BART Analysis for Centralia Power Plant

Prepared for

TransAlta

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Prepared By:

CH2MHILL

9193 South Jamaica Street
Englewood, CO 80112

Executive Summary

Background

In accordance with federal and state Best Available Retrofit Technology (BART) regulations and guidelines, CH2M HILL was requested to perform a BART analysis for TransAlta's Centralia Power Plant (CPP). This BART analysis has been conducted only for oxides of nitrogen (NOx). A BART analysis was not performed for other pollutants because the United States Environmental Protection Agency (EPA) determined that CPP installed BART for sulfur dioxide (SO_2) from 2000 to 2002 and that CPP's controls meet BART for particulate matter (PM).

In December 1996, the CPP's owners, National Park Service, EPA, the U.S. Forest Service, Ecology, the Southwest Clean Air Agency (SWCAA), and the Puget Sound Clean Air Agency reached consensus though the Collaborative Decisionmaking (CDM) Process on emission reductions at CPP to meet federal and state requirements. Controls for SO_2 and NOx were installed to comply with Regulatory Order to Establish Reasonability Control Technology No. 97-2057 (herein referred to as the Order) issued by Southwest Air Pollution Control Agency (SWAPCA. As a result of the CDM Process and the Order, from 2000 to 2002 CPP installed SO_2 scrubbers, low NOx burners, and other combustion controls. CPP's position is that the NOx controls installed in the 2000 to 2002 period also meet applicable BART requirements, but it has voluntarily agreed to submit this BART analysis.

CPP has two coal-fired units, with each unit having a net generating capacity of 702.5 megawatts (MW). Under federal BART regulations, emission limits must be achieved within 5 years after the State Implementation Plan (SIP) is approved by EPA. A compliance date of 2014 was assumed for this analysis. Figure ES-1 shows an aerial view of the facility.

FIGURE ES-1. AERIAL VIEW OF CPP

BART Engineering Analysis

The specific steps in a BART engineering analysis are identified in the Code of Federal Regulations (CFR) at 40 CFR 51 Appendix Y, Section IV, and in Washington State Department of Ecology guidance, "Best Available Retrofit Technology Determinations Under the Federal Regional Haze Rule" (June 12, 2007). Based on the aforementioned documents, the analysis must include the following components:

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

The following steps guide and incorporate the aforementioned components of the BART analysis:

Step 1 – Identify All Available Retrofit Control Technologies

Step 2 – Eliminate Technically Infeasible Options

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

Step 4 – Evaluate Energy and Non-Air Quality Impacts

Step 5 – Evaluate Visibility Impacts

As previously mentioned, this analysis has been conducted for NOx emissions. All costs included in the BART analyses are in 2008 dollars, and costs have not been escalated to the assumed 2014 BART implementation date.

Coal Characteristics

The main source of fuel burned at CPP is being transitioned to be exclusively western sub-bituminous coal from the Wyoming Powder River Basin (PRB) by 2013.

NOx Emission Control

In response to the Order, between 2000 and 2002, CPP installed new low NOx burners (LNBs), over-fire air (OFA), and other combustion controls. The level of burner combustion controls that CPP installed is referred to as LNC3. In developing the BART guidelines for similar coal-fired units, EPA recognized LNC3 as the highest level of burner technology.

In completing the BART analysis, technology alternatives were investigated and potential reductions in NOx emission rates were identified. Listed below are the NOx control technology alternatives that were considered:

- Rotating opposed-fire air (ROFA)
- Selective non-catalytic reduction system (SNCR)
- Selective catalytic reduction (SCR) system
- Neural network controls

The ROFA vendor contacted for this analysis did not demonstrate that it has successfully installed the process on units of comparable size; hence, ROFA does not qualify as an available technology for this BART analysis. Both SNCR and SCR have been demonstrated on comparable units and can reasonably be expected to achieve reductions of 25 percent and 75 percent, respectively; therefore, both were considered in this analysis. Neural network controls have not been able to guarantee a minimum level of reduction so it was not considered available for this BART analysis; however, based on the potential NOx reductions and cost-effectiveness, CPP is investigating this technology further.

None of the technologies considered above that are technically feasible for CPP and would provide guaranteed reductions would result in cost effectiveness of less than $2300 per ton of NOx reduced. This is compared to the $281 per ton national average cost for BART controls that EPA estimated for tangentially-fired sub-bituminous coal units when it established presumptive BART.

BART Modeling Analysis

The Gaussian puff dispersion model, herein referred to as CALPUFF, was used by Geomatrix, a subcontractor of CPP, to assess the visibility impacts of NOx emissions from Centralia at Class I areas. The Class I areas potentially affected are located more than 50 kilometers (km), but less than 300 km, from CPP. Ecology guidance also requests the visibility analysis to include the Columbia River Gorge National Scenic Area (CRGNSA), although it is not designated a Class I area. The Class I areas include the following national parks and wilderness areas:

- Alpine Lakes Wilderness
- Glacier Peak Wilderness
- Goat Rocks Wilderness
- Mount Adams Wilderness
- Mount Hood Wilderness
- Mount Jefferson Wilderness
- Mount Rainier National Park
- Mount Washington Wilderness
- North Cascades National Park
- Olympic National Park
- Pasayten Wilderness
- Three Sisters Wilderness

The following modeling cases were developed for NOx emission controls. The currently installed electrostatic precipitator and wet scrubber will continue to provide PM_{10} and SO_2 emission control, respectively, with no upgrades or modifications assumed.

- **Case 0: Pre-NOx Control (1997)**. 0.43 pound per million British thermal units (lb/MMBtu).
- **Case 1: Baseline**. The highest 24-hour emission rate for each unit during the modeling period of 2003-2005 – 4,984 lb/hr NOx (0.304 lb/MMBtu), 4,522 lb/hr SO_2, and 242 lb/hr PM10.
- **Case 2: 2006–2007**. The highest 24-hour emission rate during 2006-2007 (0.300 lb/MMBtu).
- **Case 3: SNCR**. NOx with 25 percent control over the Baseline (Case 1) (0.228 lb /MMBtu)
- **Case 4: Presumptive BART**. 0.150 lb/MMBtu.
- **Case 5: SCR**. 0.070 lb/MMBtu.

Table ES-1 shows the average number of days per year that each case would result in a modeled impact greater than 0.5 delta-deciview (ΔdV). For example, based on the 2006-2007 maximum actual emissions, the maximum number of days per year that CPP is modeled to have greater than 0.5 ΔdV impact in Mount Rainier National Park would be 157. Reducing the Modeling Baseline emission rate with SNCR would result in impacting Mount Rainier National Park 161 days, 3 more days than the number using the 2006-2007 maximum actual emissions. Compared with the 2006-2007 actual emissions, the modeled Presumptive BART would reduce the number of impacted days per year by only

5 additional days. For comparison, for the period prior to 2000 the model shows that CPP impacted Mount Rainier about 204 days per year. Applying either SNCR or the Presumptive BART standard to the Modeling Baseline emissions would result in little if any visibility improvement when compared to the maximum actual emissions during 2006 and 2007.

Visibility improvements for all emission control cases were analyzed and the results were compared using a least-cost envelope, as outlined in the draft EPA *New Source Review Workshop Manual* (1990).

To evaluate the impacts of the modeled control cases on the 12 Class I areas and the CRGNSA, the total annualized cost, cost per deciview (dv) reduction, and cost per reduction in number of days above 0.5 Δdv were analyzed. This report provides a comparison of the average incremental costs between relevant cases for the 12 Class I areas, the total annualized cost versus number of days above 0.5 Δdv, and the total annualized cost versus 98th percentile Δdv reduction.

The modeling results indicate that Mount Rainier National Park is the Class I area most impacted by CPP. In Mount Rainier National Park, on an annualized basis it would cost at least $3,300,000 per day to reduce the number of days that CPP has an impact greater than 0.5 dv from 168 days per year to 135 days per year. In addition, the cost per annual average dv improvement would be at least $55 million per dv per year. The modeling results also indicate that even the greatest theoretical improvement of about 2 dv, which would be in the Mount Rainier National Park, is a level that might not be perceptible by humans. To provide perspective on the visibility modeling results, several studies have shown that only dv differences of approximately 1.5 to 2.0 dv or more are perceptible by the human eye. The EPA in the July 31, 1997, Federal Register generalized that a "one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas." The actual level of visibility improvement that can be reliably perceived in the Pacific Northwest is a matter of debate, but is generally recognized to be somewhere between 1 and 3 dv.

TABLE ES-1
Average Number of Days per Year with Maximum Delta-Deciview Greater Than 0.5

Analysis Area	Pre-NOx Controls	Modeling Baseline	2006 - 2007	SNCR	Presumptive BART	SCR
Alpine Lakes Wilderness	190	144	126	135	118	95
Glacier Peak Wilderness	156	92	74	83	69	53
Goat Rocks Wilderness	170	138	123	129	118	97
Mt. Adams Wilderness	148	110	95	100	91	75
Mt. Hood Wilderness	115	75	61	66	59	46
Mt. Jefferson Wilderness	89	43	32	40	32	25
Mt. Rainier National Park	204	168	157	161	152	135
Mt. Washington Wilderness	77	34	22	29	22	17
N. Cascades National Park	136	69	50	58	46	34
Olympic National Park	113	85	74	78	71	61

TABLE ES-1
Average Number of Days per Year with Maximum Delta-Deciview Greater Than 0.5

Analysis Area	Pre-NOx Controls	Modeling Baseline	2006 - 2007	SNCR	Presumptive BART	SCR
Pasayten Wilderness	111	47	33	39	29	17
Three Sisters Wilderness	78	35	24	30	25	17
Columbia River Gorge National Scenic Area	132	82	62	65	58	40

Conclusion

CPP's recently installed LNC3 technology is the type of technology that was the primary basis for EPA's adoption of the presumptive BART standard. None of the options evaluated are cost effective when compared to the estimated national average cost of $281 per ton for tangential-fired sub-bituminous coal units that EPA used in establishing the presumptive BART standard. At a minimum, additional controls would be eight times that much per ton. Furthermore, further reductions in NOx emissions from CPP will not likely noticeably improve visibility; not only are the modeled deciview impacts small, but CPP's NOx emissions contribute less than one percent to the total visibility extinction in Mount Rainier National Park, the Class I area most impacted by CPP. Based on these considerations and the technologies considered, CPP's current LNC3 technology should be determined to be BART.

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Appendix A Economic Analysis
Appendix B Modeling Analysis

Acronyms and Abbreviations

BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CALPUFF	Gaussian puff dispersion model
CAMD	EPA Clean Air Markets Division
CCOFA	close-coupled over-fire air
CDM	Collaborative Decisionmaking
CFR	Code of Federal Regulations
CEMS	continuous emission monitoring systems
CO	carbon monoxide
CPP	Centralia Power Plant
CRGNSA	Columbia River Gorge National Scenic Area
Δdv	delta-deciview (change in deciview)
dv	deciview
DEQ	Department of Environmental Quality
Ecology	Washington State Department of Ecology
EPA	United States Environmental Protection Agency
FLM	Federal Land Manager
Fuel NOx	oxidation of fuel bound nitrogen
km	kilometer
kW	kilowatt
kW-Hr	kilowatt-hour
lb/MMBtu	pounds per million British thermal units
LAER	lowest achievable emission rate
LNB	low-NOx burner
MMBtu	million British thermal units

MW	megawatt
Mt.	Mount
N_2	nitrogen (molecular)
NO	nitric oxide
NO_2	nitrogen dioxide
NOx	oxides of nitrogen
OFA	over-fire air
PM	particulate matter
PRB	Powder River Basin
RACT	Reasonably Available Control Technology
ROFA	rotating opposed-fire air
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SOFA	separated over-fire air
SWAPCA	Southwest Air Pollution Control Agency
SWCAA	Southwest Clean Air Agency
WRAP	Western Regional Air Partnership

1.0 Introduction

1.1 Purpose

Best Available Retrofit Technology (BART) guidelines were established by the United States Environmental Protection Agency (EPA) to reduce the occurrence of regional haze in national parks and other Class I protected air quality areas in the United States.[1] These guidelines provide instruction for states when determining which major stationary sources must install additional controls and, more specifically, the type of controls that must be used. Facilities eligible for BART installation were built between 1962 and 1977 and have the potential to emit more than 250 tons per year of visibility-impairing pollutants.

Once facilities are identified, there are five basic elements related to BART that are considered when setting emission limits:

- Existing pollution control technology in use at the source
- The cost of the controls
- The remaining useful life of the source
- The energy and non-air environmental impacts of compliance
- The degree of improvement in visibility that may reasonably be anticipated from the use of such technology

This report documents the BART analysis that was performed on the Centralia Power Plant's (CPP) two coal-fired boilers, Unit 1 and Unit 2, by CH2M HILL for TransAlta Centralia Generation, LLC. The analysis was performed for oxides of nitrogen (NOx).

1.2 Report Organization

Section 2.0 of this report provides a description of the current unit operation, including a discussion of coal sources and characteristics. The BART engineering analysis is provided in Section 3.0. Section 4.0 provides the methodology and results of the BART modeling analysis, followed by recommendations in Section 5.0. References cited in the report are listed in Section 6.0, and appendices provide more detail on the economic analysis (Appendix A) and the BART modeling analysis (Appendix B).

[1] 40 Code of Federal Regulations (CFR) Part 51: Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule. 70 Federal Register, 39103-39172, July 6, 2005.

2.0 Present Unit Operation

CPP operates two BART-eligible coal-fired units, each with a net capacity of 702.5 megawatts (MW). The units were commissioned in 1971 and 1972 and are located near Centralia, Washington. Both units are currently equipped with a tangentially-fired pulverized coal boiler manufactured by Combustion Engineering. New low-NOx burners (LNBs) and over-fire air (OFA) were installed between 2000 and 2002. This system is an Alstom LNC3 system that includes separated OFA (SOFA).

Although not part of this BART analysis, both units use dual electrostatic precipitators for particulate emissions reduction and wet forced oxidation scrubbers for sulfur dioxide (SO_2) control.

The BART analysis is based on both units operating until at least 2030. Therefore, a 15-year useful life was used as 2014 is the assumed BART implementation date. This report does not attempt to quantify any additional life extension costs needed to allow the units and these control devices to operate beyond 2030.

The BART regulations and Ecology guidance state that the baseline emissions used for visibility modeling should be established by identifying the highest 24-hour average actual emission rate for the period modeled. The baseline period modeled was 2003-2005. The highest 24-hour actual NOx emission rate during that period, as measured by CPP's continuous emission monitoring system that is used for determining compliance with emission limits and reporting to the EPA Clean Air Markets Division (CAMD), was 2,474 pounds per hour (0.302 pounds per million British thermal units (lb/MMBtu)) for Unit 1 and 2,496 pounds per hour (0.306 lb/MMBtu) for Unit 2. These rates were used by Geomatrix for the visibility modeling.

In December 1996, the National Park Service, EPA, the U.S. Forest Service, Ecology, the Southwest Clean Air Agency (SWCAA), and the Puget Sound Clean Air Agency reached consensus though the Collaborative Decisionmaking (CDM) Process on emission reductions at CPP to meet state NOx and federal and state BART requirements. As a result of the CDM Process, from 2000 to 2002 CPP installed SO_2 scrubbers, low NOx burners, and other combustion controls.

The CDM Process culminated in SWCAA (then referred to as the Southwest Air Pollution Control Agency [SWAPCA]) issuing a Regulatory Order to Establish Reasonably Available Control Technology (RACT), SWAPCA 97-2057 (the Order), for CPP. The Order required CPP to limit SO_2 emissions to less than 10,000 tons per year after 2002 and limit NOx emissions to an annual average of 0.30 lb/MMBtu when the units are operating at 360 MW or greater. According to the RACT Order Technical Support Document, the estimated reduction of SO_2 was about 79,000 tons per year, at an annualized cost of about $300 per ton of SO_2 removed, expressed in 2000 dollars. The Order also resulted in CPP installing new LNB and OFA controls. The installation of the NOx controls at a capital cost of about $14 million resulted in a reduction of about 12,000 tons of NOx per year at a cost of about $230 per ton, based on information in the Order Technical Support Document.

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

TABLE 2-1
Unit Operation and Study Assumptions

Measure	Value
Site elevation (feet above MSL)	250
Stack height (feet)	470
Stack exit internal diameter (feet) / exit area (square feet)	42.06[a] / 1,389
Stack exit temperature (°F)	137
Stack exit velocity (feet/second)	50
Stack flow (actual cubic feet per minute)	4,167,000
Annual unit capacity factor (percent)	93
Net unit output (MW)	702.5 each (1,405 total)
Type of boiler	tangentially-fired
Boiler fuel	sub-bituminous coal fuel oil (startup, shutdown, flame stabilization)
Current NOx controls	LNBs with OFA
Pre-1997 NOx emission rate (lb/MMBtu)	0.43
Maximum 24-hr NOx emission rate (lb/MMBtu) each unit (2003 – 2005) for visibility modeling analysis	0.302 / 0.306
2006-2007 NO_x annual average emission rate (lb/MMBtu) (used for cost analysis)	0.25

[a] **The units were simulated as a release from a single stack. The two stacks are next to one another and the flows were combined using an equivalent diameter calculated from the combined area of the two stacks.**

The heat input rate is a function of many variables including demand and type of coal. Table 2-2 shows the quarterly average heat input rate for each unit for 2006 and 2007.

TABLE 2-2
Unit Operation Time and Heat Input (2006-2007)

Unit ID	Quarter	Operating Time (hr)	Heat Input (MMBtu)	Average Quarterly Heat Rate (MMBtu/hr)
Unit 1 (BW21)	2006Q1	1953.58	10,655,302	5,454
	2006Q2	144.88	631,744	4,360
	2006Q3	2014.49	13,977,671	6,939
	2006Q4	2128.06	14,759,392	6,936
Unit 1 2006 Total		6,241	40,024,109	6,413
Unit 1 (BW21)	2007Q1	2016.44	10,773,910	5,343
	2007Q2	1625.91	10,155,726	6,246
	2007Q3	2143.57	15,131,951	7,059
	2007Q4	2098.77	14,744,849	7,025
Unit 1 2007 Total		7,885	50,806,436	6,444
Unit 1 Total 2006-2007		14,126	90,830,545	6,430
Unit 2 (BW22)	2006Q1	2002.68	11,821,220	5,903
	2006Q2	166.5	1,266,032	7,604
	2006Q3	1188.71	7,325,872	6,163
	2006Q4	2140.73	14,067,178	6,571
Unit 2 2006 Total		5,499	34,480,302	6,271
Unit 2 (BW22)	2007Q1	1863.46	10,772,627	5,781
	2007Q2	1650.35	10,050,867	6,090
	2007Q3	2184.85	14,261,888	6,528
	2007Q4	2047.48	14,203,551	6,937
Unit 2 2007 Total		7,746	49,288,933	6,363
Unit 2 Total 2006-2007		13,245	83,769,235	6,325
Average Unit 1 and Unit 2 2006-2007		13,685	87,299,890	6,379

The EPA BART regulations set "presumptive BART limits" for electric power plants greater than 750 MW, which are rebuttable based on a balancing of the five factors described in Section 1.1. Because CPP has a generating capacity greater than 750 MW, the presumptive BART limits apply, subject to a balancing of the five factors. Therefore, this analysis includes a comparison of the presumptive BART limit against the level of emissions that each control technology would achieve.

The BART presumptive NOx limit for tangentially-fired boilers burning sub-bituminous coal is 0.15 lb/MMBtu. The source of fuel burned at CPP is anticipated to be western sub-bituminous Powder River Basin (PRB) coal.

3.0 BART Engineering Analysis

3.1 NOx Formation

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

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

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

Coal characteristics directly and significantly affect NOx emissions from coal combustion. Coal ranking is a means of classifying coals according to their degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous to anthracite. Lower-rank coals, such as the sub-bituminous coals from the PRB, produce lower NOx emissions than higher ranked bituminous coals due to their higher reactivity and lower nitrogen content. The fixed-carbon-to-volatile-matter ratio (fuel ratio), coal oxygen content, and rank are good relative indices of the reactivity of a coal type. Lower-rank coals release more organically bound nitrogen earlier in the combustion process than do higher-rank bituminous coals, which makes it easier to control the oxidation of the nitrogen by having a fuel-rich initial combustion zone. The fuel-rich zone promotes the use of oxygen for combustion rather than formation of NOx. When used with LNBs, this early release of nitrogen allows for a longer period during the total staged combustion process for the formation of stable molecular nitrogen and hence lower NOx emissions.

All coal sources that are planned to be burned in Centralia are classified as sub-bituminous.

3.2 BART Process

The specific steps in a BART engineering analysis are identified in the Code of Federal Regulations (CFR) at 40 CFR 51 Appendix Y, Section IV, and Ecology's BART guidance (Ecology, 2007). The evaluation must include the following:

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

These aforementioned requirements are incorporated into the BART analysis in the following steps:

- Step 1 – Identify All Available Retrofit Control Technologies
- Step 2 – Eliminate Technically Infeasible Options
    - The identification of available and technically feasible retrofit control options
    - Consideration of any pollution-control equipment in use at the source (which affects the applicability of options and their impacts)
- Step 3 – Evaluate Control Effectiveness and Costs of Remaining Control Technologies
- Step 4 – Evaluate Energy and Non-Air-Quality Impacts
    - The remaining useful life of the facility
    - The energy and non-air-quality environmental impacts of compliance
- Step 5 – Evaluate Visibility Impacts
    - The degree of visibility improvement that may reasonably be anticipated from feasible control options

In addition to evaluation of new control equipment, the analysis includes evaluation of any pollution control equipment in use at the source, the costs of compliance associated with the existing controls, and the energy and non-air quality environmental impacts of compliance using these existing control devices.

All costs included in the BART analysis are in 2008 dollars, and costs have not been escalated for inflation to the assumed 2014 BART implementation date.

3.2.1 Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NOx control technologies with practical potential for application to Centralia. A broad range of information sources has been reviewed in an effort to identify potentially applicable emission control technologies.

Both units at CPP are tangentially-fired. NOx emissions are currently controlled through the use of Alstom LNBs that were installed between 2000 and 2002, close-coupled over-fire air (CCOFA), and separated over-fire air (SOFA). This configuration is identified by Alstom as

"LNC3." Information regarding current LNC3 NOx emission levels was obtained from EPA's acid rain database. In spite of the recent installation of the LNC3 system, a proposal was requested from Mobotec for their rotating opposed-fire air (ROFA) and Rotamix systems.

The following potential NOx control technology options were screened for feasibility:

- Mobotec ROFA and Rotamix systems
- Selective non-catalytic reduction (SNCR) system
- Selective catalytic reduction system (SCR)
- Neural net boiler controls

3.2.2 Step 2: Eliminate Technically Infeasible Options

According to the EPA BART rules and Ecology's June 12, 2007, BART Guidance, in order for a control technology to be considered "technically feasible," the technology

1) Must have been installed and operated successfully for the type of source under review under similar conditions, or

2) It could be applied to the source under review.

In addition, the BART rules state that key concepts in determining whether a technology could be applied are "availability" and "applicability."

ROFA/ROTAMIX

Mobotec markets ROFA as an improved second-generation OFA system, where the volume of the boiler is set in rotation with asymmetrically placed air nozzles. While the Mobotec ROFA technology is available for the control of NOx from coal-fired power plants, according to Mobotec installation information, the ROFA technology alone has not been demonstrated on any tangentially-fired coal unit greater than 172 MW.

The Mobotec Rotamix technology is described as a second-generation SNCR, where the chemicals are added using lances in conjunction with the ROFA air nozzles. According to the Mobotec installation list, the largest tangentially-fired coal unit using the Mobotec ROFA/Rotamix combination is 175 MW.

Based upon the BART guidance and rules and the information presented above, Mobotec ROFA and Rotamix technologies are technically not feasible for the CPP because they have not been installed and operated successfully on boilers of similar size and design. Each unit at the CPP is equipped with a tangentially-fired boiler rated at a net capacity of 702.5 MW, which is four times the size of the referenced Mobotec units installed. Because of the large discrepancy in unit size, and considering the significant scale-up risk, the ROFA and Rotamix technologies are not deemed applicable or technically feasible for the CPP units.

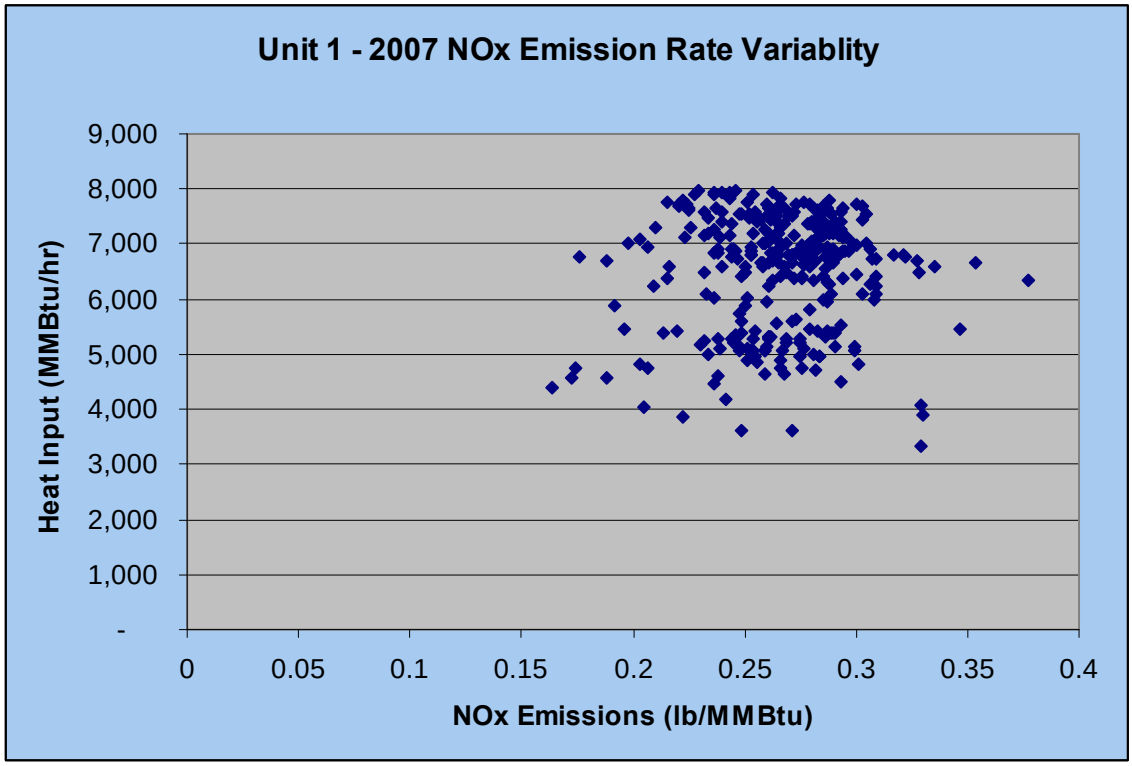
3.2.3 Step 3: Evaluate Control Effectiveness and Costs of Remaining Control Technologies

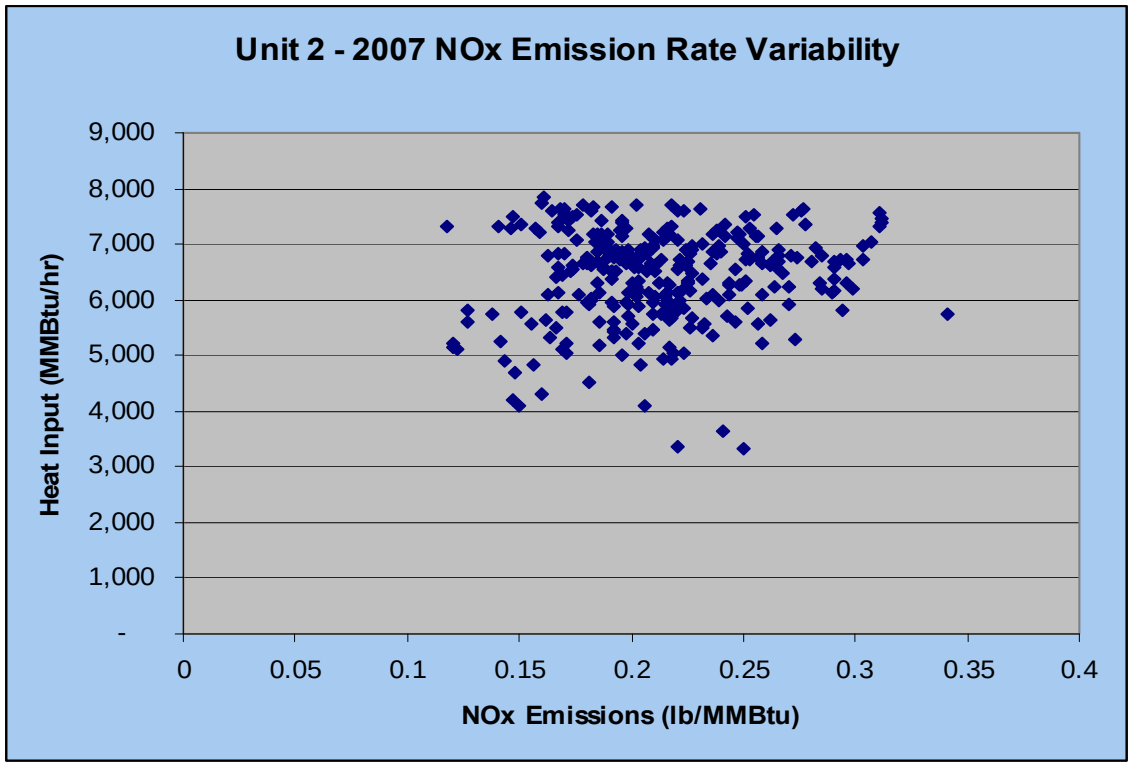
As an integral part of the BART analysis process, cost and expected emission information was developed for NOx. This information was assembled from various sources including CPP operating and engineering data and internal CH2M HILL historical information.

The level of accuracy of the cost estimate can be broadly classified as "Order of Magnitude" which can be categorized as -20/+50 percent. There are several reasons for the wide range of cost estimates included in a BART analysis; however, the uncertainty is primarily caused by the difficulty in extracting detailed and accurate information. The power industry marketplace is extremely active, and engineering and construction information is difficult to obtain due to vendor workload. Material costs and construction labor costs are also widely fluctuating in today's active economy.

The accuracy of emissions forecasts may also be questionable, and is also attributable to the inability to gain timely and accurate information. This is exemplified by the difficulty in obtaining background information, and the vendor time required to develop accurate emission projections for study purposes as opposed to their response to actual project requests for proposals. Also, variances in expected emissions can depend on the pollutant under consideration (e.g., particulate emissions can generally be more accurately predicted than NOx emissions).

FIGURE 3-1
NOx Emission Rate Variability (2007)





Therefore, when selecting emissions control technologies and establishing emission permitting levels, consideration of variability in cost and expected emissions information must be considered.

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

Existing LNBs with OFA System

The mechanism used to lower NOx with LNBs is to stage the combustion process and to initially provide a fuel-rich condition; thus, oxygen is needed for combustion and is not diverted to combine with nitrogen to form NOx. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NOx. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char.

CPP installed LNBs and made overfire air improvements between 2000 and 2002 as a result of the Order. This is the current NOx control technology used at the CPP.

SNCR

Selective non-catalytic reduction is generally used to achieve modest NOx reductions generally on smaller units (units with heat input less than 3,000 MMBtu/hr). With SNCR, an amine-based reagent such as ammonia or urea is injected into the furnace within a temperature range of 1,600 degrees Fahrenheit (°F) to 2,100°F, where it reduces NOx to nitrogen and water. NOx reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

Reagent utilization, which is a measure of the efficiency with which the reagent reduces NOx, can range from 20 to 60 percent, depending on the amount of reduction, unit size, operating conditions, and allowable ammonia slip. With low reagent utilization, low temperatures, or inadequate mixing, ammonia slip occurs, allowing unreacted ammonia to create problems downstream. The unreacted ammonia may render fly ash unsaleable, react with sulfur to foul heat exchange surfaces, and/or create a visible stack plume. Reagent utilization can have a significant impact on economics, with higher levels of NOx reduction generally requiring more reagent and higher operating cost. Reductions from high baseline concentrations (inlet NOx) are lower in cost per ton, but result in higher operating costs, due to greater reagent consumption.

The control effectiveness of SNCR is a function of many variables including the uncontrolled emissions concentrations, physical conditions, and operational conditions. The greatest control effectiveness is generally achieved with high uncontrolled NOx concentrations, on new units that have been specifically designed for SNCR, and at a specific load. For new units, it is common to install several levels of ammonia injection to accommodate different boiler loads. At the CPP, NOx levels are already low because the plant has installed low-NOx burners. The boilers were not specifically designed for SNCR, and a detailed investigation of physical constraints and temperature fluctuations would be necessary to determine ammonia injection locations to accommodate all the expected operating loads. Utilizing multiple injection levels would significantly increase system cost, as compared to a single level SNCR installation. In addition, a study by Harmon (1998) indicates that a large coal fired, tangentially fired unit equipped with a low NOx

SNCR has the potential to reduce NOx emissions by only 20 to 25 percent with an ammonia slip of less than 10 ppm. The EPA Office of Air Quality Planning and Standards' *EPA Air Pollution Control Cost Manual* (EPA, 2002) states "SNCR systems applied to large combustion units (greater than 3,000 MMBtu/hr) typically have lower NOx reduction efficiencies (less than 40 percent), due to mixing limitations." The CPP units have heat input rates of much greater than 3,000 MMBtu/hr (about 7,000 MMBtu/hr). After considering the above factors and a reasonable compliance factor, a 25 percent control effectiveness was selected.

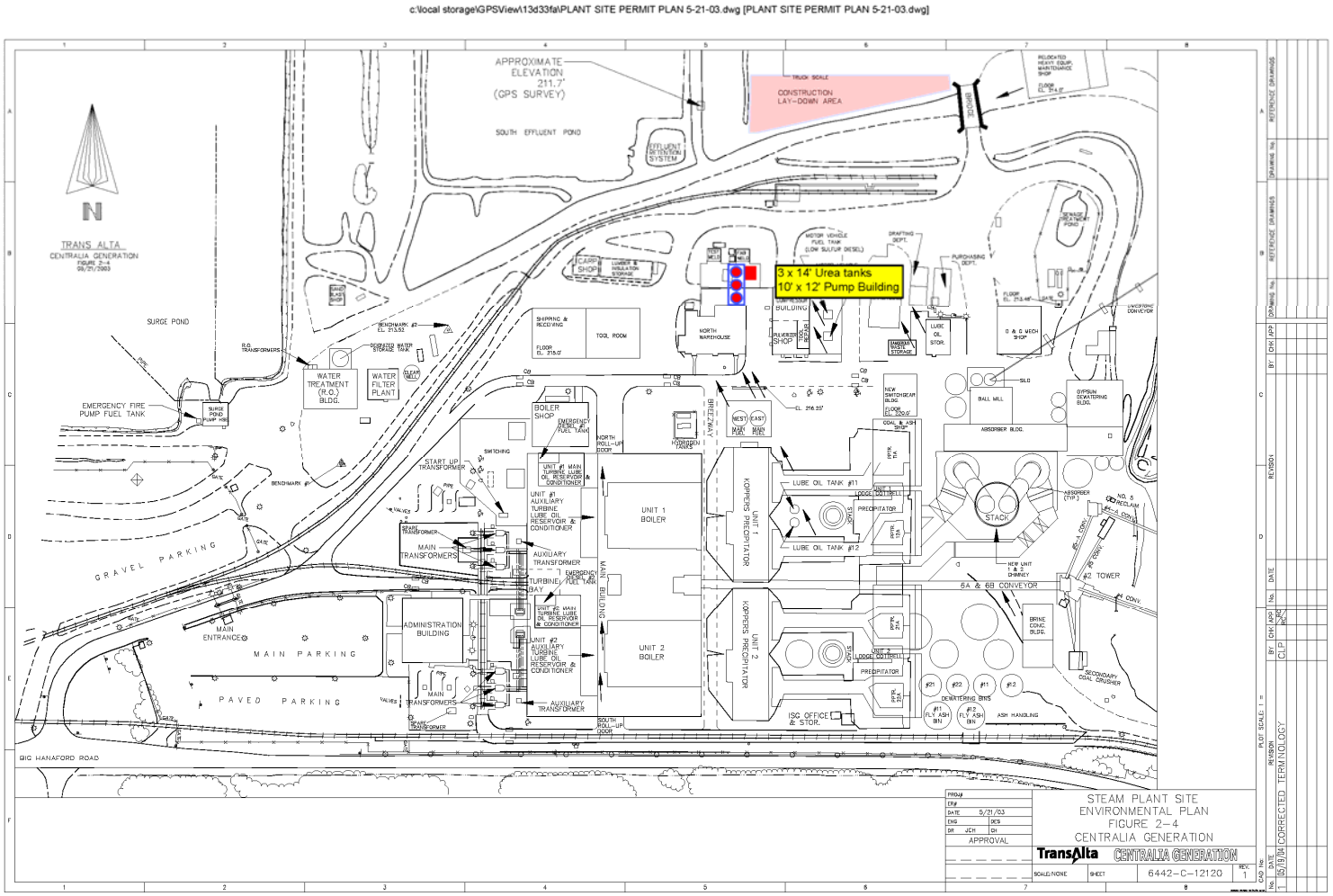
A budgetary estimate for a urea-based SNCR system, which provides nominally a 25 percent reduction from baseline NOx levels with a 5 ppm ammonia slip, was estimated using the CH2M HILL project database. Due to an extremely tight boiler outlet configuration and limited available space for new equipment, an adjustment was used for SNCR cost estimates.

A 5 ppm ammonia slip is the maximum recommended taking into account the high flue gas sulfur levels. To achieve the proposed reduction, Multiple Nozzle Lances (MNLs) are required to handle the load changes from 50 to 100 percent. The requirement of MNLs results in elevated installation, equipment, and operational costs. The MNLs will be located such that the ammonia or urea has approximately a one second reaction time. CPP's shorter boiler configuration will require detailed computational fluid dynamics and chemical kinetics modeling to ensure proper injection points and reaction times.

The ammonia or urea storage and supply equipment will be located approximately 120 yards north of Units 1 and 2, see Figure 3-2. The site arrangement does not allow for the installation of the storage and supply equipment near the units; therefore, additional stainless steel piping, heat tracing, and larger supply pumps will be required. For the purpose of this study, common storage tanks and supply equipment/piping was assumed for both units. Inadequate up-to-date drawings make it difficult to accurately estimate pipe routing and equipment locations. If separate tanks and equipment/piping was determined to be required, additional costs would need to be added.

Water tubes on the walls of the boiler add complexity to the installation. In the areas where the ammonia or urea injection lances are located the water tubes will need to be replaced to allow room. This requires the shutdown of the boilers, installation of scaffolding to the lance location, and skilled tube welders. This site specific requirement dramatically increases the cost of installation when compared to other SNCR retrofits which do not require water tube modifications.

FIGURE 3-2
SNCR Location



SCR

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

An adjustment was used for SCR cost estimates due to CPP's extremely tight boiler outlet ductwork configuration as shown in Figures 3-3, 3-4, and 3-5 and limited available space for new equipment. As with SNCR, it is generally more cost effective to reduce NOx emission levels as much as possible through combustion modifications than to increase the catalyst surface area and ammonia requirements of the SCR.

Full-scale SCRs are required for the CPP because the shorter boiler configuration does not allow the room required for the catalyst to be located in the existing flue gas duct.

The associated price adjustment of the SCR is a reflection of the current extremely active power industry, which makes it difficult to obtain engineering and construction information from vendors. Several of the typical SCR vendors are not currently accepting SCR retrofits for this size of boiler due to market conditions.

The restricted site layout requires the SCRs to be installed on top of the existing electrostatic precipitators as shown in Figures 3-3 and 3-4. The support structure, intricate duct routing, limited construction space, and complexity of erection exponentially increases the capital cost.

Since each boiler at CPP has two exhaust gas trains, each boiler unit requires two smaller separate catalyst vessels instead of a single large catalyst vessel. The capital cost of installing dual catalyst vessels for each unit is greater than a single catalyst vessel for units of similar size.

As stated in the BART analysis, an SCR retrofit impacts the existing flue gas fan system due to the additional pressure drop associated with the new catalyst, which is typically a 6- to 8-inch water gage increase. The increase in pressure drop results in higher operating costs, additional capital costs, and would require an engineering study of all components in the flue gas stream affected by the change. The extent of additional capital cost improvements would be determined during the design phase of an SCR installation.

FIGURE 3-3
SCR Location

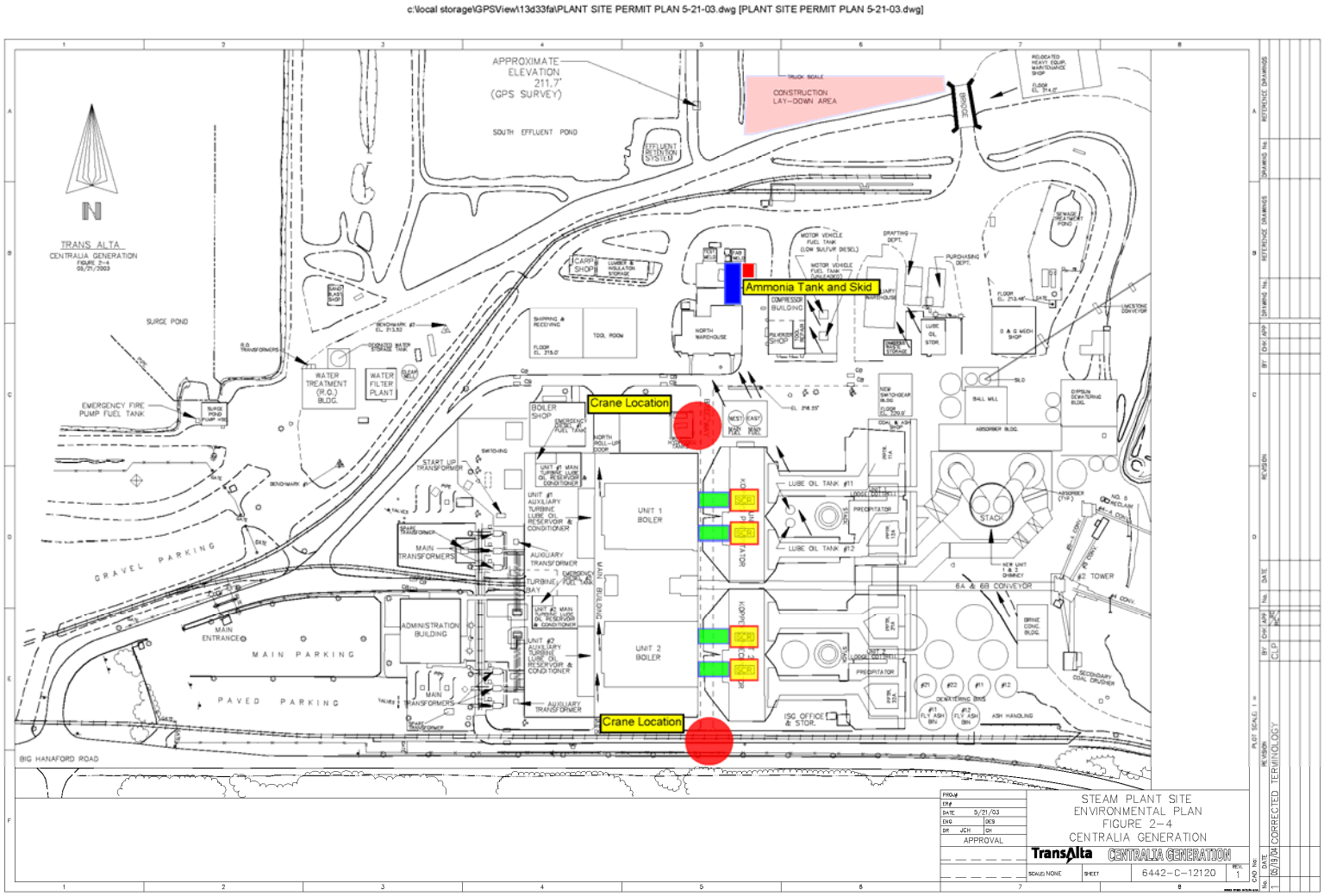


FIGURE 3-4
SCR Elevation

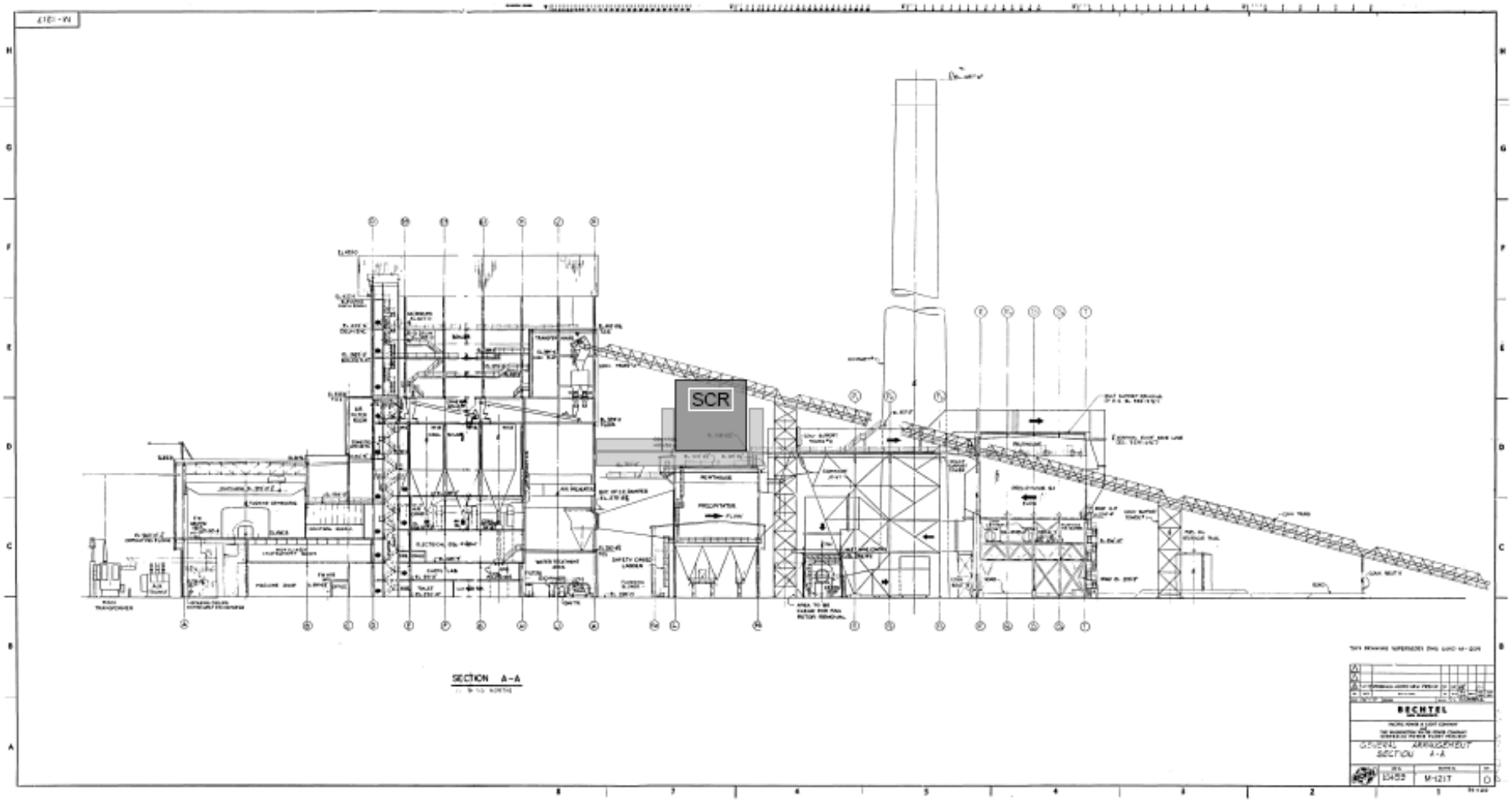


FIGURE 3-5
Unit 1 Side View

Neural Net Boiler Controls

Information regarding neural net controls for boilers was received from NeuCo, Inc. While NeuCo offers several neural net optimization products, CombustionOpt and SootOpt provide the potential for NOx reduction at some facilities. Both CombustionOpt and SootOpt are control-system-based products. CombustionOpt provides for optimized control of fuel and air to reduce NO_x and improve fuel efficiency. SootOpt improves boiler

sootblowing by proportioning heat transfer and reducing "hot spots" resulting from ineffective cleaning. NeuCo stated that these products can be used on most boiler control systems and can be effective even in conjunction with other NOx reduction technologies.

NeuCo predicts that generally CombustionOpt can reduce NOx by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Expected NOx reduction is very unit-specific, and actual results may vary greatly. Previously received budgetary prices for CombustionOpt and SootOpt were $150,000 and $175,000, respectively, with an additional $200,000 cost for a process link to the unit control system.

Because NeuCo does not guarantee NOx reduction, the estimated emission reduction levels provided cannot be considered as reliable projections. Therefore, neural net should be considered as a potential supplementary or polishing technology, but not as a NO_x technology for this BART analysis. Because of the potential NOx reductions and cost-effectiveness, CPP is investigating this technology further.

Presumptive BART

EPA's presumptive BART standard for tangentially-fired units burning sub-bituminous coal is 0.15 pound of NOx per MMBtu. In the preamble of the July 6, 2005, BART rule, EPA specifically stated that the expected national average cost of tangentially-fired sub-bituminous coal units would be $281 per ton, although in situations in which LNC3 is not technically feasible, the expected cost effectiveness of installing ROFA as BART for NOx would be less than $1,500 per ton.

The EPA Technical Support Document acknowledges that CPP currently uses the highest level of burner-based combustion controls, LNC3, upon which the presumptive standard is based. CPP has already installed a higher level of combustion control technology than almost all of the other units that EPA considered in determining the applicable presumptive BART. In addition, of the 48 tangentially-fired units burning sub-bituminous coal that EPA expected would need controls to meet presumptive BART, only 6 had a lower NOx emission rate in 2004, the base year that EPA used for cost effectiveness. Finally, as described above in Section 3.2.2 regarding the significant scale-up risk, the ROFA and Rotamix technologies are not deemed applicable or technically feasible for the two Centralia units.

For purposes of this analysis, it was assumed that CPP could achieve the presumptive BART level of 0.15 lb/MMBtu, installing SCR on one of the two units, and averaging the emissions of the two units. Hence, for the purposes of this analysis, presumptive BART (0.15 lb/MMBtu) is based on installing SCR on one of the two units at CPP. Adoption of this control option as BART would require an annual average limit across both units.

In summary, SNCR, Presumptive BART, and SCR are the technologies that warrant further evaluation and are listed in Table 3-1.

TABLE 3-1
NO_x Control Technology Cost Effectiveness Emission Rates

Technology	Source of Estimated Emissions	Expected Emission Rate (lb/MMBtu)	Emission Rate[1] (tons/yr)
Cost Analysis Baseline (2006–2007)	CPP	0.25 (4,984 lb/hr)	10,910
SNCR	CH2M HILL	0.198	8,182
Presumptive BART Limit	CH2M HILL	0.15 (average of both units)	6,546
SCR	CH2M HILL	0.07	3,055

[1] Emissions were calculated using the information from Table 3-3, which presents actual quarterly NO_x data for both Unit 1 and Unit 2 for the years of 2006 and 2007. Table 3-3 total NO_x emissions of 10,995 tons include both units with different operating times and NO_x emission rates.
Table 3-1 emissions were calculated utilizing a projected operating time of 6,843 hours/year (13,686 average 2006-7 total hours/2) for each unit. The resulting total emissions are therefore slightly different than what is shown in Table 3-3.

Cost Effectiveness of Remaining Control Technologies

Ecology's *Best Available Retrofit Technology Determinations under the Federal Regional Haze Rule* (Ecology, 2007), page 21, states:

> In the case of a fossil fueled power plant, the actual emissions for SO_2 and NO_x emissions for each BART eligible unit will be based on the emissions during the most recent 8 calendar quarters reported to the EPA Clean Air Markets Division. A different time period may be used for a unit if the plant can demonstrate that one of those years was not representative of normal operation.

In accordance with this guidance, the baseline emission rates for the cost-effectiveness analyses reflect the annual average emissions reported by the CPP to the EPA CAMD for the eight quarters of 2006 and 2007. These values were determined by continuous emission monitoring systems (CEMS) that meet the requirements of 40 CFR Part 75. As shown in Table 3-2, the average 2006–2007 NO_x emission rate for Units 1 and 2 was 10,955 tons per year (0.271 lb/MMBtu and 0.229 lb/MMBtu respectively, for an average of 0.250 lb/MMBtu).

As directed by the Ecology BART Guidance, the baseline for the cost effectiveness analysis will be the annual average for both units.

Table 3-3 shows the amount removed compared to the average emission rate for 2006-2007, the total capital costs, and the annualized costs for each available and feasible control option considered. For comparison, the table also shows the same information for the Order. The average cost per ton of NO_x removed as a result of the Order was $230 per ton, while the average cost of the SNCR is about $2,300 per ton of NO_x removed and the average cost for SCR is about $9,100 per ton.

In addition to the total cost per ton, both EPA and Ecology guidance require identification of the incremental cost of control. For example, the annualized incremental cost of SCR over SNCR is $65.2 million per year (71.4 – 6.2). As compared to SNCR, SCR would remove an

additional 5,128 tons per year (7,855 – 2,727). Thus, the incremental cost-effectiveness of SCR over SNCR is approximately $12,726 per ton.

EPA's *New Source Review Workshop Manual* (1990) states:

> Incremental cost-effectiveness comparisons should focus on annualized cost and emission reduction differences between dominant alternatives. Dominant set of control alternatives are determined by generating what is called the envelope of least-cost alternatives.

TABLE 3-2
CPP 2006 and 2007 Quarterly NO_x Data Reported to CAMD

Unit ID	Year	Operating Time (hr)	NO_x Rate (lb/MMBtu)	NO_x (tons/yr)	Heat Input (MMBtu)
Unit 1 (BW21)	2006	1953.58	0.261	1,381	10,655,302
	2006	144.88	0.311	94	631,744
	2006	2014.49	0.272	1,902	13,977,671
	2006	2128.06	0.287	2,080	14,759,392
Unit 1 2006 Total		**6,241**	**0.273**	**5,457**	**40,024,109**
Unit 1 (BW21)	2007	2016.44	0.273	1,471	10,773,910
	2007	1625.91	0.278	1,412	10,155,726
	2007	2143.57	0.267	2,020	15,131,951
	2007	2098.77	0.266	1,961	14,744,849
Unit 1 2007 Total		**7,885**	**0.270**	**6,863**	**50,806,436**
Unit 1 2006-2007 Total/Ave		**7,063**	**0.271**	**6,160**	**90,830,545**
Unit 2 (BW22)	2006	2002.68	0.226	1,348	11,821,220
	2006	166.5	0.267	169	1,266,032
	2006	1188.71	0.254	901	7,325,872
	2006	2140.73	0.256	1,790	14,067,178
2006 Total		**5,499**	**0.244**	**4,209**	**34,480,302**
Unit 2 (BW22)	2007	1863.46	0.223	1,201	10,772,627
	2007	1650.35	0.237	1,191	10,050,867
	2007	2184.85	0.211	1,505	14,261,888
	2007	2047.48	0.209	1,484	14,203,551
Unit 2 2007 Total		**7,746**	**0.218**	**5,381**	**49,288,933**
Unit 2 2006-2007 Total/Ave		**6,623**	**0.229**	**4,795**	**83,769,235**
Both Units 2006-2007 Total/Ave		**13,686**	**0.250**	**10,955**	**87,299,890**

TABLE 3-3
NO_x Control Cost Comparison [MISSING COLUMN TITLES]

Factor	RACT/BART - SO_2	RACT/BART – NO_x	SNCR	Presumptive BART	SCR
Major Materials and Design Costs			$14.7 million	$138.8 million	$277.7 million
Total Installed Capital Costs	$236.6 million	$14.1 million	$33.2 million	$290.1 million	$580.3 million
Total First Year Fixed and Variable Operation and Maintenance Costs			$2.5 million	$3.9 million	$7.7 million
Total First Year Annualized Cost	$24.7 million	$1.6 million	$6.2 million	$36.3 million	$71.4 million
Power Consumption (MW)			1.41	3.51	7.03
Annual Power Usage (1000 MW-hr/yr)			9.6	24.0	48.1
NO_x Design Control Efficiency	80.00%	36%	25%	40%	72%
NO_x Removed per Year (tons)	79,812[a]	6,883	2,727	4,364	7,855
First Year Average Control Cost ($/ton of NO_x removed)	310	232	2,258	8,205	9,091
Incremental Control Cost over SNCR ($/ton of NO_x removed)				18.116	12,726
Incremental Control Cost over Presumptive ($/ton of NO_x removed)					10,199

[a] Tons of SO_2 removed
[b] Tons removed based on 2006-2007 emissions

An analysis of incremental cost effectiveness was conducted. Figures 3-6 and 3-7 show the annualized costs for each type of technology and the annualized cost per ton for each option.

FIGURE 3-6
Least-Cost Envelope Control Options Annualized Cost

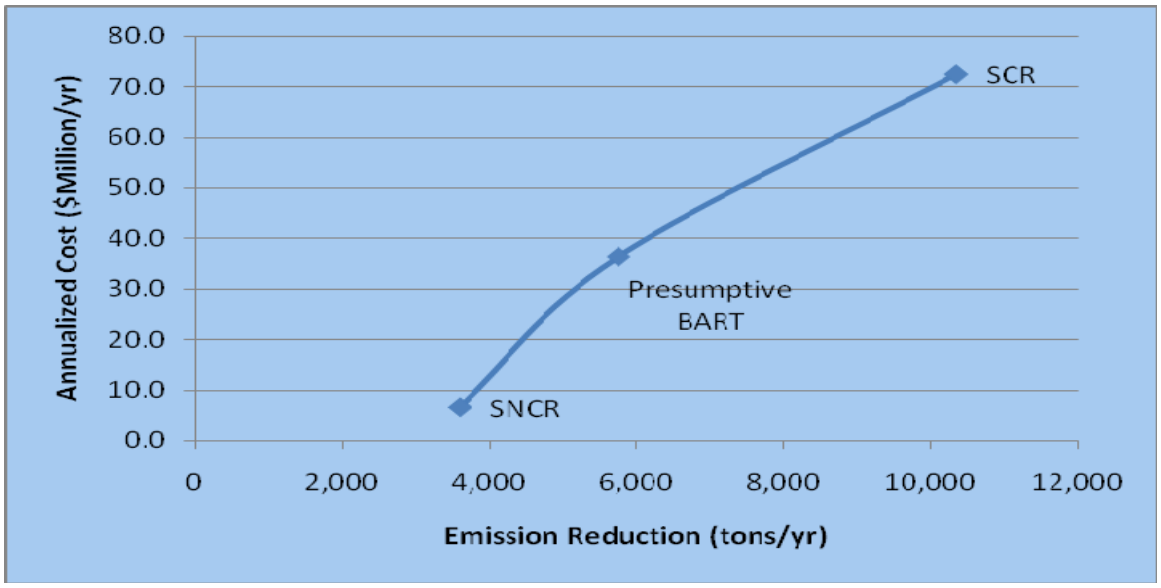
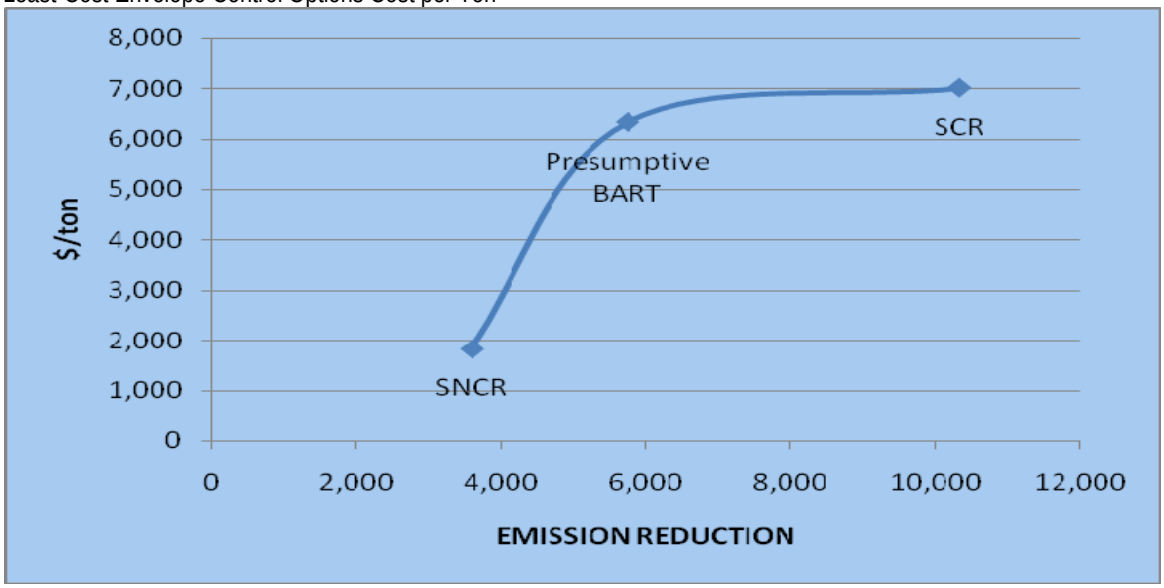


FIGURE 3-7
Least-Cost Envelope Control Options Cost per Ton



3.2.4 Step 4: Evaluate Energy and Non-Air Quality Impacts

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

Energy Impacts

The auxiliary power requirement for an SNCR system for a 702-MW unit is estimated at 702 kilowatts (kW).

SCR retrofit impacts the existing flue gas fan systems due to the additional pressure drop associated with the catalyst, which is typically a 6- to 8-inch water gage increase. In addition to higher operating costs, new capital costs may be required if additional fan capacity is necessary. The extent of additional capital cost improvements would be determined during the design phase of an SCR installation.

Other Air Quality Impacts

SNCR and SCR installation could impact the saleability and disposal of fly ash due to ammonia levels and could potentially create a visible local stack plume, which may offset other visibility improvements. SO_3 may be formed by oxidation of SO_2 on the SCR catalyst, and a resulting SO_3 "blue plume" may be observed. In addition, ammonia-based particles may also be formed. While the electrostatic precipitators and wet scrubber will likely remove some of the SO_3 and particulate matter, not all may be removed which may result in a visible plume. Other environmental impacts involve the safety hazards and potential for releases of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

Both SNCR and SCR result in emissions of ammonia, which is a Washington State toxic air pollutant.

Non-Air Quality Environmental Impacts

The existing scrubber may collect some ammonia or urea from an SNCR or SCR system. Additional ammonia captured in the flue gas desulfurization units may affect wastewater and solid waste at CPP. Much of the coal combustion byproducts produced by CPP is currently sold as a concrete additive or other useable product. Any coal combustion byproducts not managed in this manner will be required to be landfilled in a regulated solid waste facility. Although unlikely because of expected low ammonia slip levels, under some conditions the coal combustion byproducts could contain enough ammonia for the ash to be designated as a dangerous waste or a hazardous waste**.** Because of possible odor problems, the addition of ammonia may cause the coal ash to be less desirable for recycling in cement or other construction products.

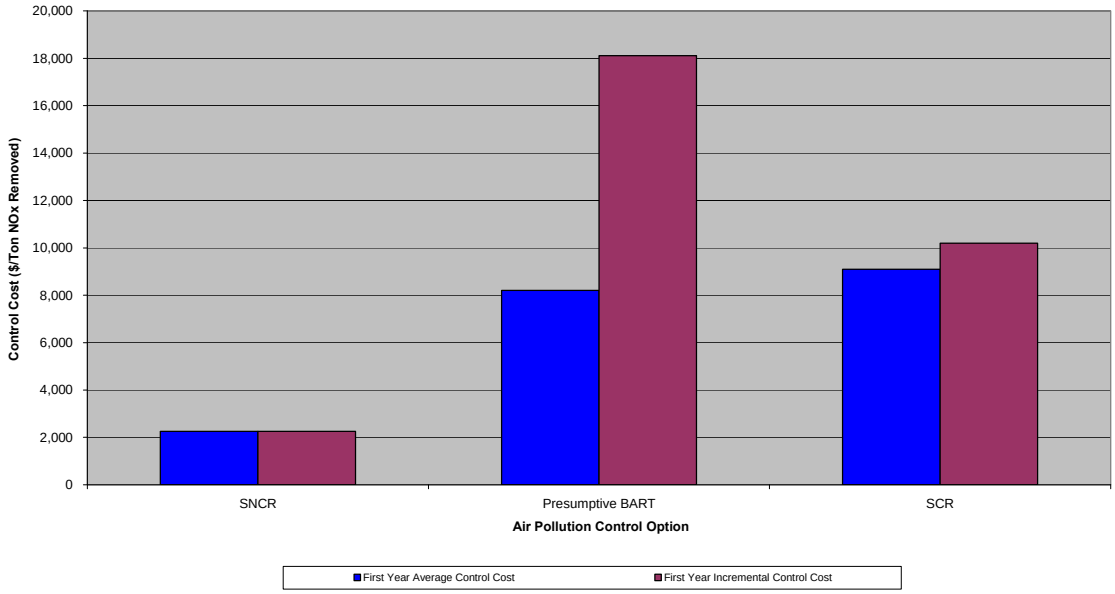
Although unlikely because of expected low ammonia slip levels, under some conditions fly ash and FGD gypsum may become contaminated by ammonia or urea from an SNCR or SCR system. Currently, the vast majority of fly ash is recycled as a concrete additive and all gypsum produced by the scrubber is recycled in the production of wallboard. Concentration of ammonia/urea in the fly ash and gypsum could render the materials less desirable due to odor problems, requiring it to be disposed into a regulated solid waste landfill.

Concentration of ammonia/urea in these materials could also cause them to designate as a dangerous solid waste due to toxicity when they are not able to be recycled. Wastewater could also be impacted from ammonia/urea if concentrated in the scrubber because current operation requires a small amount of wastewater to be released into the CPP NPDES treatment system, potentially causing toxicity in the plant's wastewater discharge.

Economic Impacts

Costs for SNCR and SCR were estimated using CH2M HILL's database. The capital costs are based on cost information gathered by CH2M HILL over the past 3 years for BART analyses developed for a number of utilities in the western U.S. The costs were adjusted upwards to account for the difficult retrofit requirements for the CPP units. EPA has published a similar cost analysis model called CUECost that was developed by Raytheon Engineers & Constructors and the Eastern Research Group in 1998. The cost estimates generated by CUECost are based on 10-year-old design and cost data that do not consider the large price increases that have occurred in the industry during this time period or the CPP's difficult retrofit requirements. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-3 above, and the first year control costs are presented in Figure 3-8 below. The complete economic analysis is contained in Appendix A.

FIGURE 3-8
First Year Control Cost for NO_X Air Pollution Control Options
Centralia



3.2.5 Step 5: Evaluate Visibility Impacts

The visibility impacts are presented in Section 4.0, BART Visibility Modeling Analysis.

4.0 BART Visibility Modeling Analysis

4.1 Introduction

This section presents the dispersion modeling methods and results for estimating the degree of visibility improvement from BART control technology options for CPP. The modeling followed the methodology outlined in the *Modeling Protocol for Washington, Oregon, and Idaho* (Idaho Department of Environmental Quality [DEQ], Oregon DEQ, and Ecology, 2006) and was used by Geomatrix Consultants, Inc. under contract to TransAlta. Additional details on this modeling analysis can be found in Appendix B. Visibility improvements for all emission control cases were analyzed, and the results are compared below using a least-cost envelope as outlined in the BART Guidelines and the draft EPA *New Source Review Workshop Manual* (1990).

4.2 Analysis Baseline and Cases

Table 4-1 compares the five emission control cases with expected emission levels for the two combined units. The Baseline is the maximum 24-hour NO_x, SO_2, and PM10 emission rate during 2003–2005. The modeling examined four cases with lower NO_x emissions than the Baseline case.

TABLE 4-1
Emission Control Cases

Case No.	Control Description Case	NO_x (lb/hr)	SO2 (lb/hr)	PM_{10} (lb/hr)
Case 0	Pre-NO_x Control[a]	7,683	32,425	321
Case 1	Baseline[b]	4,984	4,522	242
Case 2	2006-2007[c]	4,586	1,615	242
Case 3	SNCR[d]	3,738	4,522	242
Case 4	Presumptive[e]	2,460	4,522	242
Case 5	SCR[f]	1,148	4,522	242

[a]Pre-NO_x Control emission rates are based on data from the RACT Technical Support Document. NO_x emissions use 0.545 lb/MMBtu and 7,049 MMBtu/hr. SO_2 emissions are based on the 1,000-ppm emission limit and a combined flow of 5,469,000 acfm. PM_{10} emissions are based on the same flow rate and maximum grain loading from 1996 source tests.

[b]Maximum actual 24-hour emissions during 2003-2005.

[c]Maximum actual 24-hr NO_x and SO_2 emissions during 2006-2007. PM_{10} is from Baseline.

[d]NO_x emissions controlled by SNCR (75% of 2003-2005); SO_2 and PM_{10} are from Baseline.

[e]NO_x based on EPA Presumptive BART emission limit (0.15 lb/MMBtu at Baseline heat rate of 8,200 MMBtu/hr); SO_2 and PM_{10} are from Baseline.

[f]NO_x emissions controlled by SCR (0.07 lb/MMBtu at Baseline 8,200 MMBtu/hr); SO_2 and PM_{10} are from Baseline.

Table 4-2 shows the average number of days per year that each case would result in a modeled impact greater than 0.5 delta-deciview (Δdv). For example, based on the 2006-2007 actual emissions, the maximum number of days per year that CPP is modeled to have greater than 0.5-Δdv impact in Mount Rainier National Park would be 157. Compared with the 2006-2007 highest actual emissions, the modeled Presumptive BART would reduce the number of impacted days per year by only 5 additional days. For comparison, for the period prior to 2000 the model shows that CPP impacted Mount Rainier about 204 days per year. In each Class I area, the highest actual emissions for 2006-2007 resulted in less impact days than the addition of SNCR to modeling baseline emissions.

TABLE 4-2
Average Number of Days per Year with Maximum Delta Deciview Greater Than 0.5

Analysis Area	Pre-NO_x Controls	Modeling Baseline	2006-2007	Presumptive BART		
				SNCR	SCR	
Alpine Lakes Wilderness	190	144	126	135	118	95
Glacier Peak Wilderness	156	92	74	83	69	53
Goat Rocks Wilderness	170	138	123	129	118	97
Mt. Adams Wilderness	148	110	95	100	91	75
Mt. Hood Wilderness	115	75	61	66	59	46
Mt. Jefferson Wilderness	89	43	32	40	32	25
Mt. Rainier National Park	204	168	157	161	152	135
Mt. Washington Wilderness	77	34	22	29	22	17
N. Cascades National Park	136	69	50	58	46	34
Olympic National Park	113	85	74	78	71	61
Pasayten Wilderness	111	47	33	39	29	17
Three Sisters Wilderness	78	35	24	30	25	17
Columbia River Gorge National Scenic Area	132	82	62	65	58	40

Table 4-3 shows the 98th percentile daily Δdv for each control case and for pre-NO_x emissions. Based on the 2006-2007 actual emissions, CPP would have a of 4.56-Δdv impact on the 98th percentile most impacted day at Mt. Rainier National Park. Presumptive BART reduces the impact only to 3.96 dv. Before the installation of NO_x and SO_2 controls, the model shows that CPP had a 98th percentile impact of 11.999 Δdv.

TABLE 4-3
98th Percentile Daily Delta Deciview

Analysis Area	Pre-NO_x Controls	Modeling Baseline	2006-2007	SNCR	Presumptive BART	SCR
Alpine Lakes Wilderness	10.458	4.346	3.278	3.844	3.249	2.531
Glacier Peak Wilderness	7.357	2.622	2.1	2.294	1.955	1.562
Goat Rocks Wilderness	9.886	4.286	3.429	3.708	3.078	2.385
Mt. Adams Wilderness	8.683	3.628	2.819	3.152	2.595	1.934
Mt. Hood Wilderness	7.659	2.83	2.186	2.388	1.978	1.543
Mt. Jefferson Wilderness	5.531	1.888	1.379	1.596	1.332	1.061
Mt. Rainier National Park	11.999	5.489	4.597	4.743	3.958	3.275
Mt. Washington Wilderness	4.743	1.414	0.944	1.248	1.079	0.855
N. Cascades National Park	6.395	2.212	1.614	1.887	1.539	1.183
Olympic National Park	9.813	4.024	3.144	3.456	2.973	2.339
Pasayten Wilderness	4.912	1.482	1.093	1.318	1.093	0.864
Three Sisters Wilderness	4.789	1.538	1.089	1.328	1.115	0.902
Columbia River Gorge National Scenic Area	6.027	2.353	1.797	1.942	1.578	1.182

Note: Based on the 22nd highest results for each Class I area for the modeling period of 2003 through 2005.

To provide perspective on the visibility modeling results, several studies have shown that only dv differences of approximately 1.5 to 2.0 dv or more are perceptible by the human eye. The EPA in the July 31, 1997, Federal Register generalized that a "one deciview change in haziness is a small but noticeable change in haziness under most circumstances when viewing scenes in mandatory Class I Federal areas." The actual level of visibility improvement that can be reliably perceived in the Pacific Northwest is a matter of debate, but is generally recognized to be somewhere between 1 and 3 dv. The deciview scale was

designed to be linear with respect to perceived visual changes over its entire range, according to its developers Pitchford and Malm. In an April 2003 article reviewing the Pitchford and Malm work, the National Park Service's *IMPROVE Newsletter* stated that a "1 to 2 dv difference corresponds to a small, visibly perceptible change in scene appearance where the assumptions used to develop the dv scale are met."

R.C. Henry (2002), using actual data, notes: "The deciview scale is not uniform in perception over a wide range of visibility conditions. In fact, the change in deciviews needed to be noticeable varies greatly depending on the optical distance of the landscape feature and its inherent colorfulness." Henry also notes: "A 1-deciview change is never noticeable." Furthermore, in Ecology's December 5, 1997, response to EPA's July 31, 1997, proposed rulemaking, Ecology's Air Quality Program Director, Joseph Williams, stated:

> Our initial analysis suggests that, for Washington, the "one deciview" rate of progress would be undetectable because of statistical variation. In our recent review of our visibility SIP we examined data from two of our best sites (in terms of valid data recovery and length of record). We found that even using summertime afternoon hours to minimize statistical "noise", and using a very modest 50 percent confidence interval, the variance exceeds the "one deciview" reasonable progress target. Indeed, at these best sites, during their least noisy periods, the minimum trend detectable with a 50% confidence interval is 2 - 3 dv/decade.

Therefore, the modeling analysis results indicate that only minimal, if any, observable visibility improvements at the Class I areas studied would be expected under any of the cases.

Finally, it should be noted that none of the data were corrected for natural obscuration, where water in various forms (fog, clouds, snow, or rain) or other naturally caused aerosols obscure the atmosphere. For example, there are often foggy days in Mount Rainier National Park where visibility degradation from manmade sources is not an issue.

4.3 Analysis of Cost for Visibility Improvement

Visibility improvement cost and incremental cost analyses for six Class I areas are presented in this section. Five of these areas were selected because they represented the maximum baseline impacts in the state of Washington. Mount Hood Wilderness has also been included because this area represents the maximum impacts in the state of Oregon. The relative results are consistent between the Class I areas.

The six selected Class I areas are:

- Alpine Lakes Wilderness
- Goat Rocks Wilderness
- Mount Adams Wilderness
- Mount Hood Wilderness
- Mount Rainier National Park
- Olympic National Park

The total annualized cost, 98th percentile ΔdV reduction from Pre-NO_x control impact levels, cost per ΔdV reduction relative to Baseline impact levels, and cost per reduction in number of days above 0.5 ΔdV for each of the NO_x emission control cases are listed in Tables 4-4 through 4-9.

TABLE 4-4
NO_x Control Case Cost Results for Mount Rainier National Park

Controls	Average Number of Days Above 0.5 ΔdV (days/yr)	98th Percentile Δdv Reduction	Total Annualized Cost (million$)	Cost per Reduction in No. of Days Above 0.5 Δdv (million$/day reduced)	Cost per Δdv Reduction (million$/dv reduced)
Pre-NO_x Controls	204	0			
2006 – 2007 Actual	157	7.402			
SNCR	161	7.256	6.537	NI	NI
Presumptive BART	152	8.041	36.347	7.269	56.882
SCR	135	8.724	72.434	3.292	54.791

NI – No improvement over 2006-2007 Actual

TABLE 4-5
NOx Control Case Cost Results for Alpine Lakes Wilderness

Controls	Average Number of Days Above 0.5 ΔdV (days/yr)	98th Percentile ΔdV Reduction	Total Annualized Cost (million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (million$/day reduced)	Cost per ΔdV Reduction (million$/dv reduced)
Pre-NO_x Controls	190	0	0	0	0
2006 – 2007 Actual	126	7.180	0	0	0
SNCR	135	6.614	6.537	NI	NI
Presumptive BART	118	7.209	36.347	4.543	1253.355
SCR	95	7.927	72.434	2.337	96.966

NI – No improvement over 2006-2007 Actual

TABLE 4-6
NO_x Control Case Cost Results for Goat Rocks Wilderness

Controls	Average Number of Days Above 0.5 ΔdV (days/yr)	98th Percentile ΔdV Reduction	Total Annualized Cost (million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (million$/day reduced)	Cost per ΔdV Reduction (million$/dv reduced)
Pre-NO_x Controls	170	0	0	0	0
2006 – 2007 Actual	123	6.457	0	0	0
SNCR	129	6.178	6.537	NI	NI
Presumptive BART	118	6.808	36.347	7.269	103.554
SCR	97	7.501	72.434	2.786	69.381

NI – No improvement over 2006-2007 Actual

TABLE 4-7
NO_x Control Case Cost Results for Olympic National Park

Controls	Average Number of Days Above 0.5 ΔdV (days/yr)	98th Percentile ΔdV Reduction	Total Annualized Cost (million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (million$/day reduced)	Cost per ΔdV Reduction (million$/dv reduced)
Pre-NOx Controls	113	0			
2006 – 2007 Actual	74	6.669			
SNCR	78	6.357	6.537	NI	NI
Presumptive BART	71	6.84	36.347	12.116	212.557
SCR	61	7.474	72.434	5.572	89.980

NI – No improvement over 2006-2007 Actual

TABLE 4-8
NO_x Control Case Cost Results for Mount Hood Wilderness

Controls	Average Number of Days Above 0.5 ΔdV (days/yr)	98th Percentile ΔdV Reduction	Total Annualized Cost (million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (million$/day reduced)	Cost per ΔdV Reduction (million$/dv reduced)
Pre-NO_x Controls	115	0	0	0	0
2006 – 2007 Actual	61	5.473	0	0	0
SNCR	66	5.271	6.537	NI	NI
Presumptive BART	59	5.681	36.347	18.174	174.747
SCR	46	6.116	72.434	4.829	112.650

NI – No improvement over 2006-2007 Actual

TABLE 4-9
NO_x Control Case Cost Results for Mount Adams Wilderness

Controls	Average Number of Days Above 0.5 ΔdV (days/yr)	98th Percentile ΔdV Reduction	Total Annualized Cost (million$)	Cost per Reduction in No. of Days Above 0.5 ΔdV (million$/day reduced)	Cost per ΔdV Reduction (million$/dv reduced)
Pre-NO_x Controls	115	0	0	0	0
2006 – 2007 Actual	61	5.864	0	0	0
SNCR	66	5.531	6.537	NI	NI
Presumptive BART	59	6.088	36.347	18.174	162.265
SCR	46	6.749	72.434	4.829	81.846

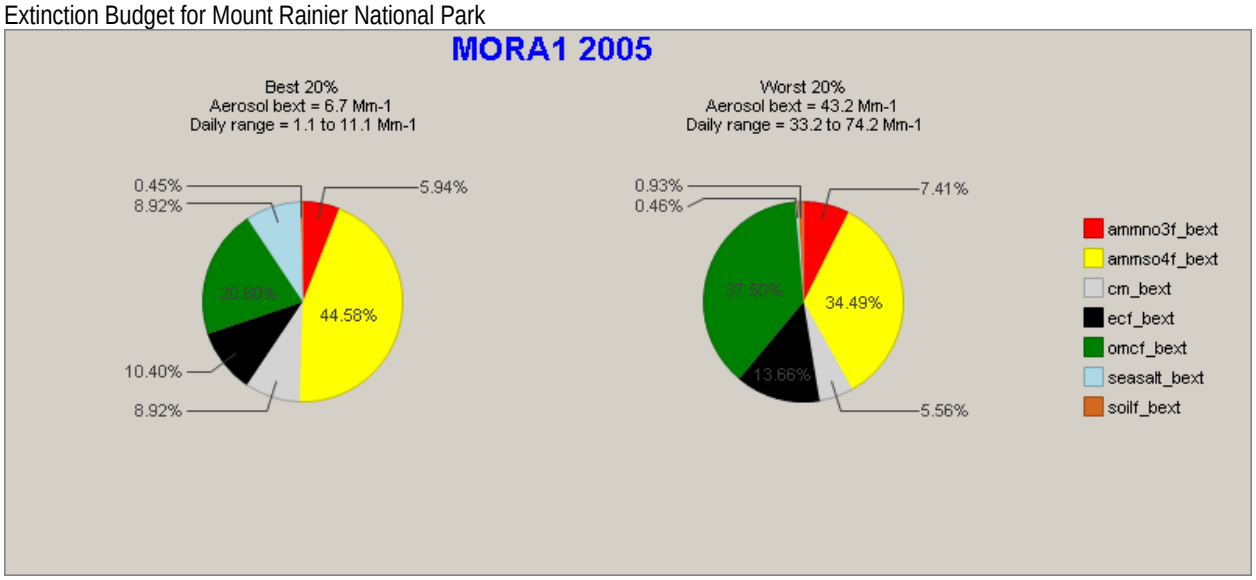
NI – No improvement over 2006-2007 Actual

4.4 Evaluate Visibility Impacts

The above analysis indicates the maximum possible visibility improvements that reductions in NO_x emissions from CPP could have on Class I areas. CPP's share of impact on visibility compared with other sources should also be considered. As shown in Figure 4-1, nitrates formed by NO_x emissions typically contribute less than 10 percent of the observed extinction in Mount Rainier National Park on both the best and worst days in 2005. Other years show similar small contributions from NO_x emissions.

As shown in Figure 4-2, according to a source apportionment study conducted by the Western Regional Air Partnership (WRAP), about 11 percent of the nitrate in Mt. Rainier National Park can be attributable to all industrial point sources. CPP is only a portion of the industrial point sources. Therefore, on the best and worst visibility days, NO_x emissions from CPP can only contribute less than one percent of the total extinction budget. Further reductions in CPP's NO_x emissions would not likely have a significant effect on visibility in the park or other Class I areas.

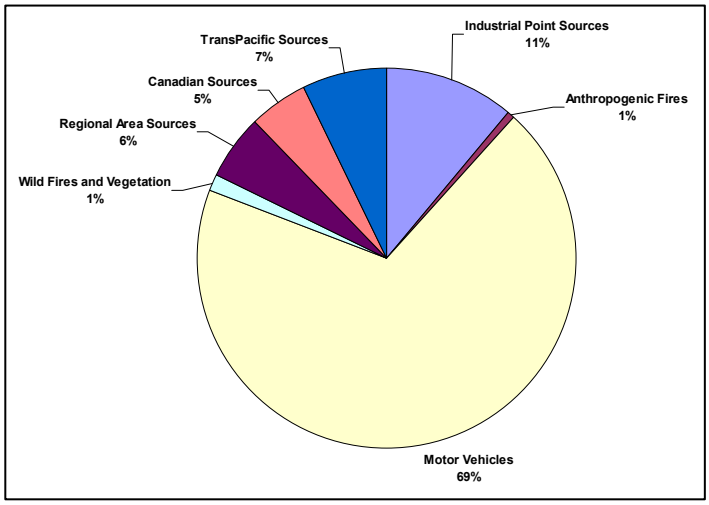
Figure 4-1
Extinction Budget for Mount Rainier National Park



ammNO3f – ammonium nitrate
CM – Coarse particles (usually soil)
OMCf – organic carbon,
Source: (http://vista.cira.colostate.edu/views/)

ammSO4f – ammonium sulfate
ECf – elemental carbon (soot)
Soilf – fine particle (usually soil)

FIGURE 4-2
Nitrate Source Contributions for 2002, Mount Rainier National Park
Based on Source Apportionment Simulations Conducted by WRAP



Source (http://www.coha.dri.edu/)

5.0 Conclusion

Costs, visibility improvement, and other environmental impacts were considered for five cases: pre-NO_x and SO_2 controls, actual emissions during 2006-2007, installation of SNCR, presumptive BART (installation of SCR on one unit), and installation of SCR on both units.

The implementation of NO_x and SO_2 BART controls from 2000 to 2002 resulted in about 86,000 tons of emission reductions at an average cost of about $300 per ton. Those controls resulted in improving visibility in 10 percent of the days (36/365) and improving visibility by 6.5 dv on the 98th percentile worst day.

The significant visibility improvements at current emission levels (2006–2007) compared with the pre-NO_x controls impacts are demonstrated clearly in Tables 4-4 through 4-9. For Mount Rainier National Park, there are 47 fewer days of impacts greater than 0.5 ΔdV for the current maximum emission levels.

Compared with the 2003 – 2005 baseline, SNCR would result in reducing CPP's NO_x emissions by about 25 percent, or 3,800 tons per year, at a cost of about $2,300 per ton with a margin of -20 percent to plus 50 percent. However, in all the Class I areas, installation of SNCR when applied to the modeling baseline emission rates (2003-2005 maximum) would result in less improvement than the current emission rates (2006-2007 maximum). For both reasons, the use of SNCR is not considered cost-effective.

Implementing presumptive BART (SCR on one unit) and installing SCR on both units would cost about $8,200 per ton and $9,100 per ton, respectively. Although the EPA BART Guidelines do not set a firm cost-effectiveness value, in establishing presumptive BART for tangentially-fired unit burning sub-bituminous coal, EPA estimated a national average cost of $281 per ton of NO_x removed for units similar to CPP to comply with the presumptive standard.

EPA's background document for establishing BART for electric generating facilities correctly identified CPP as having the level of combustion control burners, LNC3, that were the basis for setting the presumptive standard.

The additional technologies that are considered to be technically available by the Centralia Power Plant are at least eight times more expensive than the cost levels that EPA considered for similar units when EPA established the presumptive BART level of 0.15 pound of NO_x per MMBtu. CPP has already incurred the costs for NOx controls anticipated in the EPA BART Guidelines.

Further evidence that reduction of CPP's NO_x emissions is not likely to have a significant effect on visibility in the Mount Rainier National Park are the studies showing that nitrates only contribute a small portion of the visibility loss. In addition, stationary industrial sources such as CPP contribute a small portion of the total NO_x, while transportation sources contribute most of the NO_x.

The key factors in the BART analysis are cost-effectiveness of available controls and visibility improvement. Based on these considerations, CPP's current LNC3 technology should be determined to be BART.

6.0 References

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APPENDIX A

Economic Analysis

TransAlta BART Analysis Report Tables For Both Units 1 and 2

CPP

TABLE 3-1

NO_x Control Technology Emission Rate Ranking

CPP

Technology	Projected Emission Rate
SNCR	0.19
Presumptive BART	0.15
SCR	0.07

TABLE 3-2

NO_x Control Cost Comparison

CPP

Factor	SNCR	Presumptive BART	SCR
Major Materials Design Costs	$ 14.7 Million	$ 138.8 Million	$ 277.7 Million
Total Installed Capital Costs	$ 33.2 Million	$ 290.1 Million	$ 580.3 Million
Total First Year Fixed & Variable O&M Costs	$ 2.5 Million	$ 3.9 Million	$ 7.7 Million
Total First Year Annualized Cost	$ 6.2 Million	$ 35.8 Million	$ 71.4 Million
Power Consumption (MW)	1.41	3.51	7.03
Annual Power Usage (kW-Hr/Yr)	9.6	24.0	48.1
NO_x Design Control Efficiency	25.0%	40.0%	72.0%
Tons NO_x Removed per Year	2,727	4,364	7,855
First Year Average Control Cost ($/Ton of NO_x Removed)	2,258	8,205	9,091
Incremental Control Cost ($/Ton of NO_x Removed)	2,258	18,116	10,199
Tons NOx Removed per Year over SNCR		1,636	5,128
Incremental Control Cost over SNCR		18,116	12,726

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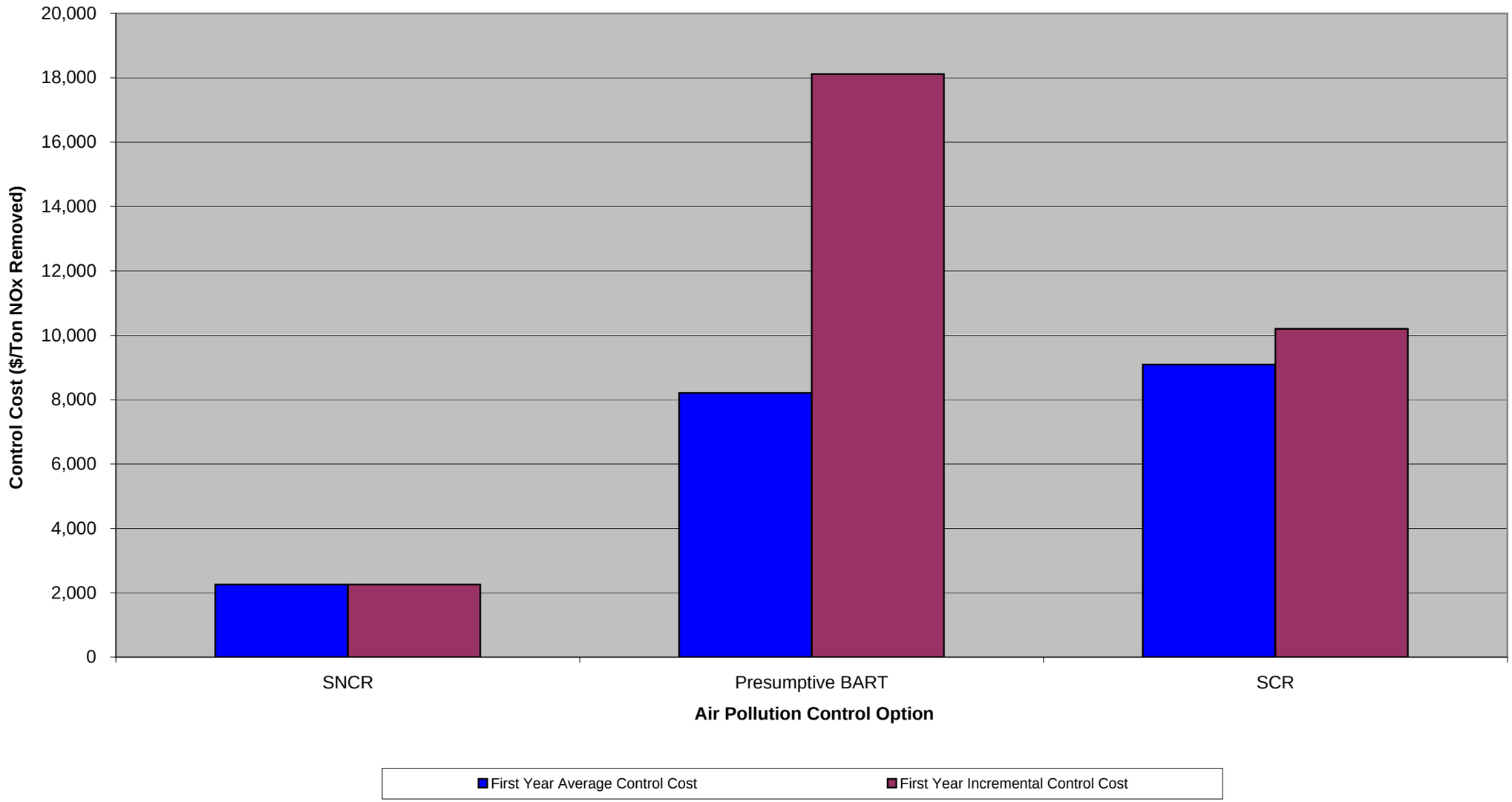

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ECONOMIC ANALYSIS SUMMARY FOR BOTH UNITS 1 AND 2

CPP **Boiler Desig Tangentially Fired**

Parameter	2006-7 Baseline	NOx Control		
		SNCR	Presumptive BART	SCR
NOx Emission Control System	LNBs with OFA	SNCR	Presumptive BART	SCR
	Forced Oxidation	Forced Oxidation	Forced Oxidation	Forced Oxidation
SO2 Emission Control System	Limestone	Limestone Scrubber	Limestone Scrubber	Limestone Scrubber
PM Emission Control System	Dual ESPs	Dual ESPs	Dual ESPs	Dual ESPs
TOTAL INSTALLED CAPITAL COST ($)	**0**	**33,198,036**	**290,145,436**	**580,290,872**
FIRST YEAR O&M COST ($)				
Operating Labor ($)	0	281,000	175,625	351,250
Maintenance Material ($)	0	562,000	351,250	702,500
Maintenance Labor ($)	0	281,000	175,625	351,250
Administrative Labor ($)	0	0	0	0
TOTAL FIXED O&M COST	**0**	**1,124,000**	**702,500**	**1,405,000**
Reagent Cost	0	909,012	990,819	1,783,475
SCR Catalyst	0	0	1,053,750	2,107,500
Electric Power Cost	0	480,721	1,201,801	2,403,603
TOTAL VARIABLE O&M COST	**0**	**1,389,733**	**3,246,371**	**6,294,577**
TOTAL FIRST YEAR O&M COST	**0**	**2,513,733**	**3,948,871**	**7,699,577**
FIRST YEAR DEBT SERVICE ($)	0	3,644,966	31,856,409	63,712,819
TOTAL FIRST YEAR COST ($)	**0**	**6,158,699**	**35,805,280**	**71,412,396**
Power Consumption (MW)	**0.0**	**1.4**	**3.5**	**7.0**
Annual Power Usage (kW-Hr/Yr)	**0.0**	**9.6**	**24.0**	**48.1**
CONTROL COST ($/Ton Removed)				
NOx Removal Rate (%)	**0.0%**	**25.0%**	**40.0%**	**72.0%**
NOx Removed (Tons/Yr)	**0**	**2,727**	**4,364**	**7,855**
First Year Average Control Cost ($/Ton NOx Rem.)	**0**	**2,258**	**8,205**	**9,091**
Incremental Control Cost ($/Ton NOx Removed)	**0**	**2,258**	**18,116**	**10,199**
		2-0	2-1	3-2
PRESENT WORTH COST ($)	**0**	**69,584,156**	**386,137,573**	**769,833,755**

PRIVILEGED AND CONFIDENTIAL ATTORNEY CLIENT COMMUNICATION AND WORK PRODUCT

INPUT CALCULATIONS FOR BOTH UNITS 1 AND 2

CPP **Boiler Design** **Tangentially Fired**

Parameter	2006-7 Baseline	NOx Control			Comments
		SNCR	Presumptive BART	SCR	
NOx Emission Control System	LNBs with OFA	SNCR	Presumptive BART	SCR	
SO2 Emission Control System	Forced Oxidation Limestone Scrubber	Forced Oxidation Limestone Scrubber	Forced Oxidation Limestone Scrubber	Forced Oxidation Limestone Scrubber	
PM Emission Control System	Dual ESPs	Dual ESPs	Dual ESPs	Dual ESPs	
Unit Design and Coal Characteristics					
Type of Unit	PC	PC	PC	PC	
Net Power Output (kW)	702,500	702,500	702,500	702,500	
Net Plant Heat Rate (Btu/kW-Hr)	9,078	9,078	9,078	9,078	
Coal Flow Rate (Lb/Hr)	724,694	1,449,389	1,449,389	1,449,389	
(Ton/Yr)	2,479,540	4,959,080	4,959,080	4,959,080	
(MMBtu/Yr)	43,639,907	87,279,814	87,279,814	87,279,814	
Emissions					
Uncontrolled NOx (Lb/Hr)	1,594	3,189	3,189	3,189	
(Lb/MMBtu)	0.25	0.25	0.25	0.25	
(Lb Moles/Hr)	53.13	106.25	106.25	106.25	
(Tons/Yr)	5,455	10,910	10,910	10,910	
NOx Removal Rate (%)	0.0%	25.0%	40.0%	72.0%	
(Lb/Hr)	0	797	1,275	2,296	
(Lb Moles/Hr)	0.00	26.56	42.50	76.50	
(Ton/Yr)	0	2,727	4,364	7,855	
NOx Emission Rate (Lb/Hr)	1,594	2,391	1,913	893	
(Lb/MMBtu)	0.25	0.19	0.15	0.07	
(Ton/Yr)	5,455	8,182	6,546	3,055	
General Plant Data					
Annual Operation (Hours/Year)	6,843	6,843	6,843	6,843	
Annual On-Site Power Plant Capacity Factor	0.78	0.78	0.78	0.78	
Economic Factors					
Interest Rate (%)	7.00%	7.00%	7.00%	7.00%	
Discount Rate (%)	7.00%	7.00%	7.00%	7.00%	
Plant Economic Life (Years)	15	15	15	15	
Installed Capital Costs					
NOx Emission Control System ($2008)	0	33,198,036	290,145,436	580,290,872	
Total Emission Control Systems ($2008)	0	33,198,036	290,145,436	580,290,872	
NOx Emission Control System ($/kW)	0	47	413	826	
Total Emission Control Systems ($/kW)	0	47	413	826	
Total Fixed Operating & Maintenance Costs					
Operating Labor ($)	0	281,000	175,625	351,250	
Maintenance Material ($)	0	562,000	351,250	702,500	
Maintenance Labor ($)	0	281,000	175,625	351,250	
Administrative Labor ($)	0	0	0	0	
Total Fixed O&M Cost ($)	0	1,124,000	702,500	1,405,000	
Annual Fixed O&M Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	
Reagent Cost	None	Urea	Anhydrous NH3	Anhydrous NH3	
Unit Cost ($/Ton)	0.00	370	400	400	
($/Lb)	0.000	0.185	0.200	0.200	
Molar Stoichiometry	0.00	0.45	1.00	1.00	
Reagent Purity (Wt.%)	100%	100%	100%	100%	
Reagent Usage (Lb/Hr)	0	718	724	1,303	
First Year Reagent Cost ($)	0	909,012	990,819	1,783,475	
Annual Reagent Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	
SCR Catalyst / FF Bag Replacement Cost			SCR Catalyst	SCR Catalyst	
Annual SCR Catalyst (m3)	0	0	351	703	
SCR Catalyst ($/m3)	3,000	3,000	3,000	3,000	
First Year SCR Catalyst	0	0	1,053,750	2,107,500	
Annual SCR Catalyst	2.00%	2.00%	2.00%	2.00%	
Auxiliary Power Cost					
Auxiliary Power Requirement (% of Plant Output)	0.00%	0.20%	0.50%	1.00%	
(MW)	0.00	1.41	3.51	7.03	
Unit Cost ($2008/MW-Hr)	50.00	50.00	50.00	50.00	
First Year Auxiliary Power Cost ($)	0	480,721	1,201,801	2,403,603	
Annual Power Cost Escalation Rate (%)	2.00%	2.00%	2.00%	2.00%	

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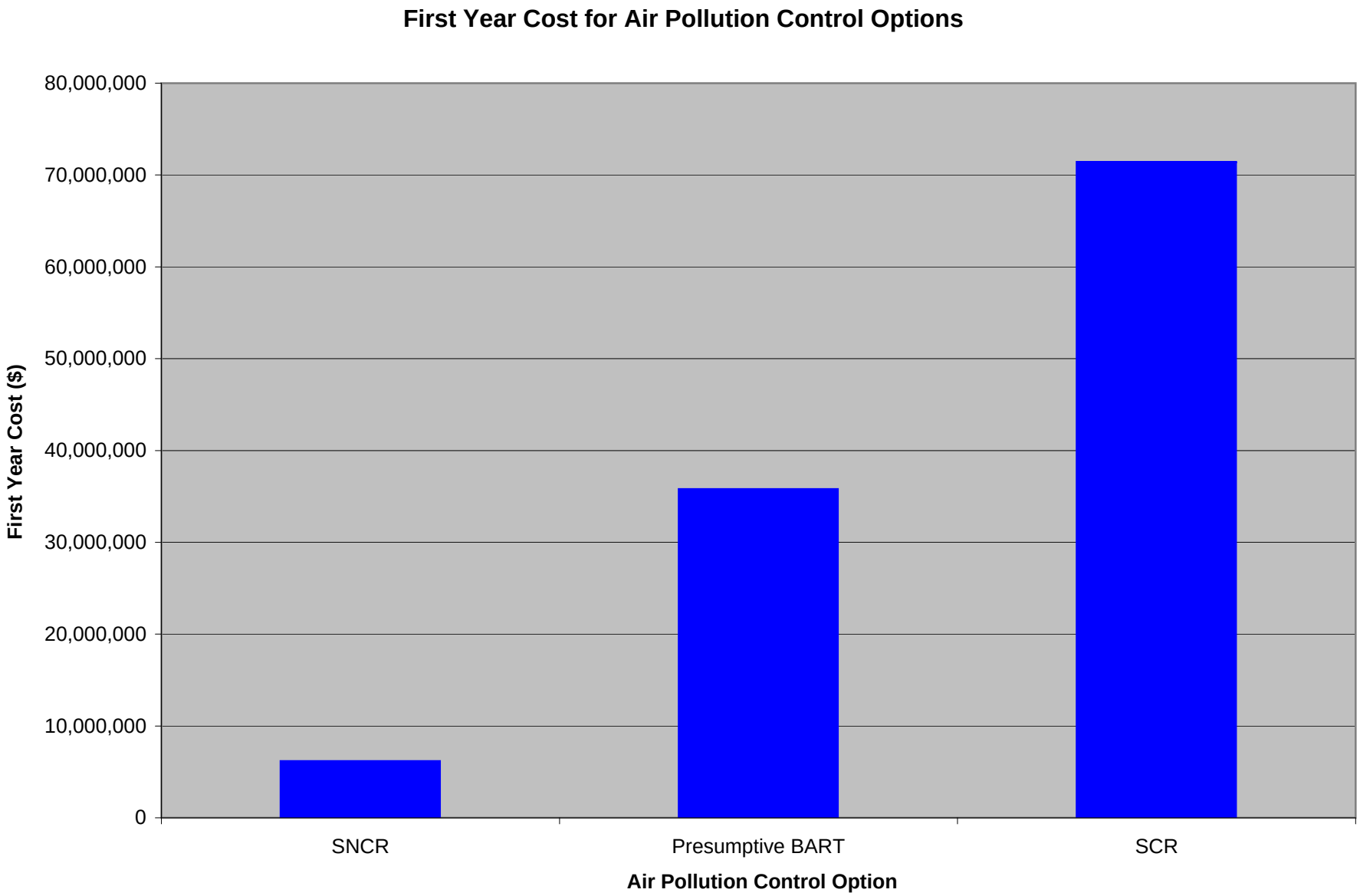
CAPITAL COST FOR BOTH UNITS 1 AND 2

CPP

Parameter	NOx Control					
	SNCR		Presumptive BART		SCR	
NOx Emission Control System	SNCR		Presumptive BART		SCR	
SO2 Emission Control System	Forced Oxidation Limestone Scrubber		Forced Oxidation Limestone Scrubber		Forced Oxidation Limestone Scrubber	
PM Emission Control System	Dual ESPs		Dual ESPs		Dual ESPs	
CAPITAL COST COMPONENT	**Factor/Source**	**Cost**	**Factor/Source**	**Cost**	**Factor/Source**	**Cost**
SNCR or SCR		**SNCR**		**SCR**		**SCR**
Major Materials Design and Supply	**CH2M HILL**	**$14,711,977**	**CH2M HILL**	**$138,842,500**	**CH2M HILL**	**$277,685,000**
Eng, Startup, & Indirect	**CH2M HILL**	$5,400,000	**CH2M HILL**	$28,750,000	**CH2M HILL**	$57,500,000
Subtotal		**$20,111,977**		**$167,592,500**		**$335,185,000**
Contingency	**15.0%**	$3,016,797	**15.0%**	$25,138,875	**15.0%**	$50,277,750
Sales Tax	**8.0%**	$1,608,958	**8.0%**	$13,407,400	**8.0%**	$26,814,800
Subtotal		**$24,737,732**		**$206,138,775**		**$412,277,550**
Margin	**10.0%**	$2,473,773	**10.0%**	$20,613,878	**10.0%**	$41,227,755
Subtotal		**$27,211,505**		**$226,752,653**		**$453,505,305**
Owner's Costs	**10.0%**	$2,721,150	**10.0%**	$22,675,265	**10.0%**	$45,350,531
AFUDC	**12.0%**	$3,265,381	**12.0%**	$27,210,318	**12.0%**	$54,420,637
Lost Generation at $20.00/MWhr and 42 days				$13,507,200		$27,014,400
Total Capital Cost for SNCR or SCR		**$33,198,036**		**$290,145,436**		**$580,290,872**

PRIVILEGED AND CONFIDENTIAL ATTORNEY CLIENT COMMUNICATION AND WORK PRODUCT



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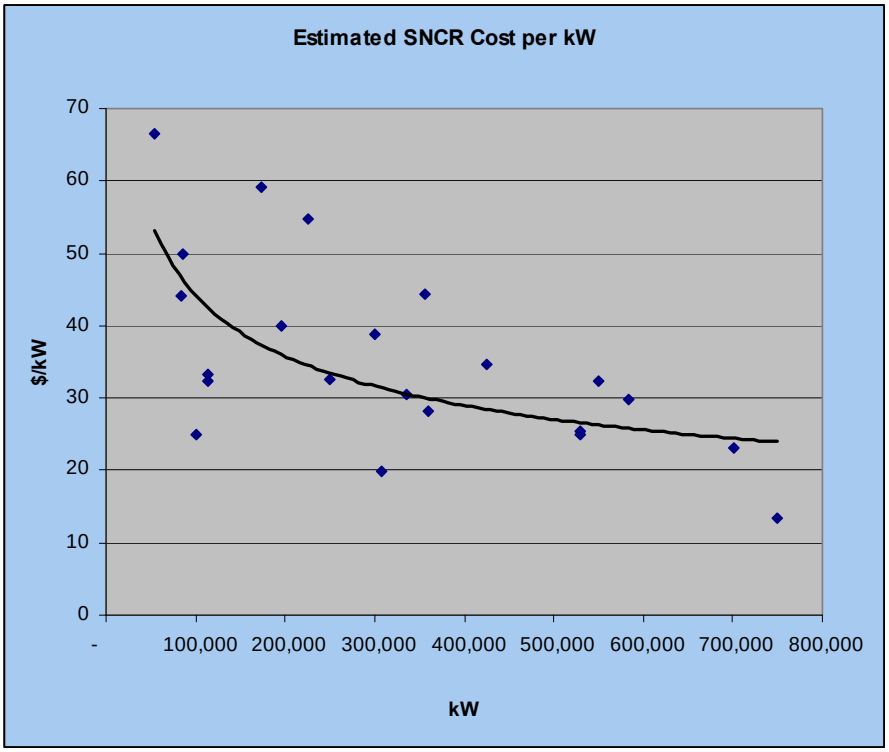
Comparison of SNCR Costs for CPP and Other Plants in the Western U.S.

The costs of installing SNCR in an existing boiler is a function many elements some of which are direct functions of size of the boiler such as the such as the size of much of the piping, while others such as engineering are much less a function of boiler size. Table 2 shows the size and estimated cost of installing SNCR on several coal fired utility boilers in the west. At 702 MW each the Centralia units are the second largest, with the Navajo 1 unit the largest at 750 MW. The estimated cost per kW ranges from $13 per kW for Navajo to over $50 per kW for the smallest units. Figure 1 shows the estimated costs plotted against the unit size. The clear trend is that cost of SNCR per kW output decreases with size of the unit. At about $24 per kW the estimated costs of installing SNCR on the Centralia units falls with the expected range for large size units (units over 300 MW).

Table 1 – Comparative Costs

Unit Name	Unit size (kW)	Total Installed Capital Cost/unit	$/kW	**Source**
Tracy 1	55,000	3,661,875	67	CH2M HILL
Tracy 2	83,000	3,661,875	44	CH2M HILL
Apache 1	85,000	4,250,000	50	CH2M HILL
RG1, 2, 3	100,000	2,497,500	25	CH2M HILL
Tracy 3	113,000	3,661,875	32	CH2M HILL
FC 1, 2, 3	113,000	3,760,313	33	CH2M HILL
Naughton Unit 1	173,000	10,226,855	59	CH2M HILL
Apache 2, 3	195,000	7,781,130	40	CH2M HILL
Naughton Unit 2	226,000	12,378,764	55	CH2M HILL
Dave Johnston Unit 3	250,000	8,135,543	33	CH2M HILL
Cholla 2, 3	300,000	11,610,000	39	CH2M HILL
Coal Strip	307,000	6,076,000	20	TRC
Wyodak	335,000	10,195,654	30	CH2M HILL
Naughton Unit 3	356,000	15,788,530	44	CH2M HILL
Dave Johnston Unit 4	360,000	10,105,779	28	CH2M HILL
Cholla 4	425,000	14,706,000	35	CH2M HILL
Jim Bridger 1, 2, 4	530,000	13,427,239	25	CH2M HILL
Jim Bridger Unit 3	530,000	13,273,632	25	CH2M HILL
Laramie River 1	550,000	17,777,778	32	B&V
Boardman	584,000	17,400,000	30	B&V
CPP 6/18/08	702,000	16,600,000	24	CH2M HILL
Navajo 1	750,000	10,000,000	13	ENSR

Figure 1 Estimated SNCR Capital Cost per Kilowatt



Comparison of CH2M HILL's Estimate and CUECost Estimate of SNCR Costs

The capital costs are based on cost information gathered by CH2M HILL over the past 3 years for BART analyses developed for a number of utilities in the western U.S. EPA has published a similar cost analysis model called CUECost that was developed by Raytheon Engineers & Constructors and the Eastern Research Group in 1998 The estimate capital cost generated by CUECost are significantly lower that the costs estimated by CH2M HILL and are not consistent with other cost estimates that have been done in the last two years for similar size units. The difference is likely due to the fact that the cost estimates generated by CUECost are based on 10 year old design and cost data that do not consider the large price increases that have occurred in the industry during this time period.

APPENDIX B

Modeling Analysis