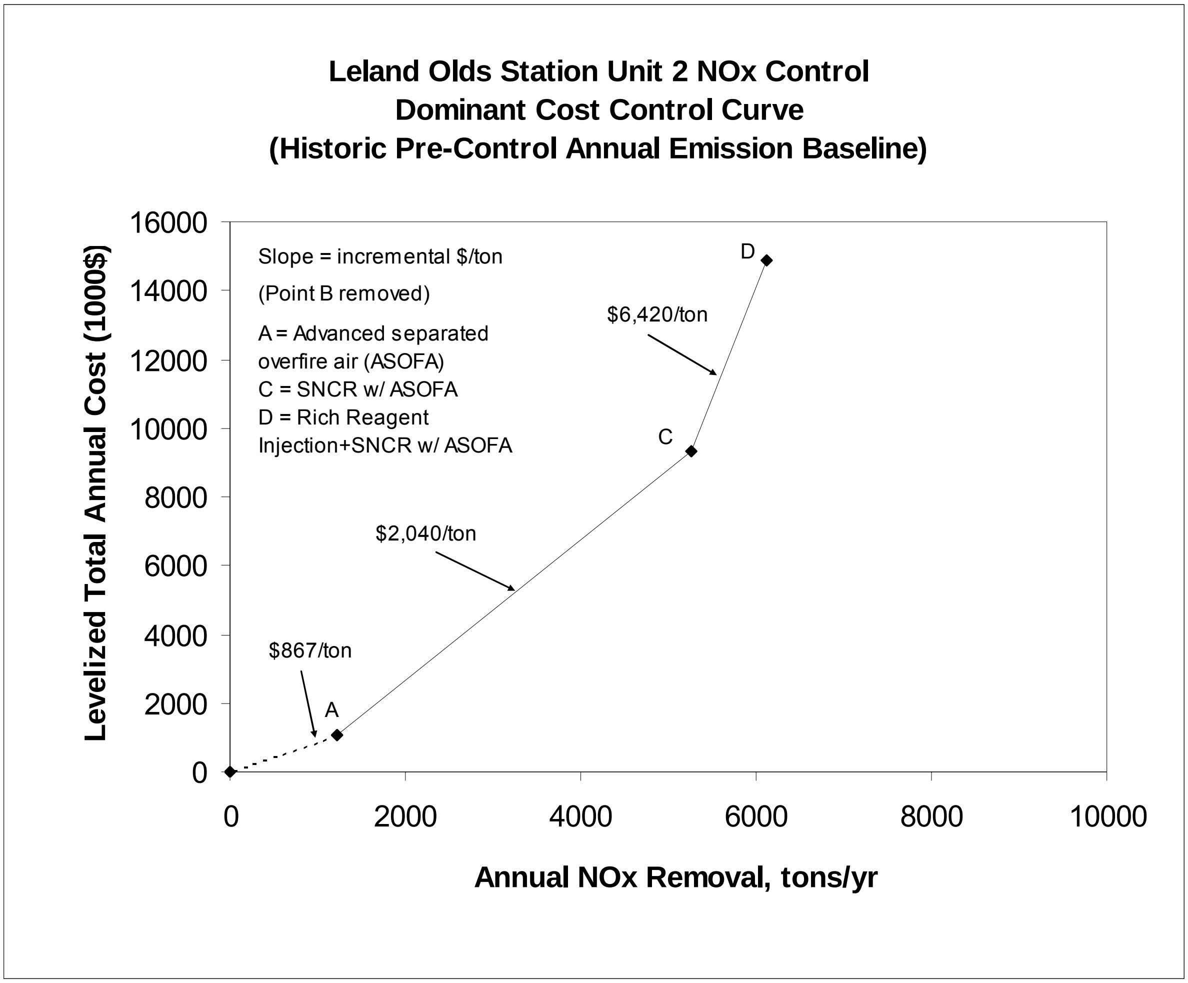
TABLE 2.5-8 – Estimated Incremental Annual Emissions and LTAC for NO_X Control Alternatives (PTE Pre-Control Annual Emission Baseline – Future PTE Case) LOS Unit 2

Alt. No.(1)	NO_X Control Technique	Levelized Total Annual Cost(2),(3) ($1,000)	Annual Emission Reduction(4) (Tons/yr)	Incremental Levelized Total Annual Cost(3),(5) ($1,000)	Incremental Annual Emission Reduction(4),(5) (Tons/yr)	Incremental Control Cost Effectiveness ($/ton)(3),(6)
D	Rich Reagent Injection (RRI) + SNCR (using urea) and ASOFA	14,900	9,094	5,570	867	6,420
C	SNCR (using urea) w/ ASOFA	9,300	8,226	8,240	4,034	2,040
A	Advanced SOFA (ASOFA)	1,060	4,193	1,060	4,193	254
	Baseline, based on annual operation at future PTE case pre-control emission rate	0	0			

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.
(2) – Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost.
See footnote #3 for Tables 2.5-2 and 2.5-3 for annualized cost factors.
Costs for increased PM collection capacity are included in coal reburn option.
(3) – Annualized cost figures in 2005 dollars.
(4) – NO_X emissions and control level reductions relative to the future potential-to-emit pre-control annual baseline for the future PTE case applied to LOS Unit 2.
(5) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest.
(6) – Incremental control cost effectiveness is incremental LTAC divided by incremental annual emission reduction (tons per year).

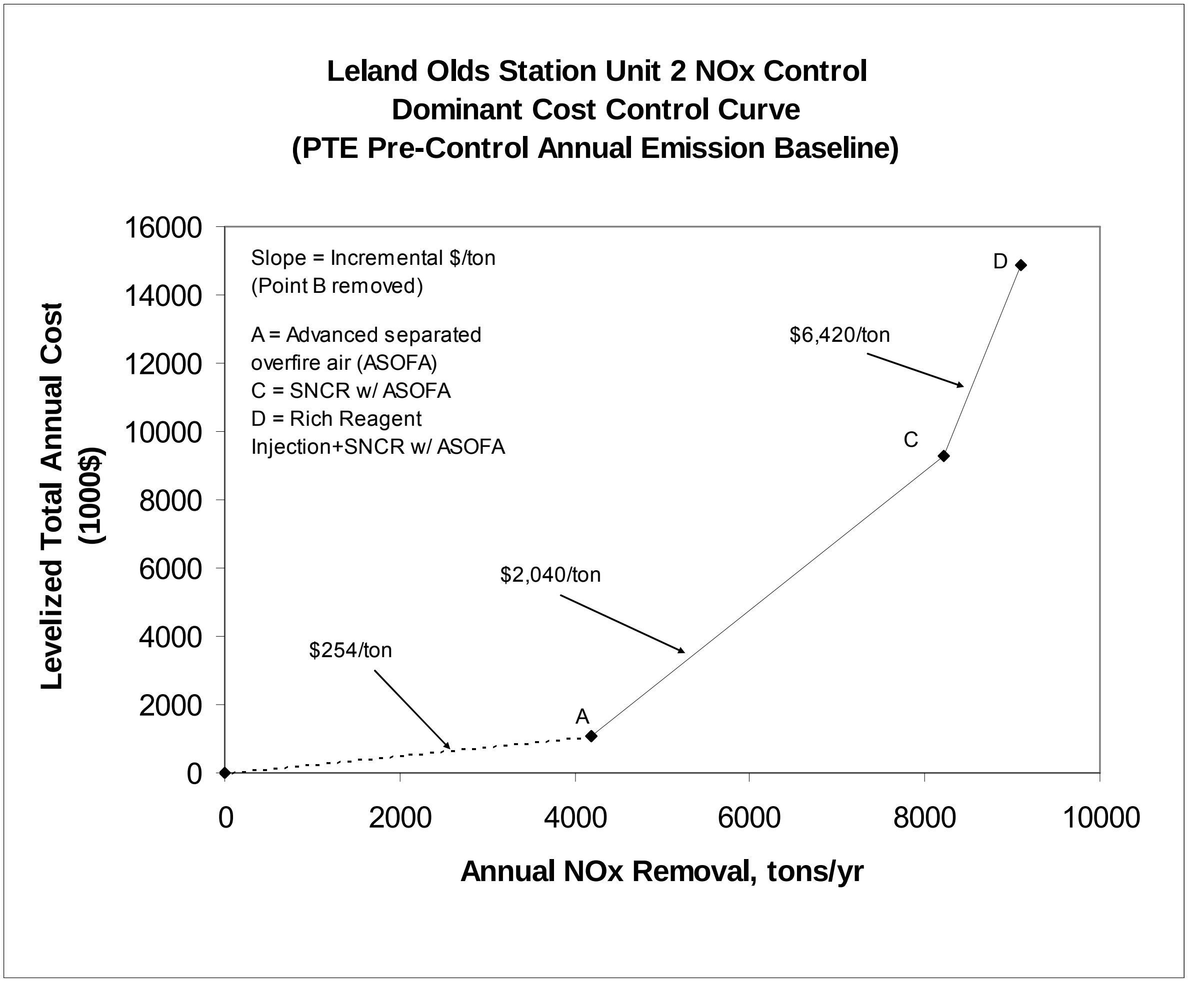
In the comparison displayed in Figure 2.5-3 and Figure 2.5-4, for the data shown in Table 2.5-7 and Table 2.5-8, the RRI+SNCR with Advanced SOFA NO_X control alternative (Point D) had a significantly higher incremental unit NO_X control cost (slope, $6,420/ton) compared against SNCR with ASOFA alternative (Point C) versus SNCR with ASOFA (Point C) compared against the ASOFA alternative (Point A) ($2,040/ton).

Figure 2.5-3 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (Historic Pre-Control Annual Emission Baseline)[(1)]



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-7.

Figure 2.5-4 – NO_X Control Cost Effectiveness – LOS Unit 2 Dominant Cost Control Curve (PTE Pre-Control Annual Emission Baseline – Future PTE Case)(1)



(1) - All cost figures in 2005 dollars. Numbers are listed and qualifiers are noted in Table 2.5-8.

In the final BART Guidelines, the EPA neither proposes hard definitions for reasonable, or unreasonable Unit Control Costs nor for incremental cost effectiveness values. As can be seen from a review of Table 2.5-5, the average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the highest 24-hour historic baseline NO_X emission ranges from $867/ton to $2,430/ton. Table 2.5-6 shows average levelized control cost effectiveness of control alternatives calculated for the future PTE case relative to the presumptive NO_X emission level ranges from $254/ton to $1,640/ton. The latter has lower costs per ton of NO_X emission removal due to the higher number of tons removed for the maximum emissions for pre-control baseline and additional controls under the future PTE case.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the Dominant Control Cost Curve) between successively more effective alternatives. The incremental cost analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is Rich Reagent Injection + SNCR with ASOFA (Point D). This control option is considered technically feasible for Leland Olds Station Unit 2 boiler, incurs a significant annual (levelized) incremental cost compared to the next highest feasible NO_X control technique, SNCR with ASOFA (Point C, slope from C to D =6,470 $/ton) compared against the next lowest alternative, ASOFA (Point A, slope from A to C = 2,040 $/ton).

The other elements of the fourth step of a BART analysis following cost of compliance are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The non-air quality environmental impacts.
- The remaining useful life of the source.

For the purposes of this BART analysis, the remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimates. The other impacts for the LOS Unit 2 NO_X emissions control alternatives from the Dominant Control Cost Curve are discussed in Section 2.5.2 and Section 2.5.3. Visibility impairment impacts for these LOS Unit 2 NO_X emissions controls are summarized in Section 2.5.4.

2.5.2 ENERGY IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 2

Operation of the top NO_X control technologies considered feasible for potential application at the Leland Olds Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various LOS Unit 2 NO_X control alternatives are summarized in Appendix A.

Control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology will result in any significant or unusual energy penalties or benefits. There are several basic kinds of energy impacts for NO_X emissions controls:

- Potential increase or decrease in power plant energy consumption resulting from a change in thermal (heat) energy to net electrical output conversion efficiency of the unit, usually expressed as an hourly unit heat rate (Btu/kW-hr) or the inverse of pounds of pollutant per unit electrical power output (MW-hr). This may or may not change the net electrical output (MW) capacity of the EGU, depending on if there are physical or imposed limits on the total heat input to the boiler or electrical power output.

- Potential increase or decrease in net electrical output of the unit, resulting from changes in physical operational limitations imposed on the ability to sustain a fuel heat input rate (mmBtu/hr) which results in a potentially lower or higher unit net electrical output (MW) capacity. This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in net electrical output of the unit, resulting from changes in auxiliary electrical power demand and usage (kW, kW-hrs). This is effectively a change in net electrical output (MW) capacity of the EGU.
- Potential increase or decrease in reliability and availability to generate electrical power. This results in a change to the number of hours of annual operation, not necessarily a change in net electrical output (MW) capacity of the EGU.

2.5.2.1 ENERGY IMPACTS OF SOFA ALTERNATIVES

There should not be a major impact on energy consumption by the operation of the advanced variation of a separated overfire air system. ASOFA was the only NO_X control technology common to all four alternatives evaluated for LOS Unit 2. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Combustion air damper actuators' electrical power demand would be insignificant (+ 1 kW) change in net electrical power consumption from LOS Unit 2. For cyclone boilers, providing effective volumes and velocities of separated overfire air at the injection ports should not require higher forced draft fan power consumption resulting from higher fan discharge pressure. Higher lignite drying system vent ductwork pressure drop impacts of the advanced SOFA system on the forced draft fans' auxiliary electrical power consumption are expected to be negligible (less than 1% of the annual auxiliary power consumed by these fans) so that unit net electrical output (MW) capacity is essentially the same as the current nameplate rating.

Operation of a SOFA system may cause a small increase in levels of unburned carbon in the flyash emitted from the boiler compared with current operation. This represents a slight amount of lost potential electrical power generation from the incompletely burned fuel, so this inefficiency could have a small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kw-hr). This impact was not quantified, as the historical variation in coal heat content that influences plant unit heat rate may be more significant.

Boiler furnace exit gas temperature and superheater steam / reheater steam outlet temperatures may be slightly elevated during air-staged cyclone operation with SOFA. This impact on the boiler's operation is typically small, and within the design capabilities of the boiler from a heat transfer and mechanical stress standpoint. This small negative impact (much less than 1%) on the plant unit heat rate (higher Btu/kW-hr) was not quantified, as the historical variation in coal heat content that influences plant unit heat rate is expected to have more significant impacts.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, once the amount of secondary combustion air that can be withdrawn from the cyclones is established for consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for LOS Unit 2. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The potential change in the frequency of furnace wall tube failures and changeouts is difficult to estimate, and has not been quantified.

2.5.2.2 ENERGY IMPACTS OF SNCR ALTERNATIVES

For SNCR-related NO_X control alternatives (with or without Rich Reagent Injection), the injection of a diluted urea solution requires some additional auxiliary power for heating and pumping the liquid, and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 150 to 400 kW. The injection of water (used for urea dilution) into the boiler flue gas also has a small negative impact on the plant heat rate (higher Btu/kw-hr), which is approximately equal to the heat released from the reaction of the reagent with NO_X or oxygen. The impact of additional flue gas created by operation of an SNCR-related system on induced draft fan power consumption should be insignificant.

Table 2.5-9 summarizes the gross demand and usage from auxiliary electrical power estimated for the NO_X control alternatives evaluated for LOS Unit 2.

TABLE 2.5-9 – Expected Auxiliary Electrical Power Impacts for NO_X Controls – LOS Unit 2

Alt. No.(1)	NO_X Control Technique	NO_X Control Equipment Estimated Annual Average Auxiliary Electrical Power Demand and Usage		
		Aux. Power Demand (2) (kW)	Generation Reduction from Aux. Power Demand(2),(3) (kW-hrs/yr)	Generation Reduction from Reduced Unit Availability(4) (kW-hrs/yr)
D	RRI + SNCR (using urea) w/ ASOFA	284	2,455,500	38,500,000
C	SNCR (using urea) w/ ASOFA	155	1,340,800	38,500,000
A	Advanced Separated Overfire Air (ASOFA)	1	8,760	0

(1) – Alternative designation has been assigned from highest to lowest unit NO_X emission rate.

(2) – The NO_X control equipment gross auxiliary electrical power demand is estimated.

(3) – The annual change in NO_X equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

(4) – The estimated total hours per year of unit unavailability multiplied by average gross generation multiplied by annual running plant capacity factor for the particular control alternative. For this analysis, SOFA was not expected to reduce annual hours of possible operation.

2.5.3 NON-AIR QUALITY AND OTHER ENVIRONMENTAL IMPACTS OF NO_X CONTROL ALTERNATIVES – LOS UNIT 2

Nitrogen oxides react with oxygen in the atmosphere to produce elemental nitrogen and ozone (O_3). This is one of the common causes of visible pollution in the atmosphere referred to as "smog". Operation of the various NO_X control technologies considered for potential application at the Leland Olds Station impose direct and indirect impacts on the environment. The most pronounced environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e. reduced visibility impairment) downwind of the facility. This is discussed in detail in the Visibility Impacts section for LOS Unit 2.

2.5.3.1 ENVIRONMENTAL IMPACTS OF SOFA

The amount of unburned carbon in the flyash produced by the boiler, collected for disposal or potentially emitted to the atmosphere, may increase by small increments due to operation of LOS Unit 2 using separated overfire air for NO_X emissions control. The potential changes in the annual amounts of flyash emissions and disposal rates are expected to be inconsequential, and have not been quantified.

The operation of an advanced form of separated overfire air system is expected to slightly increase carbon monoxide concentrations in the stack flue gas. This potential air emission increase does not qualify as a non-air environmental impact evaluated for the BART impact analysis, and therefore has not been quantified.

There were no other adverse or significant changes in non-air quality environmental impacts identified for LOS Unit 2 as a result of using separated overfire air for NO_X emissions control.

2.5.3.2 ENVIRONMENTAL IMPACTS OF SNCR ALTERNATIVES

The operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs). The chemical form of the reagent will affect the amount of carbon dioxide emitted, since urea contains CO which is readily converted to CO_2 in the boiler-furnace and convection sections by combining with available free oxygen. One mole of carbon dioxide (CO_2) will be created and emitted for every mole of urea injected for reaction with NO_X. This is a relatively small increase in the total amount of CO_2 produced as part of the combustion of carbon-based fossil fuel in the form of lignite. As CO_2 is not currently a regulated pollutant, this increase has not been calculated.

Operation of an SNCR-related system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR, with or without RRI, depends on the amount of reagent utilization and location of the injection points. Rich Reagent Injection operation typically does not produce any significant amount of ammonia slip, as the remainder of the reagent not reacted with NO_X is usually oxidized prior to leaving the boiler. Higher

SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially since the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

Some of the unreacted ammonia from SNCR operation will be collected with the flyash in the electrostatic precipitator. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition. Although the predicted amount of such potential impact from ammonia slip emissions has not been determined, it is expected to be small in comparison with the significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reductions from the use of SNCR-related alternatives.

Storage of urea or ammonia reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Regulation of storage and containment of such reagents as hazardous substances will be under the requirements of various federal Acts, which are not part of this BART impact analysis.

Visibility impairment improvement impacts are discussed in the next section.

2.5.4 VISIBLITY IMPAIRMENT IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

The fifth step in a BART analysis is to conduct a visibility improvement determination for the source. For this BART analysis, there were two baseline NO_X emission rates assumed for LOS Unit 2 – one for the historic pre-control NO_X emission rate listed in the NDDH BART protocol[3], and one applying the Potential-To-Emit (PTE) pre-control annual NO_X emission rate associated with the future PTE case. The historic pre-control emission baseline was the 24-hour average NO_X emission rate from the highest emitting day of the years 2000-2002 (meteorological period modeled per the NDDH protocol[3]). The historic (protocol) NO_X baseline condition emission rate was modeled simultaneously with the highest 24-hour average SO_2 emission rate, and the highest 24-hour average PM emission rate of the 2000-2002 time period. The historic (protocol) baseline hourly NO_X emission rate used for modeling visibility impacts due to LOS Unit 2 under the conditions stated above was 3,959 lb/hr.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from historic (protocol) pre-control baseline and post-control average hourly emission rates representing the visibility impairment impact reduction for LOS Unit 2. Three post-control CALPUFF model runs for LOS Unit 2 were conducted with the same presumptive BART SO_2 emission baseline rate of 95%, constant PM emissions, and various levels of NO_X control assuming the same boiler design rating for heat input (5,130 mmBtu/hr). For the three post-control alternatives representing LOS Unit 2 PTE annual emissions associated with the future PTE case, the model used average unit NO_X emission rates of 0.48, 0.304, and 0.265 lb/mmBtu (corresponding to the design parameter in Table 1.2-1 and control rates in Table 1.4-1) multiplied by the boiler heat input rating of 5,130 mmBtu/hr to yield average hourly NO_X emission rates 2,462, 1,560, and 1,360 lb/hr. The boiler heat input basis for LOS Unit 2's historic highest 24-hour pre-control NO_X emission baseline, in keeping with the NDDH BART visibility impairment impact modeling protocol, is different than assumed for the PTE annual post-control conditions of the NO_X control alternatives evaluated for visibility impairment impacts.

The results of the visibility impairment modeling at the historic pre-control (protocol) baseline NO_X emission rate for LOS Unit 2 showed that all four of the designated Class 1 areas exceeded 0.5 deciView for highest predicted visibility impairment impact (90th percentile, averaged for 2000-2002). Lostwood National Wildlife Refuge (LNWR) showed the biggest predicted visibility impairment impact, which averaged 0.98 dV for the three years modeled (2000-2002). Average predicted visibility impairment impacts decreased significantly with presumptive BART SO_2 emission rate combined with constant PM emissions and various post-control ASOFA-enhanced NO_X emission rates for LOS Unit 2. This is shown in Table 2.5-10.

TABLE 2.5-10 – Average Visibility Impairment Impacts from Emission Controls – LOS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)			
	Historic Pre-Control Baseline	PTE Emissions, ASOFA[2]	PTE Emissions, SNCR w/ ASOFA[2]	PTE Emissions, RRI+SNCR w/ ASOFA[2]
TRNP-South Unit	0.807	0.221	0.158	0.143
TRNP-North Unit	0.756	0.180	0.139	0.129
TRNP-Elkhorn Ranch	0.535	0.120	0.093	0.087
Lostwood NWR	0.979	0.285	0.206	0.191

(1) - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

Analysis of the reduction in visibility impairment impact included a comparison of the emission controls' effectiveness of reducing predicted visibility impairment impacts for the conditions of the future PTE case operation of LOS Unit 2 versus the historic pre-control (protocol) baseline that was modeled. LNWR again showed the highest average predicted visibility impairment impact reduction resulting from LOS Unit 2 emissions controls during PTE (future PTE case) heat inputs versus historic pre-control baseline emissions. These comparisons are shown in Table 2.5-11.

TABLE 2.5-11 –Average Visibility Impairment Impact Reductions From Emission Controls – LOS Unit 2 (vs Historic Maximum 24-Hour Average Hourly Emission Baseline)

Federal Class 1 Area	Visibility Impairment Reductions[1] (deciView)		
	PTE Emissions, ASOFA[2]	PTE Emissions, SNCR w/ ASOFA[2]	PTE Emissions, RRI+SNCR w/ ASOFA[2]
TRNP-South Unit	0.586	0.649	0.664
TRNP-North Unit	0.577	0.617	0.628
TRNP-Elkhorn Ranch	0.415	0.441	0.447
Lostwood NWR	0.694	0.773	0.788

(1) - Difference of average 90th percentile predicted post-control visibility impairment impact versus historic pre-control (protocol) baseline visibility impairment impact. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
(2) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection.

The comparison in Table 2.5-12 shows the reduction of average visibility impairment impact from LOS Unit 2 NO_X emissions expected to result from ASOFA combined with SNCR with and without RRI relative to the average visibility impairment impact from post-control ASOFA NO_X emission rates applied to LOS Unit 2.

TABLE 2.5-12 – Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission Visibility Impairment Impact)

Federal Class 1 Area	Incremental Visibility Impairment Impact Reductions, from NO_X Emission Controls(1)	
	PTE Emissions, SNCR w/ ASOFA (dV)	**PTE Emissions, RRI+SNCR w/ ASOFA (dV)**
TRNP-South Unit	0.063	0.078
TRNP-North Unit	0.040	0.051
TRNP-Elkhorn Ranch	0.027	0.033
Lostwood NWR	0.079	0.094

(1) - Incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

This analysis included a determination of the cost-effectiveness of reducing predicted visibility impairment impact for a particular NO_X emission rate associated with the control alternatives evaluated on LOS Unit 2. The basis of comparison was the average predicted visibility impairment impact and estimated levelized total annual cost (LTAC) for the advanced form of separated overfire air (ASOFA) alone under the future PTE case conditions. The estimated additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) relative to the LTAC from post-control ASOFA NO_X emission rates applied to LOS Unit 2 are shown in Table 2.5-13.

TABLE 2.5-13 – LTAC for NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC)

Incremental LTAC Change for NO_X Emission Reduction(1)	
PTE Emissions, SNCR w/ ASOFA ($/yr)	**PTE Emissions, RRI+SNCR w/ ASOFA ($/yr)**
8,250,000	13,820,000

1 - Incremental Levelized Total Annual Cost for NO_X control alternatives compared to ASOFA for PTE heat input rate (future PTE case). All cost figures in 2005 dollars. See Table 2.5-8 for details.

The comparison in Table 2.5-14 shows that the additional annualized costs of installing and operating each NO_X control alternative with PTE heat input (future PTE case) divided by the additional average predicted visibility impairment impact reduction relative to the post-control ASOFA NO_X emission rates and LTAC applied to LOS Unit 2 would result in hundreds of millions of dollars per deciview of control cost visibility impairment impact effectiveness.

TABLE 2.5-14 – Cost Effectiveness for Incremental Average Visibility Impairment Reductions from NO_X Controls – LOS Unit 2 (vs ASOFA Post-Control PTE Emission LTAC and Visibility Impacts)

	Incremental Visibility Impairment Reduction Unit Cost, from NO_X Emission Controls(1)	
Federal Class 1 Area	**PTE Emissions, SNCR w/ ASOFA ($/deciView-yr)**	**PTE Emissions, RRI+SNCR w/ ASOFA ($/deciView-yr)**
TRNP-South Unit	131,700,000	177,900,000
TRNP-North Unit	204,600,000	271,000,000
TRNP-Elkhorn Ranch	309,000,000	423,000,000
Lostwood NWR	104,900,000	147,500,000

(1) - Incremental Levelized Total Annual Cost divided by incremental average 90th percentile predicted post-control visibility impairment impact, compared to ASOFA for NO_X control with 95% SO_2 emissions control and existing ESP for PM emissions control at PTE heat input rate (future PTE case). All cost figures in 2005 dollars.

The number of days predicted to have visibility impairment due to LOS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the historic pre-control (protocol) NO_X, SO_2, and PM emission rates described previously in this Section. The results were summarized and presented in Table 3.4-15. Similarly, the same information for the post-control SO_2 and PM alternatives with presumptive BART NO_X PTE emission rates was summarized and is shown in Table 3.5-16. The differences in average visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between post-control SO_2 and PM alternatives with SNCR with ASOFA-controlled and RRI+ SNCR with ASOFA-controlled NO_X emission rates versus ASOFA-controlled NO_X emission rates are summarized and shown in Table 2.5-15.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 area. The highest number of days in which the predicted visibility impairment impact above background exceeded 0.5 deciViews was for the pre-control (protocol) emission case in year 2002 for TRNP's South Unit. A series of bar charts showing the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the pre-control model results is included in Section 3.5. The pair of post-control SO_2 and PM alternatives combined with SNCR with ASOFA or RRI+SNCR with ASOFA for NO_X control were only slightly lower for the predicted visibility impairment impacts and number of days predicted to have visibility impairment impacts greater than 0.50 and 1.00 deciViews compared to the same pair of post-control SO_2 and PM conditions with ASOFA-controlled NO_X emission rates. A series of bar charts showing the difference in the number of days with predicted visibility impairment impact greater than 0.50 and 1.00 deciViews for each Class 1 area for the RRI+SNCR with ASOFA-controlled PTE emission rates and SNCR with ASOFA-controlled PTE emission rates compared to ASOFA NO_X PTE emission rates with post-control SO_2 and PM alternatives is included in Figures 2.5-5, 2.5-6, and 2.5-7.

2.5.5 SUMMARY OF IMPACTS OF LELAND OLDS STATION NO_X CONTROLS – UNIT 2

Table 2.5-16 summarizes the various quantifiable impacts discussed in Sections 2.5.1 through 2.5.4 for the NO_X control alternatives evaluated for LOS Unit 2.

Table 2.5-15 – Visibility Impairment Improvements – Post Control vs ASOFA NO_X Control with SO_2 and PM Controls LOS Unit 2

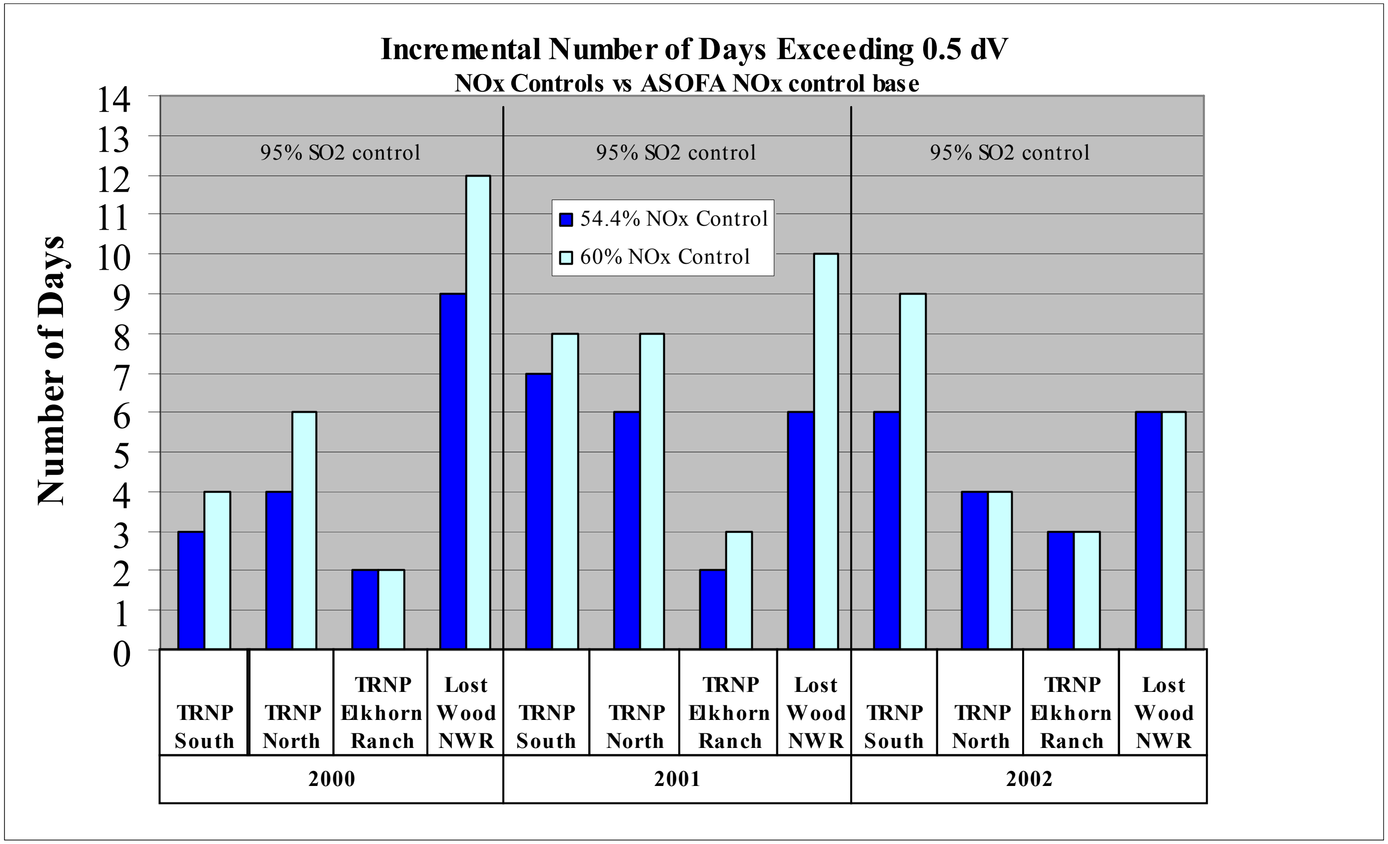
Class 1 Area	NO_X Control Technique w/ SO_2 Control Level(1)	Visibility Impairment Reduction(2) (ΔdV)	ΔDays(3) Exceeding 0.5 dV in 2000	ΔDays(3) Exceeding 0.5 dV in 2001	ΔDays(3) Exceeding 0.5 dV in 2002	ΔDays(3) Exceeding 1.0 dV in 2000	ΔDays(3) Exceeding 1.0 dV in 2001	ΔDays(3) Exceeding 1.0 dV in 2002	ΔConsecutive Days(3) Exceeding 0.5 dV 2000	ΔConsecutive Days(3) Exceeding 0.5 dV 2001	ΔConsecutive Days(3) Exceeding 0.5 dV 2002
TRNP South	RRI+SNCR w/ ASOFA	0.078	4	8	9	2	2	8	0	1	0
	SNCR w/ ASOFA	0.063	3	7	6	2	2	7	0	1	0
TRNP North	RRI+SNCR w/ ASOFA	0.051	6	8	4	2	2	8	0	0	0
	SNCR w/ ASOFA	0.040	4	6	4	2	2	6	0	0	0
TRNP Elkhorn	RRI+SNCR w/ ASOFA	0.033	2	3	3	0	1	2	0	1	0
	SNCR w/ ASOFA	0.027	2	2	3	0	1	2	0	1	0
Lostwood NWR	RRI+SNCR w/ ASOFA	0.094	12	10	6	5	7	2	0	0	1
	SNCR w/ ASOFA	0.079	9	6	6	5	5	2	0	0	1

(1) - SO_2 emissions reduction by 95% over pre-control PTE heat input baseline for the future PTE case. This case assumes existing ESP for PM collection. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - Difference in average predicted visibility impairment impacts (90th percentile) for 2000-2002 for alternatives' post-control NO_X emission levels versus ASOFA-controlled NO_X emission level with same PTE heat input SO_2 and PM post-control alternatives' emission rate (future PTE case).

(3) - Difference in number of days is 100th percentile level for predicted visibility impairment impacts provided in Appendix D1.

Figure 2.5-5 – Days of Visibility Impairment Reductions – 0.5 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2



 8/3/2006

Figure 2.5-6 – Days of Visibility Impairment Reductions – 1.0 dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

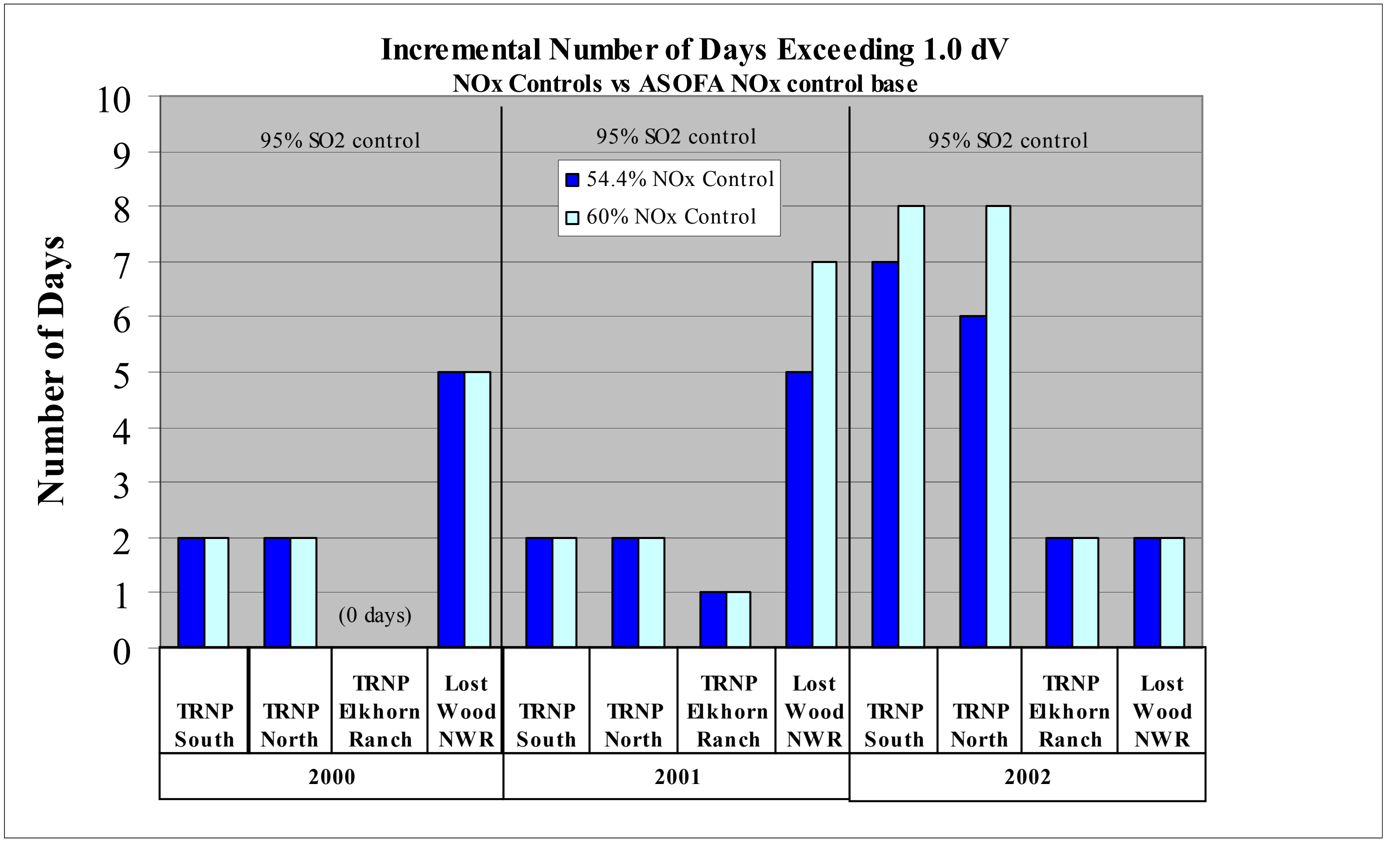


Figure 2.5-7 –Visibility Impairment Reductions – Consecutive Days Above 0.5dV
NO_X Controls versus ASOFA with SO_2 and PM Controls
LOS Unit 2

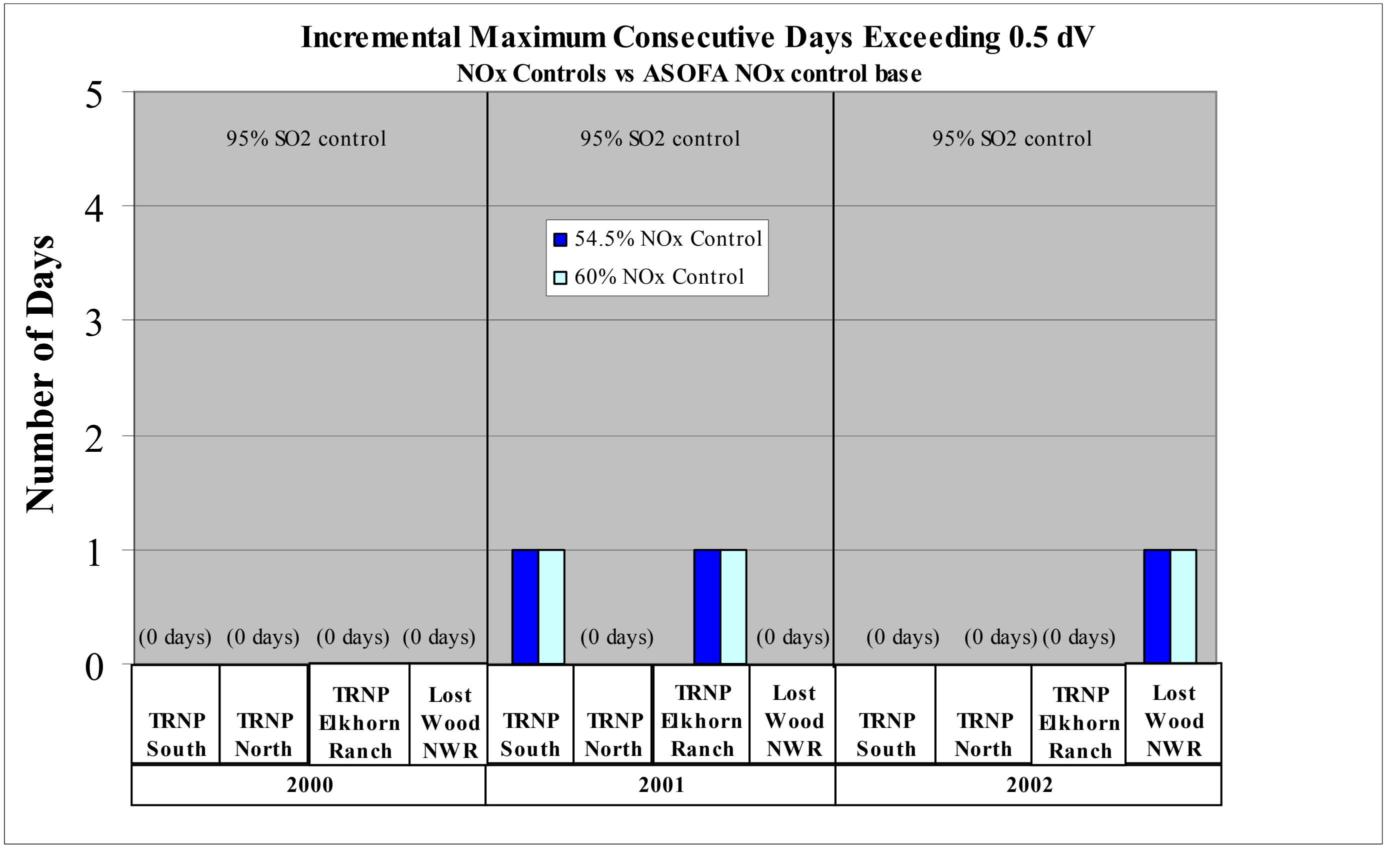


Table 2.5-16 – Impacts Summary for LOS Unit 2 NO_X Controls (vs Pre-Control PTE NO_X Emissions)

NO_X Control Technique w/ SO_2 Alternative	NO_X Control Efficiency (%)	Annual NO_X Emissions Reduction (tpy)	Levelized Total Annual Cost(1) ($)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Incremental Visibility Impairment Reduction Unit Cost(1),(3) ($/dV-yr)	Energy Impact (kW)	Non Air Quality Impacts
					Class 1 Area	Incremental(2) ΔdV			
RRI+SNCR w/ ASOFA	60.3%	9,096	14,900,000	1,640	TRNP-S	0.078	177,900,000	284	Flyash unburned carbon increase
					TRNP-N	0.051	271,000,000		
					TRNP-Elk	0.033	423,000,000		
					LNWR	0.094	147,500,000		
SNCR w/ ASOFA	54.5%	8,235	9,320,000	1,130	TRNP-S	0.063	131,700,000	155	Flyash unburned carbon increase
					TRNP-N	0.040	204,600,000		
					TRNP-Elk	0.027	309,500,000		
					LNWR	0.079	104,900,000		
ASOFA	28%	4,193	1,060,000	254	TRNP-S	base	base	1	Flyash unburned carbon increase
					TRNP-N	base	base		
					TRNP-Elk	base	base		
					LNWR	base	base		

(1) - All cost figures in 2005 dollars.
(2) - Average predicted visibility impairment impact improvements (incremental, 90th percentile) from PTE post-control NO_X emission levels relative to ASOFA post-control NO_X emission levels; all cases have 95% control SO_2 emission level and same PM post-control level at 5,130 mmBtu/hr heat input and 8,760 hours per year operation for the future PTE case, for 2000-2002.
(3) - Incremental LTAC for RRI+SNCR w/ ASOFA = $13,820k/yr; SNCR w/ ASOFA = $8,250k/yr; vs ASOFA = $0k/yr (base), divided by incremental ΔdV. See Table 2.5-14 for details.

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3.0 SO_2 BART EVALUATION

The BART determination process has five predefined steps as described in Section 1. In this section, steps 1 through 5 of the BART determination for Leland Olds Station (LOS) are described for SO_2 and a presentation is made of the results. Potentially applicable SO_2 control technologies are first identified. A brief description of the processes and their capabilities are then reviewed for availability and feasibility. A detailed technical description of each control technology is provided in Appendix B1. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal SO_2 control capability. The impacts analysis then reviews the estimated capital and O&M costs for each alternative, including taking a look at Balance Of Plant (BOP) requirements. Following the cost determination, the energy impacts and non-air quality impacts are reviewed for each technology. The impact based on the remaining useful life of the source is reviewed as part of the cost analysis. In the final step of the analysis, feasible and available technologies are assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the impact analyses are tabulated and potential BART control options are listed.

3.1 IDENTIFICATION OF RETROFIT SO_2 CONTROL TECHNOLOGIES

The initial step in the BART determination is the identification of retrofit SO_2 control technologies. In order to identify the applicable SO_2 control technologies, several reference works were consulted, including "Controlling SO_2 Emissions: A Review of Technologies (EPA-600/R-00-093, October 2000) and the RACT/BACT/LAER Clearinghouse (RLBC). From these and other literature sources, a preliminary list of control technologies and their estimated capabilities was developed. Table 3.1-1 contains the results of this effort.

TABLE 3.1-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Fuel Switching	$\leq$77%
Coal Cleaning	$\leq$30%
Wet Flue Gas Desulfurization	95%
Spray Dryer Absorber (SDA)	90%
Circulating Dry Scrubber (CDS)	93%
Flash Dryer Absorber (FDA)	90%
Powerspan ECO™	98%

SO_2 emissions from the combustion of coal are due to the sulfur content of the coal participating in the combustion process. Sulfur is present in coal in both organic and inorganic forms. Upon combustion, these compounds disassociate and the sulfur component is oxidized to SO_2 and SO_3. For the purpose of BART determination, it is assumed that 100% of the sulfur content of the coal is oxidized and present in the flue gas stream as SO_2. Removal of SO_2 from flue gas can either be accomplished prior to combustion, or post combustion. Pre-combustion methods include coal washing and fuel switching. Post-combustion methods include wet Flue Gas Desulfurization (FGD) with limestone and three semi-dry FGD technologies using lime. Additionally, there are developing multi-pollutant technologies such as the PowerSpan Electro-Catalytic Oxidation (ECO™) system which targets SO_2, NO_X, and mercury. Following are descriptions and technical analyses of the identified technologies for application to LOS.

3.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. The BART guidelines discuss consideration of two key concepts during this step in the analysis. The two concepts to consider are the "availability" and "applicability" of each control technology. A control technology is considered available, "if it has reached the stage of licensing and commercial availability." (70 FR 39165) On the contrary, a control technology is not considered available, "if it is in the pilot scale testing stages of development." (70 FR 39165) When considering a source's applicability, technical judgment must be exercised to determine "if it can reasonably be installed and operated on the source type." (70 FR 39165) The technical and feasibility analysis is presented below for each identified option.

3.2.1 PRE-COMBUSTION FUEL TREATMENTS

3.2.1.1 FUEL SWITCHING

Fuel switching can be a viable method of fuel sulfur content reduction in certain situations. Often, fossil fuel fired EGUs are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of LOS, both boilers were designed and constructed specifically for firing North Dakota lignite, which is a low Btu content, high ash, high moisture, medium sulfur content fuel. For this analysis, fuel switching would consist of changing from North Dakota lignite to Powder River Basin (PRB) sub-bituminous coal. Technical characteristics associated with fuel switching are described in Appendix B1.

Basin Electric Power Cooperative conducted a short term test burn of PRB coal at LOS Unit 1 and 2 on February 5-12, 1997.[1] An analysis of this coal is provided in Table 1.2-2. Approximately 50,000 tons of PRB were burned during the test. Approximately one half of the test period was at high load conditions and the remainder at low load. Because the test period was short, the long term effects of a PRB coal conversion were not evaluated. However, several short term effects were observed including the following:

- Coal delivery problems related to delivery train length were observed and rail system modifications would be required for a complete conversion.
- Little risk of coal fires in the coal receiving and handling systems were encountered, or expected for long term conversion. However, additional coal fire suppression systems would likely be required for the coal bunkers as a safety precaution.
- Due to the greater heat content, a 20% reduction in fuel quantity (mass) was observed. Operating requirements, including fuel handling system power and maintenance were estimated to decrease 15% during the test period.
- Coal dust generation was observed to increase with PRB coal, which may necessitate additional dust control measures on coal handling equipment.
- Reduced ash quantities were observed during the tests, but not quantified. Minor adjustments to the ash handling systems were required to achieve satisfactory operation.
- Stack opacity conditions were stable, but were observed to deteriorate somewhat during the high load portion of the test, despite lower ash quantities. The cause of this was thought to be higher ash resistivity effects on electrostatic precipitator performance. Flue gas conditioning might be required for a full conversion to mitigate this effect.
- Air heater performance decreased, most likely due to reduced flue gas flow rates. While firing PRB total flue gas flow dropped approximately 15% on Unit 1. A similar reduction in flue gas flow was not observed on Unit 2.
- Induced Draft and Forced Draft fan power requirements decreased slightly during all parts of the test burn. Total air required for PRB coal was approximately 88% of that required for lignite under the same conditions. Specifically for Unit 1, current draw (amps) on the forced draft fan remained unchanged while the primary air and induced draft fan current demands decreased approximately 11%.
- On Unit 2, Gas Recirculation fan power requirements increased by approximately 4% during high load tests and almost 31% during low load testing.

- Boiler efficiency increased approximately 2.4%, primarily due to lower fuel moisture content in the as-received condition. As a result the Net Plant Heat Rate decreased by approximately 300 Btu/kW for Unit 1 and 350 Btu/kW for Unit 2.
- Station service requirements decreased approximately 2% with PRB coal. This was primarily attributed to lower combustion air requirements.
- Stable operating conditions, observed as similar main and reheat steam temperatures and attemperator flows, were observed at both high and low loads.
- Due to the test's brevity, it was not possible to observe changes in slag deposition locations or rates and possible effects on boiler operation.
- During an URGE (Uniform Rating of Generating Equipment) test for Unit 2, the unit became unstable and the test had to be discontinued. The URGE test is a test at maximum operating conditions.

Switching to a fuel such as PRB coal will achieve significant SO_2 emission reductions. The PRB coal listed in Table 1.2-2 is one of the lower sulfur coals available in the U.S. Switching to this coal would nominally achieve a 77% reduction in SO_2 emissions for the same heat input. However, additional SO_2 control measures, such as the post combustion controls listed in Table 3.1-1 might be required to achieve BART.

As shown during the short test in 1997, conversion of LOS to fire PRB coal is feasible, although several long term effects were not assessed during the test and some currently unidentified plant modifications may be required for a full conversion. Therefore, for the purpose of this BART analysis, fuel switching is considered a viable option for SO_2 control.

3.2.1.2 COAL CLEANING

The effectiveness of coal cleaning is strongly dependent upon the chemical form of sulfur in the coal. Traditional coal cleaning methods consist of crushing the coal and then separating and removing inorganic impurities including much of the inorganic sulfur and ash content using a gravimetric separation process. However, sometimes the majority of the sulfur is contained in the organic matrix of the coal and is difficult or impossible to remove using this process. While gravimetric processes can reduce the sulfur and ash content of a given coal, at the time of this report, no commercial scale, gravimetric coal cleaning systems are in operation that can significantly reduce the sulfur content of North Dakota lignite. Due to lack of commercial experience, traditional coal cleaning systems were determined not to be commercially available as a BART alternative and were not analyzed further.

Another form of coal cleaning that specifically targets low-rank coals, like lignite, uses a different process to reduce sulfur emissions. The K-Fuel™ process, developed by KFx, uses patented heating and pressurization methods to reduce the moisture content of the fuel and remove some of the pollutants. Although the process may remove some of the sulfur components in the coal, the main focus of the process is to remove moisture and increase the coal heating value. By increasing the coal heating value, less of the treated fuel will be required to achieve an equivalent boiler heat input. By burning less fuel there will be fewer emissions. KFx estimates that the K-Fuel™ coal cleaning process might effectively reduce the sulfur content of the lignite fuel by up to 30%. To simplify cost estimates associated with coal cleaning and due to the uncertainties associated with application of the K-Fuel™ process to North Dakota lignite, the analysis assumes that stated efficiencies translate directly to operations. In other words, a 30% reduction efficiency for sulfur content results in a 30% reduction in SO_2 and a 30% increase in heat content results in a 30% decrease in fuel usage. A test burn, which would be required to provide more specific data related to burning the K-Fuel™ product, was not available. Technical characteristics associated with the process can be found on the KFx website at kfx.com. Based on the estimated 30% control being significantly less efficient than the presumptive limits and the control efficiencies of the other control technologies, the K-Fuel™ process was identified as having insufficient SO_2 reduction for BART. Due to the lower removal efficiency, the K-Fuel™ process is not considered a reasonable BART alternative and is not analyzed further.

3.2.2 POST-COMBUSTION FLUE GAS DESULFURIZATION

Five different post-combustion processes for reducing SO_2 emissions were evaluated as BART alternatives in this analysis. These include two well established Flue Gas Desulfurization (FGD) processes (wet and semi-dry); two recent variations of the semi-dry technology, the Circulating Dry Scrubber (CDS) and the Flash Dryer Absorber™ (FDA) as well as the Power-Span Electro Catalytic Oxidation (ECO™) process.

Commercially-available wet and semi-dry FGD processes achieve SO_2 removal by absorption of the SO_2 into an aqueous slurry which contains a neutralizing agent, normally either lime or ground limestone. Chemical reaction(s) between the SO_2 and the neutralizing agent convert the SO_2 to a stable compound that can be readily sold or disposed of in a permitted facility.

One significant difference between the wet and semi-dry systems is the degree of saturation of the flue gas that is achieved in the process. The wet FGD process saturates the flue gas as a result of water evaporation from the slurry utilized to absorb and neutralize SO_2. Wet FGD process design must take into account both corrosion and scale formation in the wet parts of the system which can interfere with process operations. The flue gas saturation zone, where the hot dry flue gas first enters the absorber vessel and encounters the wet FGD slurry spray, is an area of constantly shifting chemistry. With the shifting back and forth between hot, dry conditions and cooler, wet conditions, this area experiences the most aggressive corrosion of any part of the scrubbing system. Consequently, exotic materials of construction are used in the wet FGD system to combat the corrosive environment.

The semi-dry FGD process utilizing a spray dryer absorber (SDA) utilizes an aqueous slurry as well, but the degree of flue gas saturation due to evaporation is controlled to a point well above the saturation temperature so that the semi-dry FGD byproducts are a dry free flowing solid leaving the absorber and corrosion problems are minimized. CDS' and FDAs operate similarly to the SDA, except that they utilize greater amounts of recycled flyash mixed with dry hydrated lime that is moistened by water and injected into the reactor. Here the moisture coats the surface of the recycled particles in a thin film and then the water evaporates, as opposed to evaporating an entire droplet of water containing lime slurry as in the SDA. The water content of the slurry droplet or liquid film evaporates and SO_2 is absorbed and neutralized simultaneously. All of the dry and semi-dry FGD technologies require a particulate matter control device downstream of the reactor. Therefore, these technologies are often referred to in this report with a /FF following the absorber designation. The reaction products of the semi-dry FGD processes, including the SDA, CDS and FDA, are mixed with flyash when captured, and thus not do not generally have an aftermarket value.

The most common chemical reagents used in FGD processes are quicklime (calcium oxide, CaO), hydrated lime (calcium hydroxide, $Ca(OH)_2$) and limestone (predominantly calcium carbonate, $CaCO_3$). As a general rule of thumb, wet FGD processes can be assumed to utilize limestone and semi-dry FGD, including SDA, CDS and FDA systems, use lime. There are wet FGD processes that utilize lime, but these are generally used in situations where limestone is not readily available and these incur greater operating costs as a result. Dry and semi-dry FGD systems exclusively utilize lime because of its greater reactivity under typical dry and semi-dry operating conditions.

The wet FGD process was exclusively used for FGD retrofits for compliance with Phase I of the Acid Rain Program. The semi-dry process is a common SO_2 control measure identified in the review of recent new coal-fired boiler BACT determinations from the EPA's RACT/BACT/LAER

Clearinghouse (RBLC). The FDA and CDS technologies are more recent developments in semi-dry FGD technology.

3.2.2.1 WET FLUE GAS DESULFURIZATION

Wet FGD technology utilizing lime or limestone as the reagent and employing forced oxidation to produce gypsum (calcium sulfate dihydrate, $CaSO_4 \cdot 2H_2O$) as the byproduct, is commonly applied to coal-fired boilers. Wet FGD utilizes either an open spray tower, or a spray tower with a perforated plate contactor to expose flue gas to the neutralizing slurry. Absorbed SO_2 is converted to calcium sulfite and then oxidized to calcium sulfate dihydrate (gypsum) which is filtered from the scrubber solution and either disposed of in a permitted disposal facility, or possibly sold for either wallboard or cement production. Historically wet FGD systems have operated with an SO_2 control efficiency anywhere from 70% to in excess of 95%. For the purposes of this study, wet FGD performance was evaluated at 95% SO_2 control as representative of presumptive BART requirements. Further technical characteristics associated with wet FGD are described in Appendix B.

Based on the ability of a wet FGD system to achieve 95% percent SO_2 removal efficiencies and commercial availability and applicability, wet FGD systems were found to be an acceptable BART alternative for SO_2 emission control.

3.2.2.2 SEMI-DRY FLUE GAS DESULFURIZATION

As an alternative to wet FGD technology, the control of SO_2 emissions can be accomplished using semi-dry FGD technology. The most common semi-dry FGD system is the lime Spray Dryer Absorber (SDA) using a fabric filter for downstream particulate collection.

There are several variations of the semi-dry process in use today. This section addresses the spray dryer FGD process. Two other variations, the Flash Dryer Absorber and Circulating Dry Scrubber are addressed in following sections. They primarily differ by the type of reactor vessel used, the method in which water and lime are introduced into the reactor and the degree of solids recycling. Technical characteristics associated with the SDA are described in Appendix B.

No variation of semi-dry FGD systems has clearly demonstrated the ability to achieve SO_2 removal levels similar to wet FGD systems in the U.S. Table B-1, in Appendix B, lists many of the recent lime spray dryer system installations in the U.S. The information in Table B-1 was obtained from the RACT/BACT/LAER Clearing House. Two units were recently permitted with SO_2 emission rates representing removal efficiencies of 94.5% and 95%. However, Burns & McDonnell recently completed a study of the emission reduction performance of existing, electric utility, semi-dry FGD systems.[3] Information utilized for the evaluation was derived from EIA coal quality data and EPA SO_2 stack emissions and heat input data. The evaluation determined that the highest SO_2 removal efficiency maintained on a continuous basis was just above 90%. No unit was able to maintain an efficiency of 95%. For the purpose of this BART determination, semi-dry FGD is considered a viable alternative, but the upper bound on SO_2 removal efficiency was set at 90% for application based on a review of the historic performance of this technology.

3.2.2.3 FLASH DRYER ABSORBER FLUE GAS DESULFURIZATION

The Flash Dryer Absorber (FDA) is a further development of the semi-dry FGD process. The approach is similar to the SDA in that the flue gas is only partially saturated during the process and thus corrosion problems are either reduced or eliminated. Like the SDA, the FDA mixes lime, water and recycled PM for enhanced surface area. Unlike the SDA, the FDA recycles a very high fraction of the captured PM and the flue gas flows vertically upward in the FDA. A second difference for the FDA is that it utilizes quicklime, instead of hydrated lime as a reagent. Additional technical characteristics associated with FDA are described in Appendix B.

The FDA is a relatively recent modification of the semi-dry FGD concept and as such, has not established a significant field record at this time. In their paper on FDA technology in 2002[4], Alstom cited a 280 MW plant in China with an 85% SO_2 removal efficiency. In its review of a recent Alstom proposal for a project involving an FDA downstream of a CFB boiler with limestone injection, Burns & McDonnell noted that the FDA mass balance included in the bid package indicated approximately 78% of the overall SO_2 removal occurred in the boiler. The FDA/FF combination on that project was guaranteed to achieve 75% SO_2 removal, but started with a significantly lower inlet SO_2 concentration that directly affects removal efficiency. Contrary to the lower emission rates presented in this section, the FDA has been shown to be similar in SO_2 removal performance to the SDA and thus was determined to be a feasible SO_2 control alternative for LOS.

3.2.2.4 CIRCULATING DRY SCRUBBER FLUE GAS DESULFURIZATION

In the circulating dry scrubbing process, the flue gas is introduced into the bottom of a reactor vessel at high velocity through a venturi nozzle, and mixed with water, hydrated lime, recycled flyash and FGD reaction products. A CDS absorber vessel for either LOS unit would be a smaller diameter than the SDA discussed previously in this report. Particles that are entrained in the flue gas leaving the top of the reactor are collected in an ESP or fabric filter downstream of the CDS absorber. A large portion of the collected particles is recycled to the reactor to sustain the bed and improve lime utilization. CDS absorbers have been installed with both fabric filters and ESPs for particulate control. Additional technical characteristics associated with CDS are described in Appendix B.

For the purpose of this analysis, the CDS technology is evaluated with a maximum SO_2 removal efficiency of 93% with a reagent utilization ratio approximately 10% greater than that of a similar SDA. The CDS was considered a feasible SO_2 control technology for the purpose of this study.

3.2.2.5 POWERSPAN ELECTRO-CATALYTIC OXIDATION (ECO™) TECHNOLOGY

The Powerspan Electro-Catalytic Oxidation (ECO™) system is a multipollutant control technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO™ process has two main process vessels; a barrier discharge reactor and a multi-level wet scrubber. Additional technical characteristics associated with the ECO™ process are described in Appendix B.

Powerspan claims a routine SO_2 removal efficiency of 98% with inlet concentrations up to approximately 2,000 ppm and testing at a pilot plant has demonstrated performance, reliability and economics. However, no full size commercial scale ECO™ systems have been installed or are operating at the time of this report. The ECO system was determined not to be a feasible BART alternative because it is not commercially available.

3.2.3 RESULTS OF FEASIBILITY ANALYSIS

The evaluations of the identified BART alternatives following the feasibility analysis are summarized in Table 3.2-1.

TABLE 3.2-1 – BART SO_2 Control Feasibility Analysis Results

Control Technology	In service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable To Leland Olds Station
Fuel Switching	Yes	Yes	Yes	Yes
Coal Cleaning	No	Yes	Yes	No
Wet FGD	Yes	Yes	Yes	Yes
Lime Spray Dryer	Yes	Yes	Yes	Yes
Circulating Dry Scrubber	Yes	Yes	Yes	Yes
Flash Dryer Absorber	Yes	No	Yes	Yes
Powerspan ECO™	No	No	No	Yes

3.3 EVALUATE TECHNICALLY FEASIBILE SO_2 CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to evaluate the control effectiveness of the technically feasible alternatives. During the feasibility determination in step 2 of the BART analysis, the control efficiency was reviewed and presented as part of the technical description for each technology. The evaluations of the remaining BART alternatives following the feasibility analysis are summarized in Table 3.3-1. The alternatives are ranked in descending order according to their effectiveness in SO_2 control.

TABLE 3.3-1 – SO_2 Control Technologies Identified for BART Analysis

Control Technology	Control Efficiency
Wet Limestone Flue Gas Desulfurization	95%
Circulating Dry Scrubber (CDS)	93%
Spray Dryer Absorber (SDA)	90%
Flash Dryer Absorber (FDA)	90%
Fuel Switching	$\leq$77%

3.4 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART Determination Guidelines (70 FR 39166) lists four factors to be considered in the impact analysis.

- The costs of compliance;

- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four impacts required by the BART Guidelines are discussed in the following sections. The remaining useful life of the source was determined to be greater than the project life definition in the EPA's OAQPS Control Cost Manual (EPA/453/B-96-001) and thus had no impact on the BART determination for LOS. In addition, as described in Section 1.1.6, the visibility impairment impact of each alternative was evaluated as part of the impact analysis.

3.4.1 COST ESTIMATES

Cost estimates for the wet and semi-dry (including SDA and fabric filter) SO_2 control technologies were completed utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency. The CUECost model is a spreadsheet-based computer model that was specifically developed to estimate the cost of air pollution control technologies for utility power plants within +/- 30 percent accuracy. The EPA released the version of the model used for this study in February 2000. The model is available for download from the U.S. EPA website at www.epa.gov/ttn/catc/products.

The user must specify the design parameters for the air pollution control technologies in CUECost. Unit costs for consumables, labor, and other variables can be modified by the user to fit the specific situation under evaluation. Because these models are in spreadsheet form, the calculation procedures and assumptions can be readily determined and adjusted by the experienced user as necessary to fit the unique requirements of the evaluation being conducted. The program itself is also somewhat user adjustable to compensate for local conditions. The CUECost default case is a generic facility located in Pennsylvania. Burns & McDonnell has adjusted the CUECost spreadsheets as described in the following sections to account for known facility and local conditions. In addition, Burns & McDonnell has added the Balance of Plant (BOP) costs not included in CUECost to the base estimate to provide a more complete cost estimate.

Operating information utilized as input into the model for the purpose of cost estimating is listed in Tables 1.2-1 and 1.2-2. Economic information utilized as input into the model is given in Table 1.2-3. Economic information was provided in 2004 by BEPC in 2004 dollars. The model was run with

2004 designated as the cost basis year because equipment cost estimating in the model is based on the Chemical Engineering Cost Index and the composite 2004 index is the latest version available. Following completion of the estimating on a 2004 cost basis year, all costs were escalated to a 2005 basis year utilizing the inflation rates designated in Table 1.2-3.

The default General Facilities factor in CUECost is 10% of the direct costs. Because LOS is located in North Dakota where weather protection requirements are much greater than the default state of Pennsylvania, the General Facilities factor was increased to 15% to account for this additional cost.

The electrical subcontract in the BOP cost estimates includes the electrical equipment, materials and labor for engineering, procurement and installation of all electrical distribution system components for each alternative as required. The electrical estimate is based on recent experience with the LOS plant and local costs developed during a recent electrical upgrade project at LOS.

The foundation subcontract cost estimate for each alternative includes 80-foot deep piles and the necessary design and installation provisions for the high water table at the LOS plant site. The number of piles and the amount of concrete and steel required were developed from previous experience completing foundation designs for similar sized air pollution control equipment. The additional foundation subcontract was required because the generic capital cost information provided by CUECost is based on typical spread footing type foundations and does not include these extra provisions required for installation at LOS.

Capital costs for the additional alternatives were estimated from various literature sources and Burns & McDonnell's in-house experience and resources. Information from such sources was adjusted for known local conditions and BOP costs were added separately.

The indirect costs are estimates of additional costs expected to be incurred during a complete project. Engineering costs are estimated as a percentage of total direct costs and are representative of the cost for architectural/engineering services such as system design, specification production, contract evaluations and negotiations, contract administration and construction field services. The contingency is also a percent of the total direct costs and accounts for miscellaneous scope items not covered by the direct cost estimate. Finally, the BEPC indirect costs are an estimation of BEPC internal costs that would be incurred for the implementation of each alternative.

3.4.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (booster fans and ductwork) and support systems. BOP costs include a wet stack, make-up water treatment plant, electrical subcontract, foundations subcontract and repair/upgrade of the existing railroad tracks for limestone delivery. The results of the capital cost estimate are given in Table 3.4-1.

CUECost includes a cost estimate for a wet stack, but based upon Burns & McDonnell's recent experience with wet stack construction costs, this estimate was deleted from the CUECost results and a revised estimate by Burns & McDonnell was included in the BOP costs. The new stack estimate includes an alloy C-276 liner for the wet stack. The new wet stack was assumed to be 500' in height instead of the current 350' height of the existing LOS Unit 1 dry stack to prevent plume capture in building wakes.

The BOP costs include make-up water treatment equipment costs for pumps, piping, filters, and a clarifier. An estimated building cost for the makeup water treatment system is included in the Foundations Subcontract estimate.

Also included in the Foundations Subcontract cost estimate are roofed, two-walled enclosures for limestone and gypsum temporary storage to provide for weather protection.

An evaporation pond for disposal of periodic scrubber blowdown was included in the capital cost estimate.

Railroad delivery of limestone, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for limestone delivery to the LOS Unit 1 limestone railcar unloading station. The estimate also includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

TABLE 3.4-1 – Capital Cost Estimate for LOS Unit 1 Wet FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Reagent Prep System	$14,050,000	$2,110,000	$16,160,000
SO_2 Absorption System	$21,110,000	$3,170,000	$24,280,000
Flue Gas Handling System	$7,710,000	$1,160,000	$8,860,000
ByProduct Handling System	$1,740,000	$260,000	$2,000,000
Support Equipment	$2,210,000	$330,000	$2,540,000
		FGD Total Direct Cost =	**$53,840,000**
BOP COSTS			
Wet Stack	$7,490,000	NA	$7,490,000
Water Treatment Equipment	$840,000	NA	$840,000
Evaporation Pond	$930,000	NA	$930,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Ductwork	$3,430,000	NA	$3,430,000
Foundations Subcontract	$1,890,000	NA	$1,890,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$21,780,000**
		Total Direct Cost =	**$75,620,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$15,120,000
		A/E Engineering and Construction Management (10% of DC)	$7,430,000
		Allowance For Funds During Construction (AFDC 6%)	$4,540,000
BEPC INDIRECTS			
		Project Development (1% of DC)	$760,000
	Spare Parts & Plant Equipment		
		Rolling Stock	$500,000
		Initial Inventory Spare Parts (1.5% of DC)	$1,130,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$380,000
		Construction All-Risk Insurance (1.5% of DC)	$1,130,000
		Contingency (15% of BEPC Indirects)	$470,000
		Indirect Cost Subtotal	$31,600,000
		Total Capital Cost	**$107,220,000**

The total estimated capital cost estimate for a complete, stand-alone wet FGD system utilizing limestone reagent and forced oxidation is $107,220,000, or $487/kW for Unit 1.

3.4.1.2 CIRCULATING DRY SCRUBBER CAPITAL COST ESTIMATE

The Circulating Dry Scrubber (CDS) FGD technology is a relatively recent innovation in the United States, but has been used previously in Europe. Cost information on the CDS system is not as widely available as the more common wet and semi-dry systems. Capital costs for the CDS system were based on CUECost estimates for the SDA semi-dry FGD system with modifications to reflect the design and operational differences. Several literature sources[5, 6] and Burns & McDonnell in-house information were utilized in making these modifications. The CDS cost estimate is presented in a line item format with individual items adjusted to reflect differences between the CDS and SDA. The capital cost estimate is presented in Table 3.4-2.

The CDS absorber vessel is similar to the SDA, but smaller in diameter to provide for a greater gas velocity to make fluidized bed operation possible. The cost of the CDS absorber vessel was estimated at 80% of the cost of the SDA absorber vessel.

Because the CDS recirculates a much greater fraction of the flyash and absorber reaction products (80-95% vs. 30%) than the SDA, the byproduct handling system cost for the SDA was increased by 100% for the CDS estimate to account for the greater system capacity requirements.

The estimated cost for ancillary support equipment was also based on the SDA estimate from CUECost. The CUECost estimate for these systems for the SDA was increased by 10% to reflect the additional reagent usage and higher recycle flow rate.

The CUECost estimate for SDA flue gas handling systems was increased by 15% to account for the additional booster fan capacity required to accommodate the greater pressure drop of the CDS. Ductwork costs were assumed not to change due to the CDS configuration versus the SDA.

TABLE 3.4-2 – Capital Cost Estimate for LOS Unit 1 CDS FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
CDS System			
Reagent Prep System	$12,830,000	$1,920,000	$14,750,000
SO_2 Absorption System	$9,140,000	$1,370,000	$10,510,000
Flue Gas Handling System	$7,000,000	$1,050,000	$8,040,000
ByProduct Handling System	$3,620,000	$540,000	$4,160,000
Support Equipment	$2,940,000	$440,000	$3,380,000
		CDS Total Direct Cost =	**$40,840,000**
Fabric Filter			
Fabric Filter Housing	$8,840,000	$1,330,000	$10,160,000
Bags	$1,290,000	$190,000	$1,480,000
Ash Handling System	$6,620,000	$990,000	$7,610,000
Instruments & Controls	$300,000	$40,000	$340,000
		Fabric Filter Total Direct Cost =	**$19,590,000**
BOP Costs			
Water Treatment Facility	$700,000	NA	$700,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Ductwork	$3,430,000	NA	$3,430,000
Foundations Subcontract	$1,790,000	NA	$1,790,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$13,120,000**
		Total Direct Cost =	**$73,560,000**

INDIRECT COSTS	
Contingency (20% of DC)	$14,710,000
A/E Engineering and Construction Management (10% of DC)	$7,660,000
Allowance For Funds During Construction (AFDC 6%)	$4,600,000
BEPC INDIRECTS	
Project Development (1% of DC)	$740,000
Spare Parts & Plant Equipment	
Rolling Stock	$500,000
Initial Inventory Spare Parts (1.5% of DC)	$1,100,000
Plant Furnishings (0.5% of DC)	$370,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$370,000
Construction All-Risk Insurance (1.5% of DC)	$1,100,000
Contingency (15% of BEPC Indirects)	$570,000
Indirect Cost Subtotal	$31,230,000
Total Capital Cost	**$104,790,000**

Because the CDS recirculates a much greater fraction of flyash and absorber reaction products than the SDA, the estimated cost for the ash handling system was increased 25% over the CUECost estimate for the SDA. In the same manner, the estimated ash handling system and instrumentation and control costs were increased to reflect additional capacity requirements.

A new stack was not included in the BOP capital cost estimate. It was assumed that the CDS facility would be located on the west side of the plant near Unit 1 and that the existing stack could be reused. Included in the Foundations Subcontract cost estimate is a silo for temporary storage of waste products prior to transport to the permitted waste disposal facility.

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 1 railcar unloading station. The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone CDS with Fabric Filter for SO_2 control for LOS Unit 1, utilizing hydrated lime as a reagent is $104,790,000, or $476/kW.

3.4.1.3 SEMI-DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the semi-dry FGD system include the SDA, fabric filter, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a lime SDA/FF system supplier. The SDA/FF system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, spray dryer absorber, waste handling systems, flue gas handling systems (booster fans and ductwork) and support systems. A fabric filter is included in the estimate for the capture of entrained absorption products. BOP costs include an electrical subcontract, foundations subcontract, water treatment equipment and repair/upgrade of the existing railroad tracks for lime delivery. The results of the capital cost estimate are given in Table 3.4-3.

A new stack was not included in the capital cost estimate. It was assumed for the purpose of the estimate that the existing stack would be reused as the flue gas is not near saturation.

Included in the Foundations Subcontract cost estimate is a silo for temporary waste product storage.

TABLE 3.4-3 – Capital Cost Estimate for LOS Unit 1 Semi-Dry FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
SDA System			
Reagent Prep System	$9,410,000	$1,410,000	$10,820,000
SO_2 Absorption System	$10,990,000	$1,650,000	$12,640,000
Flue Gas Handling System	$6,360,000	$950,000	$7,310,000
ByProduct Handling System	$1,770,000	$270,000	$2,040,000
Support Equipment	$2,670,000	$400,000	$3,070,000
		SDA Total Direct Cost =	**$35,880,000**
Fabric Filter			
Fabric Filter Housing	$8,840,000	$1,330,000	$10,160,000
Bags	$1,290,000	$190,000	$1,480,000
Ash Handling System	$3,560,000	$530,000	$4,100,000
Instruments & Controls	$300,000	$40,000	$340,000
		Fabric Filter Total Direct Cost =	**$16,080,000**
BOP Costs			
Water Treatment Equipment	$380,000	NA	$380,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Ductwork	$1,790,000	NA	$1,790,000
Foundations Subcontract	$3,430,000	NA	$3,430,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$12,800,000**
		Total Direct Cost =	**$64,760,000**

INDIRECT COSTS	
Contingency (20% of DC)	$12,950,000
A/E Engineering and Construction Management (10% of DC)	$6,320,000
Allowance For Funds During Construction (AFDC 6%)	$3,790,000
BEPC INDIRECTS	
Project Development (1% of DC)	$650,000
Spare Parts & Plant Equipment	
Rolling Stock	$500,000
Initial Inventory Spare Parts (1.5% of DC)	$970,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$320,000
Construction All-Risk Insurance (1.5% of DC)	$970,000
Contingency (15% of BEPC Indirects)	$510,000
Indirect Cost Subtotal	$27,240,000
Total Capital Cost	**$92,000,000**

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 1 railcar unloading station.

The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone SDA/FF FGD system on LOS Unit 1, utilizing hydrated lime as a reagent is $92,000,000, or $418/kW.

3.4.1.4 FLASH DRYER ABSORBER CAPITAL COST ESTIMATE

The Flash Dryer Absorber (FDA) is a relatively recent development of the semi-dry FGD process. Because few FDA's have been placed in service at this time, cost breakdown information is difficult to find for them. The FDA cost estimate presented here is primarily based on in-house pricing information from Burns & McDonnell for an FDA/FF application to LOS Unit 1. The cost estimate includes the FDA reactor, the hydrator/mixer, the solids recycling system, and the Fabric Filter, with local waste solids handling systems. Additional cost information, for equipment and systems not included in the indicative pricing, were taken from the CUECost SDA cost estimate with individual line items adjusted to reflect modifications based on known differences in individual system capacities and capabilities. The results of the capital cost estimate for the FDA and Fabric Filter, along with BOP requirements, is provided in Table 3.4-4.

The estimated cost for the reagent preparation system for the FDA was taken as the CUECost estimate for a semi-dry system, including the estimated cost of a lime hydrator.

Estimated water treatment plant costs for the FDA system were decreased 45% from those of the wet FGD to reflect the lower makeup water requirements estimated for the FDA system.

The cost of the electrical subcontract for the FDA system was estimated to be equivalent to that of the semi-dry system due to the similarities in equipment requirements. Where system capacities changed significantly, such as ash handling systems, the number and capacity of electrical subsystems will undoubtedly change. However, sufficient information was not available to differentiate between the SDA and FDA electrical subsystem costs.

TABLE 3.4-4 – Capital Cost Estimate for LOS Unit 1 FDA with Fabric Filter

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
FDA System			
Reagent Prep System	$9,410,000	$1,410,000	$10,820,000
SO_2 Absorption System	$6,250,000	$310,000	$6,560,000
Flue Gas Handling System	$5,900,000	$890,000	$6,790,000
ByProduct Handling System	$1,470,000	$221,000	$1,691,000
Support Equipment	$2,400,000	$360,000	$2,760,000
		FDA Total Direct Cost =	**$28,620,000**
Fabric Filter			
Fabric Filter Housing	$10,630,000	$1,870,000	$12,500,000
Bags	$1,615,000	$285,000	$1,900,000
Instruments & Controls	$4,477,000	$790,000	$5,267,000
Ash Handling Systems	$2,270,000	$340,000	$2,610,000
		Fabric Filter Total Direct Cost =	**$22,300,000**
BOP Costs			
Water Treatment Plant	$570,000	NA	$570,000
Electrical Subcontract	$5,520,000	NA	$5,520,000
Ductwork	$3,430,000	NA	$3,430,000
Foundations Subcontract	$1,890,000	NA	$1,890,000
Railroad Upgrade/Repair	$300,000	NA	$300,000
		BOP Total Direct Cost =	**$11,140,000**
		Total Direct Cost =	**$62,060,000**

INDIRECT COSTS	
Contingency (20% of DC)	$12,520,000
A/E Engineering and Construction Management (10% of DC)	$5,620,000
Allowance For Funds During Construction (AFDC 6%)	$3,370,000
BEPC Indirects	
Project Development (1% of DC)	$630,000
Spare Parts & Plant Equipment	
Rolling Stock	$500,000
Initial Inventory Spare Parts (1.5% of DC)	$940,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$310,000
Construction All-Risk Insurance (1.5% of DC)	$940,000
Contingency (15% of BEPC Indirects)	$500,000
Indirect Cost Subtotal	$26,360,000
Total Capital Cost	**$88,980,000**

An estimate was not provided for a new stack for Unit 1. For the purposes of this study, it was assumed that the existing Unit 1 stack would be reused.

The estimated cost of the foundation subcontract (including pilings and weather enclosures) was left unchanged from that of the SDA primarily because it has been estimated that the reduced foundation requirements of the reactor are offset by the increased foundation requirements of the fabric filter. Similarly, for the basis of this estimate, it was assumed that any reduction in absorber enclosure requirements was offset by additional costs for enlargement of the fabric filter casing(s).

The estimated cost of the railroad upgrade/repair to allow for lime delivery was left unchanged from the SDA estimate because the slight change in reagent usage would not affect the cost of the modifications required to allow for rail delivery.

The total estimated capital cost for the installation of and FDA system on LOS Unit 1 is $88,980,000 or $404/kW.

3.4.1.5 FUEL SWITCHING CAPITAL COST ESTIMATE

The potential for switching to PRB fuel for LOS Unit 1 was investigated by BEPC and an internal report was generated in 1997[1]. This report examined the results of a test burn with a PRB coal similar to the current PRB coal used in the current blended fuel. From the 1997 report, a switch to 100% PRB usage in LOS Unit 1 would impact the operating and maintenance costs, but significant capital expenditures for modification of the coal handling system were not identified. The results of the cost estimate for the fuel switching alternative are given in Table 3.4-5. One significant problem that was identified was the unloading time of the coal delivery trains. Current rail car parking capacity is limited and with the current rail system configuration part of the coal train would have to be parked on the main line while unloading. The potential solutions to this particular problem are not analyzed in the report, though it is mentioned that it is possible the railroad operator can adjust to this condition. A cost estimate for potential rail line modifications was not included in this report because this question was not resolved during the short test period.

The cost of a flue gas conditioning system was included to maintain ESP performance for this alternative. The capital cost estimate for the flue gas conditioning system includes a dry sulfur unloading station, dry sulfur storage hopper, transfer conveyance from storage hopper to sulfur melter, sulfur metering pump skid with MCC and variable speed drives, SO_3 production skid and injection probes with metering ports.

TABLE 3.4-5 – Capital Cost Estimate for Fuel Switching with Flue Gas Conditioning

DIRECT COSTS		Estimated Cost ($2005)
Injection System		$969,000
Unloading Station		(Included Above)
Storage Hopper		(Included Above)
Transfer Conveyor		(Included Above)
Metering Pump Skid		(Included Above)
SO_3 Production Skid		(Included Above)
Injection Probes		(Included Above)
	Total Direct Cost =	**$969,000**
INDIRECT COSTS	Contingency (20% of DC)	$194,000
	A/E Engineering and Construction Management (10% of DC)	$97,000
	Allowance for Funds During Construction (AFDC 6%)	$58,000
BEPC INDIRECTS	Project Development (1% of DC)	$9,700
	Spare Parts & Plant Equipment	
	Initial Inventory Spare Parts (1.5% of DC)	$14,500
	Construction Startup and Support	
	O&M Staff Training (0.5% of DC)	$4,800
	Construction All-Risk Insurance (1.5% of DC)	$14,500
	Contingency (15% of BEPC Indirects)	$5,000
	Indirect Cost Subtotal	$398,000
	Total Capital Cost	**$1,367,000**

Additional capital investments may be required for a switch to PRB fuel, including construction of fuel barns and the installation of additional conveyors, but those costs were not identified as part of this study. The estimated total capital investment for fuel switching alternative for LOS Unit 1, including flue gas conditioning, is estimated to be $1,367,000 or $6.21/kW

3.4.1.6 WET FGD O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance. Table 3.4-6 summarizes the O&M cost estimates for the wet FGD system.

The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated as approximately 3% of the wet FGD system direct capital cost in Table 3.4-1. Administrative and support labor cost was estimated as 12% of the maintenance material and labor cost plus 30 percent of the operating labor costs. Previous studies and guidelines for FGD O&M costs by EPRI and others are in line with these percentages.

TABLE 3.4-6 – O&M Cost Estimate for LOS Unit 1 Wet FGD System

Fixed Costs	
Operating Labor	$1,460,000
Admin and Support labor	$670,000
Maintenance Material and Labor	$1,950,000
Total Fixed O&M Costs =	$4,090,000
Variable Costs	
Limestone Reagent	$1,760,000
Byproduct Disposal	$630,000
Water	$270,000
Auxiliary Power	$1,600,000
Total Variable O&M Costs =	$4,260,000
Total Annual O&M Costs	**$8,350,000**
Net Annual O&M Cost ($/MWh)	**$4.81**

The operating labor cost is based on a total of 15 additional personnel, including two operators per shift (one in the control room and one on roving duty) with two truck drivers at 40 hours per week for hauling of FGD wastes and two laborers on day shift and one on roving assignment. In addition, four maintenance staff working one shift per day, five days per week are included in the maintenance cost estimate.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on consumption rates modeled by the CUECost model and the unit cost information provided by BEPC and described in Table 1.2-3 Economic Design Criteria. A cost of $5.50 per ton for hauling the FGD wastes was included for waste disposal. No additional cost for landfilling at the permitted solid waste facility was included. The total estimated annual O&M cost for application of wet FGD to LOS Unit 1 is $8,350,000 or $4.81/kW.

3.4.1.7 CIRCULATING DRY SCRUBBER O&M COST ESTIMATE

Estimated O&M costs for the CDS/FF alternative were developed from the CUECost estimate of the O&M costs for the SDA/FF alternative. The operating labor was increased by 8% over that of the SDA as indicated in a recent study by Sargent & Lundy[5] comparing the two alternative technologies. Administration and Support and maintenance and material costs were similarly increased 8% based upon the same reference. The CDS reagent usage was also increased 17% (effective stoichiometric ratio of 2.1) above that for the SDA based upon the same findings. Waste disposal costs were increased 5% over those of the SDA, as estimated by CUECost, to reflect the increased reagent wastage. The power requirement for the CDS was increased 15% over that estimated by CUECost for the SDA based upon Sargent & Lundy's findings[5]. The estimated annual O&M costs for application of the CDS/FF alternative at LOS Unit 1 are given in Table 3.4-7.

TABLE 3.4-7 – O&M Cost Estimate for LOS Unit 1 CDS/FF System

Fixed Costs	
Operating Labor	$1,280,000
Admin and Support labor	$400,000
Maintenance Material and Labor	$1,460,000
Total Fixed O&M Costs =	$3,140,000
Variable Costs	
Lime Reagent	$4,470,000
Byproduct Disposal	$820,000
Water	$110,000
Auxiliary Power	$1,160,000
Total Variable O&M Costs =	$6,560,000
Total Annual O&M Costs	**$9,700,000**
Net Annual O&M Cost ($/MWh)	**$5.59**

3.4.1.8 SEMI-DRY FGD O&M COST ESTIMATE

The O&M cost estimate for the SDA/FF alternative was taken directly from CUECost. Lime usage was set at 1.80 lbmol of lime (CaO) per lbmol of SO_2 removed. A ratio of 5.5 lb of recycled solids per pound of lime added and a 35% solids slurry were also set as design conditions in CUECost. A total of 11" w.g. pressure drop across the combined SDA/FF system was also utilized as a design condition. The Fabric Filter was sized for a gas-to-cloth ratio of 3.5 $ACFM/Ft^2$. A three year bag life was assumed. The results of the SDA/FF O&M cost estimate are summarized in Table 3.4-8.

TABLE 3.4-8 – O&M Cost Estimate for LOS Unit 1 SDA/FF System

Fixed Costs	
Operating Labor	$1,150,000
Admin and Support labor	$360,000
Maintenance Material and Labor	$1,350,000
Total Fixed O&M Costs =	$2,860,000
Variable Costs	
Lime Reagent	$4,180,000
Byproduct Disposal	$780,000
Water	$110,000
Auxiliary Power	$1,010,000
Total Variable O&M Costs =	$6,080,000
Total Annual O&M Costs	**$8,940,000**
Net Annual O&M Cost ($/MWh)	**$5.15**

3.4.1.9 FLASH DRYER ABSORBER O&M COST ESTIMATE

The FDA/FF O&M costs were estimated from a combination of the CUECost estimate for the SDA/FF system and vendor supplied materials usage information for the FDA/FF. The operating labor, administration and support for the FDA/FF were taken directly from the SDA/FF estimate because the FDA/FF system operation is no more technically complex than the SDA/FF. Maintenance costs were estimated as 90% of the SDA/FF maintenance cost estimated by CUECost. Reagent usage and waste solids generation rates were estimated by a system vendor for the current fuel blend, increased for the additional sulfur content of the design fuel and the costs determined from the economic information in Table 1.2-3. Auxiliary power costs for the SDA/FF system were increased 10% for the FDA/FF usage. The results of the FDA/FF O&M cost estimate are given in Table 3.4-9.

TABLE 3.4-9 – O&M Cost Estimate for LOS Unit 1 FDA/FF System

Fixed Costs	
Operating Labor	$1,220,000
Admin and Support labor	$480,000
Maintenance Material and Labor	$1,000,000
Total Fixed O&M Costs =	$2,700,000
Variable Costs	
Lime Reagent	$5,070,000
Byproduct Disposal	$830,000
Water	$120,000
Auxiliary Power	$1,110,000
Total Variable O&M Costs =	$7,120,000
Total Annual O&M Costs	**$9,820,000**
Net Annual O&M Cost ($/MWh)	**$5.66**

3.4.1.10 FUEL SWITCHING O&M COST ESTIMATE

In the 1997 report[1] on the PRB test burn, BEPC reported several operational advantages to the use of PRB in LOS Unit 1. These included reduced station service (from 7.6 to 7.2%), reduced sulfur emissions and reduced ash quantities. The test report specifically mentions that although some features of PRB firing were documented, the test duration was extremely short and many potential long term impacts were neither investigated nor documented. Additional O&M cost might result from unknown impacts caused by a fuel switch. For the purpose of estimating impacts of a switch to 100% PRB fuel on the operating and maintenance costs of LOS Unit 1, the changes in fuel cost, station service costs and ash disposal were estimated based on the report contents and are summarized in Table 3.4-10.

The change in fuel cost calculated to result from a switch to 100% PRB was based upon the design heat input to LOS Unit 1, taking into account a 2.1% increase in boiler efficiency (at full generation). The station service benefit was calculated as the net decrease in station service based on operating costs given in Table 1.2-3. Because PRB has a significantly lower ash content, a credit for reduction in both bottom ash and flyash disposal costs is also included. The annual additional O&M cost of switching LOS Unit 1 to PRB is estimated to be $5,510,000 or $2.86/MWh.

TABLE 3.4-10 – O&M Cost Estimate for LOS Unit 1 Fuel Switching

Fuel Cost Change	$6,002,000
Reduced Station Service	-$292,900
Change in Ash Disposal Cost	-$355,100
Annual Flue Gas Conditioning Maintenance	$13,000
Flue Gas Conditioning Reagent	$143,000
Total Annual Change to O&M Cost	**$5,510,000**
Total Annual Change to O&M Cost ($/MWh)	**$2.86**

3.4.1.11 LEVELIZED TOTAL ANNUAL COST

The Levelized Total Annual Cost (LTAC) for all alternatives were calculated based on economic conditions given in Table 1.2-3 and a 20 year project life. The LTAC was calculated for each alternative utilizing the estimated costs in Tables 3.4-1 through 3.4-10 and the economic conditions described in Section 1 of this report. Estimated capital costs were split evenly over a two year construction period for all alternatives. A system startup date of December 17, 2013 was used based upon the projected timing of Regional Haze Rule implementation given by NDDH. O&M costs were included through the end of the calendar year 2034. No salvage value was assumed at the end of the service life for any of the alternatives. The LTAC for all BART alternatives remaining under consideration are presented in Table 3.4-11.

TABLE 3.4-11 – Levelized Total Annual Costs of Unit 1 BART SO_2 Control Alternatives(1)

BART Alternative	Control Efficiency	Annual Emission Reduction from Historical Case (tpy)(2)	Annual Emission Reduction from Future PTE Case (tpy)(3)	Installed Capital Cost ($2005)	Annual O&M Cost ($2005)	Levelized Total Annual Cost ($2005)(4)
Wet FGD	95%	17,019	37,453	$107,220,000	$8,350,000	$19,310,000
CDS/FF	93%	16,327	36,664	$104,790,000	$9,700,000	$20,720,000
SDA/FF	90%	15,289	35,482	$92,000,000	$8,940,000	$18,700,000
FDA/FF	90%	15,289	35,482	$88,980,000	$9,820,000	$19,480,000
Fuel Switching	77%	10,792	30,475	$1,367,000	$5,510,000	$6,690,000

(1) - All Costs in 2005 dollars.
(2) - Annual emission reduction is uncontrolled Historic case emissions minus controlled Future PTE case emissions.
(3) - Annual emission reduction is uncontrolled Future PTE case emissions minus controlled Future PTE case emissions.
(4) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

The annual tons of SO_2 reduction in this study are calculated for two cases. One case is the difference between the uncontrolled emissions from the Historical case (firing the baseline fuel at the historical heat input) and the controlled emissions for the Future PTE case at the nameplate heat input and a capacity factor of 1.0. The second case is the difference between the uncontrolled emissions and the controlled emissions for the Future PTE case.

Figure 3.4-1 is a plot of the Levelized Total Annual Cost for each technology alternative versus the annual removal in tons (Future PTE basis) for each BART alternative shown in Table 3.4-11. A similar graphic analysis is not presented for the Historic Case due to the similarity of the results. The purpose of Figure 3.4-1 is to identify the Dominant Controls Curve which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly above, or to the left of, this curve are inferior control alternatives on a cost effectiveness basis. Of the technically feasible BART alternatives considered for LOS Unit 1, data points for the CDS, the SDA and the FDA all lie distinctly above the least cost boundary of the control cost envelope. The reason for this

FIGURE 3.4-1 – LOS Unit 1 SO_2 Least Cost Envelope for Future PTE Case

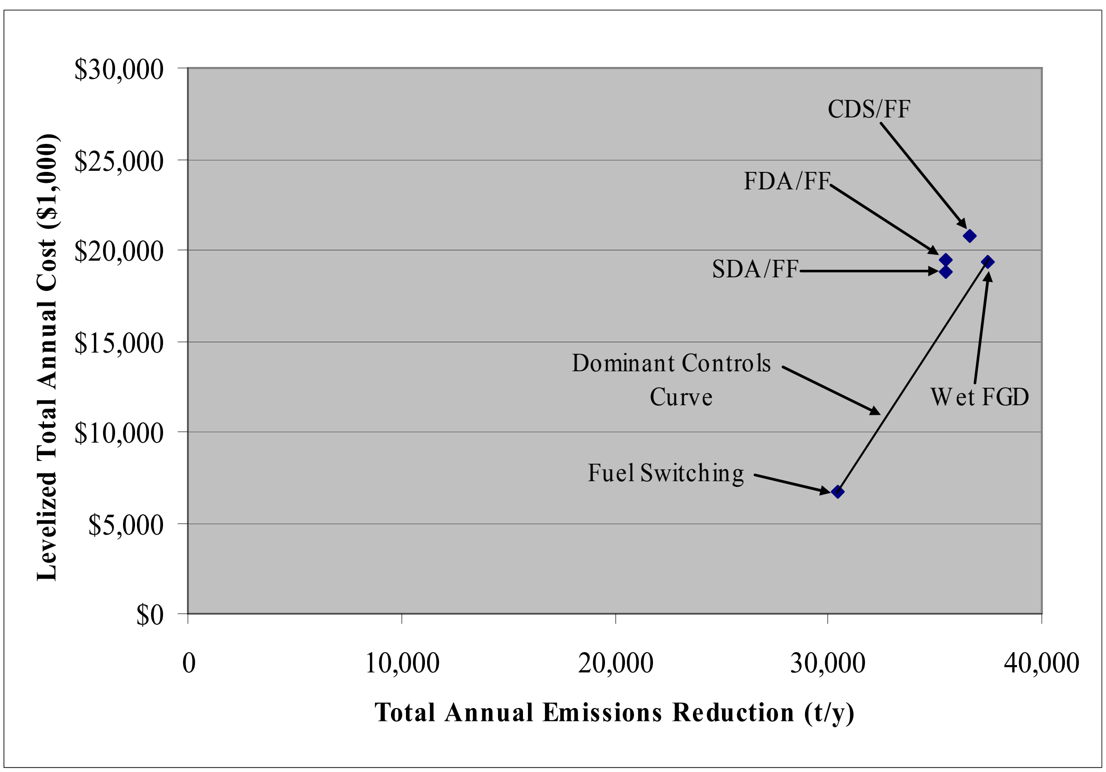


TABLE 3.4-12 – Unit Control Costs of Unit 1 BART SO_2 Control Alternatives

BART Alternative	Control Efficiency	Levelized Total Annual Cost ($2005)(1)	Annual Emission Reduction from Historical Case (tpy)	Historical Case Unit Control Cost ($/ton)	Annual Emission Reduction from Future PTE Case (tpy)	Future PTE Case Unit Control Cost ($/ton)
Wet FGD	95%	$19,310,000	17,019	$1,135	37,453	$516
CDS/FF	93%	$20,720,000	16,327	$1,269	36,664	$565
SDA/FF	90%	$18,700,000	15,289	$1,223	35,482	$527
FDA/FF	90%	$19,480,000	15,289	$1,274	35,482	$549
Fuel Switch	77%	$6,690,000	10,792	$620	30,475	$220

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

is clear from Table 3.4-12 where the unit control costs for the SO_2 control alternatives are listed. In a top down analysis each of the SO_2 control technologies represented by a data point above the Dominant Control Curve could be excluded from further analysis on a cost effectiveness basis. However, because the accuracy of the estimate (± 30%) is greater than the variance of the estimated LTACs (±11%) and the Unit Control Costs (± 12%) for all post combustion control alternatives, none of the alternatives were excluded from further analysis on a cost basis.

The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above and below it on the Dominant Controls Curve. Table 3.4-13 contains a repetition of the cost and control information from Table 3.4-11 and the incremental cost effectiveness for each dominant control alternative.

TABLE 3.4-13 – Incremental Cost Effectiveness of Unit 1 BART SO_2 Control Alternatives On the Dominant Controls Curve

BART Alternative	Levelized Total Annual Cost(1)	Annual Emission Reduction from Historic Case (tpy)	Incremental Cost Effectiveness for Historic Case ($/ton)	Annual Emission Reduction from Future PTE Case (tpy)	Incremental Cost Effectiveness for Future PTE Case ($/ton)
Wet FGD	$19,310,000	17,019	$2,267	37,453	$2,023
Fuel Switching	$6,690,000	10,792	NA	30,475	NA

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the dominant control cost curve) between successively less effective alternatives. The incremental cost effectiveness for wet FGD versus fuel switching in Table 3.4-13 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD is prohibitively expensive relative to the fuel switching alternative.

The cost analysis portion of the BART determination for LOS Unit 1 has shown that none of the Unit Control Costs for the dominant alternatives are exceedingly expensive on a Unit Control Cost basis. However, three of the BART alternatives were established as being potentially inferior to alternatives forming the Dominant Controls Curve. None of these alternatives were excluded from further analysis due to the similarity of the estimated cost impacts compared to the estimate accuracy. From a top-down economic analysis viewpoint, wet FGD appears to be the most cost effective evaluated SO_2 control alternative for LOS Unit 1. However, because the capital costs of all of these technologies are subject to market conditions at the time of purchase, such as; alloy pricing, major equipment lead times (i.e., slurry pumps, booster fans, etc.) the relative closeness of the estimated capital costs is a good indicator that the cost ranking of these alternatives might even be reversed at the time of actual purchase.

At the conclusion of the cost impact analysis, the decision was made to delete the FDA/FF alternative from further consideration as it duplicated the control efficiency of the SDA/FF alternative, but at a higher price. This deletion is not anticipated to prejudice study results because of the relative closeness of the costs of the post combustion control alternatives. It is not intended to imply that the FDA/FF is excluded from consideration as an actual technology for BART compliance, only that this alternative is excluded from the remainder of this analysis as a duplicate alternative. When Basin Electric Power Cooperative initiates procurement of SO_2 control equipment, there is no reason to exclude the FDA/FF alternative from the bidding process. The purpose of the BART analysis is to identify the emission level that constitutes BART, not to restrict the source to a specific control technology.

3.4.2 ENERGY IMPACTS

The energy impacts of each alternative, in terms of both estimated kW of energy usage and the percent of total generation, are given in Table 3.4-14. The fuel switching option actually has a negative energy demand due to the decrease in plant services primarily resulting from the decrease in the Net Plant Heat Rate of approximately 300 Btu/kW.[1]

The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, ball mills for limestone grinding and vacuum pumps for byproduct slurry dewatering. The largest energy users for the semi-dry and dry alternatives are pumps, blowers, atomizers and booster fans. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.4-14 – Energy Requirements of Unit 1 BART SO_2 Control Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	4,814	2.2%
CDS/FF	3,500	1.6%
SDA/FF	3,043	1.4%
Fuel Switching	-880	-0.4%

3.4.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include hazardous waste generation, solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives. One general exception is the fuel switching alternative which would actually result in the reduction of ash quantities and might even produce salable flyash. The cost reduction for reduced ash disposal was included in the O&M cost estimate for fuel switching, but no credit was taken for potential future ash sales.

Captured mercury in the solid waste stream from any post combustion alternative would be present as a trace contaminant in the solid waste, not affecting disposal options as long as the waste passes the Toxic Characteristic Leaching Procedure (TCLP), which FGD system wastes have historically.

A wet FGD system for LOS Unit 1 is estimated to produce approximately 14.9 tons per hour of solid waste. The waste stream would be composed of gypsum solids and inerts at approximately 15% moisture. Over the course of a year, the total solid waste quantity is estimated to be approximately

130,500 tons of gypsum solids which would be landfilled in the current permitted solid waste disposal facility near the plant.

The annual quantity of aqueous waste that would be produced by a wet FGD system is difficult to quantify because the blowdown rate from a wet FGD system is primarily a function of the dissolved chloride levels in the absorber reaction tank. Most of the chloride reaching the scrubber is in the form of hydrochloric acid which is readily absorbed and neutralized. Hydrochloric acid removal rates in a typical wet FGD system typically exceed 95%. CUECost estimates 41 lb/hr of hydrochloric acid in the flue gas stream which is assumed to be completely removed by the absorber system. The waste solids stream leaving the wet FGD system contains approximately 15% water which would contain $CaCl_2$ which would not require blowdown for disposal. Assuming the chloride to be present in the blowdown stream as $CaCl_2$ and assuming an average chloride concentration of 9,000 parts per million, one can calculate approximately 41 pounds per hour of chloride would leave the plant in the entrained moisture in the solid waste. No blowdown specifically for chloride disposal would be required under these conditions. For the purpose of this analysis, it was assumed that an irregular blowdown stream would be required and would be sent to a dedicated evaporation pond on site for disposal.

During preparation for the visibility analysis a review of the cost impact analysis results was conducted and fuel switching (77%) was identified as a significantly inferior alternative compared to the post combustion SO_2 control alternatives (90-95%) and it was decided that fuel switching should be excluded from further consideration in the study. Further explanation is provided in the next section.

3.4.4 VISIBLITY IMPACTS

The final impact analysis conducted was to assess the visibility impairment impact reduction for each proposed BART alternative. Pre-control Historic emission rates and post-control emission rates for the Future PTE case were modeled for visibility impairment impacts. CALPUFF was used to model the long-range transport and interaction of SO_2, NO_X and PM to estimate the visibility impairment impact in deciViews (dV). The reduction in visibility impairment impact due to each control scenario was then calculated as the difference between the visibility impairment impact for each control scenario and the pre-control visibility impairment impact. Per the BART Guidelines and the modeling protocol provided by NDDH, the pre-control modeling case was the maximum 24 hour emission rate for each pollutant for the years 2000-2002, inclusive. The post-control emission rates for each pollutant were developed from the Future PTE case. These results were then compared to assess the relative visibility impairment reduction for each BART alternative.

The BART guidelines state that the comparison should be made at the 98th percentile level (70 FR 39170). However, NDDH directed that the comparison should be made at the 90th percentile to be consistent with the Western Regional Air Partnership (WRAP) protocol. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

CALPUFF modeling was conducted separately for the application of each SO_2 control technology to the Future PTE case. The modeling results, expressed as the change in visibility impairment impact in deciViews (ΔdV), is the change in visibility impairment impact in the affected Class 1 area as a result of the emission reduction attributed to the implementation of each BART alternative on LOS Unit 1. The visibility impairment impact reduction (Δ dV) for each BART alternative is given in Table 3.4-15 for each affected Class 1 Area.

The visibility impairment impact reduction for each modeled BART alternative is given in column three of Table 3.4-15. This value is the average visibility impairment impact reduction over the three modeled years (2000-2002) for each affected Class 1 area. For all modeled conditions, the visibility impairment reduction for any BART alternative varied from approximately 0.2 to 0.5dV. The Lostwood National Wildlife Refuge (Lostwood NWR) shows the greatest average visibility impairment impact reduction, regardless of the BART alternative modeled, thus indicating that this area will gain the greatest benefit from SO_2 BART implementation of all the Class 1 Areas included in the modeling. The Teddy Roosevelt National Park, Elkhorn site (TRNP-Elkhorn) is shown to gain the least visibility impairment impact reduction, regardless of the BART alternative. A review of Table 3.4-15 finds the visibility impairment impacts for BART alternative vary by year and area. The observed variations between Class 1 Areas are primarily a result of different directions and distances from the plant as well as variability in the meteorological data for each area and each year.

In addition to the average ΔdV values, three other types of data are presented in Table 3.4-15, the number of days in each of the affected Class 1 Areas the visibility impairment impact, after implementation of a BART alternative, exceeded 0.5 dV, the number of days the impact exceeded 1.0

dV and the maximum number of consecutive days the impact exceeded 0.5 dV. The 0.5 dV value is the lowest visibility impairment impact that is considered discernible by the human eye and the EPA

TABLE 3.4-15 – Visibility Impairment Impacts - Unit 1

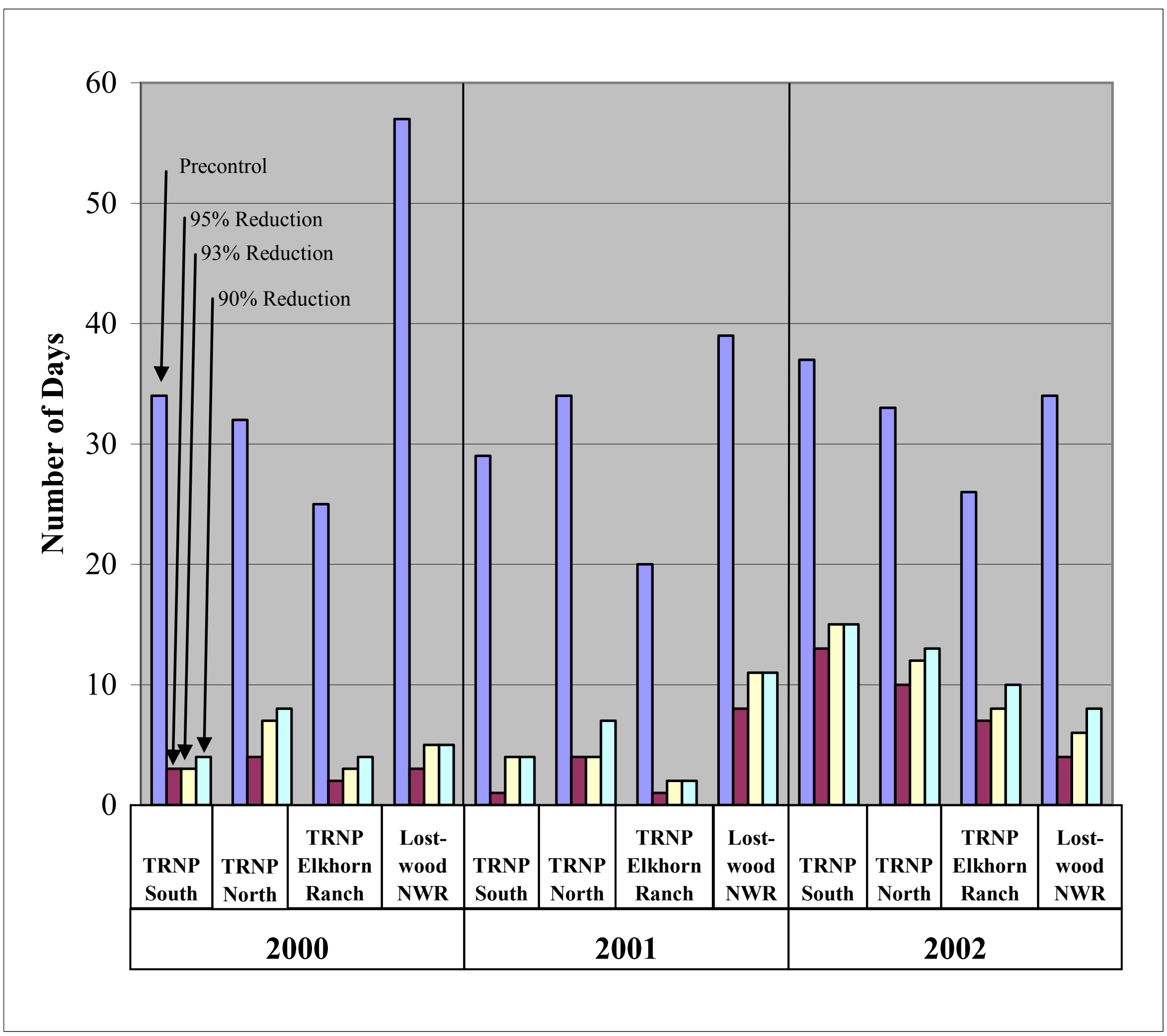
Class 1 Area	BART Alternative Control Efficiency[1]	Visibility Impairment Reduction (ΔdV)	Days Exceeding 0.5 dV in 2000	Days Exceeding 0.5 dV in 2001	Days Exceeding 0.5 dV in 2002	Days Exceeding 1.0 dV in 2000	Days Exceeding 1.0 dV in 2001	Days Exceeding 1.0 dV in 2002	Consecutive Days Exceeding 0.5 dV 2000	Consecutive Days Exceeding 0.5 dV 2001	Consecutive Days Exceeding 0.5 dV 2002
TRNP South	95%	0.337	3	1	13	0	0	3	1	1	2
	93%	0.335	3	4	15	2	0	3	1	2	2
	90%	0.316	4	4	15	2	0	3	1	2	2
TRNP North	95%	0.369	4	4	10	1	0	3	1	1	3
	93%	0.347	7	4	12	2	1	4	1	1	3
	90%	0.332	8	7	13	2	1	4	1	2	3
TRNP Elkhorn Ranch	95%	0.233	2	1	7	1	0	2	1	1	2
	93%	0.221	3	2	8	1	0	2	1	1	2
	90%	0.207	4	2	10	2	0	3	1	1	2
Lostwood NWR	95%	0.519	3	8	4	1	2	0	1	2	1
	93%	0.489	5	11	6	1	4	1	1	2	1
	90%	0.467	5	11	8	1	5	2	1	2	1

(1) - A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

set this threshold in the screening analysis, as the point above which a source is considered to be contributing to visibility impairment (70 FR 39120). The 1.0 dV threshold was established in the final rule as the threshold during the screening analysis at which a state should consider a source to be a cause of visibility impairment (70 FR 39120). The visibility impairment impact analysis consists of examining the magnitude of impact reduction for each alternative as well as the number of exceedances described above.

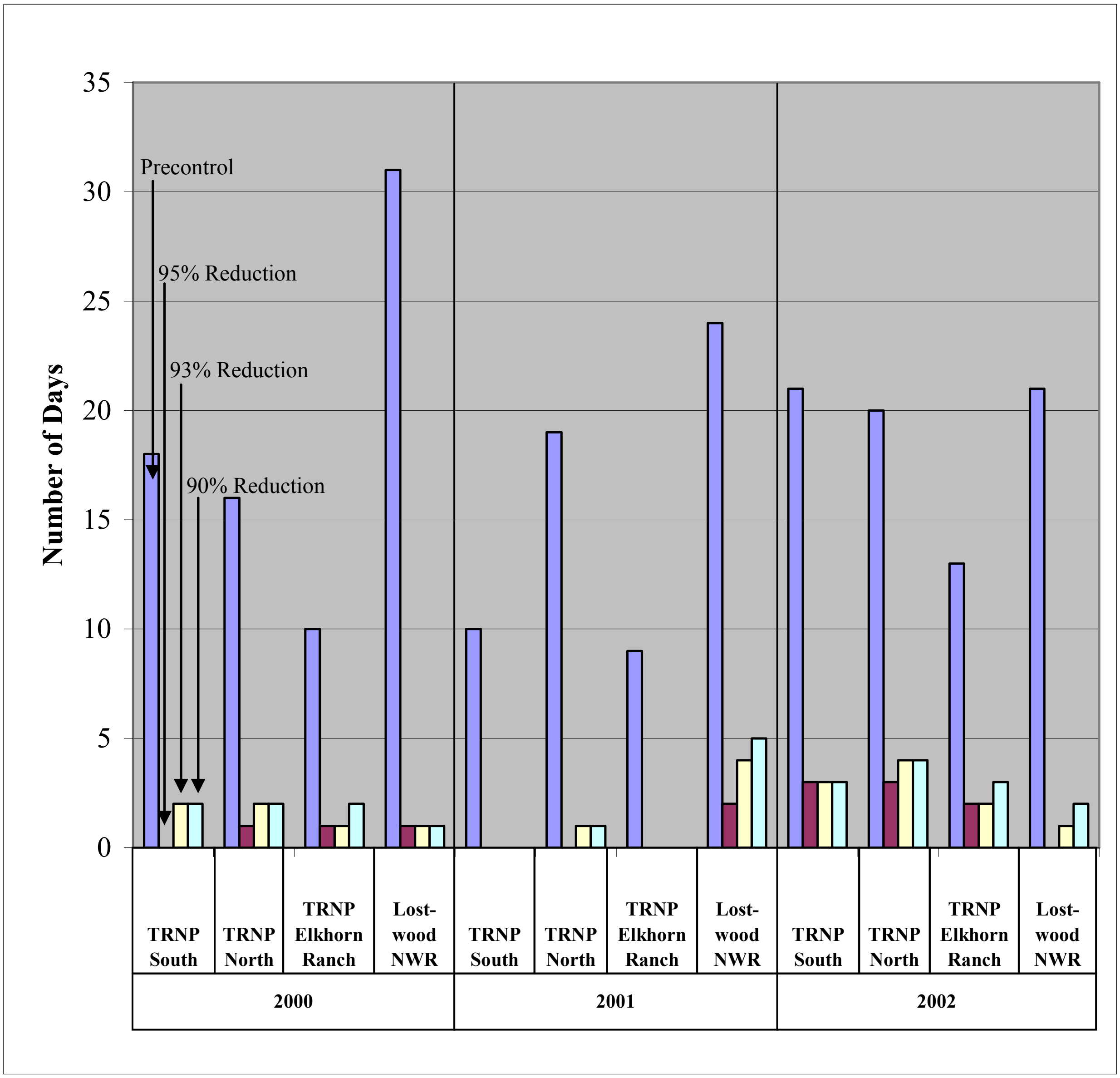
In the model year 2000, the worst impact in terms of days exceeding 0.5 dV occurs at TRNP-North, during 2001 at the Lostwood NWR and during 2002 at TRNP-South, regardless of the BART alternative under consideration. A graphic representation of these impacts is presented in Figure 3.4-2. A comparison of the number of exceedance days for the pre-control and post-control scenarios

FIGURE 3.4-2 – Number of Days Exceeding 0.5 dV for Pre- and Post-Control



shown in Figure 3.4-2 reinforces the earlier observation that the Lostwood NWR gains the most improvement in terms of visibility impairment reduction, regardless of the modeled BART alternative. A graphic representation of the number of days exceeding 1.0 dV is presented in Figure 3.4-3. During the years 2000 and 2002, the greatest number of days where visibility impairment impact

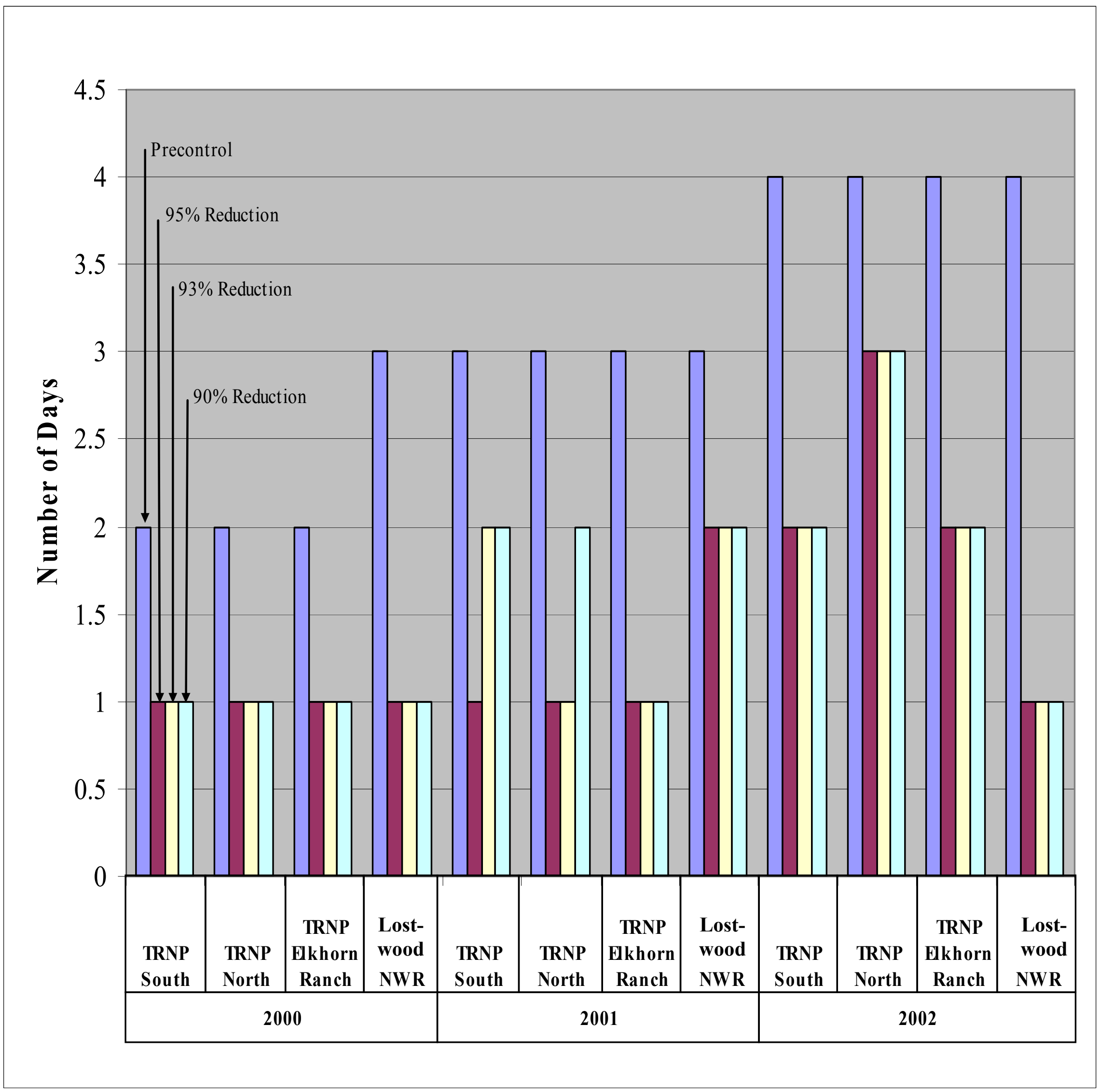
FIGURE 3.4-3 – Number of Days Exceeding 1.0 dV for Pre- and Post-Control



exceeds 1.0 dV, occurs in TRNP-North, but in the Lostwood NWR in 2001. In 2001 both TRNP South and TRNP Elkhorn Ranch have zero days of visibility impairment exceeding 1.0 dV according to the modeling results.

Figure 3.4-4 is a graphic presentation of the maximum number of consecutive days where the visibility impairment impact exceeds 0.5 dV for the modeled Class 1 Areas. Both pre-control and post-control conditions are presented for the three years 2000-2002, inclusive. In 2000, the number

FIGURE 3.4-4 – Maximum Consecutive Days Exceeding 0.5 dV for Pre- and Post Controls



of consecutive days exceeding 0.5 dV of impact is the same for all areas for both the uncontrolled and controlled scenarios. In 2001 TRNP-South and Lostwood NWR both experience the same number of consecutive days of visibility impairment greater than 0.5 dV for the 90% and 93% control cases, but at the 95% control level, the Lostwood NWR is predicted to experience two consecutive days versus one day for all other areas. In 2002 the TRNP-North area is predicted to experience three consecutive days of visibility impairment greater than 0.5 dV and in general, all modeled areas are predicted to experience more consecutive days of visibility impairment greater than 0.5 dV than in either of the two previous years.

The total number of days where the visibility impairment impact exceeded 0.5 dV over the entire modeling period (2000-2002) is greatest for TRNP-North. TRNP-South is predicted to have experienced the least number of days with a visibility impairment impact greater than 0.5 dV over the modeling period. Similarly, the total number of days where the impact exceeded 1.0 dV is greatest for TRNP-North over the modeled time period and least for the TRNP Elkhorn Ranch area. The maximum number of consecutive days with impacts greater than 0.5 dV also occurs in TRNP-North and the TRNP-Elkhorn Ranch and Lostwood NWR areas have the least number of consecutive days.

Compared to the baseline case the visibility impairment reduction predicted for each BART alternative by the visibility modeling, as shown in Figures 3.4-2 though 3.4-4, will result in a significant decrease in visibility impairment in all of the Class 1 areas. Even the least effective BART alternative under analysis will, under the worst modeled meteorological conditions, reduce the number of days with greater than 0.5dV of impact by over half. Days with visibility impairment greater than 1.0 dV will decrease by over 75% under those same worst case model meteorological conditions. Figure 3.4-4 clearly shows that averaged over all model years and Class 1 areas, the number of consecutive days with greater than 0.5 dV will be reduced by approximately half, regardless of the BART alternative under consideration.

The visibility impairment impact reduction results for each BART SO_2 removal alternative are summarized in Table 3.4-16. The second column contains the reduction in visibility impairment impact relative to the uncontrolled Future PTE case emissions. Column four shows the marginal visibility impairment impact improvement for the 93% and 95% SO_2 removal alternatives relative to a lowest removal efficiency condition of 90%. As can be seen in column four, the marginal visibility impairment impact reduction for any of the Class 1 areas is less than ten percent of the minimum change discernible by the human eye, as stated in the BART Guidelines (70 FR 39119, Footnote 28).

Therefore, it is reasonable to conclude from this table that in terms of discernible visibility impairment impact, there is no difference between any of the remaining SO_2 removal alternatives for LOS Unit 1.

TABLE 3.4-16 – Marginal Visibility Impairment Impact Reduction

BART Alternative	BART Alternative and Percent Reduction	Visibility Impairment Reduction (Δ dV)(1)	Marginal Visibility Impairment Reduction (Δ dV)(2)
TRNP-S	95%	0.337	0.021
	93%	0.335	0.019
	90%	0.316	Base
TRNP-N	95%	0.369	0.037
	93%	0.347	0.015
	90%	0.332	Base
TRNP-Elkhorn Ranch	95%	0.233	0.026
	93%	0.221	0.014
	90%	0.207	Base
Lostwood NWR	95%	0.519	0.052
	93%	0.489	0.022
	90%	0.467	Base

(1) - Average modeled visibility impairment impact over three model years. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.
(2) - Marginal visibility impairment impact improvement relative to the base impact at 90% removal.

3.4.5 IMPACT SUMMARY

As stated in Section 3.4, this report has examined the listed impacts of each BART alternative as part of the BART determination process. Table 3.4-17 summarizes the various impacts discussed in Sections 3.4.1 through 3.4.4. The cost of compliance analysis examined the capital cost of the technology that is central to each feasible BART alternative and the Balance of Plant costs necessary to implement the alternative. In addition, the cost analysis examined the operating and maintenance costs associated with each alternative. These costs were then combined into the Levelized Total Annual Cost (LTAC) for a comparative assessment of the overall cost of each alternative. Finally, as part of the top down analysis, a Dominant Control Curve was plotted and the Unit Control Costs were determined for each alternative. As discussed in Section 3.4.4, the cost impact analysis was basically inconclusive as the difference between the minimum and maximum estimated LTAC was approximately one third of the estimate accuracy and thus no strong conclusion was indicated. The visibility impairment impact analysis examined the visibility impairment impact reduction attributable to each alternative and determined that the marginal change in visibility impairment impact between any two feasible BART alternatives was less than ten percent of the minimum change in visibility impairment discernible by the human eye. So, similar to the cost analysis, the visibility impairment impact analysis reached no definitive conclusion.

The energy impact was also evaluated for each alternative and some differentiation between alternatives was identified. The energy demand for the 90% SO_2 control alternative (SDA/FF) was approximately 60% of the energy demand for the most stringent SO_2 control alternative at 95% SO_2 control (WFGD). All three BART alternatives listed in Table 3.4-17 produce solid waste streams in similar quantities. The WFGD alternative is expected to also produce an intermittent liquid blowdown stream that would be disposed of in a permitted evaporation pond on site.

TABLE 3.4-17 – LOS Unit 1 Impacts Summary for SO_2 Control Alternatives

BART SO_2 Control Alternative	Annual Emissions Reduction (tpy)	Levelized Total Annual Cost(1)	Unit Control Cost ($/ton)	Visibility Impairment Impact Reduction		Energy Impact (kW)	Non Air Quality Impacts
				Area	ΔdV(2)		
95%	37,453	$19,310,000	$516	TRNP-S	0.337	4,800	Solid and Liquid Waste Streams
				TRNP-N	0.369		
				TRNP-Elk	0.233		
				LW-NWR	0.519		
93%	36,664	$20,720,000	$565	TRNP-S	0.335	3,500	Solid Wastes
				TRNP-N	0.347		
				TRNP-Elk	0.221		
				LW-NWR	0.489		
90%	35,482	$18,700,000	$527	TRNP-S	0.316	3,040	Solid Wastes
				TRNP-N	0.332		
				TRNP-Elk	0.207		
				LW-NWR	0.467		

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Change in visibility impairment impact between uncontrolled Historical emissions and controlled Future PTE emissions.

3.5 EVALUATION OF IMPACTS FOR FEASIBLE SO_2 CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART determination guidelines (70 FR 39166) list four factors to be considered in the impact analysis. This BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four factors considered in the impact analysis are discussed in the following sections. The factor for the remaining useful life of the source is incorporated as part of the cost of compliance. In addition, as described in Section 1.1.6, the visibility impairment impacts are to be evaluated as part of the analysis. Thus, visibility impairment is included as part of the impacts analysis.

3.5.1 COST ESTIMATES

The procedure used to obtain cost estimates for LOS Unit 2 SO_2 control technologies is the same general procedure described in Section 3.4.1 for LOS Unit 1. Any exceptions to this procedure are described in the following sections for each individual control alternative.

3.5.1.1 WET FGD CAPITAL COST ESTIMATE

The capital cost estimate for the wet FGD system includes the SO_2 control system, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a wet FGD system supplier. The wet FGD system cost estimated by CUECost is broken down into the major subsystems of reagent preparation, SO_2 absorption tower, dewatering systems, flue gas handling systems (booster fans and ductwork) and support systems. BOP costs include a wet stack, make-up water treatment plant, electrical subcontract, foundations subcontract and repair/upgrade of the existing railroad tracks for limestone delivery. The results of the capital cost estimate are given in Table 3.5-1.

CUECost includes a cost estimate for a wet stack, but based upon Burns & McDonnell's recent experience with wet stack construction costs, this estimate was deleted from the CUECost results and

TABLE 3.5-1 – Capital Cost Estimate for LOS Unit 2 Wet FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Reagent Prep System	$15,300,000	$2,300,000	$17,600,000
SO_2 Absorption System	$32,180,000	$4,830,000	$37,010,000
Flue Gas Handling System	$12,170,000	$1,830,000	$14,000,000
ByProduct Handling System	$2,190,000	$330,000	$2,520,000
Support Equipment	$2,650,000	$400,000	$3,050,000
		FGD Total Direct Cost =	**$74,180,000**
BOP COSTS			
Wet Stack	$10,660,000	NA	$10,660,000
Water Treatment Equipment	$1,300,000	NA	$1,300,000
Evaporation Pond	$1,850,000	NA	$1,850,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Foundations Subcontract	$2,390,000	NA	$2,390,000
Relocate Pipe Rack	$390,000	NA	$390,000
Extend Ductwork	$5,720,000	NA	$5,720,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$29,330,000**
		Total Direct Cost =	**$103,490,000**
INDIRECT COSTS			
		Contingency (20% of DC)	$20,700,000
		A/E Engineering and Construction Management (10% of DC)	$9,910,000
BEPC INDIRECTS			
		Project Development (1% of DC)	$1,034,900
	Spare Parts & Plant Equipment		
		Rolling Stock	$1,000,000
		Initial Inventory Spare Parts (1.5% of DC)	$1,550,000
		Plant Furnishings (0.5% of DC)	$520,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$520,000
		Construction All-Risk Insurance (1.5% of DC)	$1,550,000
		Allowance For Funds During Construction (AFDC 6%)	$6,210,000
		Contingency (15% of BEPC Indirects)	$690,000
		Indirect Cost Subtotal	$44,120,000
		Total Capital Cost	**$147,600,000**

a revised estimate by Burns & McDonnell was included in the BOP costs. The new stack estimate includes an alloy C-276 liner for the wet stack. The new wet stack was assumed to be 500' in height.

The BOP costs include make-up water treatment equipment costs for pumps, piping, filters, and a clarifier. An estimated building cost for the makeup water treatment system is included in the Foundations Subcontract estimate.

Also included in the Foundations Subcontract cost estimate are roofed, two-walled enclosures for limestone and gypsum temporary storage to provide for weather protection.

An evaporation pond for disposal of blowdown, for chloride control, was included in the capital cost estimate. Railroad delivery of limestone, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading of approximately 1,500 feet of railroad track to provide for limestone delivery to the LOS Unit 2 limestone railcar unloading station. The estimate also includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost for a complete, stand-alone wet FGD system utilizing limestone reagent and forced oxidation is $147,600,000, or $335/kW for LOS Unit 2.

3.5.1.2 CIRCULATING DRY SCRUBBER CAPITAL COST ESTIMATE

The Circulating Dry Scrubber (CDS) FGD technology is a relatively recent innovation in the United States, but has been used previously in Europe. Cost information on the CDS system is not as widely available as the more common wet and semi-dry systems. Capital costs for the CDS system were based on CUECost estimates for the SDA semi-dry FGD system with modifications to reflect the design and operational differences. Several literature sources[5, 6] and Burns & McDonnell in-house information were utilized in making these modifications. The CDS cost estimate is presented in a line item format with individual items adjusted to reflect differences between the CDS and SDA. The capital cost estimate is presented in Table 3.5-2.

The CDS absorber vessel is similar to the SDA, but smaller in diameter to provide for a greater gas velocity to make fluidized bed operation possible. The cost of the CDS absorber vessel was estimated at 80% of the cost of the SDA absorber vessel.

TABLE 3.5-2 – Capital Cost Estimate for LOS Unit 2 CDS FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
CDS System			
Reagent Prep System	$16,210,000	$2,430,000	$18,640,000
SO_2 Absorption System	$16,990,000	$2,550,000	$19,540,000
Flue Gas Handling System	$11,340,000	$1,700,000	$13,050,000
ByProduct Handling System	$3,620,000	$540,000	$4,160,000
Support Equipment	$3,600,000	$540,000	$4,140,000
		CDS Total Direct Cost =	**$59,530,000**
Fabric Filter			
Fabric Filter Housing	$14,880,000	$2,230,000	$17,110,000
Bags	$2,690,000	$400,000	$3,090,000
Ash Handling System	$10,990,000	$1,650,000	$12,640,000
Instruments & Controls	$510,000	$80,000	$580,000
		Fabric Filter Total Direct Cost =	**$33,420,000**
BOP Costs			
Dry Stack	$8,530,000	NA	$8,530,000
Water Treatment Equipment	$1,220,000	NA	$1,220,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Foundations Subcontract	$2,050,000	NA	$2,050,000
Relocate Pipe Rack	$360,000	NA	$360,000
Extend Ductwork	$5,720,000	NA	$5,720,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$24,900,000**
		Total Direct Cost =	**$117,850,000**

INDIRECT COSTS	
Contingency (20% of DC)	$23,570,000
A/E Engineering and Construction Management (10% of DC)	$11,080,000
BEPC INDIRECTS	
Project Development (1% of DC)	$1,180,000
Spare Parts & Plant Equipment	
Rolling Stock	$1,000,000
Initial Inventory Spare Parts (1.5% of DC)	$1,770,000
Plant Furnishings (0.5% of DC)	$590,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$590,000
Construction All-Risk Insurance (1.5% of DC)	$1,770,000
Allowance For Funds During Construction (AFDC 6%)	$7,070,000
Contingency (15% of BEPC Indirects)	$770,000
Indirect Cost Subtotal	$50,090,000
Total Capital Cost	**$167,900,000**

Because the CDS recirculates a much greater fraction of the flyash and absorber reaction products (80-95% vs. 30%) than the SDA, the byproduct handling system cost for the SDA was increased by 100% for the CDS estimate to account for the greater system capacity requirements.

The estimated cost for ancillary support equipment was also based on the SDA estimate from CUECost. The CUECost estimate for these systems for the SDA was increased by 10% to reflect the additional reagent usage and higher recycle flow rate.

The CUECost estimate for SDA flue gas handling systems was increased by 10% to account for the additional booster fan capacity required to accommodate the greater pressure drop of the CDS. Ductwork costs were assumed not to change due to the CDS configuration versus the SDA.

Because the CDS recirculates a much greater fraction of flyash and absorber reaction products than the SDA, the estimated cost for the ash handling system was increased 86% over the CUECost estimate for the SDA.

A new dry stack was included in the BOP capital cost estimate. It was assumed that the CDS facility would be in a new location and returning the ductwork to the existing stack would be cost prohibitive.

Included in the Foundations Subcontract cost estimate is a silo for temporary storage of waste products prior to transport to the permitted waste disposal facility.

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 2 railcar unloading station. The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone CDS with Fabric Filter for SO_2 control for LOS Unit 2, utilizing hydrated lime as a reagent is $167,900,000, or $382/kW.

3.5.1.3 SEMI-DRY FGD CAPITAL COST ESTIMATE

Estimated direct costs for the semi-dry FGD system include the SDA, fabric filter, major support facilities and BOP costs. The SO_2 control system cost is representative of a typical furnish and erect contract by a lime SDA/FF system supplier and is presented in Table 3.5-3. The SDA/FF system costs estimated by CUECost are broken down into the major subsystems of reagent preparation, spray dryer absorber, waste handling systems, flue gas handling systems (booster fans and ductwork) and support systems. A fabric filter is included in the estimate for the capture of entrained absorption products. BOP costs include an electrical subcontract, foundations subcontract, water treatment equipment and repair/upgrade of the existing railroad tracks for lime delivery.

A new dry stack was included in the BOP capital cost estimate. It was assumed that the CDS facility would be in a new location and returning the ductwork to the existing stack would be cost prohibitive.

Included in the Foundations Subcontract cost estimate is a silo for temporary waste product storage.

Railroad delivery of lime, utilizing the west spur crossing the main plant entrance road was assumed for the cost estimate. The railroad track estimate includes the cost of upgrading approximately 1,500 feet of railroad track to provide for lime delivery to the LOS Unit 2 railcar unloading station. The estimate includes refurbishment of approximately 400 feet of track past the railcar unloading position for flexibility in car positioning.

The total estimated capital cost estimate for a complete, stand-alone lime SDA FGD system with a fabric filter, utilizing lime as a reagent is \$155,700,000, or \$354/kW for LOS Unit 2.

TABLE 3.5-3 – Capital Cost Estimate for LOS Unit 2 Semi-Dry FGD System

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Semi-Dry FGD System			
Reagent Prep System	$13,080,000	$1,960,000	$15,040,000
SO_2 Absorption System	$20,740,000	$3,110,000	$23,850,000
Flue Gas Handling System	$10,310,000	$1,550,000	$11,860,000
ByProduct Handling System	$1,770,000	$270,000	$2,040,000
Support Equipment	$3,270,000	$490,000	$3,760,000
		Semi Dry Total Direct Cost =	**$56,550,000**
Fabric Filter			
Fabric Filter Housing	$14,880,000	$2,230,000	$17,110,000
Bags	$2,690,000	$400,000	$3,090,000
Ash Handling System	$5,910,000	$890,000	$6,800,000
Instruments & Controls	$510,000	$80,000	$580,000
		Fabric Filter Total Direct Cost =	**$27,580,000**
BOP Costs			
Dry Stack	$8,530,000	NA	$8,530,000
Water Treatment Equipment	$1,010,000	NA	$1,010,000
Electrical Subcontract	$6,900,000	NA	$6,900,000
Foundations Subcontract	$2,390,000	NA	$2,390,000
Relocate Pipe Rack	$390,000	NA	$390,000
Extend Ductwork	$5,720,000	NA	$5,720,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$25,050,000**
		Total Direct Cost =	**$109,190,000**

INDIRECT COSTS	
Contingency (20% of DC)	$21,840,000
A/E Engineering and Construction Management (10% of DC)	$10,660,000
BEPC INDIRECTS	
Project Development (1% of DC)	$1,090,000
Spare Parts & Plant Equipment	
Rolling Stock	$1,000,000
Initial Inventory Spare Parts (1.5% of DC)	$1,640,000
Plant Furnishings (0.5% of DC)	$550,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$550,000
Construction All-Risk Insurance (1.5% of DC)	$1,640,000
Allowance For Funds During Construction (AFDC 6%)	$6,550,000
Contingency (15% of BEPC Indirects)	$720,000
Indirect Cost Subtotal	$46,490,000
Total Capital Cost	**$155,700,000**

3.5.1.4 FLASH DRYER ABSORBER CAPITAL COST ESTIMATE

The Flash Dryer Absorber (FDA) is a relatively recent development of the semi-dry FGD process. The same methodology used for estimating the FDA capital costs for Unit 1 in Section 3.4.1.4 is used for Unit 2 with exceptions provided below. The results of the capital cost estimate for the FDA and Fabric Filter, along with BOP requirements, is provided in Table 3.5-4.

An estimate is provided for a new stack for Unit 2. For the purposes of this study, it was assumed that reusing the existing Unit 2 stack would be cost prohibitive.

The total estimated capital cost for the installation of and FDA/FF system on LOS Unit 2 is $147,000,000 or $334/kW.

TABLE 3.5-4 – Capital Cost Estimate for LOS Unit 2 FDA with Fabric Filter

DIRECT COSTS	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost ($2005)
FDA System			
Reagent Prep System	$13,970,000	$2,100,000	$16,070,000
SO_2 Absorption System	$11,980,000	$600,000	$12,580,000
Flue Gas Handling System	$9,910,000	$1,490,000	$11,400,000
ByProduct Handling System	$0	$0	$0
Support Equipment	$0	$0	$0
		FDA Total Direct Cost =	**$40,050,000**
Fabric Filter			
Fabric Filter Housing	$19,900,000	$2,980,000	$22,880,000
Bags	$2,896,000	$435,000	$3,330,000
Ash Handling System	$3,180,000	$480,000	$3,650,000
Instruments & Controls	$8,028,000	$1,204,000	$9,232,000
		Fabric Filter Total Direct Cost =	**$39,090,000**
BOP Costs			
Dry Stack	$8,530,000	NA	$8,530,000
Water Treatment Equipment	$840,000	NA	$840,000
Electrical Subcontract	$5,850,000	NA	$5,850,000
Foundations Subcontract	$2,170,000	NA	$2,170,000
Relocate Pipe Rack	$360,000	NA	$360,000
Extend Ductwork	$6,070,000	NA	$6,070,000
Railroad Upgrade/Repair	$130,000	NA	$130,000
		BOP Total Direct Cost =	**$23,950,000**
		Total Direct Cost =	**$103,090,000**

INDIRECT COSTS	
Contingency (20% of DC)	$20,620,000
A/E Engineering and Construction Management (10% of DC)	$9,170,000
BEPC INDIRECTS	
Project Development (1% of DC)	$1,030,000
Spare Parts & Plant Equipment	
Rolling Stock	$1,000,000
Initial Inventory Spare Parts (1.5% of DC)	$1,550,000
Plant Furnishings (0.5% of DC)	$520,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$520,000
Construction All-Risk Insurance (1.5% of DC)	$1,550,000
Allowance For Funds During Construction (AFDC 6%)	$6,190,000
Contingency (15% of BEPC Indirects)	$690,000
Indirect Cost Subtotal	$43,960,000
Total Capital Cost	**$147,000,000**

3.5.1.5 FUEL SWITCHING CAPITAL COST ESTIMATE

The potential for switching to PRB fuel for LOS Unit 2 was investigated by BEPC and an internal report was generated in 1997[1]. This report examined the test burn of a PRB coal similar to the current PRB coal used in the current blended fuel. From the 1997 report, a switch to 100% PRB usage at LOS Unit 2 would impact the operating and maintenance costs, but significant capital expenditures for modification of the coal handling system were not identified. The results of the cost estimate for the fuel switching alternative are given in Table 3.5-5. One significant problem that was identified was the unloading time of the coal delivery trains. Current rail car parking capacity is limited and with the current rail system configuration part of the coal train would have to be parked on the main line while unloading. The potential solutions to this particular problem are not analyzed in the report, though it is mentioned that it is possible the railroad operator can adjust to this condition. A cost estimate for potential rail line modifications was not included in this report because this question could not be resolved during the short test period.

The cost of a flue gas conditioning system was included to maintain ESP performance for this alternative. The capital cost estimate for the flue gas conditioning system includes the dry sulfur unloading station, dry sulfur storage hopper, transfer conveyance from storage hopper to sulfur melter, sulfur metering pump skid with MCC and variable speed drives, SO_3 production skid and injection probes with metering ports.

Additional capital investments may be required for a switch to PRB fuel, including construction of fuel barns and the installation of additional conveyors, but those costs were not identified as part of this study. The total capital investment for the fuel switching alternative, including flue gas conditioning, is estimated to be $1,247,000 or $2.83/kW for LOS Unit 2.

TABLE 3.5-5 – Capital Cost Estimate for Fuel Switching with Flue Gas Conditioning

Direct Costs	Estimated Cost ($2005)
Injection System	$884,000
Unloading Station	(Included Above)
Storage Hopper	(Included Above)
Transfer Conveyor	(Included Above)
Metering Pump Skid	(Included Above)
SO_3 Production Skid	(Included Above)
Injection Probes	(Included Above)
Total Direct Cost	**$835,000**
INDIRECT COSTS Contingency (20% of DC)	$177,000
A/E Engineering and Construction Management (10% of DC)	$88,000
Allowance for Funds During Construction (AFDC 6%)	$53,000
BEPC INDIRECTS Project Development (1% of DC)	$9,000
Spare Parts & Plant Equipment	
Initial Inventory Spare Parts (1.5% of DC)	$13,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$4,000
Construction All-Risk Insurance (1.5% of DC)	$13,000
Contingency (15% of BEPC Indirects)	$6,000
Indirect Cost Subtotal	$363,000
Total Capital Cost	**$1,247,000**

3.5.1.6 WET FGD O&M COST ESTIMATE

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance. Table 3.5-6 summarizes the O&M cost estimates for the wet FGD system.

The fixed costs include operating labor, administrative and support labor and the maintenance material and labor costs. The maintenance material and labor cost was estimated as approximately 3% of the wet FGD system direct capital cost in Table 3.5-1. Administrative and support labor cost was estimated as 12% of the maintenance material and labor cost plus 30% of the operating labor costs. Previous studies and guidelines for FGD O&M costs by EPRI and others are in line with these percentages.

TABLE 3.5-6 – O&M Cost Estimate for LOS Unit 2 Wet FGD System

Fixed Costs	
Operating Labor	$2,330,000
Admin and Support labor	$1,020,000
Maintenance Material and Labor	$2,680,000
Total Fixed O&M Cost =	$6,030,000
Variable Costs	
Limestone Reagent	$3,340,000
Byproduct Disposal	$1,190,000
Water	$550,000
Auxiliary Power	$3,100,000
Total Variable O&M Cost =	$8,180,000
Total Annual O&M Cost =	**$14,210,000**
Net Annual O&M Cost ($/MWh)	**$4.34**

The operating labor cost is based on a total of 19 additional personnel, including two operators per shift (one in the control room and one on roving duty) with two truck drivers at 40 hours per week for hauling of FGD wastes and three laborers on day and second shifts and one on roving assignment. In addition, four maintenance staff working one shift per day, five days per week, plus two for weekend duty are included in the maintenance cost estimate.

Variable costs include reagent, makeup water, FGD byproduct disposal and auxiliary power costs. The estimated annual costs for these consumables are based on consumption rates modeled by the CUECost model and the unit cost information provided by BEPC and described in Table 1.2-3 Economic Design Criteria. A cost of $5.50 per ton for hauling the FGD wastes was included for waste disposal. No additional cost for landfilling at the permitted solid waste facility was included. The LOS Unit 2 estimated annual O&M costs are $14,210,000 or $4.34/MWh.

3.5.1.7 CIRCULATING DRY SCRUBBER O&M COST ESTIMATE

Estimated O&M costs for the CDS/FF alternative were developed from the CUECost estimate of the O&M costs for the SDA/FF alternative. The operating labor was increased by 8% over that of the SDA as indicated in a recent study by Sargent & Lundy[5] comparing the two alternative technologies. The CDS reagent usage was also increased 7% above that for the SDA. Waste disposal costs were increased 5% over those of the SDA, as estimated by CUECost, to reflect the increased reagent wastage. The power requirement for the CDS was increased 18% over that estimated by CUECost for the SDA based upon Sargent & Lundy's findings[5]. The estimated annual O&M costs for application of the CDS/FF alternative at LOS Unit 2 are given in Table 3.5-7.

TABLE 3.5-7 – O&M Cost Estimate for LOS Unit 2 CDS/FF System

Fixed Costs	
Operating Labor	$1,860,000
Admin and Support labor	$740,000
Maintenance Material and Labor	$2,440,000
Total Fixed O&M Cost =	$5,040,000
Variable Costs	
Lime Reagent	$8,740,000
Byproduct Disposal	$1,460,000
Water	$230,000
Auxiliary Power	$2,430,000
Total Variable O&M Cost =	$12,870,000
Total Annual O&M Costs	**$17,910,000**
Net Annual O&M Cost ($/MWh)	**$5.16**

3.5.1.8 SEMI-DRY FGD O&M COST ESTIMATE

The O&M cost estimate for the SDA/FF alternative was taken directly from CUECost. Lime usage was set at 1.80 lbmol of lime (CaO) per lbmol of SO_2 removed. A ratio of 5.5 lb of recycled solids per pound of lime added and a 35% solids slurry were also set as design conditions in CUECost. A total of 11" w.g. pressure drop across the combined SDA/FF system was also utilized as a design condition. The Fabric Filter was sized for a gas-to-cloth ratio of 3.5 ACFM/Ft^2. A three year bag life was assumed. The results of the SDA/FF O&M cost estimate are summarized in Table 3.5-8.

TABLE 3.5-8 – O&M Cost Estimate for LOS Unit 2 SDA/FF System

Fixed Costs	
Operating Labor	$1,670,000
Admin and Support labor	$770,000
Maintenance Material and Labor	$2,260,000
Total Fixed O&M Cost =	$4,700,000
Variable Costs	
Lime Reagent	$8,170,000
Byproduct Disposal	$1,390,000
Water	$230,000
Auxiliary Power	$2,050,000
Total Variable O&M Cost =	$11,850,000
Total Annual O&M Costs	**$16,550,000**
Net Annual O&M Cost ($/MWh)	**$4.77**

3.5.1.9 FLASH DRYER ABSORBER O&M COST ESTIMATE

The FDA/FF O&M costs were estimated from a combination of the CUECost estimate for the SDA/FF system and vendor materials. The operating labor for the FDA/FF were taken directly from the SDA/FF estimate because the FDA/FF system operation is no more technically complex than the SDA/FF. Maintenance costs were estimated as 90% of the SDA/FF maintenance cost estimated by CUECost. Reagent usage and waste solids generation rates were taken from information supplied by Alstom for the current fuel blend, increased for the additional sulfur content of the design fuel and the costs determined from the economic information in Table 1.2-3. Auxiliary power costs for the SDA/FF system were increased 10% for the FDA/FF usage. The results of the FDA/FF O&M cost estimate are given in Table 3.5-9.

TABLE 3.5-9 – O&M Cost Estimate for LOS Unit 2 FDA/FF System

Fixed Costs	
Operating Labor	$1,670,000
Admin and Support labor	$710,000
Maintenance Material and Labor	$2,090,000
Total Fixed O&M Cost =	$4,470,000
Variable Costs	
Lime Reagent	$8,450,000
Byproduct Disposal	$1,540,000
Water	$180,000
Auxiliary Power	$2,160,000
Total Variable O&M Cost =	$12,320,000
Total Annual O&M Costs	**$16,800,000**
Net Annual O&M Cost ($/MWh)	**$4.84**

3.5.1.10 FUEL SWITCHING O&M COST ESTIMATE

In the 1997 report[1] on the PRB test burn, BEPC reported several operational advantages to the use of PRB in LOS Unit 2. These included reduced station service (from 7.6 to 7.2%), reduced sulfur emissions and reduced ash quantities. The test report specifically mentions that although some features of PRB firing were documented, the test duration was extremely short and many potential long term impacts were neither investigated nor documented. Additional O&M cost might result from unknown impacts caused by a fuel switch. For the purpose of estimating impacts of a switch to 100% PRB fuel on the operating and maintenance costs of LOS Unit 2, the changes in fuel cost, station service costs and ash disposal were estimated based on the report contents and are summarized in Table 3.5-10.

The change in fuel cost calculated to result from a switch to 100% PRB was based upon the design heat input to LOS Unit 2, taking into account a 2.1% increase in boiler efficiency (at full generation). The station service benefit was calculated as the net decrease in station service based on operating costs given in Table 1.2-3. Because PRB has a significantly lower ash content, a credit for reduction in both bottom ash and flyash disposal costs is also included. The annual additional O&M cost of switching LOS Unit 2 to PRB is estimated to be $11,213,000 or $2.91/MWh.

TABLE 3.5-10 – O&M Cost Estimate for LOS Unit 2 Fuel Switching

Fuel Cost Change Reduced Station Service Change in Ash Disposal Cost	$11,743,000 -$292,900 -$449,100
Flue Gas Conditioning Reagent	$200,000
Flue Gas Conditioning Equipment Maintenance	$12,000
Total Annual Change to O&M Cost	**$11,213,000**
Total Annual Change to O&M Cost ($/MWh)	**$2.91**

3.5.1.11 LEVELIZED TOTAL ANNUAL COST

The Levelized Total Annual Cost (LTAC) for all alternatives were calculated based on economic conditions given in Table 1.2-3 and a 20 year project life. The LTAC was calculated for each alternative utilizing the estimated costs in Tables 3.5-1 through 3.5-10 and the economic conditions described in Section 1 of this report. Estimated capital costs were split evenly over a two year construction period for all alternatives. A system startup date of December 17, 2013 was used based upon the projected timing of Regional Haze Rule implementation given by NDDH. O&M costs were included through the end of the calendar year 2034. No salvage value was assumed at the end of the service life for any of the alternatives. The LTAC for each alternative are presented below in Table 3.5-11.

The annual tons of SO_2 reduction in this study are calculated for two cases. One case is the difference between the uncontrolled Historical emissions and the controlled emissions for the Future PTE case. The second case is the difference between uncontrolled emissions and controlled emissions for the Future PTE case.

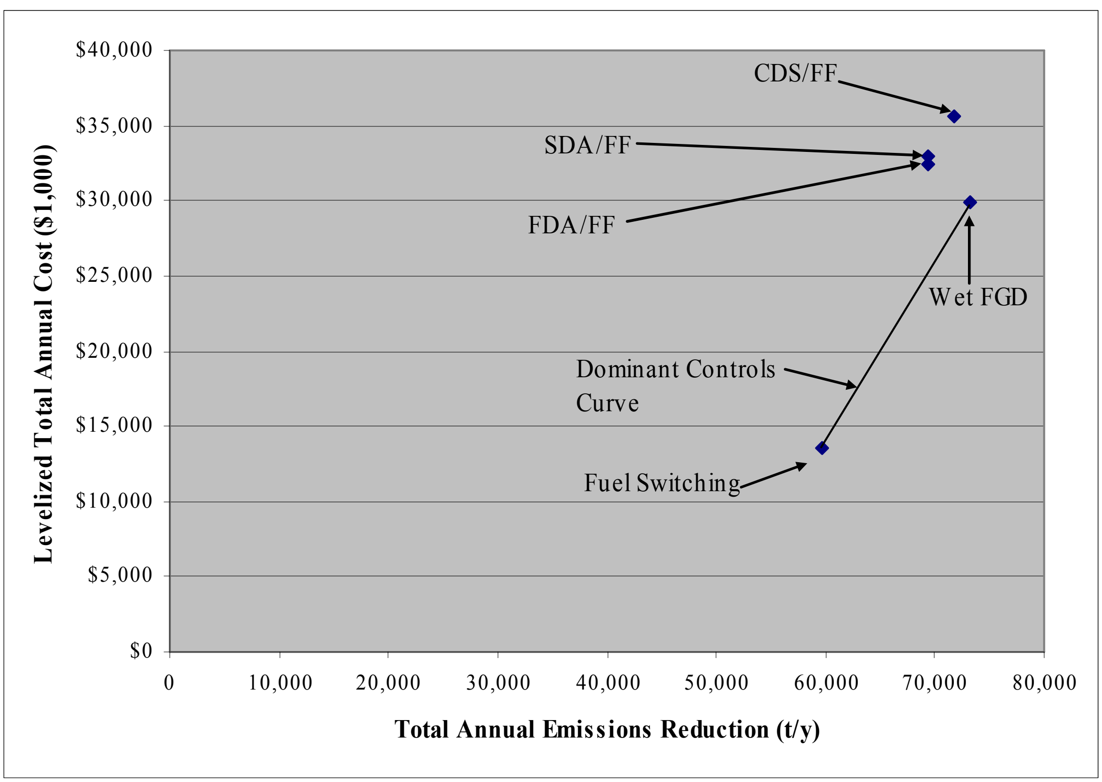
TABLE 3.5-11 – Levelized Total Annual Costs of Unit 2 BART SO_2 Control Alternatives[(1)]

BART Alternative	Control Efficiency	Annual Emission Reduction from Historical Case (tpy)[(2)]	Annual Emission Reduction from Future PTE Case (tpy)[(3)]	Installed Capital Cost ($2005)	Annual O&M Cost ($2005)	Levelized Total Annual Cost ($2005)[(4)]
Wet FGD	95%	35,568	73,272	$147,600,000	$14,210,000	$29,840,000
CDS/FF	93%	34,025	71,729	$167,900,000	$17,910,000	$35,580,000
SDA/FF	90%	31,711	69,415	$155,700,000	$16,550,000	$32,890,000
FDA/FF	90%	31,711	69,415	$147,000,000	$16,800,000	$32,430,000
Fuel Switch	77%	21,685	59,620	$1,247,000	$11,213,000	$13,490,000

(1) - All Costs in 2005 dollars.
(2) - Annual emission reduction is uncontrolled Historical emissions minus controlled Future PTE emissions.
(3) - Annual emission reduction is uncontrolled emissions minus controlled emissions for Future PTE case.
(4) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

Figure 3.5-1 is a plot of the Levelized Total Annual Cost versus the annual removal in tons (Future PTE case basis) for each BART alternative shown in Table 3.5-11. A similar graphic analysis was not presented for the Historic case due to the similarity to the Future PTE case analysis. The purpose

FIGURE 3.5-1 – LOS Unit 2 SO_2 Least Cost Envelope for Future PTE Case



of Figure 3.5-1 is to identify the Dominant Controls Curve which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly above or to the left of this curve are inferior control alternatives on a cost effectiveness basis. Of the technically feasible BART alternatives considered for LOS Unit 2, data points for the CDS, the SDA and the FDA all lie distinctly above the least cost boundary of the control cost envelope. The reason for this is clear from Table 3.5-12 where the unit control costs for all of the BART alternatives are listed. In a top down analysis each of the SO_2 control technologies represented by a data point above the Dominant Control Curve could be excluded from further analysis on a cost effectiveness basis.

TABLE 3.5-12 – Unit Control Costs of Unit 2 BART SO_2 Control Alternatives

BART Alternative	Control Efficiency	Levelized Total Annual Cost ($2005)(1)	Annual Emission Reduction from Historical Case (tpy)	Historical Case Unit Control Cost ($/ton)	Annual Emission Reduction from Future PTE Case (tpy)	Future PTE Case Unit Control Cost ($/ton)
Wet FGD	95%	$29,840,000	35,568	$839	73,272	$407
CDS/FF	93%	$35,580,000	34,025	$1,046	71,729	$496
SDA/FF	90%	$32,890,000	31,711	$1,037	69,415	$474
FDA/FF	90%	$32,430,000	31,711	$1,023	69,415	$467
Fuel Switch	77%	$13,490,000	21,685	$622	59,620	$226

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above or below it on the Dominant Controls Curve. Table 3.5-13 contains a repetition of the cost and control information from Table 3.5-11 and the incremental cost effectiveness between each dominant control alternative.

TABLE 3.5-13 – Incremental Cost Effectiveness of Unit 2 BART SO_2 Control Alternatives

BART Alternative	Levelized Total Annual Cost ($2005)(1)	Annual Emission Reduction from Historical Case (tpy)	Incremental Cost Effectiveness for Baseline Case ($/t)	Annual Emission Reduction from Future PTE Case (tpy)	Incremental Cost Effectiveness for Future PTE Case ($/t)
Wet FGD	$29,840,000	35,568	$1,380	73,272	$1,406
Fuel Switching	$13,490,000	21,685	NA	59,620	NA

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

In the BART Determination guidelines, EPA does not provide definition, or even discussion of reasonable, or unreasonable, Unit Control Costs. Similarly, EPA does not address reasonable or unreasonable ranges for the incremental cost effectiveness. The incremental cost effectiveness is a marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the Dominant Control Cost curve) between successively less effective alternatives. The incremental cost effectiveness for wet FGD versus fuel switching in Table 3.5-13 is within the range of reasonable costs used in other regulatory analyses and thus does not indicate that wet FGD is prohibitively expensive.

The cost analysis portion of the BART determination for LOS Unit 2 has shown that none of the Unit Control Costs for the dominant alternatives are exceedingly expensive on a Unit Control Cost basis. However, three of the BART alternatives were established as being inferior based upon the Dominant Controls Curve. Unlike the Unit 1 SO_2 BART analysis, the range of the estimated LTACs ($\pm$ 20%) for Unit 2 post combustion controls approaches much closer to the estimate accuracy ($\pm$ 30%). Similarly, the range for the post combustion control alternative Unit Control Costs ($\pm$ 25%) is much closer to the estimate accuracy. For this reason, the Unit 2 cost impact analysis results were interpreted to indicate that further analysis for the recommended SO_2 BART for LOS Unit 2 should be limited to alternatives on the Dominant Control Curve.

Considering the results of the cost impact analysis for LOS Unit 2, fuel switching (77%) was identified as a significantly inferior alternative to presumptive BART. Further, the remaining alternative, wet FGD, achieving 95% SO_2 emission reduction equals presumptive BART and was the recommended alternative at the end of the cost impact analysis. Therefore, Basin Electric Power Cooperative decided that fuel switching should be excluded from further consideration in the study.

This decision leaves wet FGD as the sole SO_2 control alternative for LOS Unit 2 and meets the recommended presumptive BART for units of its size.

3.5.2 ENERGY IMPACTS

The energy impacts of wet FGD, both in terms of estimated kW of energy usage and the percent of total generation, are given in Table 3.5-14. The primary energy impacts of the wet FGD alternative consists of the additional electrical load resulting from pumps, blowers, booster fans, ball mills for limestone grinding and vacuum pumps for byproduct slurry dewatering. Building HVAC and interior and exterior lighting loads are also included, but the major energy consumption is due to the primary systems described above.

TABLE 3.5-14 – Energy Requirements of Unit 2 BART SO_2 Control Alternatives

BART Alternative	Energy Demand (kW)	Percent of Nominal Generation
Wet FGD	9,315	2.1%

3.5.3 NON-AIR QUALITY ENVIRONMENTAL IMPACTS

Non-air quality environmental impacts of the installation and operation of the various BART alternatives include hazardous waste generation, solid and aqueous waste streams, and salable products that could result from the implementation of various BART alternatives.

The captured mercury in the solid waste stream from a wet FGD system is a trace contaminant in the solid waste, not affecting disposal options as long as the waste passes the Toxic Characteristic Leaching Procedure (TCLP), which most FGD system wastes do. Therefore, this potential non-air quality environmental impact was not considered to warrant attention during this analysis.

The wet FGD system for LOS Unit 2 is estimated to produce approximately 28.3 tons per hour of solid wastes. The waste stream would be composed of gypsum solids and inerts at approximately 10% - 15% moisture. Over the course of a year, the total solid waste quantity is estimated to be approximately 248,000 tons of gypsum solids which would be landfilled in the current permitted solid waste disposal facility near the plant.

The annual quantity of aqueous waste that would be produced by the wet FGD system is difficult to quantify because the blowdown rate from a wet FGD system is primarily a function of the dissolved chloride levels in the absorber and recycle tank. Most of the chloride reaching the scrubber is in the form of hydrochloric acid which is readily absorbed and neutralized. Hydrochloric acid removal rates in a typical wet FGD system typically exceed 95%. CUECost estimates 80 lb/hr of hydrochloric acid in the flue gas stream which is assumed to be completely removed by the absorber system. The waste solids stream leaving the wet FGD system contains approximately 15% water which would contain $CaCl_2$ which would not require blowdown for disposal. Assuming the chloride to be present in the blowdown stream as $CaCl_2$ and assuming an average chloride concentration of 9,500 parts per million, one can calculate approximately 80 pounds an hour of chloride would leave the plant in the gypsum wastes. No blowdown specifically for chloride disposal would be required. For the purpose of this analysis, it was assumed that an irregular blowdown stream would be sent to a dedicated evaporation pond on site for disposal.

3.5.4 VISIBILITY IMPACTS

The final impact analysis conducted was to assess the visibility impairment impact reduction for the presumptive BART control level. Visibility impairment impacts due to pre-control historical emissions and post-control (future PTE) emission levels were modeled. CALPUFF was used to model long-range transport of SO_2, NO_X and PM to estimate the visibility impairment impact in deciViews (dV). The reduction in visibility impairment impact due to presumptive SO_2 BART (95% control) was then calculated as the difference between the visibility impairment impact for wet FGD and the pre-control visibility impairment impact.

The BART guidelines state that the comparison should be made at the 98th percentile level (70 FR 39170). However, NDDH directed that the comparison should be made at the 90th percentile. Therefore, the visibility impairment impact reduction presented for each control scenario in this section is based on the 90th percentile value.

CALPUFF modeling was conducted for the application of presumptive BART. The modeling results, expressed as the change in visibility impairment impact, in deciViews (ΔdV) is the change in visibility impairment impact in the affected Class 1 area as a result of the implementation of wet FGD on LOS Unit 2. The visibility improvement for the modeled case is given in Table 3.5-15 for each Class 1 Area. In addition to the average ΔdV values, three other types of data are presented in this table, the number of days exceeding 0.5 dV, the number of days exceeding 1.0 dV and the maximum number of consecutive days exceeding 0.5 dV after implementation of presumptive BART. The 0.5 dV value is the lowest visibility impairment impact that is considered discernible by the human eye and the EPA set this threshold as the point where a given source is considered a "contributing source" (70 FR 39120). The 1.0 dV threshold was established in the final rule as the threshold at which a state should consider a source to be a cause of visibility impairment (70 FR 39120). Therefore, the number of occurrences of each of these impacts is part of the visibility impairment impact analysis. The final criteria, the maximum number of consecutive days in which the visibility impairment impact exceeds 0.5 dV is also tabulated as this is a further measure of the extent of visibility impairment attributable to a given source.

The visibility impairment impact reduction attributable to the application of presumptive BART is given in column 2 of Table 3.5-15. This value is the 90th percentile visibility impairment impact reduction over each modeled year (2000-2002) for each affected Class 1 area. Column 3 of the table lists the three year average impact for each Class 1 Area. The Lostwood National Wildlife Refuge (Lostwood NWR) shows the greatest average visibility impairment impact reduction, thus indicating that this area will gain the greatest benefit from BART implementation of all the Class 1 Areas included in the modeling. The Teddy Roosevelt National Park, Elkhorn site (TRNP-Elkhorn) is shown to gain the least visibility impairment impact reduction from presumptive BART implementation.

A review of Table 3.5-15 finds that the visibility impairment impacts for presumptive BART vary with area and year of modeled results. The greatest number of days exceeding 0.5 dV in column 4 of Table 3.5-15 is shown graphically in Figure 3.5-2 for clarity. Both precontrol and postcontrol modeling results are presented to demonstrate the impact reduction achieved by presumptive BART implementation. The worst impact in terms of days exceeding 0.5 dV after BART implementation

TABLE 3.5-15 – Visibility Impairment Impacts – Unit 2

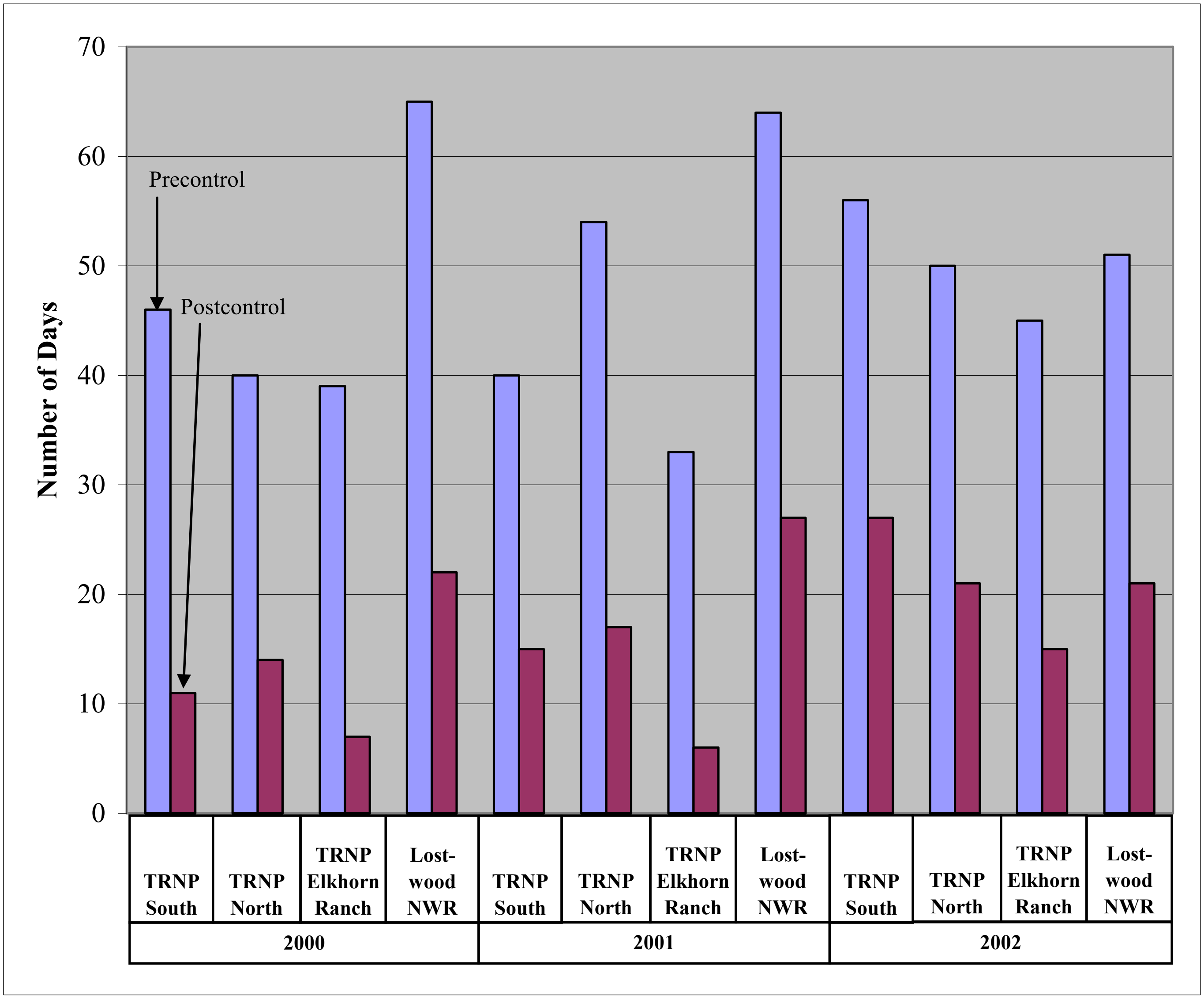
Year And Class 1 Area	Visibility Impairment Reduction (ΔdV)(1),(2)	Three Year Average Visibility Impairment Reduction (Δ dV)	Days(2) Exceeding 0.5 dV	Days(2) Exceeding 1.0 dV	Consecutive Days(2) Exceeding 0.5 dV
2000					
TRNP South	0.496	0.586	11	4	2
TRNP North	0.535	0.578	14	6	1
TRNP Elkhorn	0.411	0.415	7	2	1
Lostwood NWR	0.802	0.694	22	6	2
2001					
TRNP South	0.438	0.586	15	2	2
TRNP North	0.646	0.578	17	5	2
TRNP Elkhorn	0.358	0.415	6	1	2
Lostwood NWR	0.693	0.694	27	12	3
2002					
TRNP South	0.825	0.586	27	15	3
TRNP North	0.549	0.578	21	14	3
TRNP Elkhorn	0.475	0.415	15	8	2
Lostwood NWR	0.587	0.694	21	5	3

(1) - 90^{th} percentile visibility impairment impact reduction. A summary of the modeling scenarios is provided in Table 1.4-1 and the modeling results are presented in Appendix D.

(2) - All values in this table are for combination case of WFGD for SO_2 control and Advanced SOFA for NO_X control.

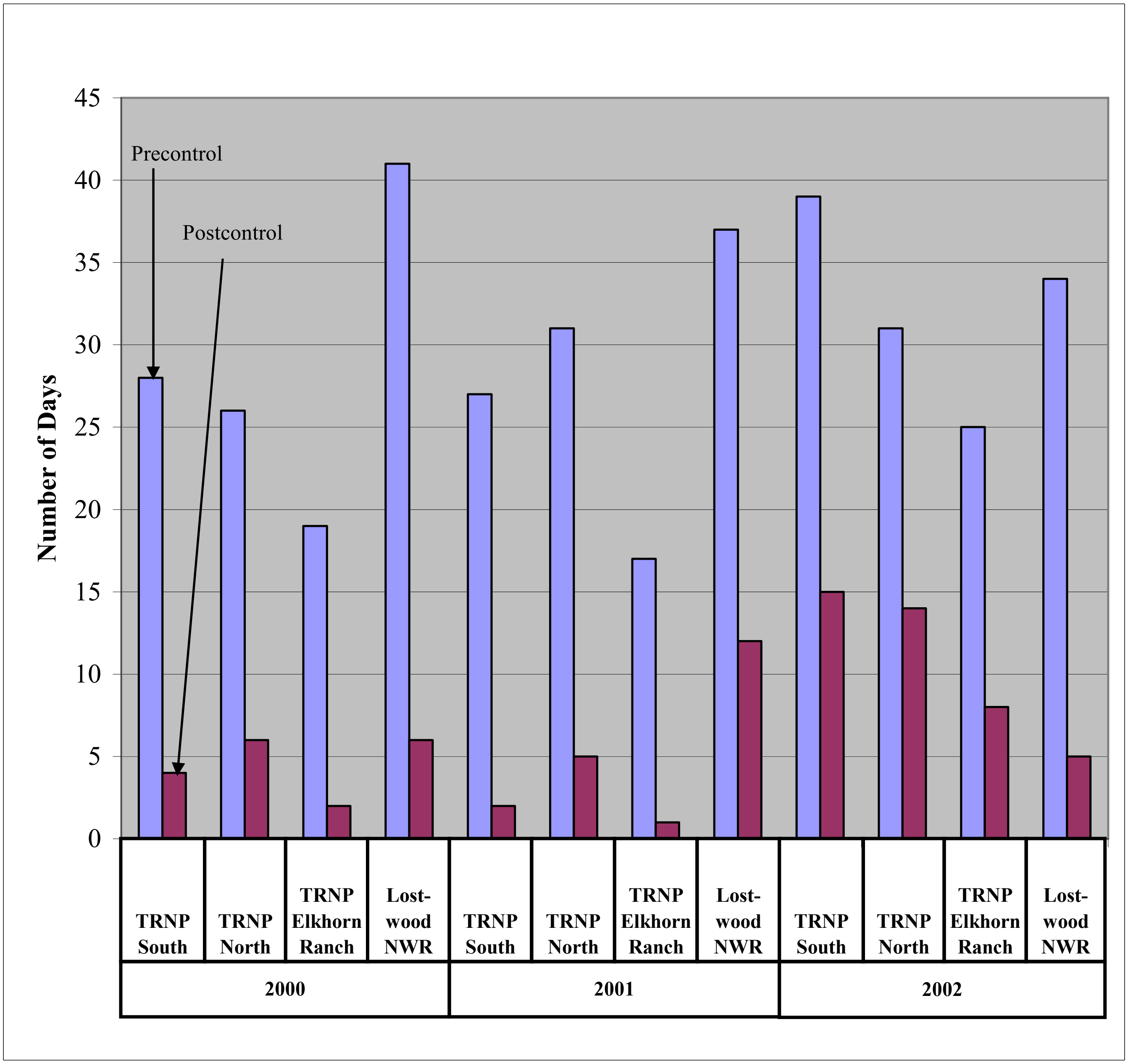
occurs at Lostwood NWR for model years 2000 and 2001. However, in 2002, the greatest number occurs at TRNP South. The TRNP Elkhorn Ranch site consistently exhibits the least number of days exceeding 0.5 dV after BART implementation.

FIGURE 3.5-2 – Number of Days Exceeding 0.5 dV for Pre- and Post-Control



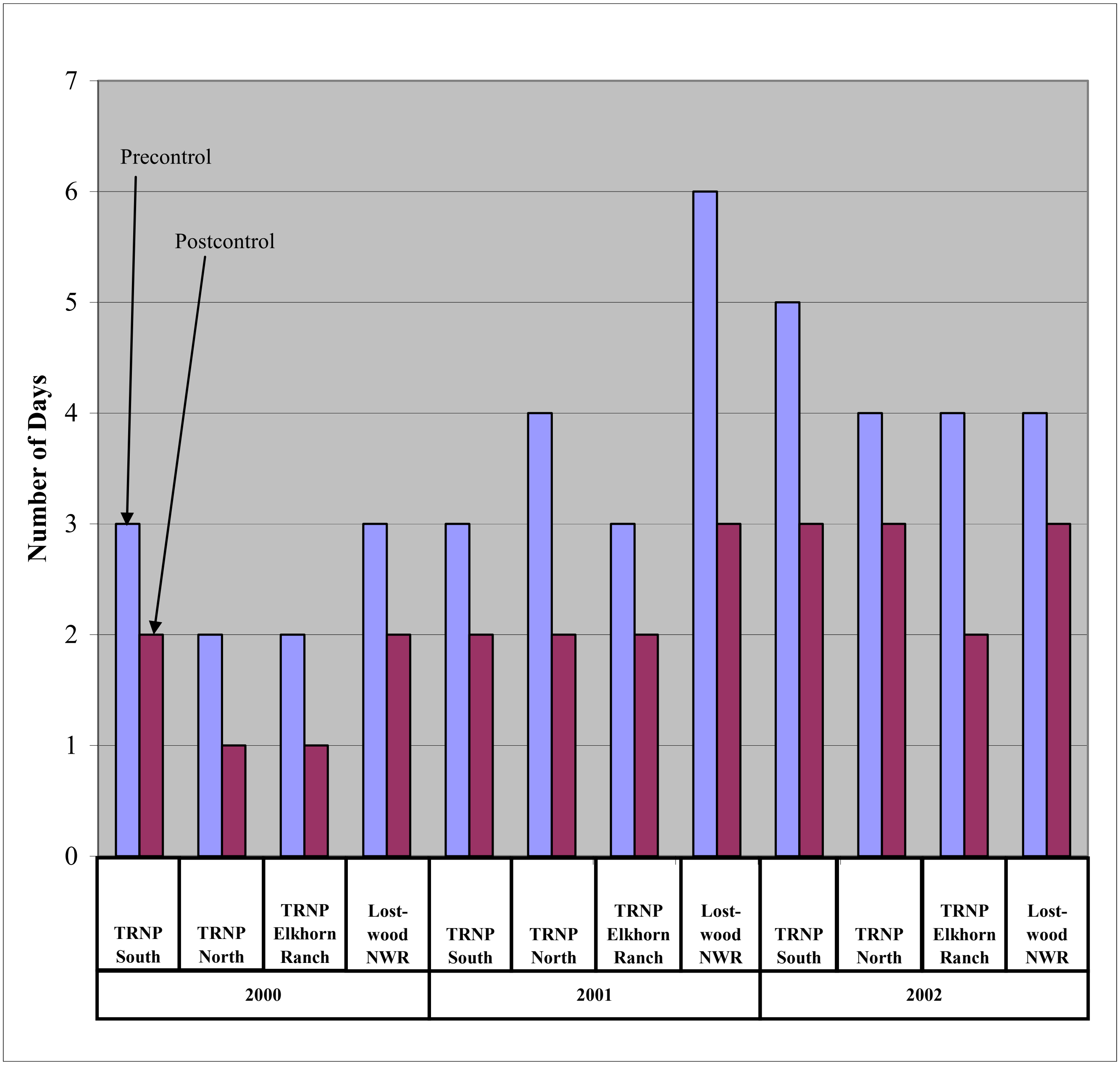
The number of days in a year where the modeled visibility impairment impact exceeded 1.0 dV are listed in column five of Table 3.5-15 and shown graphically in Figure 3.5-3. Both pre-control and post-control modeling results are presented to demonstrate the impact reduction achieved by presumptive BART implementation. The greatest number of days with at least 1.0 dV of impact occurs in both TRNP-North and Lostwood NWR in 2000, in Lostwood NWR in 2001 and TRNP-South in 2002. The least number of days with at least 1.0 dV of impact occurs in TRNP Elkhorn Ranch in 2000 and 2001 and in Lostwood NWR in 2002. This trend is similar to the one observed for the number of post BART implementation days with an impact exceeding 0.5 dV.

FIGURE 3.5-3 – Number of Days Exceeding 1.0 dV for Pre- and Post-Control



The greatest number of consecutive days exceeding 0.5 dV of impact is listed in column six of Table 3.5-15 and shown graphically in Figure 3.5-4. Both precontrol and postcontrol modeling results are presented to demonstrate the impact reduction achieved by presumptive BART implementation. The model year 2000 results are the same for TRNP-North and TRNP Elkhorn Ranch with only one day

FIGURE 3.5-4 – Maximum Consecutive Days Exceeding 0.5 dV for Pre- and Post-Control



occurrences. TRNP-South and Lostwood NWR tie for the highest number of consecutive days at two per year in 2000. The greatest number of consecutive days in 2001 occurs in Lostwood NWR at three days and two days per year for all TRNP sites. In 2002 the model predicts that TRNP-South, TRNP-North and Lostwood NWR would all experience the three consecutive days while the TRNP Elkhorn Ranch site would have only experienced two consecutive days that same year.

The total number of days where the visibility impairment impact exceeded 0.5 dV over the entire modeling period (2000-2002) is greatest for Lostwood NWR. Similarly, the total number of days where the impact exceeded 1.0 dV is greatest for TRNP-North over the model period and the maximum number of consecutive days with impacts greater than 0.5 dV is slightly greater for Lostwood NWR overall. The model results predict that the TRNP Elkhorn Ranch site would have experienced the least overall post BART implementation visibility impacts on all modeled sites.

A review of Table 3.5-15 and Figures 3.5-2 through 3.5-4 clearly demonstrates a significant visibility impairment reduction due to the implementation of presumptive BART (95% SO_2 control), regardless of model year and Class 1 area.

3.5.5 IMPACT SUMMARY

Section 3.5 of this report has analyzed the impacts of BART alternatives for LOS Unit 2. Table 3.5-16 summarizes the results of this analysis. At the conclusion of the cost impact analysis, it was determined that only two of the BART alternatives, wet FGD and fuel switching, were cost effective. The other three alternatives, CDS/FF, SDA/FF and FDA/FF were excluded from further analysis on a cost impact basis. Neither the Unit Control Costs for wet FGD and fuel switching, nor the marginal Unit Control Cost for wet FGD relative to fuel switching were unreasonable. Thus, it was determined that fuel switching at 77% control was clearly inferior to wet FGD as a BART alternative and fuel switching was also excluded from further analysis at the end of the cost analysis. Visibility impact analysis results were presented for the wet FGD alternative in Section 3.5.4. The impact analysis results for wet FGD are summarized in Table 3.5-16.

TABLE 3.5-16 – LOS Unit 2 Impacts Summary for SO_2 Control Alternatives

BART Alternative and Control Efficiency (%)	Annual Emissions Reduction (tpy)	Levelized Total Annual Control Cost ($2005)[1]	Unit Control Cost ($/tons)	Visibility Impairment Impact Reduction		Visibility Impairment Reduction Unit Cost ($/dV)	Energy Impact (kW)	Non Air Quality Impacts
				Class 1 Area	ΔdV[2]			
WFGD 95	73,272	$29,840,000	$407	TRNP-S	0.586	$50,920,000	9,315	Solid and Liquid Wastes
				TRNP-N	0.577	$51,720,000		
				TRNP-Elkhorn	0.415	$71,900,000		
				Lostwood NWR	0.694	$43,000,000		

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Average three year change in visibility impairment impact between uncontrolled and controlled emissions for the Future PTE case with both WFGD and ASOFA.

SO_2 SECTION REFERENCES:

1. "Powder River Basin Coal Test at Leland Olds Station, Units 1 And 2"; Basin Electric Power Cooperative Internal Report; February, 1997.

2. http://www.state.nd.us/ndic/lrc-infopage.htm

3. "SO_2 Removal Efficiency Achieved in Practice by U.S. Electric Utility Semi-Dry FGD Systems"; Electric Utility Environmental Conference (EUEC); Weilert, C. and Randall, D.; Tucson, AZ; January 2006.

4. "Alstom Power's Flash Dryer Absorber For Flue Gas Desulfurization", Ahman, Barranger and Marin, Proceedings of IJPGC '02, June 24-26, 2002.

5. "Economics of Lime and Limestone for Control of Sulfur Dioxide"; DePriest, William & Gaikwas, Rajendra P. ; National Lime Association (www.lime.org/NLADryFGD.pdf); September, 2002.

6. "Use of a Circulating Fluid Bed for Flue Gas Desulfurization"' Toher, John, G. Lurgi-Lentjes N. America.

7. "K-Fuel™ Commercialization"; http://kfx.com.

8. "How much does K-Fuel™ cost"; http://kfx.com.

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4.0 PARTICULATE MATTER BART EVALUATION

The primary source of particulate matter (PM) associated with a coal-fired boiler is the ash from combustion of the coal. There is also unburned carbon present in the flue gas, which is the result of incomplete combustion that adds to the PM emissions. In this section, steps 1 through 5 of the BART determination for Leland Olds Station (LOS) Units 1 and 2 are described for PM. All PM control technologies are first identified. A technical description of the processes and their capabilities are then reviewed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to nominal PM control capability. The impacts analysis then reviews the estimated cost, energy, and non-air quality impacts for each technology. The impact of the remaining useful life of the source was reviewed as part of the cost analysis. In the final step of the analysis, the remaining technologies were assessed for their potential visibility impairment impact reduction capability via visibility modeling results. The results of the complete analyses are tabulated and possible BART control options are listed.

The quantity of uncontrolled PM emissions is a strong function of the type of boiler utilized. Different boiler types generate different splits between bottom ash, which is collected in the bottom of the boiler, and fly ash, which is entrained in the flue gas and becomes boiler particulate matter emissions. Unit 1 is a wall-fired, dry-bottom, pulverized coal boiler with a bottom ash/fly ash split of 30/70 respectively. Unit 2 is a cyclone-fired unit burning crushed coal, with a bottom ash/fly ash split of 70/30 respectively. The design parameters, including coal analysis, unit type, unit size, etc., used in this analysis are displayed in Tables 1.2-1 and 1.2-2.

The BART guidelines published in the Federal Register on July 6, 2005 (70 FR 39104) do not specify presumptive BART levels for particulate matter (PM) emissions. The guidelines suggest the use of PM_{10} as the indicator for all $PM_{2.5}$, because $PM_{2.5}$ emissions are encompassed within the PM_{10} emissions fraction. (70 FR 39160) For modeling purposes, both the BART guidelines and the NDDH protocol specify that a distinction between coarse (PM_{10} minus $PM_{2.5}$) or fine ($PM_{2.5}$) PM be used to determine visibility impacts. The distinction between course and fine particulate was made during CALPUFF visibility modeling.

The BART guidelines indicate that one of the evaluated emission limits must be at least as stringent as the New Source Performance Standard (NSPS) requirement for the source (70 FR 39164). The PM emission limit under NSPS that most closely relates to LOS is 0.1 lb/mmBtu. Therefore, for the purpose of this report, at least one of the evaluated control technologies achieves a PM emission level of 0.1 lb/mmBtu.

4.0.1 FILTERABLE AND CONDENSABLE PARTICULATE MATTER

Particulate matter emissions are composed of filterable and condensable particles. The filterable particles are characterized using EPA standard reference methods (i.e., Method 5, 17, 201, or 201A) and are commonly referred to as the front-half of the particulate sample train. The reference method used for characterization is dependent upon the size of the particle, the temperature of the flue gas, and is usually specified in the applicable permit. Solid particles are captured using a heated filter while the majority of condensable particles are not collected as they are in the gaseous form until after the flue gas has passed through the filter.

As flue gas moves through the different processes associated with each unit, condensable particulate matter (condensable PM) may react with atmospheric or flue gas constituents and then either condense into a droplet, coalesce into a solid particle, or form a solid particle as more volatile components evaporate. Condensable PM is characterized using EPA standard reference Method 202 which is commonly referred to as the back-half of the particulate sampling train. Using Method 202, the flue gas passes through a heated filter to remove filterable PM and condensable flue gas constituents are condensed by bubbling them through water at 20^{o}C. The water is evaporated and the remaining residue is weighed to determine condensable PM emissions. However, Method 202 has an inherent flaw because the means by which condensable particulate is collected differs from how particulate condenses in the stack. Method 202 can provide inaccurate measurements due to the creation of PM artifacts in the sampling water that would not normally condense in the stack plume (e.g., SO_2 and NH_3 compounds). For a fixed operating condition, Method 202 can provide inconsistent emission rate measurements and can result in high emission rates. Thus, there is considerable uncertainty surrounding emissions measured with Method 202 for the purpose of compliance demonstration.

Condensable PM may include both organic and inorganic constituents. Organic constituents in the flue gas can exist as a vapor at stack temperatures and a liquid or solid at ambient temperatures. Control technologies designed to minimize the formation of condensable organic emissions are the same technologies that are used to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. A review of the RBLC database shows that good combustion practices are universally used to control CO/VOC emissions for similar units. Both LOS units already practice good combustion practices while maintaining combustion efficiency in the boiler and controlling NO_X emissions. Because good combustion practices are already in use at both units, the organic portion of condensable PM is not addressed further in this report.

Sulfuric acid (H_2SO_4) mist is the most widely recognized form of inorganic condensable PM emitted by combustion sources. Other inorganic condensable PM constituents may include to a lesser extent other acid gases, ammonium sulfate ($(NH_4)_2SO_4$), and unidentified inorganic species. Control technologies designed to reduce sulfuric acid mist will also reduce the other inorganic constituents. H_2SO_4 is typically generated in the flue gas when sulfur trioxide (SO_3) reacts with water. SO_3 is a by-product created during the combustion of fuels containing sulfur and is formed when sulfur dioxide (SO_2) in the flue gas is oxidized. Limited data is available on the quantity of SO_2 that will be converted to SO_3 in a lignite fired unit. Estimates of the conversion range from 0.2 to 1.0 percent.

Combustion controls commonly used to control NO_X (e.g., staged combustion and separated overfire air) provide a co-benefit of sulfuric acid mist control by limiting the oxygen available in the boiler and reducing formation of SO_3 in the boiler. The H_2SO_4 vapor will adsorb on the fly ash as the flue gas cools under appropriate temperature and moisture conditions. Consequently, when those conditions exist, H_2SO_4 mist is removed from the gas stream by particulate control equipment. Control technologies designed to remove SO_2 will also achieve SO_3 removal and reduce emissions of H_2SO_4. Typical SO_3 removal associated a wet FGD process is 40 to 60 percent and higher for semi-dry FGD processes. The Southern Company estimates a 50% reduction in H_2SO_4 emissions for use of wet FGD.[1] Thus, control technologies used to control NO_X through combustion controls, SO_2 through a FGD process and filterable PM through a device to be analyzed in this section of the report are also able to provide H_2SO_4 control.

Under Section 313 of the Emergency Planning and Community Right-to-Know Act (EPCRA), industrial facilities such as LOS must submit information to the State about the annual release of certain chemicals. Three of the main constituents of inorganic condensable PM are included in the chemicals that must be reported. Sulfuric acid mist, hydrogen chloride and hydrogen fluoride are the reported constituents that make up the majority of inorganic condensable PM emissions. During the period from 2000 to 2004 under EPCRA, utilizing the Southern Company estimating procedures, LOS reported a maximum annual condensable particulate release of 0.0029 lb/mmBtu and 0.0025 lb/mmBtu for Unit 1 and Unit 2 respectively. For the same time period LOS reported in their Annual

Emission Inventory report, the average front half particulate emission of 0.027 and 0.032 lb/mmBtu for Unit 1 and Unit 2 respectively. Therefore the total PM Emissions including PM_{10}, $PM_{2.5}$, HCL, HF and H_2SO_4 were approximately 0.030 and 0.034 lb/mmBtu respectively.

Based upon a review of the RACT/BACT/LAER database, the emission limit associated with the current Best Available Control Technology (BACT) for PM from new EGUs, including condensable PM, is approximately 0.03 lb/mmBtu. Because condensable PM is controlled through technologies that will be in place for NO_X, SO_2 and PM, the actual release of the main constituents of inorganic condensable PM are expected to be reduced by a minimum of 50% from the installation of SO_2 controls on each unit.

Recommended BART for condensable PM is the co-benefit of NO_X control through combustion controls, SO_2 control through a FGD process and filterable PM control through a device to be analyzed in this section of the report and is not addressed further. Therefore this BART analysis investigates control methods to reduce filterable PM emissions only.

4.1 IDENTIFICATION OF AVAILABLE RETROFIT PM CONTROL TECHNOLOGIES

The initial step of the BART determination is the identification of available retrofit PM control technologies. In order to produce a list of control technologies and their estimated capabilities, sources such as the RACT/BACT/LAER Clearinghouse (RBLC) were used. The results of the investigation determined that the removal of PM from flue gas is accomplished using post combustion technology. The two most common post combustion technologies used to control PM emissions include fabric filters (FF) and electrostatic precipitators (ESPs). The existing LOS configurations contain ESPs with each control technology rated at 99.1% control. Table 4.1-1 contains the results of the available PM control technologies.

TABLE 4.1-1 – PM Control Technologies Identified for BART Analysis

Control Technology	Approximate Control Efficiency
Fuel Switching with Flue Gas Conditioning w/ ESP	99.1%
Fabric Filter or Baghouse	99.7%
COHPAC Baghouse	99.7%
New Electrostatic Precipitator	99.7%
Existing Unit 1 Electrostatic Precipitator	99.5%
Existing Unit 2 Electrostatic Precipitators	99.1%

4.2 TECHNICAL DESCRIPTION AND FEASIBLITY ANALYSIS

The second step in the BART analysis procedure is a technical feasibility analysis of the options identified in Step 1. This analysis is presented below for each identified option.

4.2.1 FUEL SWITCHING WITH FLUE GAS CONDITIONING

Fuel switching along with flue gas conditioning is a viable method of reducing particulate matter emissions in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of LOS, the boilers were designed and constructed specifically for firing North Dakota lignite, which is a low Btu content, high ash, high moisture, and medium sulfur content fuel. For this analysis, fuel switching would consist of changing from North Dakota lignite to Powder River Basin (PRB) coal. Technical characteristics associated with fuel switching are described in Appendix C1.

Fly ash conditioning methods installed upstream of an ESP usually involve the injection of a chemical into the flue gas stream to reduce the electrical resistivity of the fly ash. The PRB coal being evaluated with this option contains low concentrations of sulfur (0.43%) while the ash has a relatively high concentration of calcium oxide (24.6%). The low sulfur content and the high alkaline ash both contribute to high resistivity. The low sulfur content limits the amount of sulfur trioxide that is formed while the calcium oxide will preferentially react with the acid and form a non-conducting ash. Therefore, this analysis assumed that flue gas conditioning would be required as part of any fuel switching option.

The most common types of flue gas conditioning systems for this application include humidification of the flue gas, sulfur trioxide injection, ammonia injection, or a combination of these conditioning methods. Because most, if not all, of the humidification process used for flue gas conditioning on

PRB coal have been replaced with another type of conditioning system, humidification was not evaluated in this analysis. Considering the size of the ESPs installed on both LOS units, it was assumed that sulfur trioxide injection alone could effectively reduce the resistivity of the ash and ammonia injection was not evaluated in this analysis.

Switching to a fuel such as PRB and adding a flue gas conditioning system to achieve lower PM emission rates would achieve approximately 50% reduction in PM emissions prior to particulate controls. Assuming that the control efficiency of the existing ESPs when firing PRB coal can be restored by adding a flue gas conditioning system, fuel switching was considered a viable option for PM control.

4.2.2 FABRIC FILTER (FF)

A fabric filter or baghouse removes particulate by passing flue gas through filter bags. A pulse-jet fabric filter (PJFF), a common type of fabric filter, consists of isolatable compartments and a tube sheet which separates the particulate laden flue gas from the clean flue gas. The flue gas passes through the PJFF by flowing from the outside of the bag to the inside up the center of the bag through the hole in the tube sheet and out the PJFF. Fly ash particles are collected on the outside of the bags and the cleaned gas stream passes through the bag to the outlet of the fabric filter. Each filter bag alternates between relatively long periods of filtering and short periods of cleaning. During the cleaning period, fly ash that has accumulated on the bags is removed by pulses of air and falls into a hopper for disposal. Additional technical characteristics associated with fabric filters are described in Appendix C1.

Fabric filters have been proven to control PM with removal efficiency in excess of 99%. It is anticipated that the use of fabric filters on LOS could achieve a filterable PM emission rate of approximately 0.015 lb/mmBtu. Therefore, the use of a fabric filter is a technically feasible option.

4.2.3 COHPAC

A COmpact Hybrid PArticulate Collector (COHPAC) is a high air-to-cloth ratio pulse jet fabric filter located downstream of an existing ESP. The COHPAC acts as a polishing device for control of particulate emissions. The difference between a COHPAC and the fabric filter described above is that a COHPAC is installed after an ESP. The ESP prior to the COHPAC will remove the majority of the fly ash. This allows the COHPAC to have a higher air-to-cloth ratio than a typical fabric filter. The air-to-cloth ratio for a COHPAC unit is typically greater than or equal to 6 ACFM/ft^2 while the air-to-cloth ratio for a typical pulse jet fabric filter is approximately 3.5 to 4.0 ACFM/ft^2.

The advantages and disadvantages of a COHPAC are similar to those mentioned for a fabric filter above; however, there are a few differences worth mentioning. Because the COHPAC has a higher air-to-cloth ratio, it is smaller and less costly than a conventional PJFF. However, the operation of the COHPAC is dependent upon continued operation and maintenance of the ESP.

COHPAC units have been proven to control PM removal efficiencies in excess of 99%. It is anticipated that for LOS Unit 1 or Unit 2, an installed COHPAC could achieve a filterable PM emission rate of 0.015 lb/mmBtu. Therefore, the use of a COHPAC is a technically feasible option.

4.2.4 ELECTROSTATIC PRECIPITATOR (ESP)

ESPs are commonly used as the primary filterable PM control device on coal fired units. The ESP discharge electrodes generate a high voltage electrical field that gives the particulate matter an electric charge (positive or negative). The charged particles will then be collected on a collection plate. Technical characteristics associated with ESPs are described in Appendix C1.

ESPs have proven to control PM in excess of 99%. It is anticipated that a new ESP installed for either unit at LOS could achieve a PM emission rate of approximately 0.015 lb/mmBtu. Therefore, the use of a new electrostatic precipitator is a technically feasible option.

Unit 1 at LOS has an existing ESP that is an older design which achieves lower removal efficiency than a new ESP. The existing ESPs can achieve a filterable PM emission rate of 0.1 lb/mmBtu. Therefore, the existing ESP is a technically feasible option.

Unit 2 at LOS has two parallel existing ESPs that are of an older design which achieves slightly lower removal efficiency than a new ESP. The existing ESPs can achieve a combined filterable PM emission rate of 0.1 lb/mmBtu. Therefore, the existing ESPs are a technically feasible option.

The results of the feasibility analysis for the available BART alternatives following the feasibility analysis are summarized in Table 4.2-1. Every alternative was identified as commercially available, in service on the same or similar services and technically applicable to LOS Units 1 & 2 in a retrofit situation.

TABLE 4.2-1 – BART PM Control Feasibility Analysis Results

Control Technology	In Service on Existing Utility Boilers	In Service on Other Combustion Sources	Commercially Available	Technically Applicable to Leland Olds Station
Fabric Filter	Yes	Yes	Yes	Yes
COHPAC	Yes	Yes	Yes	Yes
Fuel Switching with Flue Gas Conditioning	Yes	Yes	Yes	Yes
New ESP	Yes	Yes	Yes	Yes
Existing ESPs	Yes	NA	NA	Yes

4.3 RANK OF TECHNICALLY FEASIBLE PM CONTROL OPTIONS BY EFFECTIVENESS

The third step in the BART analysis procedure is to rank the technically feasible alternatives. The BART alternatives remaining in consideration following the feasibility analysis are listed in Table 4.3-1, ranked according to their effectiveness in PM control.

TABLE 4.3-1 – PM Control Technologies Identified for BART Analysis

Control Technology	PM Emission Capability (lb/mmBtu)
COHPAC	0.015
Fabric Filter	0.015
New ESP	0.015
Fuel Switching with Flue Gas Conditioning	0.054
Existing Unit 1 ESP	0.10
Existing Unit 2 ESP	0.10

4.4 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 1

Step four in the BART analysis procedure is the impact analysis. The BART determination guidelines (70 FR 39166) list four factors to be considered in the impact analysis. This BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;

- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four factors considered in the impact analysis are discussed in the following sections. The factor for the remaining useful life of the source is incorporated as part of the cost of compliance. In addition, as described in Section 1.1.6, the visibility impairment impacts are to be evaluated as part of the analysis. Thus, visibility impairment is included as part of the impacts analysis.

4.4.1 COST OF COMPLIANCE

Cost estimates for all of the Unit 1 particulate control technologies except fuel switching with flue gas conditioning were conducted utilizing the Coal Utility Environmental Cost (CUECost) computer model (Version 1.0) available from the U.S. Environmental Protection Agency. A description of the CUECost model is in Section 3.4.1 of this report. Operating information utilized as input into the model for the purpose of estimating the cost of the particulate control technologies is listed in Table 1.2-1 and 1.2-2. Economic information utilized as input into the model is given in Table 1.2-3. Economic information was provided in 2004 by BEPC in 2004 dollars. The model was run with 2004 designated as the cost basis year because equipment cost estimating in the model is based on the Chemical Engineering Cost Index and the composite 2004 index is the latest version available. Following completion of the estimating with a 2004 cost basis year, all costs were escalated to a 2005 basis year utilizing the inflation rates designated in Table 1.2-3. Burns & McDonnell added estimated Balance of Plant (BOP) costs not included in the CUECost output to the base estimate to provide a more complete cost estimate.

The cost estimate for fuel switching with flue gas conditioning was obtained from vendor quotes. The estimate in this report only includes capital costs for the flue gas conditioning system and does not include any capital costs for fuel switching. As mentioned in Section 3.4.1 of this report, potential rail line modifications may be required to fully implement the fuel switching alternative, but no capital expenditures were included in the report for these modifications. Therefore, all of the costs associated with fuel switching were assumed to be operating and maintenance costs, which are discussed in the Operating and Maintenance Costs section.

4.4.1.1 CAPITAL COSTS

The capital cost estimate is comprised of direct costs and indirect costs. The direct costs for each technology except the flue gas conditioning system include the particulate control system, ash handling system, booster fan, instrument and controls, and balance of plant costs. The particulate control system cost is representative of a typical furnish and erect contract cost by a fabric filter or ESP system supplier. The particulate control system cost estimated by CUECost is broken down into the major subsystems consisting of fabric filter or ESP, ash handling system, booster fan, and instrumentation and controls. It should be noted that a booster fan would not be required for a new ESP as the existing ID fan is sufficient. BOP costs include the electrical subcontract.

The electrical subcontract estimate includes the electrical equipment, materials and labor for engineering, procurement and installation of all electrical distribution system components. The electrical estimate is based on recent experience with the LOS plant and local costs developed during a recent electrical upgrade project at LOS.

The capital cost estimate for the flue gas conditioning system includes the dry sulfur unloading station, dry sulfur storage hopper, transfer conveyance from storage hopper to sulfur melter, sulfur metering pump skid with MCC & variable speed drives, SO_3 production skid, and injection probes with metering ports. The existing ESP would be utilized with this option.

The indirect costs are estimates of additional costs expected to be incurred during fabrication, construction, startup and commissioning. Engineering costs are estimated as a percentage of total direct costs and are representative of the cost for architectural/engineering services such as system design, specification production, contract evaluations and negotiations, contract administration and construction field services. The contingency is estimated as a percent of the total direct costs and accounts for miscellaneous scope items not covered by the direct cost estimate. Finally, the BEPC indirect costs are an estimation of the internal costs that would be incurred by BEPC for a project. The results of the capital cost estimate are given in Table 4.4-1, Table 4.4-2, Table 4.4-3, and Table 4.4-4. The option to utilize the existing ESP does not require any capital expenditure so it is not shown.

TABLE 4.4-1 – Capital Cost Estimate for LOS Unit 1 Fabric Filter

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Fabric Filter	$10,810,000	$1,620,000	$12,440,000
Bags	$1,640,000	$250,000	$1,880,000
Ash Handling System	$1,200,000	$180,000	$1,380,000
Booster Fan	$1,390,000	$210,000	$1,600,000
Instruments & Controls	$290,000	$40,000	$330,000
BOP Subcontract	$690,000	NA	$690,000
		Total Direct Cost =	**$18,320,000**
INDIRECT COSTS		Contingency (20% of DC)	$3,660,000
		A/E Engineering and Construction Management (10% of DC)	$1,830,000
BEPC INDIRECTS		Project Development (1% of DC)	$180,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$270,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$90,000
		Construction All-Risk Insurance (1.5% of DC)	$270,000
		Allowance For Funds During Construction (AFDC 6%)	$1,100,000
		Contingency (15% of BEPC Indirects)	$120,000
		Indirect Cost Subtotal	$7,520,000
		Total Capital Cost	**$25,840,000**

TABLE 4.4-2 – Capital Cost Estimate for LOS Unit 1 New ESP

Direct Costs	Estimated Cost ($2003)	General Facilities Markup (15%)	Total Direct Cost
ESP	$11,680,000	$1,750,000	$13,430,000
Foundations	(resuse existing)		
Ash Handling System	$4,310,000	$650,000	$4,960,000
Instruments & Controls	$330,000	$50,000	$380,000
BOP Subcontract	$690,000	NA	$690,000
		Total Direct Cost =	$19,460,000
INDIRECT COSTS		Contingency (20% of DC)	$3,890,000
		A/E Engineering and Construction Management (10% of DC)	$1,950,000
BEPC INDIRECTS		Project Development (1% of DC)	$190,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$290,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$100,000
		Construction All-Risk Insurance (1.5% of DC)	$290,000
		Allowance For Funds During Construction (AFDC 6%)	$1,170,000
		Contingency (15% of BEPC Indirects)	$130,000
		Indirect Cost Subtotal	$8,010,000
		Total Capital Cost	**$27,470,000**

TABLE 4.4-3 – Capital Cost Estimate for LOS Unit 1 COHPAC

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
COHPAC	$5,710,000	$860,000	$6,570,000
Foundations	(Included above)	(Included above)	
Bags	$860,000	$130,000	$990,000
Ash Handling System	$1,090,000	$160,000	$1,250,000
Booster Fan	$1,260,000	$190,000	$1,440,000
Instruments & Controls	$170,000	$30,000	$200,000
BOP Subcontract	$690,000	NA	
		Direct Cost Total	**$11,140,000**
INDIRECT COSTS		Contingency (20% of DC)	$2,230,000
		A/E Engineering and Construction Management (10% of DC)	$1,110,000
BEPC INDIRECTS		Project Development (1% of DC)	$110,000
		Spare Parts & Plant Equipment	
		Initial Inventory Spare Parts (1.5% of DC)	$170,000
		Construction Startup and Support	
		O&M Staff Training (0.5% of DC)	$60,000
		Construction All-Risk Insurance (1.5% of DC)	$170,000
		Allowance For Funds During Construction (AFDC 6%)	$670,000
		Contingency (15% of BEPC Indirects)	$80,000
		Indirect Cost Subtotal	$4,600,000
		Total Capital Cost	**$15,740,000**

TABLE 4.4-4 – Capital Cost Estimate for LOS Unit 1 Fuel Switching with Flue Gas Conditioning

Direct Costs	Estimated Cost ($2005)
Injection System	$969,000
Unloading Station	(Included Above)
Storage Hopper	(Included Above)
Transfer Conveyor	(Included Above)
Metering Pump Skid	(Included Above)
SO_3 Production Skid	(Included Above)
Injection Probes	(Included Above)
Total Direct Cost	**$969,000**
INDIRECT COSTS Contingency (20% of DC)	$194,000
A/E Engineering and Construction Management (10% of DC)	$97,000
BEPC INDIRECTS Project Development (1% of DC)	$10,000
Spare Parts & Plant Equipment	
Initial Inventory Spare Parts (1.5% of DC)	$15,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$5,000
Construction All-Risk Insurance (1.5% of DC)	$15,000
Allowance for Funds During Construction (AFDC, 6%)	$58,000
Contingency (15% of BEPC Indirects)	$7,000
Indirect Cost Subtotal	$401,000
Total Capital Cost	**$1,370,000**

4.4.1.2 OPERATING AND MAINTENANCE COSTS

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs except for fuel switching with flue gas conditioning were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance.

The fixed costs include maintenance costs. The maintenance cost was estimated as approximately 1.35% of the sum of the total direct cost.

The annual variable cost for the fabric filter and COHPAC is the auxiliary power costs plus the cost of 1/3 of a total bag replacement. The 1/3 is derived from the estimated three year bag filter life. The variable costs for the existing ESP consist solely of the auxiliary power cost.

The annual variable cost for the fuel switching with flue gas conditioning consists of the fuel cost change, reduced station service, change in ash disposal cost and reagent cost for the flue gas conditioning system. Section 3.4.1.11 of this report contains a description of the variable annual O&M costs associated with fuel switching.

The fixed and variable costs of the existing ESP were also included in the evaluation. The existing ESP would no longer function if a fabric filter or new ESP were installed. Therefore, the O&M costs associated with the existing ESP are shown as negative costs for those alternatives that would result in the replacement of the ESP. However, if a COHPAC unit or fuel switching with flue gas conditioning were utilized, the O&M costs of the existing ESP would not constitute a new cost and thus would not appear in those cost estimates.

The annual O&M cost estimate for each of the particulate control alternatives is summarized in Table 4.4-5.

TABLE 4.4-5 – Annual O&M Cost Estimates for Unit 1 PM Control Alternatives

	FF	NEW ESP	COHPAC	Fuel Switching with Flue Gas Conditioning
Fixed Costs				
Maintenance Costs	$262,000	$279,000	$160,000	$13,000
Existing ESP Maintenance Costs	($91,000)	($91,000)	$0	$0
Total Fixed O&M Costs	**$171,000**	**$188,000**	**$160,000**	**$13,000**
Variable Costs				
Bag Replacement	$279,000	NA	$147,000	NA
Auxiliary Power	$565,000	$180,000	$520,000	(included below)
Auxiliary Power (Existing ESP)	($179,000)	($179,000)	$179,000	$0
Auxiliary Power & Reagent				$109,000
Fuel Cost Change				$4,796,000
Reduced Station Service				($292,900)
Change in Ash Disposal Cost				($369,100)
Total Variable O&M Costs	**$665,000**	**$1,000**	**$846,000**	**$4,243,000**
Total Annual O&M Costs	**$836,000**	**$189,000**	**$1,006,000**	**$4,256,000**
Net Annual O&M Costs ($/MWh)	**$0.43**	**$0.098**	**$0.52**	**$2.20**

4.4.1.3 LEVELIZED TOTAL ANNUAL COST RESULTS

In order to effectively compare the cost of installing, operating and maintaining each of the particulate control systems capital and O&M costs need to be evaluated on a levelized basis. The levelized costs and associated PM emissions are shown in Table 4.4-6.

TABLE 4.4-6 – Levelized Total Annual Costs of Unit 1 BART PM Control Alternatives

PM Control Alternative	Emissions		Economic Impacts			
	Emission Rate (lb/mmBtu)	Emission Reduction[1] (tons/yr)	Installed Capital Cost ($2005)	Annual O & M Cost ($2005)	Levelized Total Annual Cost ($2005/yr)	Unit Control Cost ($/ton)
FF	0.015	827	$25,840,000	$836,000	$3,260,000	$3,940
New ESP	0.015	827	$27,470,000	$189,000	$2,630,000	$3,180
COHPAC	0.015	827	$15,740,000	$1,006,000	$2,473,000	$2,990
Fuel Switch with Flue Gas Conditioning	0.054	448	$1,370,000	$4,256,000	$5,197,000	$11,600
Existing ESP	0.100	Baseline	Baseline	Baseline	Baseline	Baseline

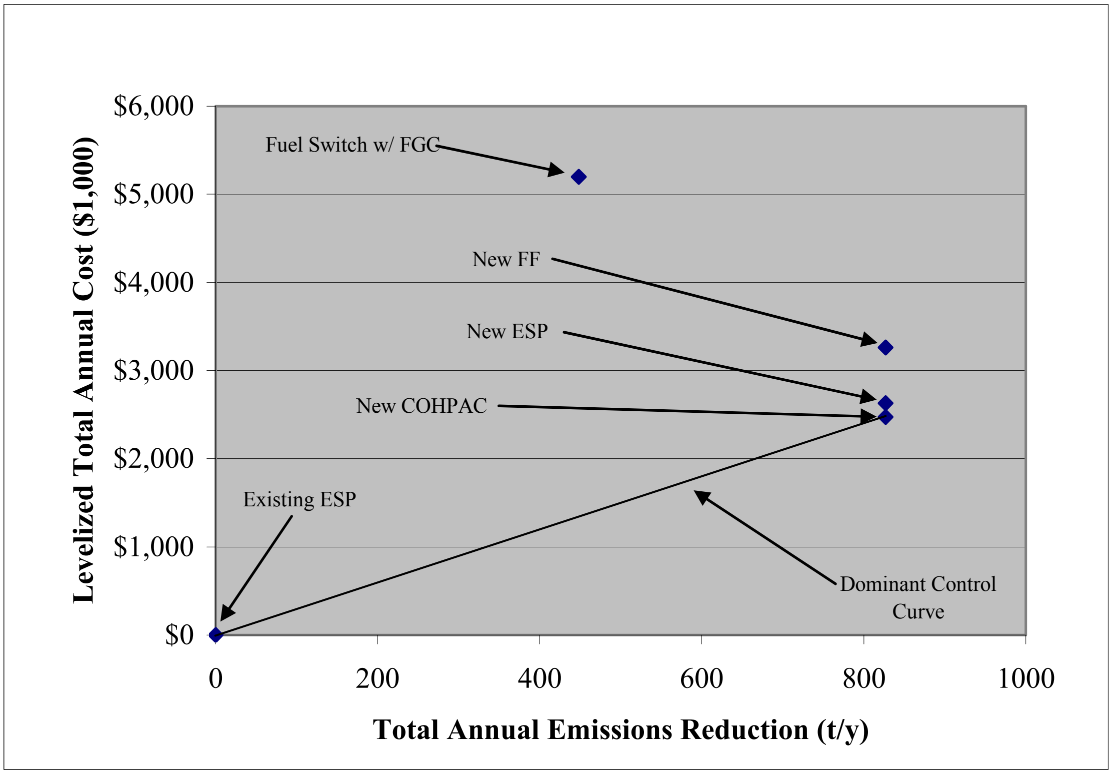
[1]Annual emissions are based on Future PTE case.

Life, years	20
Cost of Money, %	6%
Capital Recovery Factor	0.08718
Conversion Tax (FF), $	7,947
Conversion Tax (New ESP), $	7,949
Conversion Tax (COHPAC), $	7,516
O &M Levelization Factor	1.19314

Figure 4.4-1 is a plot of the Levelized Total Annual Cost (LTAC) for each alternative versus the annual removal in tons. The purpose of Figure 4.4-1 is to identify the Dominant Controls Curve, which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly to the left of this curve are inferior control alternatives on a cost effectiveness basis. The existing ESP was chosen as the baseline for both LTAC and annual emissions. Therefore, the existing ESP is shown graphically as not having any emission reduction benefits or any added cost.

Of the technically feasible BART alternatives considered for LOS Unit 1 the data point for the fuel switching with flue gas conditioning lies distinctly above the least cost boundary of the control cost envelope. This chart also clearly shows that the new FF and new ESP alternatives are inferior to a COHPAC as all three of these options can achieve the same emissions reduction, but the FF and ESP both have greater LTAC. The reason for this is clear from Table 4.4-6 where the unit control costs for all of the BART alternatives are listed. Considering the small cost difference between new ESP and COHPAC and the accuracy of the cost estimates, both technologies should be considered equivalent. In a BART analysis each of the PM control technologies represented by a data point above the Dominant Control Curve could be excluded from further analysis on a cost efficiency basis. Therefore, the fuel switching with flue gas conditioning, FF and new ESP options are not considered cost effective PM control alternatives for LOS Unit 1 and could be excluded from further analysis.

FIGURE 4.4-1 – LOS Unit 1 Least Cost Envelope for PM Control Alternatives



The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above and below it on the Dominant Control Curve shown in Figure 4.4-1. The incremental cost effectiveness is the slope of a line between any two adjacent points on the Dominant Controls Curve as shown in Figure 4.4-1. Table 4.4-7 contains a repetition of the cost and control information from Table 4.4-6 and the incremental cost effectiveness between the successive set of alternatives.

TABLE 4.4-7 – Incremental Cost Effectiveness of Unit 1 BART PM Control Alternatives

Alternative	Levelized Total Annual Cost ($2005)(1)	Annual Reduction (tpy)	Incremental Cost Effectiveness ($/t)
COHPAC	$2,473,000	827	$2,990
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

In the BART Determination guidelines, EPA neither proposes hard definitions for reasonable, or unreasonable, Unit Control Costs nor for incremental cost effectiveness values. The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the dominant control cost curve) between successive, dominant alternatives. While these findings do not eliminate any alternative, because there are no Unit Control Cost or incremental control cost criteria during a BART analysis, the findings do clearly define the more cost effective alternatives.

4.4.2 ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

The energy requirement for an ESP is due to the pressure drop across the ESP, expressed as fan power, and the power required to operate the T/R sets and rappers. The power consumption of an ESP system is estimated to be approximately 590 kW. However, since there is an existing ESP installed on LOS Unit 1, it was assumed there would not be an additional energy impact with the installation of a new ESP as a similar level of power is currently being consumed by the existing ESP.

There are not any significant non-air quality environmental impacts associated with the existing ESP or a new ESP. One difference between the two options is that the new ESP will have a greater control efficiency and collect 827 more tons per year of fly ash that would be sent to the permitted disposal facility.

4.4.3 VISIBLITY IMPACTS

Visibility impacts for Historical pre-control and Future PTE post-control emission levels were modeled using CALPUFF. CALPUFF is used to model long-range transport of PM to determine the visibility impacts measured in deciViews (dV). Unlike emissions from NO_X and SO_2, PM emissions for LOS do not significantly contribute to visibility impacts in nearby Class 1 areas. As part of the CALPUFF output, every visibility impact is broken down into a percent contribution by each pollutant. This percentage was used to calculate the PM contribution to the modeled impact for each Class 1 area and then averaged over the three model years. When pre-control PM contributions were determined for the 90th percentile, the highest PM impact was 0.0097 dV for Unit 1 and occurred in Lostwood NWR.

Because this is the highest visibility impact attributed to PM emissions from Unit 1, any reduction in impact caused by the use of more effective controls would be only a percentage of this impact. To be conservative, this report analyzed a 100% reduction in visibility impairment impact for the visibility improvement comparison. In other words, although other control technologies would provide various levels of emission reduction and visibility impairment impact reduction, a reduction of 0.0097 dV was used as the best achievable impact reduction for the visibility comparison and assigned to each alternative. The assigned visibility improvement and estimated LTAC for each alternative are given in Table 4.4-8. The LTAC for each control technology was divided by the visibility impairment impact reduction in dV's to obtain a cost per dV of improvement relative to the existing ESP. These values are also tabulated in Table 4.4-8.

The highest modeled impact of 0.0097 dV is approximately 1.9 percent of the 0.5 dV impact that the BART guidelines define as contributing to visibility impairment. Achieving this slightly greater visibility improvement requires a significantly higher cost per dV when compared with other pollutants addressed in this study. Based upon these two factors, this analysis recommends that the existing ESP be maintained as the technology used for controlling particulate matter.

TABLE 4.4-8 – Visibility Improvement and Associated Costs

BART Alternative	Levelized Total Annual Cost ($2005)(1)	Visibility Impairment Impact Reduction (dV)	Cost per dV of Improvement ($/dV)
Fuel Switch w/ FGC	$5,197,000	0.0097	$535,800,000
New FF	$3,260,000	0.0097	$336,100,000
New ESP	$2,630,000	0.0097	$271,100,000
COHPAC	$2,473,000	0.0097	$254,900,000
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

Although condensable PM was removed from the BART analysis in Section 4.0.1, one additional aspect should be mentioned with regard to the effect of condensable PM on visibility in the nearest

Class 1 area. As discussed above, the modeled visibility impact for the filterable portion of PM was 0.0097 dV when modeled at the Permit Emission limit of 0.1 lb/MMBtu. Compared to a BART guideline that defines a contributing impact as more than 0.5 dV of visibility impairment impact, the filterable PM emission impact is insignificant. Current estimated emissions of condensable PM are approximately 11 percent of the amount of filterable PM emissions. Because condensable PM emission rates are significantly less than filterable PM emissions and the modeled visibility impairment impact attributable to filterable PM is insignificant even at the permit conditions, it is reasonable to assume that the visibility impairment impact attributable to condensable PM would also be insignificant. Thus, the elimination of condensable PM from this analysis is supported by the insignificant visibility impairment impact of filterable PM as determined by the visibility modeling included in this report.

4.4.4 IMPACT SUMMARY

The results of the impact analysis for PM control on LOS Unit 1 are presented below in Table 4.4-9. The cost of compliance analysis examined the capital cost of each alternative and any Balance of Plant costs necessary to implement the alternative. In addition, the cost analysis examined the operating and maintenance cost for each alternative. These costs were then combined into the Levelized Total Annual Cost for a comparative assessment of the total implementation cost of each alternative. As part of the top down analysis, a Dominant Control Curve was plotted and the Unit Control Cost for each alternative was evaluated. Two alternatives, the existing ESP and a COHPAC downstream of the existing ESP, were on the Dominant Controls Curve and identified as the more cost effective alternatives. Three of the alternatives, a new Fabric Filter, a new ESP and the COHPAC were evaluated at the same control level and the COHPAC, the more cost effective of the three, fell on the Dominant Control Curve. The estimated LTAC for these three alternatives varied by approximately 30% and thus the COHPAC was determined to be significantly more cost effective.

TABLE 4.4-9 – LOS Unit 1 Impacts Summary for PM Control Alternatives

PM Control Alternative	Emission Reduction (tpy)	Levelized Total Annual Cost ($2005)(1)	Unit Control Cost ($/t)	Maximum Visibility Impairment Impact Reduction (dV)	Unit Cost Effectiveness ($/dV)
Fabric Filter	827	$3,260,000	$3,942	0.0097	$443,900,000
New ESP	827	$2,630,000	$3,180	0.0097	$336,100,000
COHPAC	827	$2,473,000	$2,990	0.0097	$271,100,000
Fuel Switch w/ FGC	448	$5,197,000	11,600	0.0097	$254,900,000
Existing ESP	Baseline	$0	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

The visibility impairment impact analysis evaluated the modeled impact of PM emission and determined that even if 100% of the visibility impairment impact attributed to PM emissions were eliminated, the change in visibility impairment would be significantly less than detectable by the human eye. As can be determined from the information summarized in Table 4.4-9, the cost of any PM_{10} BART alternative would be prohibitively high on both a unit cost and visibility impairment basis.

4.5 EVALUATION OF IMPACTS FOR FEASIBLE PM CONTROLS – UNIT 2

Step four in the BART analysis procedure is the impact analysis. The BART determination guidelines (70 FR 39166) list four factors to be considered in the impact analysis. This BART Determination will consider the following four factors in the impact analysis:

- The costs of compliance;
- Energy impacts;
- Non-air quality environmental impacts; and
- The remaining useful life of the source.

Three of the four factors considered in the impact analysis are discussed in the following sections. The factor for the remaining useful life of the source is incorporated as part of the cost of compliance. In addition, as described in Section 1.1.6, the visibility impairment impacts are to be evaluated as part of the analysis. Thus, visibility impairment is included as part of the impacts analysis.

4.5.1 COST OF COMPLIANCE

Cost estimates for all of the Unit 2 particulate control technologies use the same general estimation procedure that was described for Unit 1 in Section 4.4.1. Any exceptions to this procedure are described in the following sections for each individual control alternative.

4.5.1.1 CAPITAL COSTS

The capital cost estimate is comprised of direct costs and indirect costs. The methodology used to estimate Unit 2 direct and indirect costs is the same as was described for Unit 1 in Section 4.4.1.1. The results of the capital cost estimate are given in Table 4.5-1, Table 4.5-2, Table 4.5-3, and Table 4.5-4. The option to utilize the existing ESP does not have any capital costs so it is not shown.

TABLE 4.5-1 – Capital Cost Estimate for LOS Unit 2 Fabric Filter

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
Fabric Filter	$18,520,000	$2,780,000	$21,300,000
Bags	$3,500,000	$520,000	$4,020,000
Ash Handling System	$1,090,000	$160,000	$1,250,000
Booster Fan	$2,220,000	$330,000	$2,550,000
Instruments & Controls	$480,000	$70,000	$550,000
BOP Subcontract	$680,000	NA	$680,000
		Total Direct Cost =	**$30,350,000**
INDIRECT COSTS		Contingency (20% of DC)	$6,070,000
		A/E Engineering and Construction Management (10% of DC)	$3,040,000
BEPC INDIRECTS		Project Development (1% of DC)	$300,000
	Spare Parts & Plant Equipment		
		Initial Inventory Spare Parts (1.5% of DC)	$460,000
	Construction Startup and Support		
		O&M Staff Training (0.5% of DC)	$150,000
		Construction All-Risk Insurance (1.5% of DC)	$460,000
		Allowance For Funds During Construction (AFDC 6%)	$1,820,000
		Contingency (15% of BEPC Indirects)	$480,000
		Indirect Cost Subtotal	$12,780,000
		Total Capital Cost	**$43,130,000**

TABLE 4.5-2 – Capital Cost Estimate for LOS Unit 2 New ESP

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
ESP	$22,580,000	$3,390,000	$25,970,000
Foundations	(Included Above)	NA	(Included Above)
Ash Handling System	$7,150,000	$1,070,000	$8,230,000
Instruments & Controls	$610,000	$90,000	$700,000
BOP Subcontract	$680,000	NA	$680,000
		Total Direct Cost =	**$35,580,000**
INDIRECT COSTS		Contingency (20% of DC)	$7,120,000
		A/E Engineering and Construction Management (10% of DC)	$3,560,000
BEPC INDIRECTS		Project Development (1% of DC)	$360,000
		Spare Parts & Plant Equipment	
		Initial Inventory Spare Parts (1.5% of DC)	$530,000
		Construction Startup and Support	
		O&M Staff Training (0.5% of DC)	$180,000
		Construction All-Risk Insurance (1.5% of DC)	$530,000
		Allowance For Funds During Construction (AFDC 6%)	$2,130,000
		Contingency (15% of BEPC Indirects)	$560,000
		Indirect Cost Subtotal	$14,970,000
		Total Capital Cost	**$50,550,000**

TABLE 4.5-3 – Capital Cost Estimate for LOS Unit 2 COHPAC

Direct Costs	Estimated Cost ($2005)	General Facilities Markup (15%)	Total Direct Cost
COHPAC	$9,780,000	$1,470,000	$11,250,000
Bags	$1,850,000	$280,000	$2,120,000
Ash Handling System	$990,000	$150,000	$1,130,000
Booster Fan	$2,010,000	$300,000	$2,310,000
Instruments & Controls	$280,000	$40,000	$320,000
BOP Subcontract	$680,000	NA	$680,000
		Total Direct Cost =	**$17,810,000**
INDIRECT COSTS		Contingency (20% of DC)	$3,560,000
		A/E Engineering and Construction Management (10% of DC)	$1,780,000
BEPC INDIRECTS		Project Development (1% of DC)	$180,000
		Spare Parts & Plant Equipment	
		Initial Inventory Spare Parts (1.5% of DC)	$270,000
		Construction Startup and Support	
		O&M Staff Training (0.5% of DC)	$90,000
		Construction All-Risk Insurance (1.5% of DC)	$270,000
		Allowance For Funds During Construction (AFDC 6%)	$1,070,000
		Contingency (15% of BEPC Indirects)	$280,000
		Indirect Cost Subtotal	$7,500,000
		Total Capital Cost	**$25,310,000**

TABLE 4.5-4 – Capital Cost Estimate for LOS Unit 2 Fuel Switching with Flue Gas Conditioning

Direct Costs	Estimated Cost ($2005)
Injection System	$884,000
Unloading Station	(Included Above)
Storage Hopper	(Included Above)
Transfer Conveyor	(Included Above)
Metering Pump Skid	(Included Above)
SO_3 Production Skid	(Included Above)
Injection Probes	(Included Above)
Total Direct Cost	**$884,000**
INDIRECT COSTS Contingency (20% of DC)	$177,000
A/E Engineering and Construction Management (10% of DC)	$88,000
BEPC INDIRECTS Project Development (1% of DC)	$9,000
Spare Parts & Plant Equipment	
Initial Inventory Spare Parts (1.5% of DC)	$13,000
Construction Startup and Support	
O&M Staff Training (0.5% of DC)	$4,000
Construction All-Risk Insurance (1.5% of DC)	$13,000
Allowance for Funds During Construction (AFDC 6%)	$53,000
Contingency (15% of BEPC Indirects)	$6,000
Indirect Cost Subtotal	$363,000
Total Capital Cost	**$1,247,000**

4.5.1.2 OPERATING AND MAINTENANCE COSTS

The annual operating and maintenance costs (O&M) costs are comprised of fixed costs (maintenance and labor) and variable cost (consumables). These costs except for fuel switching with flue gas conditioning were developed as part of the CUECost model and include operating labor, administrative and support labor and maintenance.

The fixed costs include maintenance costs. The maintenance cost was estimated as approximately 1.35% of the sum of the total direct cost.

The annual variable cost for the fabric filter and COHPAC is the auxiliary power costs plus the cost of 1/3 of the total bags. The 1/3 is determined by the bag life. It was assumed that the bag life for both of these systems is 3 years. The variable costs for the ESP consist solely of the auxiliary power costs.

The annual variable cost for the fuel switching with flue gas conditioning consist of the fuel cost change, reduced station service, and change in ash disposal cost. Section 3.4.1.11 of this report contains a description of the costs associated with fuel switching.

TABLE 4.5-5 – Annual O&M Cost Estimate for Unit 2 PM Control Alternatives

	NewFF	New ESP	New COHPAC	Fuel Switching with Flue Gas Conditioning
Fixed Costs				
Maintenance Costs	$435,000	$510,000	$255,000	$12,000
Existing ESP Maintenacne Costs	($91,000)	($91,000)	$0	$0
Total Fixed O&M Costs	**$344,000**	**$419,000**	**$255,000**	**$12,000**
Variable Costs				
Bag Replacement	$596,000	NA	$315,000	NA
Auxiliary Power	$1,197,000	$384,000	$1,101,000	(included below)
Auxiliary Power (Existing ESP)	($358,000)	($358,000)	$0	$0
Auxiliary Power & Reagent				$200,000
Fuel Cost Change				$9,383,000
Reduced Station Service				($292,000)
Change in Ash Disposal Cost				($467,200)
Total Variable O&M Costs	**$1,435,000**	**$26,000**	**$1,416,000**	**$8,835,000**
Total Annual O&M Costs	**$1,779,000**	**$445,000**	**$1,671,000**	**$8,835,000**
Net Annual O&M Cost ($/MWh)	**$0.54**	**$0.14**	**$0.51**	**$2.63**

The fixed and variable costs of the existing ESP were also included in the evaluation. The existing ESP would be abandoned if a fabric filter or a new ESP were installed; therefore, the O&M costs associated with the existing ESP are shown as negative costs. However, if a COHPAC unit or fuel switching with flue gas conditioning were utilized, the O&M costs of the existing ESP would remain.

The annual O&M cost estimate for each of the particulate control systems is summarized in Table 4.5-5.

4.5.1.3 LEVELIZED TOTAL ANNUAL COST RESULTS

In order to effectively compare the cost of installing, operating and maintaining each of the particulate control systems capital and O&M costs need to be evaluated on a levelized basis. The levelized costs and associated PM emissions are shown in Table 4.5-6.

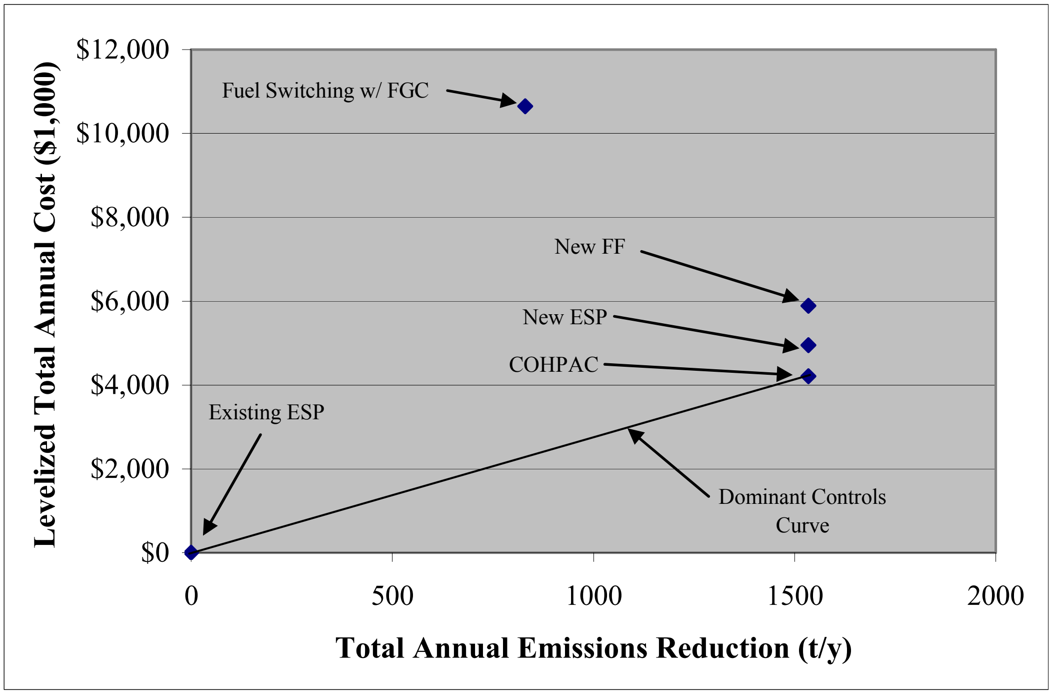
TABLE 4.5-6 – Levelized Total Annual Costs of Unit 2 BART PM Control Alternatives

PM Control Alternative	Emissions: Emission Rate (lb/mmBtu)	Emissions: Emission Reduction[1] (tons/yr)	Economic Impacts: Installed Capital Cost ($2005)	Economic Impacts: Annual O & M Cost ($2005)	Economic Impacts: Levelized Total Annual Cost ($2005/yr)	Economic Impacts: Unit Control Cost ($/ton)
FF	0.015	1,534	$43,130,000	$1,779,000	$5,892,000	$3,841
New ESP	0.015	1,534	$50,550,000	$445,000	$4,948,000	$3,226
COHPAC	0.015	1,534	$25,310,000	$1,671,000	$4,210,000	$2,744
Fuel Switch with Flue Gas Conditioning	0.054	830	$1,247,000	$8,835,000	$10,650,000	$12,830
Existing ESP	0.100	Baseline	Baseline	Baseline	Baseline	Baseline
[1]Annual emissions are based on Future PTE Case.						
					Life, years	20
					Cost of Money, %	6%
					Capital Recovery Factor	0.08718
					Conversion Tax (FF), $	15,845
					Conversion Tax (New ESP), $	15,849
					Conversion Tax (COHPAC), $	15,032
					O &M Levelization Factor	1.19314

Figure 4.5-1 is a plot of the Levelized Total Annual Cost (LTAC) for each alternative versus the annual removal in tons. The purpose of Figure 4.5-1 is to identify the Dominant Controls Curve, which is the rightmost boundary of the control cost envelope. The Dominant Controls Curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the LTAC versus the annual removal tonnage for the various BART alternatives. Points distinctly above and to the left of this curve are inferior control alternatives on a cost effectiveness basis. The existing ESP was chosen as the baseline for levelized cost and annual emissions. Therefore, the existing ESP is shown graphically as not having any emission reduction benefits or any added cost.

Of the technically feasible BART alternatives considered for LOS Unit 2 the data point for the fuel switching with flue gas conditioning lies distinctly above the least cost boundary of the control cost envelope. This chart also displays that a new FF and/or a new ESP are inferior to a COHPAC as all three of these options can achieve the same emissions reduction; however, the FF and the new ESP have a greater LTAC. The reason for this is clear from Table 4.5-6 where the unit control costs for all of the BART alternatives are listed. In a BART analysis each of the PM control technologies represented by a data point above the Dominant Control Curve can be excluded from further analysis on a cost efficiency basis. Therefore, the fuel switching with flue gas conditioning, the new FF and new ESP options are shown not to be cost effective PM control alternatives for LOS Unit 2 and could be excluded from further analysis.

FIGURE 4.5-1 – LOS Unit 2 Least Cost Envelope for PM Control Alternatives



The next step in the cost effectiveness analysis for the remaining BART alternatives is to review the incremental cost effectiveness between a given alternative and those above and below it in the ranking shown in Table 4.5-7. The incremental cost effectiveness is the slope of a line between any two adjacent points shown in Figure 4.5-1. Table 4.5-7 contains a repetition of the cost and control information from Table 4.5-6 and the incremental cost effectiveness between each successive set of alternatives.

TABLE 4.5-7 – Incremental Cost Effectiveness of Unit 2 BART PM Control Alternatives

Alternative	Levelized Total Annual Cost ($2005)(1)	Annual Reduction (tpy)	Incremental Cost Effectiveness ($/ton)
COHPAC	$4,210,000	1,534	$2,744
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

In the BART Determination guidelines, EPA neither proposes hard definitions for reasonable, or unreasonable, Unit Control Costs nor for incremental cost effectiveness values. The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the dominant control cost curve) between successively less effective alternatives. The alternatives involving the installation of new PM control equipment were all evaluated at the same particulate matter control efficiency and thus the incremental analysis does not provide any useful information for comparing these alternatives. However, based on the cost estimates for each, the COHPAC is more cost effective than a new FF or ESP and thus only the COHPAC alternative needs to be carried forward from this analysis as representative of a general BART alternative for control of emissions to the 0.015 lb/mmBtu level.

4.5.2 ENERGY AND NON-AIR QUALITY ENVIRONMENTAL IMPACTS

The energy requirement for an ESP is due to the pressure drop across the ESP, expressed as fan power, and the power required to operate the T/R sets and rappers. The power consumption of the existing ESPs is estimated to be approximately 1,180 kW. Because two existing ESPs are installed on LOS Unit 2, it was assumed there would not be an additional energy impact with the installation of a new ESP.

There are no significant non air quality environmental impacts associated with the existing ESP versus a new ESP. One difference between the two options is that the new ESP will have a greater control efficiency. Therefore, a new ESP will collect 73 more tons per year of fly ash that would be sent to the landfill.

4.5.3 VISIBLITY IMPACTS

Visibility impacts for Historical pre-control and Future PTE post-control emission levels were estimated using CALPUFF. CALPUFF is used to model long-range transport of PM to determine the visibility impacts measured in deciViews (dV). Unlike emissions from NO_X and SO_2, PM emissions for LOS never significantly contribute to visibility impacts. As part of the CALPUFF results, each modeled impact includes a percent contribution for each pollutant. That percentage is used to calculate the PM contribution to the modeled impact for each Class 1 area and then is averaged for the 3 modeled years. When pre-control PM contributions are calculated for the 90th percentile, the highest impact is 0.015 dV for Unit 2 and occurs in Lostwood NWR.

The 0.015 dV visibility impact contribution was estimated by modeling the pre-control ESP emission rate. Since this is the highest impact attributed to PM emissions from Unit 2, any reduction in impact caused by the use of more effective controls would be only a percentage of this impact. To be conservative, this report uses a 100% reduction in visibility impairment reduction for the visibility impairment impact reduction evaluation. Although three control alternatives provide the same PM emission reduction, which would be an 85% reduction of PM emissions compared to the existing ESP, the potential visibility impairment reduction is very low and thus an improvement of 0.015 dV was the maximum possible visibility impairment impact reduction. The LTAC, maximum visibility impairment impact reduction and resultant cost per dV of improvement are given in Table 4.5-8. The LTAC for each control technology was divided by the visibility improvement to obtain a cost per dV of visibility impairment reduction for each alternative.

LOS Unit 2 has a particulate control device in operation that satisfactorily meets the permit limitation for PM emissions of 0.1 lb/mmBtu. Therefore, any PM control alternative was expected to be inordinately expensive on a Unit Control Cost basis as was shown in Section 4.5.1.3. The maximum potential visibility impairment reduction of 0.015 dV is approximately three percent of the 0.5 dV impact that the BART guidelines define as contributing to visibility impairment. Achieving this slightly greater visibility improvement requires a significantly higher cost per dV when compared with other pollutants addressed in this study. Therefore, the maximum achievable visibility impairment impact reduction would be extremely expensive on a unit cost basis and would not result in any discernible change in visibility in the affected Class 1 areas.

TABLE 4.5-8 – Visibility Improvement and Associated Costs

Alternative	Levelized Total Annual Cost ($2005)(1)	Maximum Visibility Impairment Impact Reduction (dV)	Unit Cost Effectiveness ($/dV)
Fuel Switch w/ FGC	$10,650,000	0.015	$710,000,000
New FF	$5,892,000	0.015	$392,800,000
New ESP	$4,948,000	0.015	$329,900,000
COHPAC	$4,210,000	0.015	$280,700,000
Existing ESP	$0	0	ND(2)

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.
(2) - Not Defined - baseline condition.

Although condensable PM was removed from the BART analysis in Section 4.0.1, one additional aspect should be mentioned with regard to the effect of condensable PM on visibility in the nearest Class 1 area. As discussed above, the modeled visibility impact for the filterable portion of PM was 0.015 dV when modeled at the Permit Emission limit of 0.1 lb/MMBtu. Compared to a BART guideline that defines a contributing impact as more than 0.5 dV of visibility impairment impact, the filterable PM emission impact is insignificant. Current estimated emissions of condensable PM are approximately 8 percent of the amount of filterable PM emissions. Because condensable PM emission rates are significantly less than filterable PM emissions and the modeled visibility impairment impact attributable to filterable PM is insignificant even at the permit conditions, it is reasonable to assume that the visibility impairment impact attributable to condensable PM would also be insignificant. Thus, the elimination of condensable PM from this analysis is supported by the insignificant visibility impairment impact of filterable PM as determined by the visibility modeling included in this report.

4.5.4 IMPACT SUMMARY

As stated at the beginning of this report, the cost, energy, non-environmental and visibility impacts of each PM_{10} BART alternative were evaluated in this Section. Table 4.5-9 summarized the various impacts discussed in Sections 4.5-1 through 4.5-3. The cost of compliance analysis examined the capital cost of each alternative and any Balance of Plant cost necessary to implement the alternative. In addition, the cost analysis examined the operating and maintenance cost associated with each alternative. These costs were then combined into the Levelized Total Annual Cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top down analysis, a Dominant Control Curve was plotted and the Unit Control Cost for each alternative was evaluated. Two alternatives, the existing ESP and installation of a new COHPAC following the existing ESP, were on the Dominant Controls Curve and thus were identified as the more cost effective alternatives. Three of the BART alternatives, a new Fabric Filter, a new ESP and a new COHPAC following the existing ESP, were evaluated at the same PM control level and only the least expensive of these, the COHPAC alternative, fell on the Dominant Controls Curve. The range of the cost estimates for these three alternatives was approximately 40% and thus the COHPAC was perceived to be significantly more cost effective than the other two alternatives.

The visibility impairment impact analysis evaluated the modeled impact of PM emissions and determined that even if 100% of the visibility impairment attributed to PM emissions were eliminated, the change in visibility impairment would be significantly less than detectable by the human eye. As can be determined from the information summarized in Table 4.5-9, the cost of any PM BART alternative would be prohibitively high on both a unit cost and visibility impairment basis.

TABLE 4.5-9 – LOS Unit 2 Impacts Summary for PM Control Alternatives

PM Control Alternative	Emission Reduction (tons/yr)	Levelized Total Annual Cost ($2005)(1)	Unit Control Cost ($/ton)	Maximum Visibility Impairment Impact Reduction (dV)	Unit Cost Effectiveness ($/dV)
New FF	1,534	$5,892,000	$3,841	0.015	$710,000,000
New ESP	1,534	$4,948,000	$3,226	0.015	$392,800,000
COHPAC	1,534	$4,210,000	$2,744	0.015	$329,900,000
Fuel Switch w/ FGC	830	$10,650,000	$12,830	0.015	$280,700,000
Existing ESP	Baseline	$0	Baseline	0	Baseline

(1) - For LTAC calculation, Capital Recovery Factor = 0.08718 and O&M Levelization Factor = 1.19314.

PM SECTION REFERENCES:

1. "An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants"; Monroe, Larry S. & Harrison, Keith E.; Southern Company Generation and Energy Marketing; Revised March, 2003.

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5.0 BART RECOMMENDATIONS

This report presents the analysis of control technologies for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Basin Electric Power Cooperative's (BEPC's) Leland Olds Station (LOS) Units 1 and 2. The final result of this analysis is a recommendation of the Best Achievable Retrofit Technology (BART) for each unit based upon "the costs of compliance, the energy and non-air quality environmental impacts of compliance, any pollution control equipment in use at the source, the remaining useful life of the source, and the degree of improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). The presented emission rates in this section are the BART recommendation. However, because the accuracy of the cost estimate is $\pm$ 30% and in some cases is greater than the variance of the estimated costs between control alternatives, the technology used to meet the BART recommendation may change. This section summarizes the analysis performed for each unit and its associated pollutants.

5.0 UNIT 1 BART RECOMMENDATIONS

In previous sections of the report, the 5 steps of the technology evaluation provided in the BART Determination Guidelines were completed for Unit 1 and the results for each pollutant were summarized. Each pollutant required a different approach in order to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 1.

5.0.1 UNIT 1 NO_X BART

In the BART Guidelines, the EPA lists the presumptive NO_X emission limits for BART-eligible coal-fired units, distinguished by unit type, and coal type. The analysis performed by the EPA for establishing the presumptive limits for NO_X emissions from pulverized coal-fired EGUs assumed only the application of low-NOx burners and overfire air combustion controls. For dry-bottom, wall-fired electric generating units (EGUs) burning lignite coal, the NO_X presumptive limit is 0.29 lb/mmBtu. These presumptions apply to EGUs greater than 200 MW at power plants with the generating capacity greater than 750 MW and are based on control strategies that the EPA determined are generally cost-effective for all such units.

Unit 1 at Leland Olds Station is a dry-bottom, wall-fired unit greater than 200 MW output located at a power plant less than 750 MW total output capacity. The actual highest 24-month rolling NO_X summation total from 2000-2004 divided by the actual 24-month rolling summation unit heat input for the same time period for Unit 1 at LOS meets the presumptive BART NO_X emission limits stated above. The requirements of performing a NO_X BART analysis, on a BART-eligible coal-fired unit with a nameplate capacity greater than 200 MW at a powerplant less than 750 MW that has a historic 24-month average unit NO_X emission rate that meets the EPA's presumptive BART NO_X emission limit for larger power plants, are not apparent in the BART Guidelines. However, this BART analysis performed a NO_X control technology feasibility evaluation, with impact analysis for a separated overfire air (SOFA) alternative. This included the four prescribed impact criteria plus the impact assessment for visibility impairment improvement following the general procedures of the BART Guideline.

The impacts analysis for separated overfire air at LOS Unit 1 found only insignificant negative energy and non-air environmental impacts; remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimate.

Average predicted visibility impairment impacts decreased significantly for the presumptive BART NO_X emission rate and high levels of SO_2 control, and slightly more with post-control SOFA-enhanced NO_X emission rates compared to the average predicted visibility impairment impacts at the pre-control (NDDH protocol) baseline emission rates for NO_X, SO_2, and PM. An analysis of the incremental cost-effectiveness of reducing predicted visibility impairment impact for the SOFA alternative was performed for LOS Unit 1. The comparison showed that the ratio of the estimated additional annualized costs of installing and operating SOFA to the average predicted visibility impairment improvement relative to the presumptive BART NO_X baseline emission rate for the future Potential-To-Emit boiler heat input (future coal case) scenario applied to LOS Unit 1 would result in millions of dollars per deciView-year of visibility impairment improvement. The range for this incremental visibility impairment impact reduction was \$7.8M to \$25.4M per deciView-yr, depending on the Class 1 area and SO_2 control associated with the SOFA NO_X control alternative.

The actual highest 24-month rolling average NO_X unit emission rate meets the EPA's presumptive BART NO_X emission limit of 0.29 pounds per million Btu of fuel heat input for BART-eligible coal-fired EGU's greater than 200 MW nameplate capacity at power plants with the generating capacity greater than 750 MW. Use of existing low-NO_X burners and close-coupled overfire air translates into a BART emission rate of 0.29 pounds per million Btu of fuel heat input for the future PTE coal case scenario applied to LOS Unit 1. Thus, this evaluation recommends the presumptive limit of 0.29 lb/MMBtu as BART.

5.0.2 UNIT 1 SO_2 BART

In step 1 of the technology evaluation, 7 control processes were identified for SO_2 control. The identified processes included Fuel Switching, Coal Cleaning, Wet Limestone Flue Gas Desulfurization (FGD), Spray Dryer Absorber (SDA), Circulating Dry Scrubber (CDS), Flash Dryer Absorber (FDA), and the Powerspan ECO™ process. While evaluating the availability and applicability of each process in step 2, the Coal Cleaning and the Powerspan ECO™ processes were eliminated. In step 3 the remaining 5 processes were ranked by effectiveness. After ranking the processes, the impacts analysis including visibility was conducted in steps 4 and 5. The main result of the impacts analysis was quantifying the cost effectiveness of each process. The SDA, CDS and FDA were quantified as being inferior on a cost effectiveness basis.

After conducting all steps of the evaluation for SO_2, 90% removal remains as the best possible control alternative. Based upon the cost analysis, none of the feasible BART alternatives were exceedingly expensive. Due to the relative closeness of the cost estimates and fluctuation in market conditions, all of the alternatives had similar cost impacts. The visibility impairment impact analysis examined the visibility impairment impact reduction attributable to each alternative and determined that the marginal change in visibility impairment impact between any two feasible BART alternatives was less than ten percent of the minimum change in visibility impairment discernible by the human eye. So, similar to the cost analysis, the visibility impairment impact analysis reached the conclusion that there is no definitive difference between alternatives. Since 90% control is cost effective and provides indiscernible visibility impact compared to other alternatives, it is recommended as BART. Application of 90% control for LOS Unit 1 translates into an emission rate of 0.34 pounds per million Btu.

5.0.3 UNIT 1 PM BART

Five control technologies were identified for step 1 of the PM control evaluation. The identified technologies included Fuel Switching with Flue Gas Conditioning, a Fabric Filter, a COHPAC Baghouse, a New Electrostatic Precipitator (ESP), and the Existing ESP. In step 2, all five of the control technologies were determined as feasible alternatives based upon availability and applicability. In step 3, the 5 processes were ranked by effectiveness. While evaluating the impacts of each technology during steps 4 and 5, visibility impairment became the principle factor for determining BART. PM emissions, unlike other pollutant emissions, use existing controls and do not significantly contribute to visibility impairment. In addition, using a new control technology to achieve a slightly greater visibility improvement requires a significantly higher cost per deciView when compared with other pollutants. Based upon these two factors, this analysis recommends that the existing ESP be maintained as the technology used for controlling particulate matter. The evaluated emission rate for the existing ESP was 0.10 pounds per million Btu.

5.1 UNIT 2 BART RECOMMENDATIONS

Unit 2 uses the same 5 steps of the technology evaluation provided in the BART Determination Guidelines. Previous sections provide the evaluation results for each pollutant and describe the different approaches used to determine BART. This section provides a brief description of the approach used for each pollutant and summarizes the results for Unit 2.

5.1.1 UNIT 2 NO_X BART

In step 1 of the technology evaluation, three basic categories of NO_X control for EGUs were-identified: pre-combustion, combustion, and post-combustion. Eleven basic types of NO_X control processes were derived from these three categories. Twenty two variations of these eleven processes were reviewed for NO_X controls potentially available and applicable to cyclone-fired EGUs burning North Dakota lignite. While evaluating the availability and applicability of each process for LOS Unit 2's NO_X control in step 2 of the BART analysis process, low NO_X burners, Selective Catalytic Reduction (SCR), and the Powerspan ECO™ process were eliminated. Controls such as oxygen-enhanced combustion, water/steam injection, hydrocarbon-enhanced SNCR, and fuel reburn with SNCR all lack appropriate demonstration or permanent installation experience in full-scale, full-time applications for NO_X emissions reduction on cyclone-fired boilers. Of the pre-combustion and combustion-related NO_X control processes, fuel switching, basic combustion control improvements, basic separated overfire air, flue gas recirculation, fuel lean gas reburn, and conventional gas reburn were considered technically feasible but have zero or low control effectiveness, or are economically unattractive due to the high capital costs and on-going natural gas consumption costs for implementation and operation.

An "advanced" form of separated overfire air, alone and in combination with coal reburn, and Selective Non-Catalytic Reduction (SNCR) with and without Rich Reagent Injection, were evaluated for cost-effectiveness. Of these four alternatives, coal reburn with ASOFA was determined to be an inferior control from a cost-effectiveness standpoint, and thus eliminated from further impacts analysis for LOS Unit 2. For Rich Reagent Injection + SNCR with ASOFA, the small incremental reduction in annual NO_X emissions (approximately 10 percent) for a 60 percent increase in levelized total annual cost yields a 220 percent increase in incremental dollars per ton control cost versus the SNCR with ASOFA alternative. The control cost-effectiveness analysis favored the SNCR with ASOFA alternative for LOS Unit 2 NO_X control.

The impacts analysis for remaining NO_X control alternatives at LOS Unit 2 found only insignificant negative energy and non-air environmental impacts; remaining useful life of the source was assumed to exceed the 20-year project life utilized in the cost impact estimate.

Average predicted visibility impairment impacts decreased significantly for the post-control ASOFA-enhanced NO_X emission rate, and slightly more with a SNCR-enhanced NO_X emission rate, and a very small incremental amount for the RRI + SNCR-enhanced NO_X emission rate when modeled with the single sulfur emission control rate for LOS Unit 2. These impacts were compared to the average predicted visibility impairment impacts at the pre-control (NDDH protocol) baseline emission rates for NO_X, SO_2 , and PM. An analysis of the incremental cost-effectiveness of SNCR and RRI + SNCR controls in reducing predicted visibility impairment impact beyond the ASOFA alternative was performed for LOS Unit 2. Installing and operating SNCR applied to LOS Unit 2 relative to the ASOFA NO_X emission rate for the future Potential-To-Emit boiler heat input (future coal case) scenario would result in hundreds of millions of dollars per deciView-year of control cost effectiveness visibility impairment improvement. The range for this incremental visibility impairment impact reduction was \$105M to \$310M per deciView-yr for SNCR -based control added to the ASOFA NO_X control alternative, depending on the Class 1 area. Adding RRI to the SNCR with ASOFA NO_X control alternative would reduce average predicted visibility impairment impact by 0 to 12.5 percent on a deciView basis while increasing control cost of the incremental visibility impairment improvement by 25 to 40 percent on a M\$ per deciView-year basis, depending on the Class 1 area. The range for this incremental visibility impairment impact reduction was \$148M to \$423M per deciView-yr for adding RRI + SNCR to the ASOFA NO_X control alternative, depending on the Class 1 area.

After conducting all steps of the evaluation for NO_X emissions control, Rich Reagent Injection + SNCR with ASOFA and SNCR with ASOFA alternatives remain as the highest and next highest-performing feasible control technologies for LOS Unit 2. An incremental analysis for control costs and visibility impairment impacts shows that the SNCR with ASOFA alternative was significantly more cost-effective. SNCR with ASOFA is recommended as BART for LOS Unit 2. Application of SNCR with ASOFA for 54.5 percent NO_X control translates into a BART emission rate of 0.304 pounds per million Btu of fuel heat input for the future PTE coal case scenario applied to LOS Unit 2.

5.1.2 UNIT 2 SO_2 BART

Steps 1 through 3 of the technology evaluation for Unit 2 ended with the same results from Unit 1. The 5 remaining processes, ranked in order by efficiency, are Wet Limestone Flue Gas Desulfurization (FGD), Circulating Dry Scrubber (CDS), Spray Dryer Absorber (SDA), Flash Dryer Absorber (FDA), and Fuel Switching. After ranking the processes, the impacts analysis including visibility was conducted in steps 4 and 5. The main result of the impacts analysis was quantifying the cost effectiveness of each process. The SDA, CDS and FDA were quantified as being inferior on a cost effectiveness basis. After conducting all steps of the evaluation for SO_2, Fuel Switching and Wet Limestone FGD remain as the best possible control technologies. Of the two BART alternatives remaining under consideration, wet FGD, achieving 95% SO_2 reduction, consistently achieves the greatest visibility impact reduction and meets presumptive BART limits. Because 95% SO_2 reduction is cost effective and meets presumptive BART limits, it is recommended as BART. Application of ninety-five percent control for LOS Unit 2 translates into an emission rate of 0.17 pounds per million Btu.

5.1.3 UNIT 2 PM BART

The approach used to recommend BART for Unit 2 was exactly the same as was used for Unit 1. The only difference was the higher costs associated with using a new control technology for Unit 2. The increased size of Unit 2 requires new controls to be larger and results in higher costs. Using a new control technology to achieve a slightly greater visibility improvement requires a significantly higher cost per deciView when compared with other pollutants and compared to Unit 1. However, using existing PM controls, emissions from Unit 2 still never significantly contribute to visibility impairment. Based upon these two factors, this analysis recommends that the existing ESPs be maintained as the technology used for controlling particulate matter. The evaluated emission rate for the existing ESP was 0.10 pounds per million Btu.

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6.0 PERMIT LIMIT RECOMMENDATIONS

To complete the determination process, the BART guidelines state that an enforceable emission condition must be established for each subject emission unit and for each pollutant subject to review. (70 FR 39172) The guidelines suggest that emission limits be developed on a 30-day rolling average for Electric Generating Units (EGUs). Unfortunately, the guidelines do not provide a methodology to calculate the limit for permitting purposes and only state that an enforceable limit that reflects BART requirements must be established.

The BART Determination was conducted based upon historical operating conditions for LOS. However, because the fuel characteristics of the North Dakota lignite fired at LOS will be changing in the future, a Future PTE case was developed for the recommended BART determination. Two additional factors, boiler Heat Input and short term variations in fuel composition were reviewed prior to recommending enforceable permit conditions for BART.

In general, when the Boiler Heat Input increases, emission rates of fuel borne pollutants increase. Although the design Heat Input is specified by the boiler manufacturer, factors such as fuel characteristics and operating procedures can affect the maximum Heat Input of a boiler that is actually experienced in practice. Historical Heat Input values from 2000-2004, for both LOS Unit 1 and Unit 2, were reviewed to determine the amount of time in which the Nameplate Heat Input Rating used as the basis for the predicted future emissions in this report was exceeded. The review showed that the design boiler Heat Input was exceeded 10.6% and 7.6% of the operating time for Units 1 and 2 respectively. Because a 30-day averaging period should mitigate some of the effect of higher Heat Input on emissions somewhat, a five percent increase in heat input was used for calculating the recommended emission limits for each pollutant. With this approach, Basin Electric Power Cooperative (BEPC) is provided a bit of a cushion between operating conditions and permit limits such that minor short term variations in operating conditions would not result in an apparent permit violation where BEPC had not, in fact, materially changed any of their normal daily operating conditions.

Variability in coal composition was the second factor that was taken into account because the emission rate of SO_2 and PM are directly related to the sulfur and ash content of the fuel. Sulfur content of the fuel is the primary constituent of concern because SO_2 emissions are directly related to the amount of sulfur in the coal and cannot be improved with combustion improvements as NO_X and

PM. When BART compliance is required for LOS, they will still be burning coal from the Freedom Mine in Beulah, ND. A forty year mining plan, provided by the mining company and containing projected coal quality data, was analyzed to determine the future annual average sulfur content of the coal (Appendix B2). The results indicated that the future coal will have a higher maximum annual average sulfur content of approximately 1.13%. A further analysis of the short term variability of fuel sulfur content and Higher Heating Value (HHV) was conducted by the mining company at the train load level, for LOS fuel deliveries over the 2000-2004 period. The detailed analysis identified one standard deviation in sulfur content as being equal to $\pm$ 0.12% change in fuel sulfur content and one standard deviation in the heat content as $\pm$ 158 Btu/lb. Assuming a normal distribution of both the fuel sulfur and heat content, the annual average, plus or minus one standard deviation, would represent approximately 68.27% of the possible range of sulfur and heat content LOS is expected to experience. This range was taken to be representative of the range of sulfur and heat content that LOS would experience over a given year on a 30 day rolling average. For determining a 30 day rolling average for the purpose of calculating SO_2 emissions, the average annual sulfur content of 1.13% plus one standard deviation of 0.12%, plus an average annual fuel heat content of 6,520 Btu/lb was utilized. Therefore, the basis for the recommended permit conditions for recommended BART for each unit was 105% of the nameplate Heat Input, while firing 1.25% sulfur fuel with a heat content of approximately 6,520 Btu/lb. In this manner, an owner's margin of one standard deviation on fuel and heat content would be preserved. This margin is important to protect the owner from variations in fuel properties over shorter operating periods than the annual average taken as the basis for the remainder of this analysis.

For NO_X emissions, the five percent higher Boiler Heat Input was the only variation from the BART Determination basis that was used to develop the proposed permit conditions. The Boiler Heat Input is the single most important variable affecting the NO_X emissions rate. Fuel nitrogen content may vary slightly but, because it is a minor contributor to overall NO_X emissions rates, potential variations were not taken into account while developing the recommended permit conditions. After performing emissions calculations for Unit 1 using the higher Heat Input and applying recommended BART, the resulting recommended NO_X permit limit is 0.29 lb/mmBtu.

For Unit 2, it is generally seen that when the Boiler Heat Input increases, the NO_X emission rate increases. Applying recommended BART to LOS Unit 2's boiler operating at a higher heat input rate with a higher pre-control baseline 30-day rolling average emission rate, the recommended NO_X

permit limit is 0.35 lb NO_X/mmBtu. These recommendations are summarized in Tables 6.0-1 and 6.0-2 below.

The recommended NO_X permit conditions are based upon performance estimates considering recognized operational factors and equipment designs that are different from emission reduction experience achieved by other coal-fired cyclone boilers. The combustion characteristics of the future lignite supply are expected to include a decrease in higher heating value (Btu/lb) and an increase in ash content. Operation of Unit 2 with air-staged cyclones with the advanced form of separated overfire air system and with low Btu/high ash lignite can cause conditions to occur that exceed the ability to adjust operational practices sufficiently to maintain low NO_X emissions. A provisional operating period of one year of operational experience is recommended in conjunction with the recommended BART 30-day rolling average NO_X emission rate limit. This provisional period will allow BEPC to demonstrate the actual control system capabilities of an SNCR system in addition to the ASOFA system specifically designed for lignite firing in Unit 2's boiler. At the end of that period, it is recommended that the BART NO_X emission limit be reviewed considering the demonstrated operating history.

To account for predicted variations in future fuel sulfur and heat content, a representative SO_2 emission rate was calculated based upon a five percent higher heat input, the maximum sulfur content plus 1 standard deviation and the future annual average fuel HHV minus one standard deviation). After performing emissions calculations for Unit 1 using the basis described above and applying the recommended BART SO_2 reduction level of 90%, the resulting recommended 30 day rolling average SO_2 permit limit for LOS Unit 1 is 0.39 lb SO_2/mmBtu. Similar calculations for Unit 2, applying recommended BART of 95% SO_2 control, yield a recommended SO_2 permit limit of 0.19 lb SO_2/mmBtu. These recommendations are summarized in Tables 6.0-1 and 6.0-2 below.

Emission rates for particulate matter are based upon the design of the existing electrostatic precipitator and the boiler heat input. To maintain the same methodology that was used for both NO_X and SO_2, the heat input used to calculate the emissions in pounds per hour was increased by five percent. Note that the emission rate in pounds per million Btu did not change. Along with recommended emission limits for NO_X and SO_2, PM emission limits for each unit are tabulated below.

Table 6.0-1 – Recommended 30-Day Rolling Average BART Emission Limits LOS Unit 1

Pollutant	Emission Rate
	lb/million Btu
SO_2	0.39
NO_X	0.29
PM	0.10

Table 6.0-2 – Recommended 30-Day Rolling Average BART Emission Limits LOS Unit 2

Pollutant	Emission Rate
	lb/million Btu
SO_2	0.19
NO_X	0.35
PM	0.10

Although the emission limits presented above for each unit are recommended for permitting purposes, this analysis also recommends discussing an alternative compliance method as suggested in the BART Guidelines. The guidelines provide that states, "should consider allowing sources to ''average'' emissions across any set of BART-eligible emission units within a fence line, so long as the emission reductions from each pollutant being controlled for BART would be equal to those reductions that would be obtained by simply controlling each of the BART-eligible units that constitute a BART-eligible source." (70 FR 39172) During the process of developing enforceable permit conditions, the opportunity to apply a plant-wide limit using an "averaging" or "bubbling" strategy should be considered.

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