BART Analysis for Reid Gardner Station Unit 3

Prepared for

NV Energy

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Executive Summary

Background

In response to the Regional Haze Rule and Best Available Retrofit Technology (BART) regulations and guidelines, CH2M HILL was requested to perform a BART analysis for NV Energy Reid Gardner Station Unit 3 (hereafter referred to as Reid Gardner 3). A BART analysis has been conducted for the following criteria pollutants: oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}). The Reid Gardner Station consists of four units: three nominal 100-megawatt (MW) units and one nominal 265-MW unit, for a total station nominal generating capacity of 565 MW. Only units 1 through 3 are BART-eligible. BART must be implemented within 5 years after the State Implementation Plan (SIP) is approved by the United States Environmental Protection Agency (EPA). A compliance date of 2015 was assumed for this analysis.

In completing the BART analysis, technology alternatives were investigated, and potential reductions in NO_x, SO_2, and PM_{10} emission rates were identified. While expected emissions levels for each pollutant were estimated, comparisons with the proposed NV Energy BART Limits for NO_x, SO_2, and PM_{10} are also presented. Listed below by pollutant are the technology alternatives that were investigated:

NO_x emission controls:

- Low NO_x Burners (LNB) with Overfire Air (OFA)
- Low NO_x Burner (LNB) with selective non-catalytic reduction system (SNCR)
- Rotating Opposed Fire Air (ROFA) with Rotamix
- LNB with selective catalytic reduction (SCR) system
- ROFA with SCR

SO_2 emission controls:

- Dry flue gas desulfurization (FGD) system
- Dry sorbent injection
- Furnace sorbent injection
- New wet FGD system
- Improve or upgrade wet soda ash FGD system operation

PM_{10} emission controls:

- Upgrade mechanical collector
- Electrostatic precipitator (ESP)
- Fabric filter

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. The evaluation must include the following:

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

These steps are incorporated into the BART analysis:

Step 1 – Identify All Available Retrofit Control Technologies

Step 2 – Eliminate Technically Infeasible Options

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

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

- Costs associated with control technologies are summarized in the economic analysis presented in Appendix A. For clarity, Appendix A also includes sample economic analysis spreadsheet calculations and explanation of assumptions used.

Step 4 – Evaluate Energy and Non-Air Quality Impacts

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

Step 5 – Evaluate Visibility Impacts

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

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analyses are in 2007 dollars, and costs have not been escalated to the assumed 2015 BART implementation date.

Establishing Emission Reduction Levels from BART Analysis Results

As an integral part of the BART analysis process, control cost and expected emission information was developed for NO_x, SO_2, and PM_{10}. This information is assembled from various sources including emission reduction equipment vendors, NV Energy operating and engineering data, and internal CH2M HILL historical information.

The level of accuracy of the cost estimate can be broadly classified as American Association of Cost Engineers (AACE) Class V or "Order of Magnitude," which can be categorized as +50 percent/-30 percent. There are several reasons for selecting this range of cost estimates to be included in the BART analysis. They are primarily a result of the difficulty in receiving detailed and accurate information from equipment vendors based on limited available data provided to the vendors. Because of the active power industry marketplace, obtaining engineering and construction information is restricted due to vendor workload. Material and construction labor costs also change rapidly in today's active economy. However, this level of cost estimate precision is adequate for comparison of control technology alternatives. The accuracy of expected emissions may also be questionable, and is also attributable to the inability to gain timely and accurate vendor information. This is exemplified by the difficulty in obtaining background information, and the vendor time required to develop accurate emission projections for study purposes in comparison to their response to actual project request for proposals. Also, variance in expected emissions can be dependent upon the pollutant under consideration (i.e., particulate emissions can generally be more accurately predicted than NO_x emissions). Therefore, when establishing emission limitations in permits, consideration of variability in cost and expected emissions information must be considered.

Coal Characteristics

The source of fuel burned at Reid Gardner Unit 3 is primarily western bituminous coal. Natural gas will be utilized during startup, shutdown, and flame stabilization.

Recommendations

NO_x Emission Control

LNB with OFA has been selected as the NO_x reduction technology with a NV Energy BART Limit (NVEBL) of 0.39 lb/MMBtu averaged on an annual basis. There is significant uncertainty involved in obtaining vendor emission guarantees and associated equipment/construction costs at this stage of analysis when retrofitting older boiler units. Site specific engineering is required on a "unit by unit" basis to determine the most effective control technology.

Due to uncertainties in future coal supply, and changes in boiler operation from the current pressurized operation to balanced draft operation, the NVEBL of 0.39 lb/MMBtu on an annual basis was established.

SO_2 Emission Control

The utilization of the existing wet soda ash FGD system is BART for Reid Gardner 3 with an NV Energy BART Limit (NVEBL) of 0.40 lb/MMBtu averaged on a 24-hour basis.

PM_{10} Emission Control

BART for Reid Gardner 3 will be accomplished by the installation of a fabric filter with an NV Energy BART Limit (NVEBL) of 0.02 lb/MMBtu averaged on a 3-hour basis, which is currently planned for installation by July 1, 2010. No further PM_{10} emission control will be required to achieve BART.

Control Recommendation

The BART selections include the utilization of LNB and OFA, continued FGD system operation, and installing a fabric filter for Reid Gardner 3. These selections are supported by cost and visibility analyses. Even though the NVEBL for each pollutant was established utilizing technology specific estimated design values, NVE maintains the flexibility to meet the limit by implementing operational or technology options of their choice BART Modeling Analysis.

CH2M HILL is using the CALPUFF modeling system to assess the visibility impacts of emissions from Reid Gardner 3 at nearby Class I areas. The Class I areas potentially affected are located more than 50 kilometers (km), but less than 300 km, from the Reid Gardner Station.

The Class I areas include the following national parks (NP) and wilderness areas (WA):

- Bryce Canyon NP
- Grand Canyon NP
- Joshua Tree NP
- Sycamore Canyon WA
- Zion NP

Visibility impacts were determined for the 1) WRAP baseline, 2) the current Title V emission permit limits, and 3) the proposed NV Energy BART Limits (NVEBL).

Contents

Appendices

Acronyms and Abbreviations

ACFM	actual cubic feet per minute
AQRV	air quality related value
ASOS	Automated Surface Observing System
BACT	Best Available Control Technology
BART	Best Available Retrofit Technology
Btu	British thermal unit
CalDESK	Program to display data and results
CALMET	Meteorological data preprocessing program for CALPUFF
CALPOST	Post-processing program for calculating visibility impacts
CALPUFF	Gaussian puff dispersion model
$CaSO_4$	calcium sulfate
CDPHE	Colorado Department of Health and Environment
CFR	Code of Federal Regulations
CO	carbon monoxide
CTG	Composite Theme Grid
DBA	dibasic acid
ΔdV	delta deciview, change in deciview
DEM	digital elevation model
dV	deciview
EC	elemental carbon
EPA	United States Environmental Protection Agency
ESP	electrostatic precipitator
f(RH)	relative humidity factor
FDDA	Four Dimensional Data Assimilation
FGD	flue gas desulfurization
FLM	Federal Land Manager
ft./sec.	feet per second

Fuel NO_x	oxidation of fuel bound nitrogen
HHV	higher heating value
hp	horsepower
km	kilometer
kW	kilowatt
kW-Hr	kilowatt-hour
LAER	lowest achievable emission rate
lb/MMBtu	pounds per million British thermal unit
LCC	Lambert Conformal Conic
LNB	low-NO_x burner
LOI	loss on ignition
MM5	Mesoscale Meteorological Model, Version 5
MMBtu	million British thermal unit
MSL	mean sea level
MW	megawatt
N_2	nitrogen
NCDC	National Climatic Data Center
NDEP	Nevada Division of Environmental Protection
NO	nitric oxide
NOAA	National Oceanic and Atmospheric Administration
NO_x	oxides of nitrogen
NP	National Park
NPS	National Park Service
NSR	New Source Review
NVE	NV Energy
NWS	National Weather Service
OFA	over-fire air
O&M	operations and maintenance
$PM_{2.5}$	particulate matter less than 2.5 microns in aerodynamic diameter
PM_{10}	particulate matter less than 10 microns in aerodynamic diameter

ppb	part per billion
PPM	parts per million
PRB	Powder River Basin
RMC	Regional Modeling Center
ROFA	Rotating Opposed Fire Air
S&L	Sargent & Lundy
NVEBL	NV Energy BART Limit
SCR	selective catalytic reduction
SIP	State Implementation Plan
SNCR	selective non-catalytic reduction
SO_2	sulfur dioxide
SO_4	sulfates
sq. ft.	square feet
USGS	U.S. Geological Survey
WA	Wilderness Area
WRAP	Western Regional Air Partnership

1.0 Introduction

1.1 Purpose

Best Available Retrofit Technology (BART) guidelines were established as a result of United States Environmental Protection Agency (EPA) regulations intended 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 guidance for states when determining which facilities must install additional controls, and 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/year of visibility-impairing pollutants.

The State of Nevada has identified those eligible in-state facilities that are required to reduce emissions under BART and will set BART emissions limits for those facilities. This information will be included in the Nevada State Implementation Plan (SIP), which the State has estimated will be formally submitted to the EPA by December 1, 2008. The EPA BART guidelines also state that the BART emission limits must be fully implemented within 5 years of EPA's approval of the SIP.

There are five basic elements related to BART, when addressing the issue of emissions for the identified facilities:

- Any 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 Reid Gardner Station Unit 3 (hereafter referred to as Reid Gardner 3) by CH2M HILL for NV Energy. The analysis was performed for the pollutants oxides of nitrogen (NO_x), sulfur dioxide (SO_2), and particulate matter less than 10 microns in aerodynamic diameter (PM_{10}) because they are the primary criteria pollutants that affect visibility.

Section 2.0 of this report provides a description of the present unit operation, including a discussion of coal sources and characteristics. The BART Engineering Analysis is provided in Section 3.0 by pollutant type. Section 4.0 provides the BART modeling methodology and Section 5.0 discusses the BART analysis and recommendations. References are provided in Section 6.0. Appendices A and B provide supporting information on the economic analysis and the BART modeling protocol.

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[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

The Reid Gardner Station consists of four units: three nominal 100-megawatt (MW) units and one nominal 265-MW unit, for a total nominal generating capacity of 565 MW. Reid Gardner 4 is not a BART-eligible unit. Reid Gardner 3 is a nominal 100-MW output unit commissioned in 1965 and is located in Moapa, Nevada. Unit 3 is currently equipped with a wall-fired pulverized coal boiler manufactured by Foster Wheeler with low-NO_x burners (LNB) and over-fire air (OFA), mechanical collector for particulate control, and a venturi/tray scrubber that uses soda ash for SO_2 removal.

A unit upgrade project is currently in progress on Reid Gardner 3 and consists of the following scope:

- Installation of a pulse jet fabric filter
- Installation of a new fly ash handling system
- Removal of existing mechanical collector

This pulse jet fabric filter is scheduled for completion by July 2010; therefore this BART analysis assumes that the above scope and equipment will be implemented. However, for purposes of this analysis, the costs and emissions reduction for the fabric filter are included in the analysis. For Table 2-1 below, the PM_{10} emission rate shown is equal to the fabric filter vendor guarantee.

Reid Gardner 3 was placed in service in 1976 and this analysis is based on a 20-year life for BART control technologies. Assuming a BART implementation date of 2015, this will result in an approximate remaining useful life for Reid Gardner 3 of 20 years from the installation date of any BART-related equipment. However, this report does not attempt to quantify any additional life extension beyond current plans or costs needed to allow the unit and these control devices at Reid Gardner 3 to operate until 2035.

The BART regulations state that the baseline emissions utilized for visibility modeling be established by identifying the highest 24-hour average actual emission rate from the period modeled for the pre-control scenario. Modeling would then consider the expected emissions rate after the installation of BART controls to establish the level of visibility improvement.

For the pre-control scenario, modeling was conducted at the WRAP 24-hour maximum values and at the Title V permit limits for the unit. The post-control scenario was modeled at the proposed NV Energy BART Limits (discussed in Sections 3, 4 and 5, with the exception of the NO_x and PM_{10} emission rates which is higher than the NVEBL.

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

TABLE 2-1
Unit Operation and Study Assumptions
Reid Gardner 3

General Plant Data	
Site Elevation (feet above MSL)	1,570
Stack Height (feet)	270
Stack Exit ID (feet)/Exit Area (sq. ft.)	12.9/130.7
Stack Exit Temperature (°F)	151
Stack Exit Velocity (ft./sec.)	71.4
Stack Flow (ACFM)	559,911
Annual Unit Capacity Factor (percent)	91
Net Unit Output (Nominal MW)	100
Net Unit Heat Rate (Btu/kW-Hr)(100 percent load)	11,351
Boiler Heat Input (MMBtu/Hr)(100% load)	1,237
Type of Boiler	Wall-fired
Boiler Fuel	Bituminous Coal (Primary)
	Natural Gas (Startup, Shutdown, Flame Stabilization)
Coal Sources	See Table 2-2
NO_x Emissions Data (24-hour Average Maximum)	
Current NO_x Controls	LNBs with OFA
Title V NO_x Permit Limit (lb/MMBtu)	0.46
WRAP NO_x Emission Rate (lb/MMBtu)	0.592
Average NO_x Emission Rate (lb/MMBtu)[b]	0.321
Maximum NO_x Emission Rate (lb/MMBtu)[d]	0.579
SO_2 Emissions Data (24-hour Average Maximum)	
Current SO_2 Controls	Soda Ash FGD
Title V SO_2 Permit Limit (lb/MMBtu)	0.55
WRAP SO_2 Emission Rate (lb/MMBtu)	0.320
Average SO_2 Emission Rate (lb/MMBtu)[c]	0.050
Maximum SO_2 Emission Rate (lb/MMBtu)[d]	0.290
PM_{10} Emissions Data (24-hour Average Maximum)	
Current PM_{10} Controls[a]	Fabric filter
Title V PM_{10} Permit Limit (lb/MMBtu)	0.1
WRAP PM_{10} Emission Rate (lb/MMBtu)	0.040
Average PM_{10} Emission Rate (lb/MMBtu)[a]	0.015

[a] After completion of fabric filter installation.
[b] Used 2004 annual averages.
[c] Used an average of the 2004 annual averages for Reid Gardner 1, 2, & 3.
[d] Maximum emission rate as per evaluation of the EPA Acid Rain Database for 2001 through 2003.

The primary source of fuel burned at Reid Gardner 3 is western bituminous coal. Coal sources and characteristics are summarized in Table 2-2.

TABLE 2-2
Coal Sources and Characteristics
Reid Gardner 3

Mines	Bowie	Skyline	Sufco	Dugout	Aberdeen	Crandall	West Ridge
Moist. %	8.50	9.79	9.69	5.53	6.83	7.50	5.78
Ash %	9.06	7.64	7.97	8.65	8.50	8.00	7.48
Volatile Matter %	33.53	38.20	35.95	33.05	38.00	41.05	34.91
Fixed Carbon %	48.91	44.37	46.39	52.77	46.16	43.00	51.84
Sulfur %	0.46	0.57	0.29	0.51	0.51	0.45	1.35
HHV, Btu/lb	12,012	11,712	11,463	12,469	12,276	12,400	12,856

Data from report done by NV Energy January 18, 2007, Fly Ash Conveyor System – Units 1, 2 and 3.
CH2M HILL based inlet SO_2 calculations on coal from the Skyline mine since it exhibits the highest sulfur content with the exception of West Ridge (not considered typical).
HHV = higher heating value

3.0 BART Engineering Analysis

3.1 Applicability

In compliance with regional haze requirements, the State of Nevada must prepare and submit visibility SIPs to the EPA for Class I areas. The State has estimated that the formal submittal of the SIPs to EPA will occur by December 1, 2008. The first phase of the regional haze program is the implementation of BART emission controls on all BART eligible units within 5 years after EPA approval of the SIP.

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. The evaluation must include the following:

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

These steps are incorporated into the BART analysis as follows:

Step 1 – Identify All Available Retrofit Control Technologies

Step 2 – Eliminate Technically Infeasible Options

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

Step 3 – Evaluate Control Effectiveness of Remaining Control Technologies

- Costs associated with control technologies are summarized in the economic analysis presented in Appendix A. For clarity, Appendix A also includes sample economic analysis spreadsheet calculations and explanation of assumptions used.

Step 4 – Evaluate Energy and Non-Air Quality Impacts

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

Step 5 – Evaluate Visibility Impacts

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

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

Separate analyses have been conducted for NO_x, SO_2, and PM_{10} emissions. All costs included in the BART analysis are in 2007 dollars, and costs have not been escalated to the assumed 2013 BART implementation date.

3.2.1 BART NO_x Analysis

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

3.2.1.1 Formation of NO_x

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

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

Coal characteristics directly affect NO_x emissions from coal combustion. Coal ranking is a means of classifying coals according to their degree of metamorphism in the natural series, from lignite to sub-bituminous to bituminous and on to anthracite. Lower rank coals, such as the sub-bituminous coals from the Powder River Basin (PRB), produce lower NO_x emissions than do higher rank 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. Lower rank coals release more organically bound nitrogen earlier in the combustion process than do higher rank bituminous coals. When used with LNBs, sub-bituminous coals create a longer time for the kinetics to promote more stable molecular nitrogen; hence resulting in lower NO_x emissions.

3.2.1.2 Step 1: Identify All Available Retrofit Control Technologies

The first step of the BART process is to evaluate NO_x control technologies with practical potential for application to Reid Gardner 3, including those control technologies identified as Best Available Control Technology (BACT) or lowest achievable emission rate (LAER) by permitting agencies across the United States. A broad range of information sources has been reviewed in an effort to identify potentially applicable emission control technologies.

Reid Gardner 3 NO_x emissions are currently controlled through the use of Foster Wheeler LNBs, which were installed in 1999, and OFA. Reid Gardner 3 is a wall-fired boiler, with burners arranged in a 4-by-2 (four-high and two-wide) configuration.

The following potential NO_x control technology options were considered:

- Low NO_x Burners (LNB) with Overfire Air (OFA)
- Low NO_x Burner (LNB) with selective non-catalytic reduction system (SNCR)
- Rotating Opposed Fire Air (ROFA) with Rotamix
- LNB with selective catalytic reduction (SCR) system
- ROFA with SCR

3.2.1.3 Step 2: Eliminate Technically Infeasible Options

For Reid Gardner 3, a wall-fired configuration burning primarily bituminous coal, technical feasibility will primarily be determined by physical constraints, boiler configuration, and on the ability to achieve the proposed NV Energy BART Limit of 0.46 lb/MMBtu.

For this BART analysis, information pertaining to LNB with OFA, ROFA with Rotamix, SNCR, and SCR was based on a combination of vendor information, internal CH2M HILL information, and the EPA Air Pollution Cost Control Manual. Sources of cost estimates for Reid Gardner 3 are listed in Table 3-1, which also summarizes the control technology options evaluated in this BART analysis, along with projected NO_x emission rates. All technologies listed can meet the proposed NVE BART Limit of 0.39 lb/MMBtu.

It should be noted estimated emissions information from NO_x technologies presented represent design targets. With a significant potential for variability in emissions due to changes in unit operation, a longer averaging period results in a higher probability in meeting the permit emissions value. Emissions based on a 24-hour averaging period are not directly comparable to emissions targets based on a longer averaging time.

TABLE 3-1
NO_x Control Technology Emission Rate Ranking
Reid Gardner Station Unit 3

Technology	Source of Estimated Emissions	Expected Emission Rate (lb/MMBtu)[c]
Current Permit Limit	Title V	0.46
NVE BART Limit	NVEBL[a]	0.39 (Annual)
Enhancement of the Existing or New LNB w/OFA	Foster Wheeler	<0.390
LNB w/OFA and SNCR[b]	Foster Wheeler, Fuel Tech	0.23
ROFA w/Rotamix	Mobotec	0.20
LNB w/OFA and SCR	Foster Wheeler	0.07
ROFA w/SCR	Mobotec	0.07

[a] NVEBL – Based on LNB with OFA information from Foster Wheeler
[b] Assumes 25 percent SNCR removal efficiency.
[c] All emission rates are treated as expected rather than guaranteed values.

ROFA = rotating opposed fire air
SCR = selective catalytic reduction
SNCR selective non-catalytic reduction

3.2.1.4 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

Preliminary vendor proposals, such as those used to support portions of this BART analysis, may be technically feasible and provide expected or guaranteed emission rates; however, they include inherent uncertainties. These proposals are usually prepared in a limited time frame, may be based on incomplete information, may contain over-optimistic conclusions, and are non-binding. Therefore, emission rate values obtained in such preliminary proposals must be qualified, and it must be recognized that contractual guarantees are established only after more detailed analysis has been completed. Also, emission rates are typically based on a design value (i.e., 30-day rolling average) versus a maximum 24-hour value.

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

The steps used for determining a level of confidence for the vendor-expected value are as follows:

1. Establish expected NO_x emissions value from vendor.
2. Evaluate vendor experience and historical basis for meeting expected values.

3. Review and evaluate unit physical and operational characteristics and restrictions. The fewer variations there are in operations, coal supply, etc., the more predictable and less variable the NO_x emissions are.
4. Make adjustments to the expected value. For each technology expected value, there is a corresponding potential for actual NO_x emissions to vary from this expected value. From the vendor information presented, along with anticipated unit operational data, an adjustment to the expected value can be made.

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

LNBs with OFA System. The mechanism used to lower NO_x with LNBs is to stage the combustion process and provide a fuel-rich condition initially; this is so oxygen needed for combustion is not diverted to combine with nitrogen and form NO_x. Fuel-rich conditions favor the conversion of fuel nitrogen to N_2 instead of NO_x. Additional air (or OFA) is then introduced downstream in a lower temperature zone to burn out the char. Enhancing the existing or installing new LNBs and OFA is considered to be a capital cost, combustion technology retrofit that may require boiler water wall tube replacement.

Neural Net Boiler Controls. Information regarding neural net controls for the boiler was received from NeuCo, Inc. While NeuCo offers several neural net products, CombustionOpt and SootOpt provide the potential for NOx reduction. NeuCo stated 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 CombustionOpt can reduce NOx by 15 percent, and SootOpt can provide an additional 5 to 10 percent. Because NeuCo does not offer guarantees on this projected emission reduction, a nominal reduction of 15 percent was assumed for evaluation purposes. The 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 can not be considered as reliable projections. Therefore, neural net should be considered as a supplementary or polishing technology, but not on a stand-alone basis.

ROFA. Mobotec markets ROFA as an improved second-generation OFA system. Mobotec states that the flue gas volume of the furnace is set in rotation by asymmetrically placed air nozzles. Rotation is reported to prevent laminar flow and improve gas mixing so that the entire volume of the furnace can be used more effectively for the combustion process. In addition, the swirling action reduces the maximum temperature of the flames and increases heat absorption. Mobotec expects that enhanced mixing will also result in reduction in hot/cold furnace zones, improved heat absorption and boiler efficiency, and lower carbon monoxide (CO) and NO_x emissions.

A typical ROFA installation will have a booster fan(s) to supply the high-velocity air to the ROFA boxes. Mobotec proposed one 1,000-horsepower (hp) fan for Reid Gardner 3 located at grade, which would provide hot air at all boiler loads.

Mobotec does not typically provide installation services because they believe that the Owner can more cost-effectively contract for these services. However, they did provide a budgetary price for installation labor. Mobotec provides one onsite construction supervisor during installation and startup.

Due to previous experience with ROFA, NVE does not consider ROFA as a stand-alone technology option.

ROFA w/Rotamix. As described above, ROFA is marketed as an improved OFA system. Mobotec provided a proposal for their Rotamix SNCR system, which anticipated 12 to 24 injection ports for Reid Gardner 3. The guaranteed NO_x emission rate for the Rotamix system, operating in conjunction with ROFA, is 0.20 lb/MMBtu. Ammonia slip is guaranteed at 5 parts per million (ppm) with an ammonia/urea flow rate of 70 to 110 gallons per hour.

SNCR. Selective non-catalytic reduction is generally used to achieve modest NO_x reductions on smaller units. 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 NO_x to nitrogen and water. NO_x reductions of up to 60 percent have been achieved, although 20 to 40 percent is more realistic for most applications.

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

A budgetary proposal was received from Fuel Tech for their urea-based SNCR system, which provides nominally a 25 percent reduction from baseline NO_x levels. Fuel Tech proposed using 16 injectors located over three boiler levels.

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 NO_x to nitrogen and water. Unlike the high temperatures required for SNCR, in SCR the 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 NO_x emissions. The most common type of SCR is the high-dust configuration, where the catalyst is located downstream from the boiler economizer and upstream of the air heater and any particulate control equipment. In this location, the SCR is exposed to the full concentration of fly ash in the flue gas that is leaving the boiler. The high-dust configuration is assumed for Reid Gardner 3. In a full-scale SCR, the flue ducts are routed to a separate large reactor containing the catalyst. With in-duct SCR, the catalyst is located in the existing gas duct, which may be expanded in the area of the catalyst to reduce flue gas flow velocity and increase flue gas residence time. Due to the higher removal rate, a full-scale SCR was used as the basis for analysis at Reid Gardner 3.

As with SNCR, it is generally more cost effective to reduce NO_x emission levels as much as possible through combustion enhancements than to minimize the catalyst surface area and ammonia requirements of the SCR.

3.2.1.5 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 installation of LNB with OFA is not expected to impact the boiler efficiency to a large degree or forced draft fan power usage. Therefore, these technologies will not have energy impacts.

The Mobotec ROFA system requires installation and operation of one 1,000-hp ROFA fan (746 kilowatts [kW] total). Fuel Tech provided an estimated auxiliary power requirement of 343 kW, and the same estimate was used for Rotamix.

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.

The energy impacts summarized above are included in the economic analysis presented in Appendix A.

Environmental Impacts. Mobotec has predicted that CO emissions, and unburned carbon in the ash, commonly referred to as loss on ignition (LOI), would be the same or lower than prior levels for the ROFA system.

SNCR and SCR installation could impact the salability and disposal of fly ash due to ammonia levels and could potentially create a visible stack plume, which may negate other visibility improvements. Other environmental impacts involve the storage of ammonia, especially if anhydrous ammonia is used, and the transportation of the ammonia to the power plant site.

These environmental impacts have not been quantified in the economic analysis presented in Appendix A.

Economic Impacts. Costs for the LNB with OFA, ROFA with Rotamix, SNCR, and SCR were furnished to CH2M HILL through vendor-obtained price and performance quotations. A comparison of the technologies on the basis of costs, design control efficiencies, and tons of NO_x removed is summarized in Table 3-2, and the first year control costs are presented in Figure 3-1.

The complete Economic Analysis is contained in Appendix A.

3.2.1.6 Step 5: Evaluate Visibility Impacts

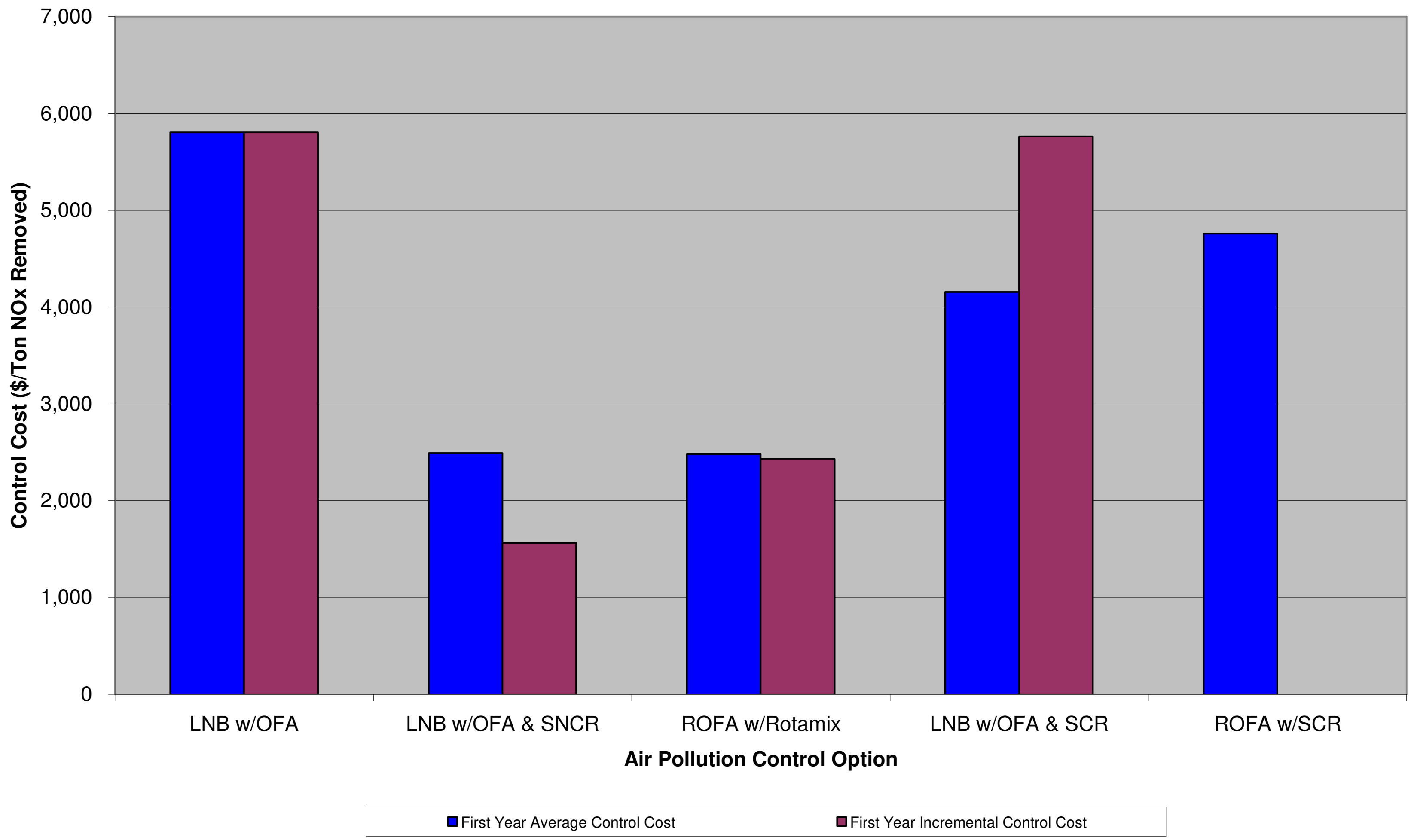
This is presented in Section 4.0, BART Modeling Analysis.

TABLE 3-2
NO_x Control Cost Comparison
Reid Gardner Station Unit 3

Factor	LNB w/OFA	LNB w/OFA & SNCR	ROFA w/Rotamix	LNB w/OFA & SCR	ROFA w/SCR
Total Installed Capital Costs	$4.4 Million	$6.9 Million	$7.9 Million	$35.0 Million	$38.5 Million
Total First Year Fixed and Variable O&M Costs	$0.1 Million	$0.3 Million	$0.5 Million	$1.0 Million	$1.3 Million
Total First Year Annualized Cost	$0.6 Million	$1.1 Million	$1.4 Million	$4.7 Million	$5.4 Million
Power Consumption (MW)	-	0.10	0.75	0.66	1.41
Annual Power Usage (Million kW-Hr/Yr)	-	0.8	5.9	5.3	11.2
NO_x Design Control Efficiency	6.5%	29.9%	38.3%	78.2%	78.2%
Tons NO_x Removed per Year	95	434	556	1,136	1,136
First Year Average Control Cost ($/Ton of NO_x Removed)	5,807	2,493	2,480	4,155	4,757
Incremental Control Cost ($/Ton of NO_x Removed)	5,807	1,564	2,433	5,764	0

O&M = operations and maintenance
The incremental control cost for ROFA w/SCR when compared with LNB w/OFA & SCR results in a non number as the two technologies have the same NOx removal in tons/year

FIGURE 3-1
First-Year Control Cost for NO_X Air Pollution Control Options
Reid Gardner Station Unit 3



3.2.2 BART SO_2 Analysis

SO_2 forms in the boiler during the combustion process from the oxidation of the sulfur in the coal and is primarily dependent on coal sulfur content. The BART analysis for SO_2 emissions on Reid Gardner 3 is described below.

3.2.2.1 Step 1: Identify All Available Retrofit Control Technologies

A broad range of information sources were reviewed to identify potentially applicable emission control technologies for SO_2 at Reid Gardner 3. This review included control technologies identified as BACT or LAER by permitting agencies across the United States.

The following potential new SO_2 control technology options were considered:

- Dry flue gas desulfurization (FGD) system
- Dry sorbent injection
- Furnace sorbent injection
- New wet lime/limestone FGD system

Because Reid Gardner currently uses a soda ash scrubber for SO_2 reduction and current removal efficiency is greater than 50 percent, the EPA BART regulations state that cost-effective scrubber upgrades should be considered. Therefore, the following upgrades to the existing scrubber were also considered:

- Eliminate bypass reheat
- Install liquid distribution rings
- Install perforated trays
- Use organic acid additives
- Improve or upgrade scrubber auxiliary system equipment
- Redesign spray header or nozzle configuration

3.2.2.2 Step 2: Eliminate Technically Infeasible Options

The current soda ash scrubber SO_2 emissions average approximately 0.15 lb/MMBtu or less and meet a Title V permit limit of 0.55 lb/MMBtu. Assuming an uncontrolled SO_2 emission level of 0.97 lb/MMBtu, the currently operating soda ash scrubber is achieving a reduction of SO_2 of up to 95 percent. With the fabric filter installation, the scrubber venturi section will be opened further to reduce draft loss through the equipment, and the scrubber operation will be improved to primarily remove SO_2 in the scrubber vessel.

Dry FGD System. A lime spray dryer typically injects lime slurry in the top of the absorber vessel with a rapidly rotating atomizer wheel. The rapid speed of the atomizer wheel causes the lime slurry to separate into very fine droplets that intermix with the flue gas. The SO_2 in the flue gas reacts with the calcium in the lime slurry to form dry calcium sulfate particles. At Reid Gardner 3, this dry particulate matter would be captured downstream in the baghouse that is currently being constructed, along with the fly ash. A lime spray dryer system typically produces a dry waste product suitable for landfill disposal.

A dry FGD system is estimated to achieve a maximum of 90 percent SO_2 removal at Reid Gardner 3. This would result in a controlled SO_2 emission rate of 0.054 lb/MMBtu, based on an uncontrolled SO_2 emission rate of 0.97 lb/MMBtu. Therefore, this option cannot reduce the current soda ash scrubber emissions of 0.05 lb SO_2/MMBtu, and is therefore eliminated from further analysis.

Dry Sodium Sorbent Injection. Dry duct injection of sodium materials, such as sodium carbonate or sodium bicarbonate, can be used to remove moderate levels of SO_2 from flue gas. The sorbent is injected dry into the flue gas downstream of the air heater at approximately 300°F, and the reacted and unreacted sorbent material and fly ash would be collected in the fabric filter. Maximum SO_2 removal efficiency for this technology is approximately 75 percent, far less than is now being achieved with the soda ash scrubber, which eliminates this technology from further consideration.

Furnace Sorbent Injection. Furnace sorbent injection consists of injecting lime or limestone into the boiler above the combustion zone (approximately 2,200°F) or ahead of the economizer (approximately 1,100°F). The sorbent reacts with the SO_2 in the flue gas to form calcium sulfate ($CaSO_4$), and the $CaSO_4$, unreacted sorbent, and fly ash is collected in the fabric filter. While furnace sorbent injection is relatively simple, it has a limited SO_2 removal efficiency limitation of approximately 60 percent. Because this is far less than the current soda ash scrubber performance, this option is eliminated from further analysis.

New Wet Lime/Limestone Scrubber. A typical wet lime/limestone scrubber consists of SO_2 laden flue gas entering a scrubber vessel where it is sprayed with a water/calcium slurry. The calcium reacts to form calcium sulfite or sulfate, and is then either removed and disposed as scrubber waste or reclaimed as gypsum. Wet lime/limestone scrubbers are capable of very high SO_2 removal efficiencies, with a 95 percent removal efficiency assumed for this BART analysis.

Wet Soda Ash FGD System. Wet soda ash FGD systems operate by treating the flue gas in large scrubber vessels with a soda ash solution. The scrubber mixes the flue gas and alkaline reagent using a tray arrangement to distribute the reagent across the scrubber vessel. The sodium in the reagent reacts with the SO_2 in the flue gas to form sodium sulfite and sodium bisulfite, which are removed from the scrubber and disposed.

The wet soda ash FGD system at Reid Gardner 3 currently achieves up to 94 percent SO_2 removal, resulting in an average SO_2 outlet emission rate of approximately 0.15 lb/MMBtu or less. The following scrubber upgrade alternatives were investigated:

- **Eliminate bypass reheat.** With the completion of the fabric filter installation, the flue gas leaving the scrubber will not be reheated. Therefore, this scrubber upgrade option has already been implemented.
- **Install liquid distribution rings.** Perforated trays accomplish the same purpose of liquid distribution rings, namely better distribution of scrubber liquid.
- **Install perforated trays.** Reid Gardner 3 scrubber has distribution sieve trays that allow the flue gas to bubble through the liquid. With the installation of a new fabric filter for improved particulate control ahead of the scrubber, enhanced scrubber operation is anticipated due to lessened tray pluggage from fly ash.

- **Use organic acid additives.** Organic acid additives such as dibasic acid (DBA) may be used to improve SO_2 removal efficiency by increasing scrubbing liquor alkalinity; however, any potential improvements in SO_2 removal are difficult to predict. Testing would be required to demonstrate feasibility and determine any possible impacts.
- **Improve or upgrade scrubber auxiliary system equipment.** With the installation of a fabric filter, particulate loading into the scrubber will be reduced. This will lessen pluggage of the scrubber trays and nozzles with fly ash, which should result in improved SO_2 removal and greater reliability.
- **Redesign spray header or nozzle configuration.** Reduced particulate loading will reduce pluggage of scrubber nozzles, which should improve liquid distribution and scrubber reliability.

It is projected that the operation of the present wet soda ash FGD system may be improved as a result of the fabric filter installation. However, even with incremental improvements, minimal additional improvement to the current low SO_2 emission level can be consistently expected from upgrades to the existing wet soda ash scrubber.

Table 3-3 summarizes the control technology options evaluated in this BART analysis, along with projected SO_2 emission rates. Only scrubber upgrades and new lime/limestone wet scrubber technology options can equal or exceed the removal efficiency of the current wet soda ash scrubber. Therefore, only these two alternatives are considered technically feasible for purposes of this analysis.

TABLE 3-3
SO_2 Control Technology Emission Rate Ranking
Reid Gardner Station Unit 3

Technology	Projected Emission Rate (lb/MMBtu)	Estimated SO_2 Removal Efficiency (%)
Current Permit Level	0.55	N/A
NVE BART Limit	0.40	N/A
Current Wet Soda Ash Scrubber	0.15 or less	94+
Improve Existing Wet Soda Ash Scrubber Operation	0.15 or less	95
Dry Sorbent Sodium Injection	0.24	75
New Dry FGD System	0.15 or less	90
Furnace Sorbent Injection	0.39	60
New Wet Lime/Limestone Scrubber	0.15 or less	95

FGD = flue gas desulfurization

3.2.2.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

When evaluating the control effectiveness of SO_2 reduction technologies, each option can be compared against benchmarks of performance. The projected emission rate for an upgraded wet soda ash FGD system for Reid Gardner 3 is 95 percent SO_2 removal or less than 0.15 lb/MMBtu, while a new wet lime/limestone scrubber installation would have similar removal efficiency.

Essentially the same level of SO_2 reduction can be achieved through scrubber upgrades and new wet scrubber installation. Therefore, the new wet lime/limestone scrubber option is eliminated because little additional scrubber capital or operating cost is required by improving the current wet soda ash scrubber.

3.2.2.4 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. Upgrading the existing wet soda ash FGD system operation will not require additional power.

Environmental Impacts. There will be no environmental impacts due to improving the current wet soda ash scrubber operation.

Economic Impacts. There will be no economic impacts due to improving the current wet soda ash scrubber operation.

3.2.2.5 Step 5: Evaluate Visibility Impacts

This is presented in Section 4.0, "BART Modeling Analysis."

3.2.3 BART PM_{10} Analysis

Reid Gardner 3 is currently equipped with a mechanical collector and a venturi/tray wet soda ash scrubber for both particulate and SO_2 control. However, as part of the planned environmental upgrade on Reid Gardner 3, the mechanical collector is being removed and a new fabric filter is being installed.

The BART analysis for PM_{10} emissions at Reid Gardner 3 is described below. For the modeling analysis in Section 4.0, PM_{10} was used as an indicator for PM, and PM_{10} includes particulate matter less than 2.5 microns in aerodynamic diameter ($PM_{2.5}$) as a subset.

3.2.3.1 Step 1: Identify All Available Retrofit Control Technologies

Three retrofit control technologies have been identified for additional PM_{10} control:

- Fabric filter
- Upgrade existing mechanical collector
- Electrostatic precipitator

3.2.3.2 Step 2: Eliminate Technically Infeasible Options

Fabric Filter. A fabric filter retrofit project is currently planned to be installed by July 1, 2010, on Reid Gardner 3 with guaranteed filterable particulate emissions from the fabric filter of 0.015 lb/MMBtu.

Upgrade Existing Mechanical Collector. With the planned fabric filter installation, the mechanical collector internals will be removed to eliminate the pressure drop and allow the full range of particulate sizing to the fabric filter. In addition, any upgrade to the mechanical collector would not meet the level of emissions reduction possible with a fabric filter. Therefore, an upgrade of the mechanical collector is not feasible or desirable.

New Electrostatic Precipitator. An installation of a new electrostatic precipitator is not justified because the potential level of emissions reduction is not as great as with the fabric filter installation currently planned.

3.2.3.3 Step 3: Evaluate Control Effectiveness of Remaining Control Technologies

The guaranteed PM_{10} control technology emission rate is 0.015 lb/MMBtu.

3.2.3.4 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. While there will be additional fan horsepower to overcome pressure drop from a fabric filter installation, this will be more than offset by the reduction in pressure drop from both the venturi section of the wet scrubber and the removal of the mechanical collector. Therefore, a fabric filter installation is expected to result in a net energy reduction required for operation.

Environmental Impacts. There are no environmental impacts expected from the installation of a fabric filter.

Economic Impacts. Because the planned fabric filter project is considered to be BART, a comparison of technologies on the basis of costs, design control efficiencies, and tons of PM_{10} removed was not done. Cost for the fabric filter is summarized in Table 3-4.

The complete Economic Analysis is contained in Appendix A.

TABLE 3-4
PM_{10} Control Cost
Reid Gardner Station Unit 3

Factor / Control Option	Fabric Filter
Total Installed Capital Costs	$23.5 Million
Total First Year Fixed and Variable O&M Costs	$0.6 Million
Total First Year Annualized Cost	$3.1 Million

3.2.3.5 Step 5: Evaluate Visibility Impacts

This is presented in Section 4.0, BART Modeling Analysis.

4.0 BART 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 the NV Energy Reid Gardner Station Units 1, 2, and 3.

To a large extent, the modeling followed the methodology outlined in the Western Regional Air Partnership (WRAP) protocol for performing BART analyses (WRAP, 2006). Any proposed deviations from that methodology are documented in the modeling protocol that is included as Appendix B to this report.

4.2 Model Selection

CH2M HILL used the Gaussian puff dispersion model (CALPUFF) modeling system to assess the visibility impacts at Class I areas. Work groups that represent the interests of the Federal Land Managers (FLM) recommend that an analysis of Class I area air quality and air quality related values (AQRVs) be performed for major sources located more than 50 km from these areas (EPA, 1998). The CALPUFF model is routinely recommended for these types of regulatory analyses.

The CALPUFF modeling system includes the meteorological data preprocessing program for CALPUFF (CALMET) with algorithms for chemical transformation and deposition, and a post processor capable of calculating concentrations, visibility impacts, and deposition (CALPOST). The CALPUFF modeling system was applied in a full, refined mode.

CH2M HILL used the latest version (Version 6) of the CALPUFF modeling system preprocessors and models in lieu of the EPA-approved versions (Version 5). The FLMs and others have noted that the EPA-approved Version 5 contained errors and that a newer version should be used. Consequently, it was decided to use the latest (as of April 2006) version of the CALPUFF modeling system (available at www.src.com):

- CALMET Version 6.211 Level 060414
- CALPUFF Version 6.112 Level 060412

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

4.3 CALMET Methodology

4.3.1 Dimensions of the Modeling Domain

CH2M HILL defined domains for Mesoscale Meteorological Model, Version 5 (MM5), CALMET, and CALPUFF that were slightly different than those established for the Nevada BART modeling in WRAP (2006). In addition, the CALMET and CALPUFF Lambert Conformal Conic (LCC) map projection is based on a central meridian of 117° W rather than 97° W. This puts the central meridian near the center of the domain.

CH2M HILL used the CALMET model to generate three-dimensional wind fields and other meteorological parameters suitable for use by the CALPUFF model. A CALMET modeling domain has been defined to allow for at least a 50-km buffer around all Class I areas within 300 km of the Reid Gardner Power Plant. Grid resolution for this domain was 4 km. Figure 4-1 shows the extent of the modeling domain.

The technical options recommended in WRAP (2006) were used for CALMET. Vertical resolution of the wind field included 11 layers, with vertical cell face heights as follows (in meters):

- 0, 20, 100, 200, 350, 500, 750, 1000, 2000, 3000, 4000, 5000

Also, following WRAP (2006), ZIMAX were set to 4,500 meters based on the Colorado Department of Health and Environment (CDPHE) analyses of soundings for summer ozone events in the Denver area (CDPHE, 2005). The CDPHE analysis suggests mixing heights in the Denver area are often well above the CALMET default value of 3,000 meters during the summer. For example, on some summer days, ozone levels are elevated all the way to 6,000 meters mean sea level (MSL) or beyond during some meteorological regimes, including some regimes associated with high-ozone episodes. It is assumed that, as in Denver, mixing heights in excess of the 3,000 m AGL CALMET default maximum would occur in the domain used for this analysis.

FIGURE 4-1
Reid Gardner Power Plant, CALMET/CALPUFF Domain

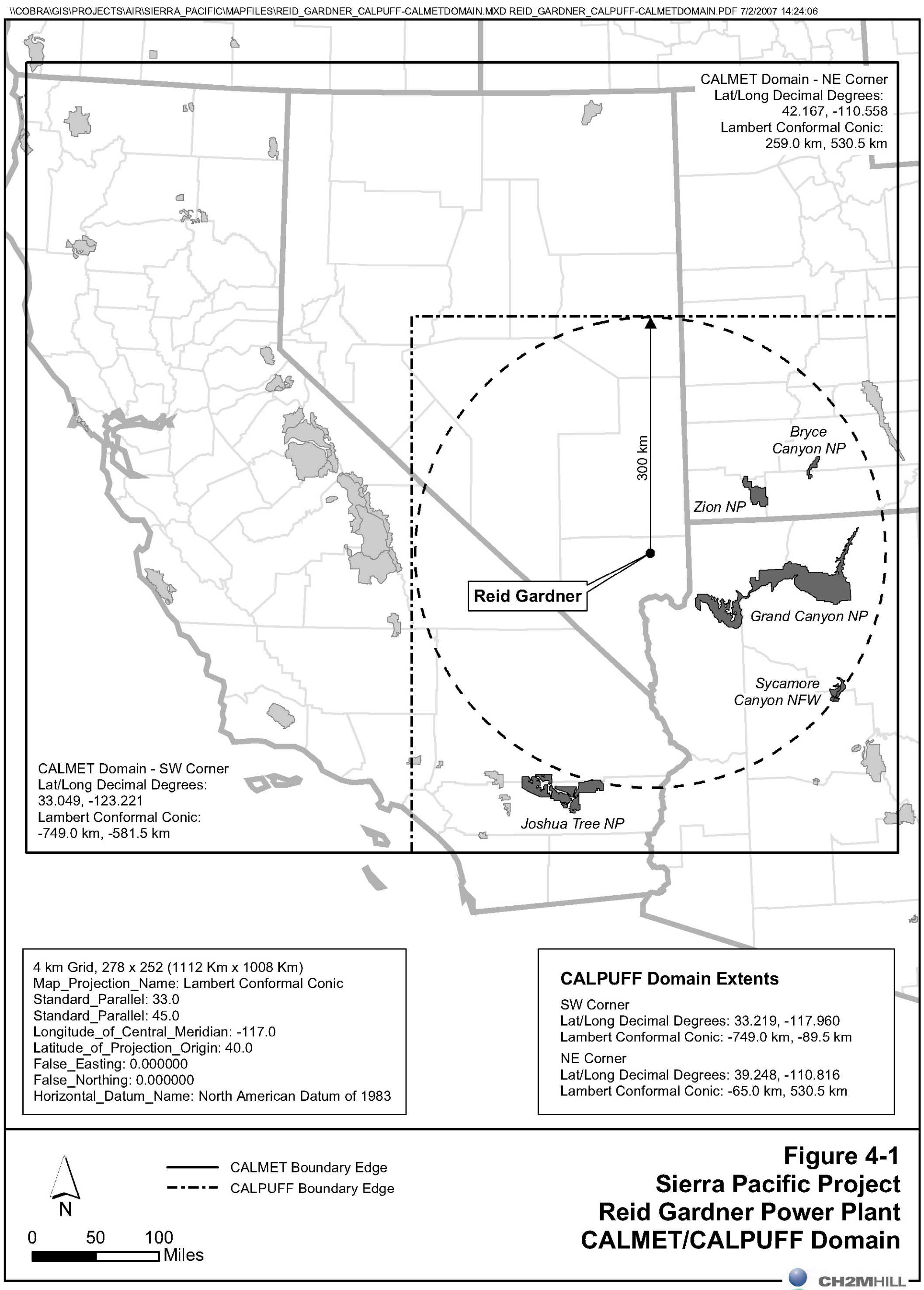


Table 4-1 lists the key user-specified options.

TABLE 4-1
User-Specified CALMET Options

Description	CALMET Input Parameter	Value
	CALMET Input Group 2	
Map projection	PMAP	Lambert Conformal Conic (LCC)
Grid spacing	DGRIDKM	4
Number vertical layers	NZ	11
Top of lowest layer (m)		20
Top of highest layer (m)		5000
	CALMET Input Group 4	
Observation mode	NOOBS	1
	CALMET Input Group 5	
Prognostic or MM-FDDA data switch	IPROG	14
Max surface over-land extrapolation radius (km)	RMAX1	50
Max aloft over-land extrapolations radius (km)	RMAX2	100
Radius of influence of terrain features (km)	TERRAD	10
Relative weight at surface of Step 1 field and obs	R1	100
Relative weight aloft of Step 1 field and obs	R2	200
	CALMET Input Group 6	
Maximum over-land mixing height (m)	ZIMAX	4500

4.3.2 CALMET Input Data

CH2M HILL ran the CALMET model to produce 3 years of analysis: 2001, 2002, and 2003. CH2M HILL used MM5 data as the basis for the CALMET wind fields. The horizontal resolution of the MM5 data is 36 km.

For 2001, CH2M HILL used MM5 data at 36-km resolution that were obtained from the contractor (Alpine Geophysics) who developed the nationwide data for the EPA. For 2002, CH2M HILL used 36-km MM5 data obtained from Alpine Geophysics, originally developed for the WRAP. Data for 2003 (also from Alpine Geophysics), at 36-km resolution, were developed by the Wisconsin Department of Natural Resources, the Illinois Environmental Protection Agency, and the Lake Michigan Air Directors Consortium (Midwest RPO).

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

Surface data for 2001-2003 were obtained from the National Climatic Data Center (NCDC). CH2M HILL processed data for all stations from the National Weather Service's (NWS) Automated Surface Observing System (ASOS) network that are in the domain. The surface data were obtained in abbreviated DATSAV3 format. A conversion routine available from the TRC website was used to convert the DATSAV3 files to CD 144 format for input to the SMERGE preprocessor and CALMET.

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

Precipitation data were ordered from the NCDC. All available data in fixed-length, TD-3240 format were ordered for the modeling domain. The list of available stations and stations that have collected complete data varies by year, but CH2M HILL processed all available stations/data within the domain for each year. Precipitation data were prepared with the PXTRACT/PMERGE processors in preparation for use within CALMET.

Following the methodology recommended in WRAP (2006), no observed upper-air meteorological observations were used as they are redundant to the MM5 data and may introduce spurious artifacts in the wind fields. In the development of the MM5 data, the twice daily upper-air meteorological observations were used as input with the MM5 model. The MM5 estimates were nudged to the upper-air observations as part of the Four Dimensional Data Assimilation (FDDA). This results in higher temporal (hourly vs. 12 hour) and spatial (36 km vs. ~300 km) resolution for the upper-air meteorology in the MM5 field. These MM5 data are more dynamically balanced than those contained in the upper-air observations. Therefore, the use of the upper-air observations with CALMET is not needed, and, in fact, will upset the dynamic balance of the meteorological fields potentially producing spurious vertical velocities.

4.3.3 Validation of CALMET Wind Field

CH2M HILL used the CalDESK (program to display data and results) data display and analysis system (v2.97, Enviromodeling Ltda.) to view plots of wind vectors and other meteorological parameters to evaluate the CALMET wind fields. We used observed weather conditions, as depicted in surface and upper-air weather maps from the National Oceanic and Atmospheric Administration (NOAA) Central Library U.S. Daily Weather Maps Project (http://docs.lib.noaa.gov/rescue/dwm/data_rescue_daily_weather_maps.html), to compare to the CalDESK displays.

4.4 CALPUFF Methodology

4.4.1 CALPUFF Modeling

CH2M HILL ran the CALPUFF model with the meteorological output from CALMET over the CALPUFF modeling domain (Figure 4-1). The CALPUFF model was used to predict visibility impacts for the pre-control (baseline) scenario for comparison to the predicted impacts for post-control scenarios.

4.4.1.1 Background Ozone and Ammonia

Hourly values of background ozone concentrations were used by CALPUFF for the calculation of SO_2 and NO_X transformation with the MESOPUFF II chemical transformation scheme. CH2M HILL used the hourly ozone data generated for the WRAP BART analysis for 2001, 2002, and 2003.

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

4.4.1.2 Stack Parameters

The baseline stack parameters for the baseline and post-control scenarios were the same as those used the WRAP Regional Modeling Center (RMC) analyses. None of the emission controls included in this BART analysis would substantially affect the exhaust exit flows or temperatures.

4.4.1.3 Pre-Control Emission Rates

Pre-control emission rates reflect normal maximum capacity 24-hour emissions that may occur under the source's current permit. The emission rates reflect actual emissions under normal operating conditions. As described by the EPA in the Regional Haze Regulations and Guidelines for BART Determinations; Final Rule (40 CFR Part 51; July 6, 2005, pg. 9129):

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

CH2M HILL selected the emissions rates used in the WRAP RMC modeling as the Pre-control (baseline) emission rates. The WRAP PM_{10} and SO_2 were speciated to determine emission rates for coarse particulate, fine particulate, elemental carbon, organic aerosols, and sulfates.

Emissions were modeled for the following species:

- Sulfur dioxide (SO_2)
- Nitrogen oxides (NO_x)
- Coarse particulate ($PM_{2.5}$ < diameter ≤ PM_{10})
- Fine particulate (diameter ≤ $PM_{2.5}$)
- Elemental carbon (EC)

- Organic aerosols (SOA)
- Sulfates (SO_4)

4.4.1.4 Post-control Emission Rates

Post-control emission rates represent the NV Energy BART Limit emission levels presented in Table 5-1, with the exception of the NO_x and PM_{10} emission rate which are in excess of the NVEBL.

4.4.1.5 Modeling Process

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

- Model WRAP-RMC parameters to verify results
- Model Title V Permit Limits

Model Scenario 1 (NVE BART Limit) emissions, with the exception of the NO_x and PM_{10}emission rate which are in excess of the NVEBL.

- Determine the degree of visibility improvement

4.4.2 Receptor Grids and Coordinate Conversion

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

For the Class I areas that are within 300 km of the Reid Gardner Power Plant, discrete receptors for the CALPUFF modeling were taken from the NPS database for Class I area modeling receptors. The entire area of each Class I area that is within or intersects the 300-km circle (Figure 3-1) were included in the modeling analysis. The following lists the Class I areas that were modeled for the Reid Gardner facility:

- Bryce Canyon National Park (NP) (Brca)
- Grand Canyon NP (Grca)
- Joshua Tree NM (Jotr)
- Sycamore Canyon Wilderness (Syca)
- Zion NP (Zion)

4.5 Visibility Post-processing

4.5.1 CALPOST

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

Calculations of light extinction were made for each pollutant modeled. The sum of all extinction values was used to calculate the delta-dv (Δdv) change relative to natural background. Default extinction coefficients for each species, as shown below, were used:

- Ammonium sulfate 3.0

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

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

The natural background conditions used in the post-processing to determine the change in visual range background - or delta-deciview (Δdv) - represent the average natural background concentration for western Class I areas.

Table 4-2 lists the annual average species concentrations from the EPA Guidance.

TABLE 4-2
Average Natural Levels of Aerosol Components

Aerosol Component	Average Natural Concentration (µg/m³) for Western Class I Areas
Ammonium Sulfate	0.12
Ammonium Nitrate	0.10
Organic Carbon	0.47
Elemental Carbon	0.02
Soil	0.50
Coarse Mass	3.0

Note: Taken from Table 2-1 of Guidance for Estimating Natural Visibility Conditions Under the Regional Haze Rule. EPA-454/B-03-005, September 2003.

4.6 Results

Input and output files for the CALMET/CALPUFF modeling and post-processing will be provided upon request.

4.6.1 WRAP Verification Runs Results

Tables 4-3 and 4-4 present the results of WRAP-RMC model verification runs. Except for the results at Joshua Tree NP, the results show good correlation in estimated maximum Δdv. Much of the difference between these values is probably attributed to the different alignment of the LCC grids (reference discussion in Section 4.3.1).

TABLE 4-3
Results from WRAP-RMC CALPUFF Modeling for Reid Gardner Boilers 1, 2, and 3 (WRAP 2007)

Class I Area	Min Distance (km)	Max Delta Δdv	98th Percentile Δdv	Days > 0.5 Δdv	98th Percentile Δdv for Each Year			98th Δdv 3-year Avg
					2001	2002	2003	
Grca	85	3.61	1.11	60	1.72	1.03	1.00	1.25
Zion	148	2.44	0.73	38	0.83	0.46	0.74	0.68
Brca	226	1.27	0.29	8	0.29	0.21	0.37	0.29
Syca	288	0.73	0.18	4	0.19	0.17	0.14	0.17
Jotr	292	1.56	0.70	48	0.88	0.56	0.55	0.67

TABLE 4-4
Verification CALPUFF Modeling Results

Class I Area	Min Distance (km)	Max Delta Δdv	98th Percentile Δdv	Days > 0.5 Δdv	98th Percentile Δdv for Each Year			98th Δdv 3-year Avg
					2001	2002	2003	
Grca	86	3.76	1.94	47	1.83	1.93	1.94	1.90
Zion	148	2.14	0.58	14	0.55	0.45	0.80	0.60
Brca	227	1.16	0.36	5	0.39	0.24	0.38	0.34
Syca	289	0.61	0.18	2	0.14	0.18	0.23	0.18
Jotr	292	1.92	0.86	32	1.04	0.85	0.58	0.82

4.6.2 BART Modeling Analysis

The results and comparisons of the CALPUFF modeling for the baseline emission rates and those for the NVE BART Limit emission rates are provided in Section 5. As previously mentioned, the NO_x and PM_{10} emission rates modeled are in excess of the NVEBL.

5.0 BART Analysis and Recommendations

5.1 Recommended BART Controls

As a result of the completed technical and economic evaluations, and consideration of the modeling analysis for Reid Gardner 3, the recommended BART controls for NO_x, SO_2, and PM_{10} are as follows:

- LNB with OFA for NO_x control
- Continued wet soda ash FGD operation for SO_2 control
- Fabric filter for PM_{10} control

Table 5-1 compares the baseline emission control scenario with expected emission levels utilizing the NVE BART Limit emission levels. Because of the basis utilized to establish the estimated emissions rate for each of these cases, it is important to consider economic and dispersion modeling results for each scenario in making the overall BART recommendation.

The WRAP baseline represents a snap-shot view of emissions based upon the year 2006, and does not necessarily represent worst case potential emission rates. While the NO_x emission rate modeled is in excess of the current NVEBL, modeling results represent worst case visibility impacts. The Title V permit limit offers a more representative view of maximum potential emission rates, since these are enforceable operating limits.

Comparison of dispersion modeling results for the three scenarios are presented below.

TABLE 5-1
Modeled Emission Control Scenarios
Reid Gardner Station Unit 3

Case	Expected NOx Emissions (lb/MMBtu)	Expected SO2 Emissions (lb/MMBtu)	Expected PM10 Emissions (lb/MMBtu)
WRAP Baseline	0.592	0.320	0.040
Title V Emission Limit Baseline	0.46	0.55	0.1
Scenario 1 – NVE BART Limit[a]	0.46	0.40	0.03

[a] – NO_x and PM_{10} emission rates higher than NVEBL

The ranking of the different NO_x emission control scenarios based on annual costs, from lowest to highest cost, is presented on Table 5-2.

TABLE 5-2
Ranking of NO_x Control Scenarios by Cost
Reid Gardner Station Unit 3

Rank	Controls	Total Annual Cost
1	LNB w/OFA	$0.6 Million
2	New LNB w/OFA and SNCR	$1.1 Million
3	ROFA w/Rotamix	$1.4 Million
4	New LNB w/OFA and SCR	$4.7 Million
5	ROFA w/SCR	$5.4 Million

5.2 Dispersion Modeling Results

The results of the dispersion modeling are shown below. In this analysis the WRAP emission rates are used as a historical baseline. Table 5-3 compares visibility impacts of the WRAP baseline, the current Title V permit limits and the NVE BART Limit emission rates. The NVE BART Limit emission rates for Reid Gardner Unit 3 demonstrate an improvement in visibility.

TABLE 5-3
Comparison of Visibility Impacts by Class I Area
Reid Gardner Unit 3

		98th Percentile Δdv			Number of Days Exceeding 0.5 Δdv		
Area	Distance (km)	WRAP Baseline	Title V Permit Limit	NVE BART Limit	WRAP Baseline	Title V Permit Limit	NVE BART Limit
Grca	86	0.79	0.82	0.73	17	18	18
Zion	148	0.22	0.23	0.20	3	4	2
Brca	227	0.13	0.15	0.13	0	0	0
Syca	289	0.07	0.08	0.07	0	0	0
Jotr	292	0.33	0.40	0.34	3	7	4

FIGURE 5-1
Comparison of 98th Percentile Delta Deciview Visibility Impacts
Reid Gardner 3

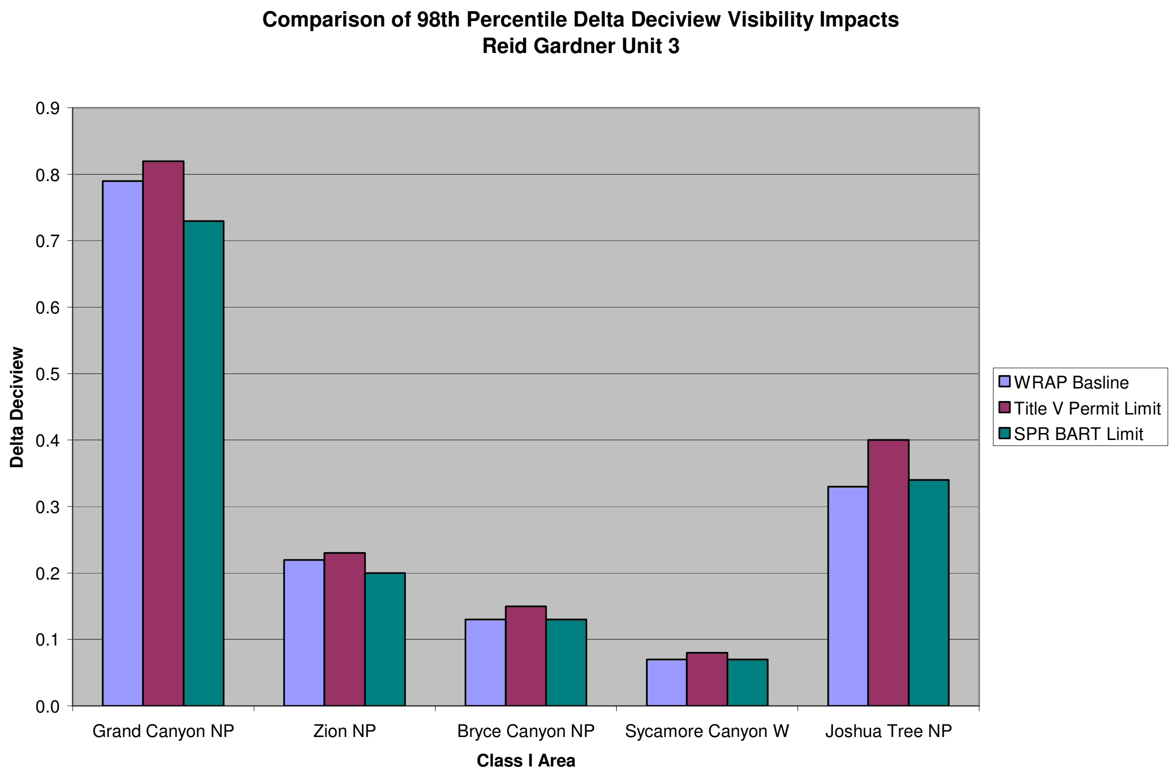
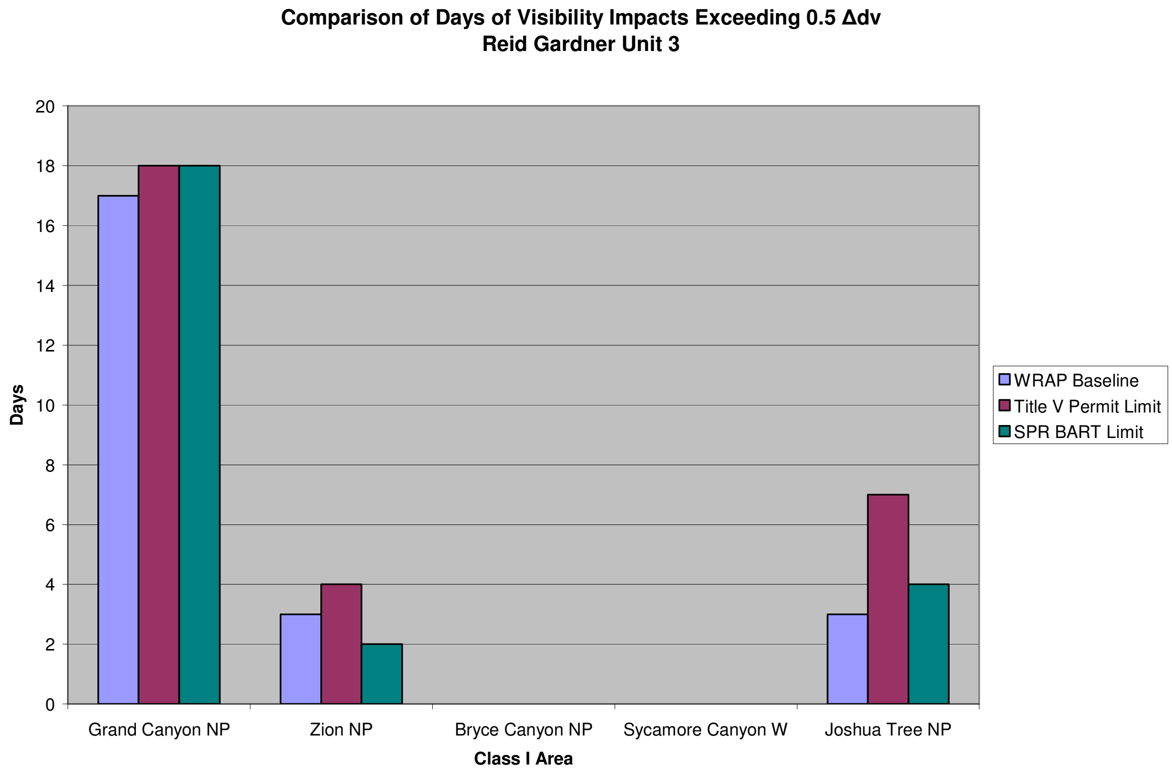


FIGURE5-2
Comparison of Days of Visibility Impacts Exceeding 0.5 Δdv
Reid Gardner 3



As shown in Figures 5-1 through 5-2, there is a decrease in modeled visibility impact when reducing the modeled emission levels from the Title V Permit Limit to the NVEBL emission rates. The modeled visibility impact from the modeled emission levels from the WRAP and NVEBL are similar.

NO_x Control Scenario Visibility Modeling

While visibility modeling has not been completed for the combination of NO_x, SO_2, and PM_{10} NBEBL values, Table 5-4 below compares the results for the various NO_x control technologies. Results from one representative Class I area is provided.

Based on an evaluation of the cost per Δdv reduction from Table 5-4, LNB with OFA is selected as BART for Reid Gardner 3.

TABLE 5-4
Control Scenario Results for the Grand Canyon National Park
Reid Gardner 3

Scenario	Controls	Average Number of Days Above 0.5 ΔdV (Days)	98th Percentile ΔdV Reduction	Total Annualized Cost (Million$)	Cost per ΔdV Reduction (Million$/dV Reduced)
Base		5	0.386	0	0
1	LNB w/OFA	5	0.407	0.552	1.356
2	LNB w/OFA and SNCR	3	0.485	1.083	2.232
3	ROFA w/Rotamix	3	0.514	1.380	2.684
4	ROFA w/SCR	0	0.652	4.718	7.236
5	LNB w/OFA and SCR	0	0.652	5.402	8.285

5.3 Recommendations

5.3.1 NO_x Emission Control

LNB with OFA has been selected as the NO_x reduction technology with a NVE BART Limit (NVEBL) of 0.39 lb/MMBtu averaged on an annual basis. . A unit specific engineering analysis will be performed to determine the required operational and technology options to achieve the NVEBL.

Due to uncertainties in future coal supply, and changes in boiler operation from the current pressurized operation to balanced draft operation, the NVEBL of 0.39 lb/MMBtu on an annual basis was established.

5.3.2 SO_2 Emission Control

The use of the existing wet soda ash FGD system with a NVE BART limit of 0.40 lb/MMBtu averaged on a 24-hour basis is selected as BART for Reid Gardner 3. Although no scrubber upgrades are required to meet the NVE BART Limit, improved operation is anticipated due to the currently planned fabric filter installation. . A unit specific engineering analysis will be performed to determine the required operational and technology options to achieve the NVEBL.

5.3.3 PM_{10} Emission Control

A fabric filter is considered BART for Reid Gardner 3 based on its reduction in PM_{10} emissions with a NVE BART Limit of 0.02 lb/MMBtu averaged on a 3-hour basis. A unit specific engineering analysis will be performed to determine the required operational and technology options to achieve the NVEBL.

5.4 Just-Noticeable Differences in Atmospheric Haze

Conclusions reached in the reference document *Just-Noticeable Differences in Atmospheric Haze* by Dr. Ronald Henry of the University of Southern California, state that only dV differences of approximately 1.5 to 2.0 dV, or more are perceivable by the human eye. Deciview changes of less than 1.5 cannot be distinguished by the average person. 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 scenarios. Thus the results indicate that even though many millions of dollars will be spent, only minimal, if any, noticeable visibility improvements may result.

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. During the period of 2001 through 2003, there were several mega-wildfires that lasted for many days and could have had a major impact of background visibility in these Class I areas. If natural obscuration were to reduce the reduction in visibility impacts modeled for the Reid Gardner facility, the effect would be to increase the costs per ΔdV reduction that are presented in this report.

6.0 References

40 CFR Part 51. 2005. *Regional Haze Regulations and Guidelines for Best Available Retrofit Technology Determinations; Final Rule* (July 6, 2005, pg 39129).

United States Environmental Protection Agency. 1990. *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting.* October 1990.

EPA. 1998. *Interagency Workgroup on Air Quality Modeling (IWAQM) Phase 2 Summary Report and Recommendations for Modeling Long-Range Transport Impacts.* Air Quality Modeling Group (MD-14), Research Triangle Park, North Carolina; National Park Service, Air Resources Division, Denver, Colorado; USDA Forest Service, Air Program, Fort Collins, Colorado; and U.S. Fish and Wildlife Service, Air Quality Branch, Denver, Colorado. December 1998.

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Appendices

APPENDIX A

Economic Analysis

APPENDIX B

BART Protocol