Appendix A

NO_x BART Review for the Mohave Generating Station

RILEYPower
A Babcock Power Inc. Company

NOx BART REVIEW

For

MOHAVE
GENERATING STATION
UNITS 1&2
CLARK COUNTY, NEVADA

Date Issued: July 28, 2008

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APPENDIX A:
Babcock Power Inc. NOx BART Review for the Mohave Generating Station

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1.0 EXECUTIVE SUMMARY

1.1 OBJECTIVE

Evaluate the Mohave Generating Station options to reduce NOx emissions. The predicted NOx values in this report will be used for the preparation of the BART evaluation.

1.2 FINDINGS

The evaluation of the boiler emissions profiles in this report are based on the future predicted operating conditions as shown in Table A-1.

Table A-1 – Predicted Operating Conditions

		Natural Gas Firing Predicted operation	Natural Gas Firing Max. operation
Fuel Flow Rate		7,163,100 SCFH	7,635,659 SCFH
Fuel HHV		1032 Btu/ft³	1032 Btu/ft³
Heat Input (per boiler)	M Btu/hr	7,392.3	7,880.0
Flue Gas Flow (from combustion)	Lb/hr	6,049,300	6,448,300
Air Heater Leakage (12%)	Lb/hr	725,916	773,796
Flue Gas Flow to Stack	Lb/hr	6,775,216	7222,096
FG Temp. Leaving AH	ºF	252	252
FG Temp. Leaving AH	K	395.4	395.4
FG Density (@ temp above)	Lb/ft³	0.053	0.053
Flue Gas Flow Rate (to stack per boiler)	ACFM	2,130,570	2,271,100
Total Flue Gas Flow Rate (to stack – both boilers)	ACFM	4,261,140	4,542,200
Stack Height	ft (m)	500 (152.4)	
Base Site Elevation	ft (m)	712 (217)	
Stack Diameter	ft (m)	32.5 (9.91)	
Flow Area	ft² (m²)	829.6 (77.1)	
Flue Gas Exit Velocity	ft/s (m/s)	85.6 (26.1)	91.3 (27.8)

Utility boilers firing fossil fuels have generally employed two techniques for reducing NOx emissions including modifications to the combustion system and the use of chemical reagents. These methods of NOx control can be used in combination to help further reduce NOx emissions. Each of the different

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emissions controls has inherent advantages and disadvantages that can be compared and evaluated. The three areas that are usually compared and evaluated include: level of NOx reduction, initial "Capital" costs, and annual operating costs.

Modifications to the combustion system are designed to reduce the temperature of the combustion zone thereby reducing the thermal NOx. Typical modifications to the combustion system include:

- Low excess air operation
  - The typical excess air design range for natural gas is 8-12%.
  - Operating at lower excess airs works to reduce the flame temperatures thereby reducing thermal NOx.
  - Low excess air operation can be done in conjunction with low NOx burner modifications and is typically achieved through testing and tuning of the combustion system
  - Low excess air levels can result in an increase in CO emissions
- Operating with Burners out of service
  - Operating with burners out of service is a method of staging the combustion zone with out overfire air ports.
  - This method controls thermal NOx by reducing flame temperatures.
  - Minimal capitol cost to upgrade the combustion control system.
- Low NOx burners
  - Reduces the NOx emissions by controlling the mixing of fuel and air during combustion.
  - Low NOx burners reduce flame temperatures thereby reducing the production of thermal NOx
  - Low NOx burners can be used with Overfire air to achieve further staging of the combustion zone and further NOx reduction.
  - Low NOx burners can also be used in conjunction with Flue Gas Recirculation.
  - Low NOx burners alone are the base case for NOx emissions.
- Overfire air
  - Overfire air ports divert some of the combustion air away from the burners (primary combustion zone) to lower the combustion temperatures and therefore NOx emissions
  - Overfire air ports are typically located above the top row of burners.
  - This technology can be used with other NOx control techniques such as Low NOx burners and Flue Gas Recirculation.

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- Minimal impact on boiler performance and operation (i.e. minimal increase in CO emissions and opacity)
- Modifications include the addition of ductwork, air registers, airflow measurement, and boiler wall openings.

- Flue gas recirculation
  - Flue gas from the outlet of the boiler is mixed with the combustion air to the burners.
  - Reduces the combustion temperatures to achieve a reduction in NOx.
  - Increases the flue gas flow through the convective pass of the boiler thereby increasing heat transfer.
  - Retrofitting the boiler with this system involves new fans, ductwork and dampers, control system, flow measurement and a mixing device.
  - Increase in plant operating cost as a result of the FGR fan motor power absorption.

The second method of NOx control is performed after combustion has taken place and NOx molecules have been formed. NOx reduction in this case is achieved by the use of chemical reaction between the NOx in the flue gas and ammonia. There are two methods that are used to initiate the chemical reaction:

- Selective Non-Catalytic Reduction (SNCR)
  - Ammonia or Urea is injected into the flue gas to act as the chemical reagent in the reaction with NOx.
  - The ammonia or urea is injected in the area were the flue gas is in the temperature range of 1600ºF to 2200ºF.
  - NOx reduction levels is dependent on injection point, residence time within the temperature range, and mixing efficiency.
  - NOx reductions are limited on the Mohave Boilers due to
    - Already low levels of NOx
    - Physical size of the boiler
    - CO levels entering the SNCR zone
    - Temperature profiles in the boiler
    - Low residence times
  - Ammonia slip of 6 ppmv dry corrected to 3% oxygen
  - Modifications include:
    - A reagent transfer, storage and pumping station
    - Reagent transport system (Pumps, flow meters, heaters)
    - Control system
    - Injection equipment including furnace penetrations
- Selective Catalytic Reduction (SCR)
  - Lower reaction temperatures then SNCR (600 – 800 ºF)
  - The reaction takes place in a bed of catalyst.

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- Can be designed as either a stand alone reactor vessel or for natural gas part of the ductwork (in-duct SCR)
- NOx emissions reduction of 90% with an ammonia slip of 2 ppm.
- The addition of a SCR system involves the following modifications and additional equipment:
  - Reagent (ammonia or urea) transfer, storage and pumping station
  - Reagent injection grid and mixing devices
  - SCR system controls for reagent flow, temperature, boiler load, NOx emissions monitoring and control, and system safety
  - Reactor and catalyst
  - Structural considerations for both the reactor and boiler proper
  - FD and ID fan upgrades including their electrical system
  - Boiler system upgrades (e.g., implosion study)
  - Economizer modifications if necessary to achieve proper reactor temperatures over the boiler load range

A summary of the BART technology and cost review are presented in Table A-2. A detailed discussion of NOx formation and control options is provided in the next section.

Table A-2 MGS BART Technology Options Summary

	NOx Emissions (lb/MMBtu)	Capital Costs (10^6 $)	Operating Costs (10^6 $/yr)	Ammonia Slip (ppm)*
LNB + OFA	0.10	8	0	-
LNB+OFA+FGR	0.07	75-150	4	-
LNB+OFA+SNCR	0.08	60	7.5	6
LNB+OFA+SCR (in-line)	0.03	105 – 180	12	2
LNB+OFA+SCR (stand alone)	0.01	200	12	2

*ppmv dry corrected to 3% oxygen

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2.0 DISCUSSION OF NOx FORMATION AND AVAILABLE CONTROLS

2.1 NOx FORMATION

Oxides of nitrogen (NOx) are formed during the combustion process of natural gas via three distinct mechanisms. The first mechanism, called "thermal" NOx, refers to the NOx that is formed through the oxidation of nitrogen that is present in the air and is supplied to complete the combustion process. Thermal NOx typically represents virtually all of the NOx generated during natural gas combustion. The second mechanism, called "fuel" NOx, refers to the NOx that is formed through the oxidation of the nitrogen that is chemically bound in the fuel itself. There is no "fuel" NOx produced during natural gas combustion. The third and final mechanism, "prompt" NOx, refers to the NOx that is formed within the flame front from hydrocarbon fragments that react with molecular nitrogen. Prompt NOx represents a very small amount (approximately 2 – 10 ppm[1]) of the total NOx emissions generated during fuel oil combustion. A review of basic NOx emissions formation during the combustion process is important in understanding how NOx control technologies described in this report act in reducing NOx emissions, their impact on unit operation. This would then allow in the selection of "best available retrofit technology" (BART).

"Thermal" NOx formation has been adequately described by the Zeldovich mechanism and it is dependent on temperature, local fuel and oxygen concentrations and residence time at the reaction temperature. Molecular nitrogen present in the air that is supplied to complete combustion is a fairly inert material, that under high temperatures (typically >2800 °F) it dissociates and reacts with oxygen to form mainly nitric oxide (NO) and small quantities (<5%) of nitrogen dioxide (NO_2). The Zeldovich mechanism indicates that the rate of "thermal" NOx formation is exponentially proportional to temperature of the reaction and proportional to the local oxygen concentration.

"Fuel" NOx is formed by the direct oxidation of the nitrogen that is organically bound in the fuel. It can represent a significant (~ 50%) of the total NOx that is formed and emitted during fuel oil combustion even though a small portion of the fuel bound nitrogen is converted to NOx. Its rate of formation is not dependent on temperature but rather on the oxygen concentration during the early stages of combustion but less so to combustion temperatures.

Since the Mohave units will be converted to natural gas resulting in all of the NOx emissions produced are due to "thermal" NOx.

[1] All ppm numbers referred in this report are by volume, dry and corrected to 3% oxygen

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2.2 NOx EMISSIONS CONTROL

There are basically two techniques that have been used in reducing and controlling NOx emissions generated by utility boilers combusting fossil fuels:

- Modifications to the combustion process
- Use of chemical reagents to reduce NOx to molecular nitrogen

Both of these general techniques by themselves or in combination have been used throughout the industry with various degrees of success to achieve reductions in NOx emissions.

2.2.1 Modifications to the Combustion Process/Optimization

Over the past forty years it has been shown that modifying or "retrofitting" the combustion process through the reduction of oxygen concentrations during the initial stages of natural gas combustion, thereby reducing the temperatures of combustion, and/or reducing the amount of oxygen that is present have resulted in significant reductions in NOx emissions from utility boilers. These modifications to the combustion process have included changes to the unit's operation such as low excess air, burners out of service (BOOS) and general optimization of the combustion system settings or the installation of equipment such as low NOx burners (LNB) and overfire air (OFA) ports.

The Mohave units are tangentially fired supercritical boilers originally designed to fire pulverized coal, natural gas or a combination of both to achieve full load. Typical emissions from these units averaged 0.4 – 0.5 lbs/MBtu fired at full load boiler operation on coal.

2.2.1.1 Low Excess Air Operation

Operating natural gas fired utility boilers at Low Excess Air (LEA) levels is an operational change that has been shown to provide some improvement in NOx reductions. This operation provides for a reduction in the amount of available oxygen to the combustion zone lowering the overall NOx formation stoichiometry and combustion temperatures. A natural gas fired boiler would typically operate at excess air levels of 8 –12%. This level of operating excess air is anticipated for the Mohave units. Further reducing operating excess air levels could have negative emission and operating impact by increasing the amount of combustible losses (e.g., CO and particulates). It is anticipated that the proposed excess air level of 8 –

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12% provides for the best compromise in terms of emissions and unit performance.

This method of NOx control can be used in conjunction with other combustion modifications such as low NOx burners, overfire air and flue gas recirculation. An excess air level of 8-12% is recommended for the design of the fuel burning equipment and after modifications are made the unit may be able to further reduce NOx emissions by lowering excess air levels. Testing and tuning of the combustion system is typically performed when lowering the excess air. This is done while the boiler is on-line so that the overall unit performance (i.e. steam temperatures and CO emissions) can be monitored while changes are being made.

2.2.1.2 Burners-Out-of-Service

Burners-out-of-service (BOOS) is an inexpensive and proven means of achieving staged combustion (i.e., the reduction of burner zone stoichiometry) and subsequent reduction in NOx emissions, without the use of overfire air ports. Staged combustion involves the generation of fuel-rich zone during the initial stages of the fuel combustion that reduces the oxygen concentration and flame temperatures. The remainder of air necessary to complete combustion is added downstream through overfire (OFA) ports in another section of the furnace (i.e., the "second stage") resulting in an overall reduction of NOx emissions. BOOS eliminate the need of capital and installation expenditures of OFA ports. Figure A-1 provides a graphical indication of the BOOS concept.

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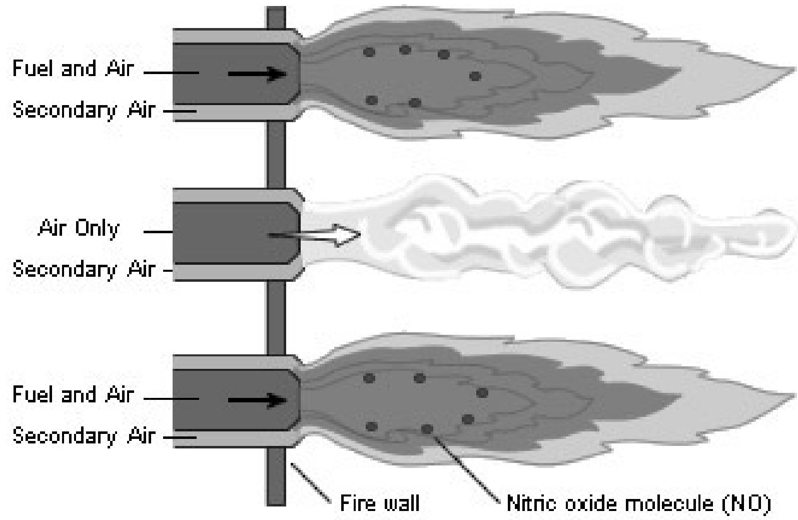

Figure A-1 - Typical Burner out of Service (BOOS) arrangement

BOOS operation is accomplished by eliminating fuel flow to selected burner and only providing air through them. Fuel flow to remaining burners is increased to maintain the heat input required to produce the fuel rich atmosphere required for reducing NOx emissions. The BOOS takes the place of OFA ports and assists in completing the combustion. This technique has been used extensively through out the U.S. on heavy oil and gas fired units over the past 30+ years due to its simplicity and low cost and has resulted in significant (25 – 50%) NOx reductions. Typically the numbers of burners removed from operation in the unit is 20 –25% of the total. Generally removing burners from service in the upper rows of the burner array results in the lowest NOx emission levels.

The advantage of the BOOS technique is that it offers significant NOx emissions reductions, at minimal capital costs, it can be implemented in a short period of time and it is applicable to all types of utility boilers. Large site-to-site variations in the effectiveness of the BOOS technique have been encountered depending on the unit's design, and burner arrangement (the larger number of burners the larger the NOx reduction achieved and design flexibility allowed).

BOOS can be implemented to existing utility boilers without significant modifications to the existing combustion equipment or to the boiler in general. Typically the modifications required would be to upgrade the boiler control system and combustion instrumentation and increasing fuel flow to the reduced number of operating burners.

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The current Mohave units having been designed for pulverized coal and natural gas firing lend themselves to BOOS since the existing burner corner (tangential) openings are oversized for natural gas. The proposed conversion of the units calls for the use of the excess space as overfire (OFA) ports for NOx emissions control.

2.2.1.3 Low NOx Burners (LNB)

Low NOx burners (LNB) are designed to reduce NOx emissions by controlling the mixing of fuel and air during the initial stages of combustion. The basic concept that forms the basis of the LNB design is to delay the mixing of the fuel and air during the initial stages of the combustion process. This delay is achieved through the physical separation of some of the air from the fuel, or through aerodynamic means by imparting swirl to the air, or both. The production of NOx is minimized under these conditions since the availability (concentration) of oxygen to react with the liberated organically bound nitrogen is minimized (see Figure A-2).

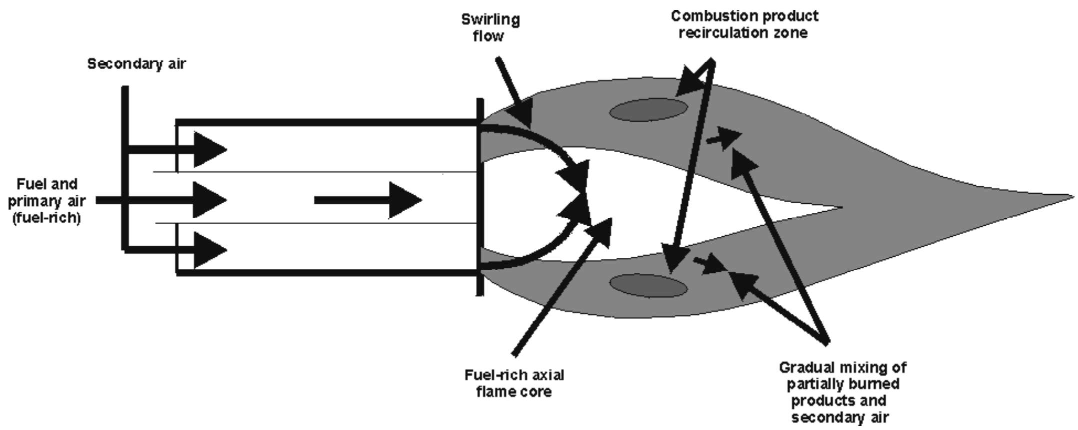

Figure A-2 - Typical Low NOx Burner Concept

The Mohave units are tangentially – fired boilers that are characterized by their inherent lower NOx emissions when compared to wall – fired boilers. Tangentially – fired boilers introduce the fuel and air at the corners of the combustion chamber (furnace) in an alternating manner. As a result the mixing of fuel and air is delayed resulting in lower temperatures and hence lower NOx emissions. It has been shown that the most effective way of reducing emissions in these units is to design OFA ports that further delay the introduction of air in the combustion process further reducing NOx emissions. This is proposed approach for the Mohave units.

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2.2.1.4 Overfire Air (OFA)

Overfire air (OFA) involves the use of air injection ports above the main combustion (burner) zone in the upper furnace to divert a portion of the combustion air away from the initial combustion zone (burners). Figure A-3 shows a typical OFA system for a utility boiler.

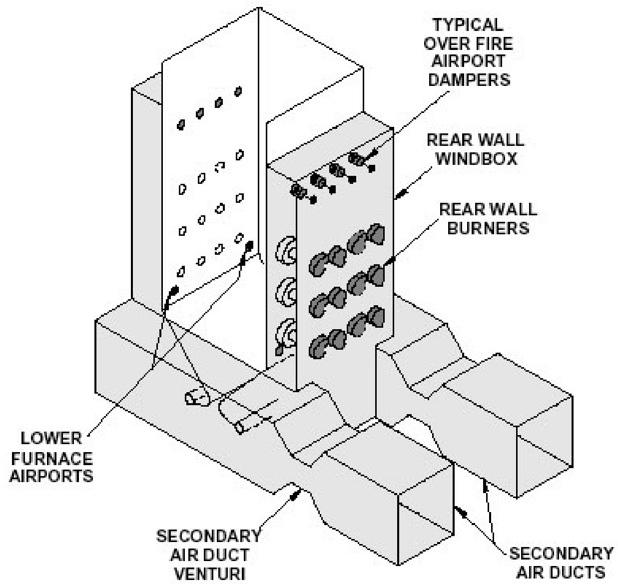

Figure A-3 - Typical OFA system for a wall-fired utility boiler

The quantity of air that is diverted to the OFA ports typically varies from 5 to 25% with the primary objective being to reduce oxygen concentrations and temperatures in the primary combustion zone thereby reducing NOx emissions. The air injected through the OFA ports assists in completing combustion. This technology has been applied to control NOx emissions to power boilers over the past 35+ years with success. The technology can be used in combination with other NOx control techniques such as low NOx burners (LNB), flue gas recirculation (FGR) on several units in the US with success and is applicable to all utility boilers with its effect on NOx reductions being additive. Its success and applicability depends on boiler design (i.e., available boiler height to install the OFA ports and complete combustion) and available space to route the combustion air necessary for the OFA ports.

The NOx reduction that has been achieved with OFA ports has ranged between 10 to 30% with some units as high as 40% from uncontrolled levels. Typical boiler modifications include the addition of new boiler

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wall openings, and an air register assembly to control mixing and flow of the OFA with the furnace gasses. Ductwork that delivers the air from its main supply to the OFA ports is also required along with the necessary structural supports and thermal expansion joints. Flow measurement and control of the air flow to each OFA ports may also be required such that OFA flow can be optimized to maximize NOx emissions reductions with minimal impact on boiler performance and operation (i.e., increased combustibles and opacity).

The Mohave units will be equipped with OFA ports to provide the maximum NOx emissions reduction via retrofit technology resulting in anticipated NOx emissions of 0.1 lbs/MBtu when firing natural gas at boiler full load.

2.2.1.5 Flue Gas Recirculation (FGR)
Flue gas recirculation (FGR) refers to the mixing of the combustion products (flue gas) with combustion air to reduce NOx emissions. FGR lowers oxygen concentration during the initial stages of combustion along with combustion temperature reducing NOx emissions. Since flue gas is inert (consists mainly of nitrogen, carbon dioxide and water vapor) it is important that the oxygen concentration of combustion air/flue gas mixture is kept above 17% (as compared to air of 21%) in order to ensure that sufficient oxygen for the combustion of natural gas is available. Failure to do so could result in unsafe operating conditions.

The flue gas is typically taken from the outlet of the boiler upstream of the air heater and is then mixed with hot combustion air exiting the air heater (see Figure A-4 for typical approaches to FGR).

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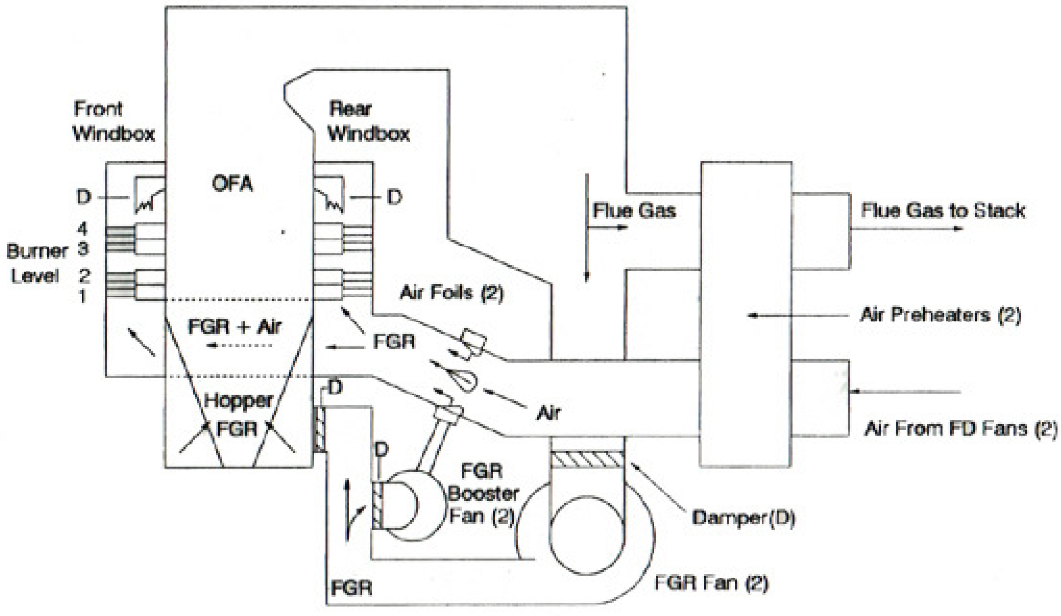

Figure A-4 - Typical utility boiler FGR system

For utility boiler applications the mixture is then transported to the burners (windbox) through the existing combustion air ductwork. To reduce the cost of application "induced" FGR has also been used. During this approach flue gas from the stack is transported to the inlet of the forced draft (FD Fan) using the induction force of the FD fan itself (see Figure A-5).

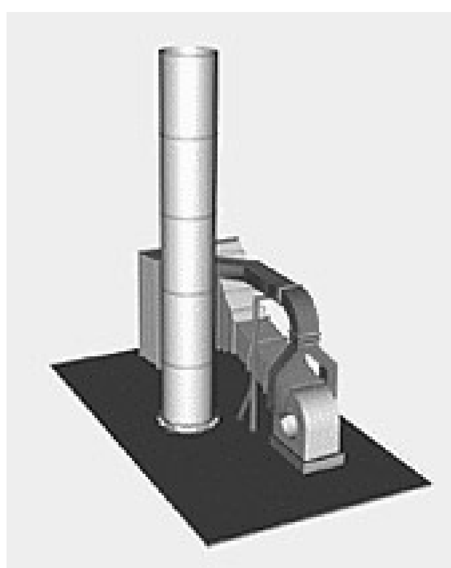

Figure A-5 - Typical Induced FGR system[20]

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This approach is less expensive since it does not require a dedicated FGR fan and mixing device, however is limited to the capability of the existing FD Fan and ductwork.

FGR has been in use for over 30 years on boilers firing natural gas as one of the main techniques in reducing NOx emissions. It has been and can be retrofitted to most utility heavy boilers although an engineering study would need to be performed to establish its compatibility with existing boiler and burner designs. The study should at a minimum establish burner air/FGR flow requirements, air ductwork size and velocities, boiler convective section heat transfer impact, existing fan (forced and induced) capacity, and furnace pressure limits.

The NOx reduction levels achieved though the use of FGR in heavy oil combustion are primarily dependent on: (1) FGR flow rate, (2) excess air levels, (3) burner stoichiometry, and (4) burner/furnace heat release rate. In general FGR is effective in reducing the levels of “thermal” NOx produced due to its dilution effect on the combustion and its reduction of combustion temperatures. Typically the NOx reductions that are achieved with the use of FGR range on the order of 20 – 50% from uncontrolled levels.

To retrofit FGR in a natural gas fired boiler one would need to establish first if the unit has an existing FGR system for controlling steam temperatures. If the boiler is equipped with an existing FGR system the capability of the existing FGR fan would need to be evaluated to establish if it can provide the necessary flows and pressures required for NOx control FGR system. If the existing fan is not adequate (typically existing FGR fans are not capable) it needs to either be upgraded or replaced and the existing motor electrical system be upgraded. If the unit does not have an existing FGR fan a new fan along with the necessary equipment (transformer, switchgear, etc.) will need to be purchased and installed, along with the necessary ductwork from the boiler (extraction point), to the fan and then to the combustion air duct. Mixing devices to thoroughly mix the gas with the air and gas flowing measuring devices will also need to be supplied. It is not advisable to mix FGR with the OFA, so if the unit is already equipped with OFA a “fresh” air system needs to be maintained to supply the OFA.

FGR can have some significant impacts on boiler operation and its implementation needs to follow a careful study. Since it dilutes the oxygen content of the combustion air careful consideration should be

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given to flame (combustion) stability. This is typically done by limiting the amount of FGR that is mixed with the combustion air to the mixture minimum oxygen content of 17%.

The addition of FGR increases the total mass flow of the flue gases passing the boiler's convective heat transfer surfaces (i.e., superheater, reheater, and economizer). This results in increased heat transfer and hence in increased steam and heating surface metal temperatures leading to premature failures. This increase in flow is most critical during boiler full load operation while at lower loads the increased FGR flow could be helpful in meeting steam temperature requirements. Careful operation will be required to minimize furnace vibrations that are the result of flame instability and the emissions of combustibles (CO), opacity and particulates that could result from the application of FGR.

The capital costs of FGR systems are estimated to be in the range of $35 - $50[2]/kW, however if significant upgrades to existing equipment are required such as modifications of heating surfaces, FGR fan replacement, boiler structural and controls upgrades, these costs could be significantly higher. "Induced" FGR implementation has significantly lower costs (<$40/kW) due to the elimination of the FGR dedicated fan and its ancillary equipment and controls, along with a significant reduction in FGR ductwork.

A review of the Mohave units indicates that the applicability of FGR recirculation would provide some reduction in NOx emissions (from 0.1 to 0.075 lbs/MBtu) however at a high cost of retrofit. Specifically the following modifications to the unit will be required:

- Installation of two FGR recirculation fans per unit
- Installation of required switchgear for the fan motors
- Flue gas and air mixing devices
- Removal/addition of convective section surface
- Upgrade of furnace materials
- Modifications to unit's control system
- Addition of "fresh" air system for the OFA ports

The addition of the FGR system would represent increased operating costs due to the power required to operate the FGR fans as well as increased unit maintenance. The addition of an "induced" FGR

[2] ***The costs included in this report have been adjusted to reflect 2004 costs in US $, however over the past four years there have been unprecedented increases in the price of steel, and materials in general***

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system was also evaluated, and it was deemed not to be cost effective since the Mohave units are pressurized. The IFGR system to be applied at the Mohave units would require their conversion to balanced draft necessitating the addition of Induced Draft (ID) fans and re-enforcement of the units to withstand the significant increase in negative pressure from the current design.

2.2.2 Post – Combustion NOx Emissions Control

NOx emissions can be controlled following their generation from the combustion of fossil fuels through the use of chemical reagents such as ammonia or urea. There are two major commercially available processes that can be used using this basic principle:

- Selective Non – Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

In both of these processes the following chemical reaction forms the basis for the reduction of NOx:

$$2NH_3 + 2NO + 1/2O_2 \rightarrow 2N_2 + 3H_2O \qquad (1)$$

Urea has also been used as an ammonia (NH_3) substitute with the overall NOx reduction reaction being:

$$(NH_2)_2CO + 2NO + 1/2O_2 \rightarrow 2H_2O + CO_2 + 2N_2 \qquad (2)$$

The basic difference between these process (SNCR and SCR) is that in the SCR process reaction (1) is used and is assisted through the use of a catalyst.

2.2.2.1 Selective Non – Catalytic Reduction (SNCR)

The Selective Non – Catalytic Reduction (SNCR) process is accomplished within the boiler and typically uses ammonia (NH_3) or urea [$(NH_2)_2CO$] as the chemical reagent. Either of those reagents can be injected directly into the flue gas to react and reduce NOx according to reactions (1) or (2) above. The optimum reaction temperature for either reaction is in the range of 1600 to 2200 °F. This is a critical process parameter in that injection at higher temperatures (>2200 °F) would result in the conversion of ammonia or urea to NOx while injection at lower temperatures (<1600 °F) would result in the reagent remaining un-reacted (increased quantities of ammonia slip).

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Urea based SNCR uses an aqueous solution of urea (typically 30 – 50% by weight) while the ammonia process uses either anhydrous or aqueous solution. The injection location of the reagent is important and should be given careful consideration. To allow for better mixing and for variation of flue gas temperatures as a result of boiler load variations multiple injection ports and levels have been used in commercial applications of the SNCR process. The majority of experience with SNCR systems is with urea based systems. A typical utility SNCR system is shown in Figure A-6.

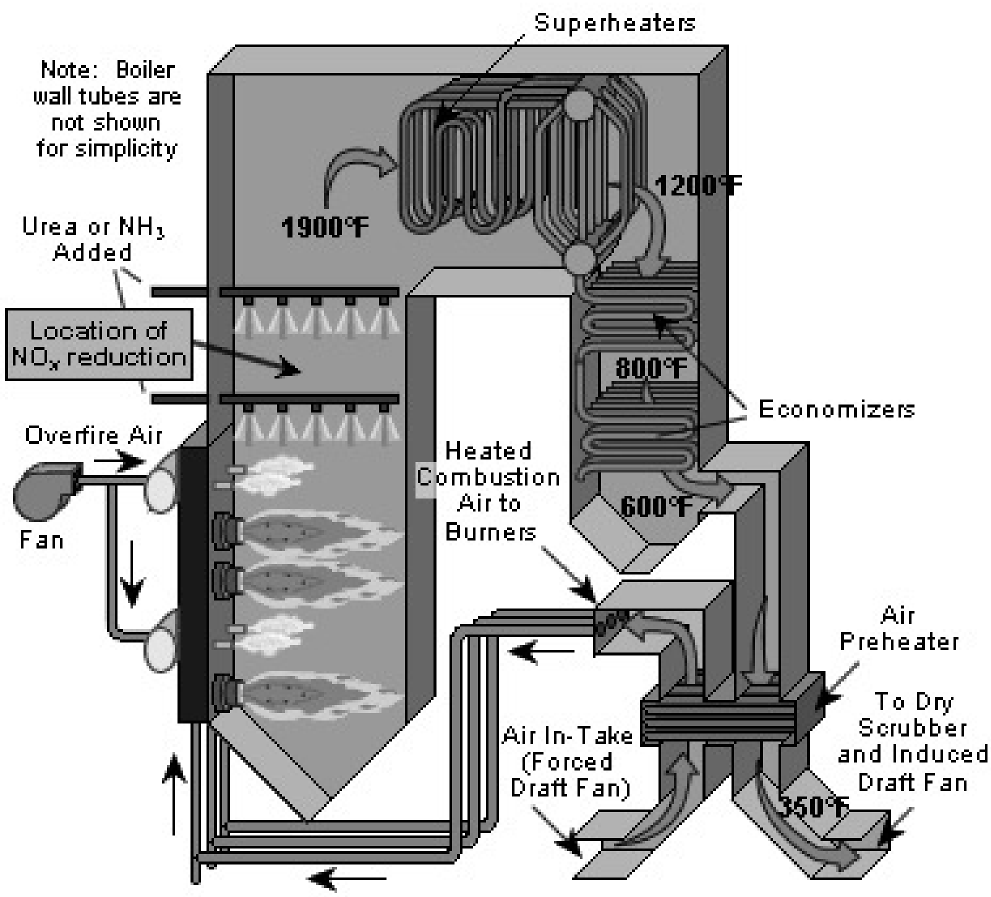

Figure A-6 - Typical SNCR system for utility boiler application

The temperature of flue gas at the point of reagent injection and the available residence time within the optimum reaction temperature window along with mixing efficiency are the key ingredients in achieving maximum NOx reductions with the SNCR process. The SNCR process can be retrofit to most if not all residual oil fired utility boilers however the NOx reductions achieved are very site specific

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since they are highly dependent on the temperature and residence time profiles of the individual boiler. It is therefore recommended that a study is performed to establish the residence times of the flue gases in the reaction temperature window, the location of the temperature window, ease of access for installation of the reagent injection ports at that temperature window, and the ability to achieve rapid and complete mixing of the reagent within that temperature window.

Typical boiler modifications and equipment required for retrofitting SNCR to a natural gas boiler include:

- Urea or ammonia loading and storage station including safety equipment for the prevention of spills and reagent escape
- Reagent transport equipment, including pumps, flow meters, controls, heaters and carrying medium (e.g., air) if required
- Reagent injection equipment (e.g., lances), installation of furnace penetrations at the appropriate location
- Process control system to control injection rates as a function of boiler load and NOx emissions levels required

A SNCR process schematic is shown in Figure A-7.

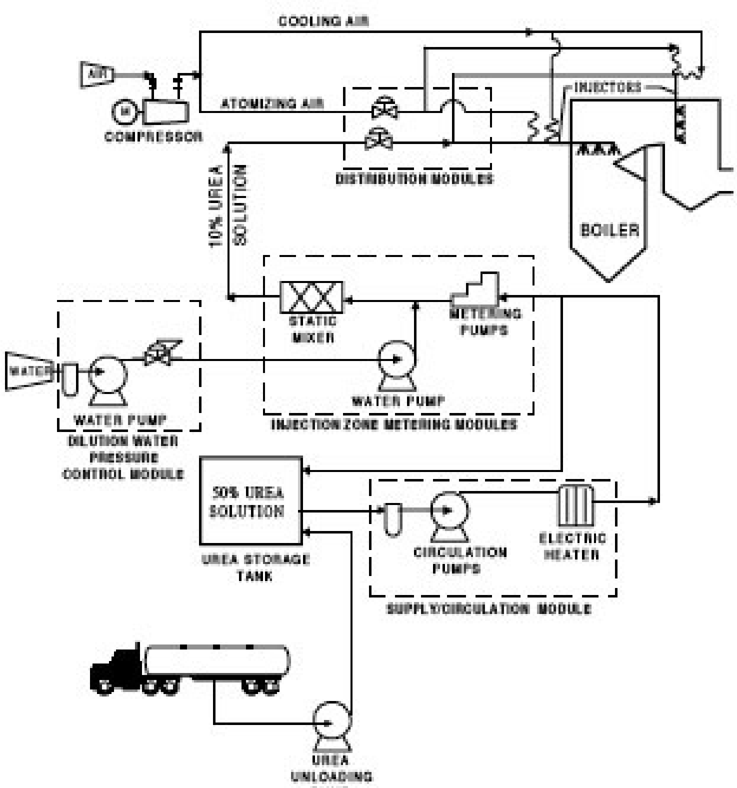

Figure A-7 - SNCR process schematic

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Typical capital costs of the SNCR process range from \$20 to \$40/kW. The cost of the reagents is a major operating expense with the cost of ammonia and urea being tied to the cost of natural gas. Typical operating and maintenance (O&M) costs range from \$1 to \$5/kW-yr, while annualized technology costs are \$3 - \$30/kW.

An analysis of the Mohave units indicates that NOx emissions reductions using NSCR will be only on the order of 15 – 25% in addition to those achieved with OFA. The primary reasons for these low reductions are:

- Low NOx levels flowing into the SNCR control zone
- The unit's physical size
- CO levels entering the SNCR
- Temperature levels present in the boiler
- Low available residence times in the appropriate temperature window

2.2.2.2 Selective Catalytic Reduction (SCR)

The Selective Catalytic Reduction (SCR) process involves the following two chemical reactions:

$$2NH_3 + 2NO + 1/2O_2 \rightarrow 2N_2 + 3H_2O \qquad (3)$$

$$4NH_3 + 2NO_2 + O_2 \rightarrow 3N_2 + 6H_2O \qquad (4)$$

Ammonia (NH_3) is injected and mixed with the products of combustion (flue gases) and reacts with NOx over a bed of catalyst producing molecular nitrogen and water vapor. The use of catalyst lowers the reaction temperature from the typical 1600 – 2100 °F to a 600 – 800 °F. Since over 95% of the NOx contained in the flue gases consists of NO reaction (3) above is the predominant reaction. Approximately one mole of ammonia (17 lbs by weight) to one mole of NO (30 lbs by weight) is required to produce NOx emissions reductions of 90% at an ammonia slip (un-reacted) level of 2 ppm. The ammonia reagent is typically anhydrous or aqueous ammonia or derived through the thermal hydrolysis of urea.

SCR catalysts generally consist of a base material such as titanium oxide (TiO_2) or a zeolite. The primary ingredient is vanadium pentoxide (V_2O_5) including some other metals such as molybdenum, cobalt, tungsten, chromium, iron, nickel and chromium. Structurally here are three basic types of catalysts:

- Honeycomb
- Plate

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- Corrugated

All three have been used in residual oil applications however the most commonly used has been the honeycomb. Catalyst is specified according to the NOx removal rate required, hours of life, ammonia "slip", space velocity, and pitch (e.g., the size of each honeycomb). Typical pitch for heavy oil applications ranges between 3.5 to 7 mm depending on the ash content of the fuel. The volume of catalyst required depends on the operating temperature, NOx removal required, and gas flow (i.e., boiler size).

The vessel (reactor) where the reducing reaction takes place contains the catalyst and is typically located between the boiler outlet and the air heater due to the NOx reduction reaction temperature requirements (see Figure A-8).

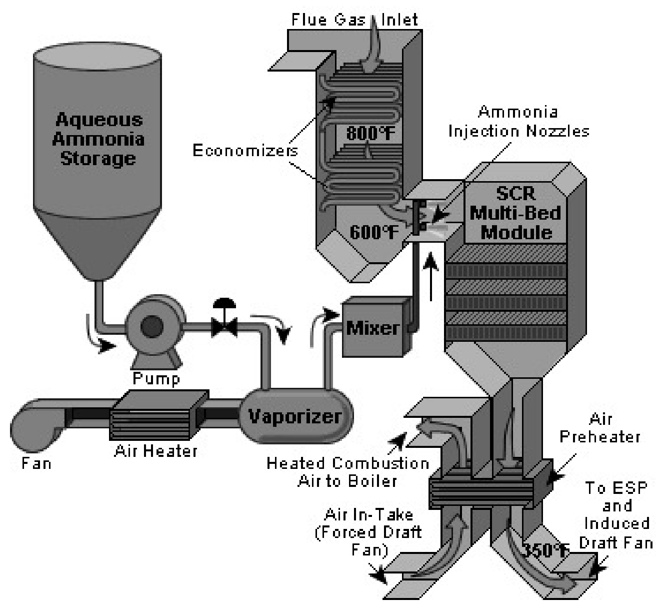

Figure A-8 - Typical aqueous ammonia SCR system for utility boiler with separate reactor

In some applications where there is no available space the SCR system has been located close to the boiler stack downstream of the air heater and other air pollution control devices. In those cases the flue gas needs to be reheated to achieve proper reaction temperatures. The benefits of this approach is lower construction costs, reduced size of catalyst (clean flue gas), however increased operating costs due to the reheating of the flue gas and the increased capital costs (purchase of

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gas – to – gas heat exchanger) make the overall costs of this design higher.

For natural gas applications the reactor can be a separate vessel or it can be part of the ductwork or as is commonly called "in-line" (see Figure A-9).

In-line SCR systems are typically applied to residual oil and gas fired units. Due to the lower velocities (approximately half to one-third of typical flue gas velocities) required for the NOx reduction reaction to take place in the catalyst laden reactor the existing ductwork is replaced with larger size.

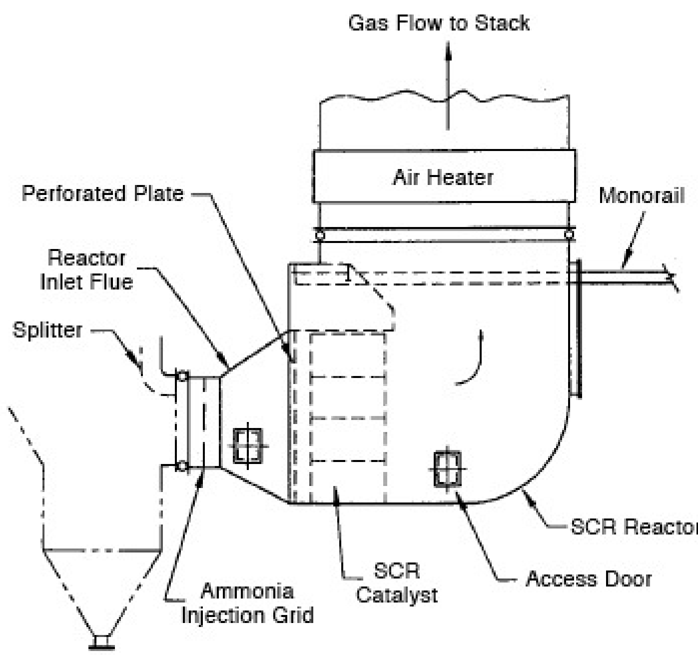

Figure A-9 - In-line SCR system for natural gas-fired boiler application

The addition of a SCR system is a major project, requiring careful study and typically involves the following modifications and additions:

- Reagent (ammonia or urea) transfer, storage and pumping station
- Reagent injection grid and mixing devices

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- SCR system controls for reagent flow, temperature, boiler load, NOx emissions monitoring and control, and system safety
- Reactor and catalyst
- Structural considerations for both the reactor and boiler proper
- FD and ID fan upgrades including their electrical system
- Boiler system upgrades (e.g., implosion study)
- Economizer modifications if necessary to achieve proper reactor temperatures over the boiler load range

A typical ammonia storage and supply system schematic for utility boiler application is shown in Figure A-10.

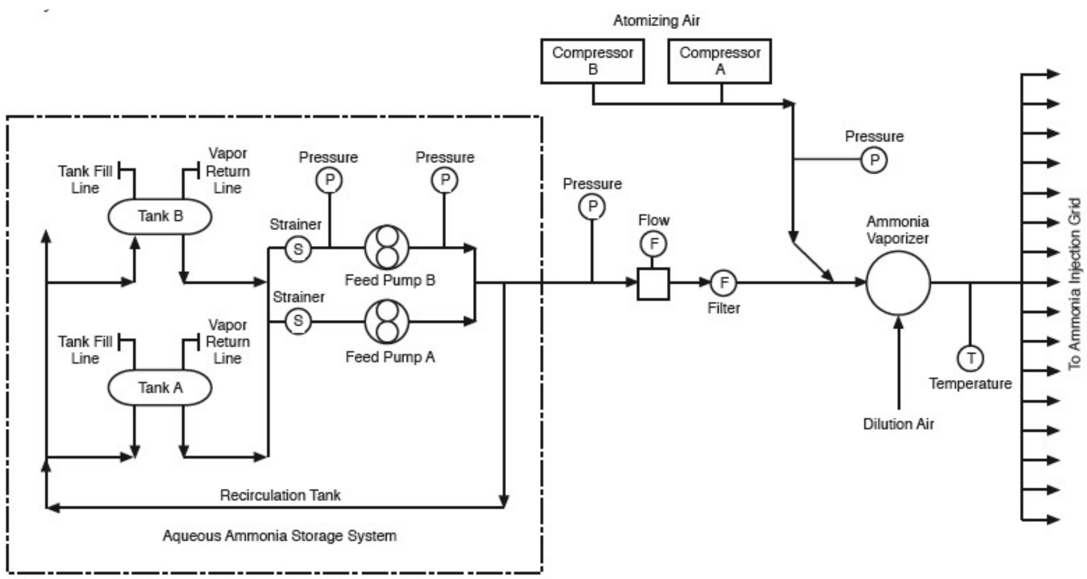

Figure A-10 - Typical ammonia storage and supply system

The capital costs of the application of SCR to a natural gas unit range from $70 to $120/kW depending on unit size, available space, and SCR design (separate versus "in-line" reactor). In-line SCR is less expensive. O&M costs average about $8/kW-yr while overall technology annualized costs average about $12/kW.

SCR systems have been applied extensively throughout Japan, Europe and the U.S. In the U.S. approximately 100 GW of electric generation has been equipped with SCR systems and of those approximately 6 GW are oil and natural gas fired units (mainly gas fired in California). The NOx removal efficiency has been averaging 85% to 90% for all those units with levels as low as 10 ppm for gas fired utility boilers.

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The installation of SCR on a natural gas fired boiler would increase overall system pressure drop (approximately 6 – 8 inches w.c.) resulting in increased fan power consumption and loss of overall plant efficiency.

The application of an in-line SCR system at the Mohave units would require the following systems:

- Ammonia, or aqueous ammonia or urea storage and supply system
- Modification to the boiler's flue system (between economizer outlet and air heater inlet) to provide catalyst space
- Catalyst
- Addition of mixing devices and reagent injection system
- Control system additions and modifications
- Conversion of the unit to balanced draft
- Installation of ID fan(s) and necessary switchgear

It is estimated that the cost of in-line SCR addition at the Mohave units will be in the order of $130 - $150 million. The cost of the conversion to balanced draft would increase the project cost by an additional $30 - $50 million.

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Appendix B

Guidance on CALMET Settings

National Park Service guidance on CALMET settings

-----Original Message-----
From: John_Notar@nps.gov [mailto:John_Notar@nps.gov]
Sent: Monday, November 28, 2005 3:20 PM
To: Paine, Bob; Bohning.Scott@epamail.epa.gov
Cc: Don_Shepherd@nps.gov; Connors, Jeffrey; John_Vimont@nps.gov;
John_Notar@nps.gov
Subject: RE: Desert Rock protocol
Importance: High

Bob: Yes we agree that you should make the CALMET runs with the "R"
settings below.
thanks
John Notar
National Park Service
Air Resources Division
12795 W. Alameda Pkwy.
Lakewood, CO 80228
Phone: 303-969-2079
Fax: 303-969-2822
E-Mail: john_notar@nps.gov

"Paine, Bob"
<BPaine@ensr.com> To: <John_Notar@nps.gov>
cc:
<Bohning.Scott@epamail.epa.gov>, <Don_Shepherd@nps.gov>, "Connors,
11/28/2005 03:08 Jeffrey" <JConnors@ensr.com>,
<John_Vimont@nps.gov>
PM EST Subject: RE: Desert Rock
protocol

John,

Just so I understand it, the final settings for the range of available
MM5 files are as follows:

4-km MM5 (assorted periods in 2001, 2003, and 2004, in addition to the
three full years of 2001-2003 with other grid resolutions):
TERRAD=10km
R1=2
R2=20
RMAX1=6
RMAX2=30

12-km MM5 (all of 2002):
TERRAD=10km
R1=6
R2=20
RMAX1=12
RMAX2=30

20-km RUC (all of 2003):
TERRAD=10km
R1=10
R2=20
RMAX1=20
RMAX2=30

36-km MM5 (all of 2001):
TERRAD=10km
R1=18
R2=20
RMAX1=30
RMAX2=100

Please confirm.

Bob

Excerpts from recent EPA Region IX guidance on BART modeling for Navajo Nation EGUs

1) CALMET settings

“After discussion with Federal Land Managers representatives, we request the following changes to input switches for the CALMET meteorological processor:

- NOOBS = 0, to use both surface and upper observations;
- IEXTRP = -4, to extrapolate surface wind observations to the upper layers using similarity theory, and ignore layer 1 from the upper air soundings;
- ITPROG = 1, to use surface station temperature and the MM5 for upper air.

These settings are more appropriate for BART determination modeling, as opposed to ‘subject to BART’ modeling that the WRAP modeling protocol addressed.”

2) Ammonia background

“We withdraw the request for additional reprocessing using a 1 ppb ammonia background concentration, as we believe the background values already used are appropriate.”

Appendix C

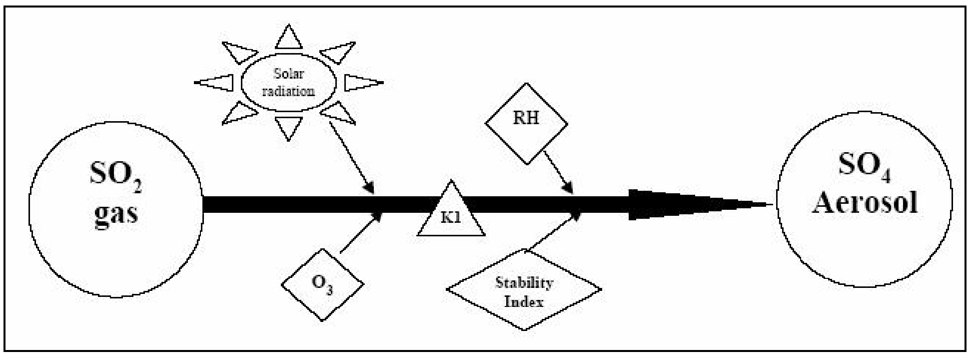
Factors Influencing NO_x Emissions Effects on Visibility

Secondary pollutants such as nitrates and sulfates are significant contributors to the visibility extinction in Class I areas. The CALPUFF model was used to determine the effect of these pollutants on Class I areas, associated with the candidate BART control options. CALPUFF uses the EPA-approved MESOPUFF II chemical reaction mechanism to convert SO_2 and NO_x emissions to secondary sulfates and nitrates. The discussion below describes how the secondary pollutants are formed and the factors affecting their formation.

Formation of Sulfates

The rate of transformation of gaseous SO_2 to ammonium sulfate $(NH_4)_2SO_4$ aerosol is dependent upon solar radiation, ambient ozone concentration, atmospheric stability, and relative humidity, as shown in Figure C-1 (taken from the CALPUFF users guide, 2000). Homogeneous gas phase reaction is the dominant SO_2 oxidation pathway during clear, dry conditions (Calvert et al., 1978). CALPUFF assumes that the sulfate reacts preferentially with ammonia (NH_3) to form ammonium sulfate and that any remaining ammonia is available to form ammonium nitrate (NH_4NO_3).

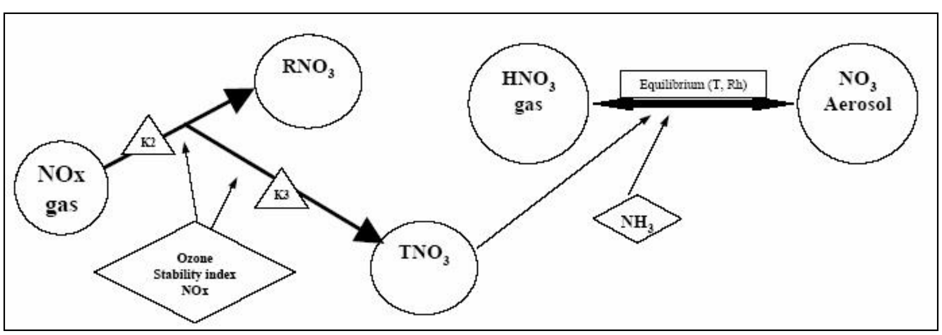
Figure C-1 MESOPUFF II SO_2 Oxidation



Formation of Nitrates

The oxidation of NO_x to nitric acid (HNO_3) depends on the NO_x concentration, ambient ozone concentration, and atmospheric stability. Some of the nitric acid is then combined with available ammonia in the atmosphere to form ammonium nitrate aerosol in an equilibrium state that is a function of temperature, relative humidity, and ambient ammonia concentration, as shown in Figure C-2 (from the CALPUFF users guide).

Figure C-2 MESOPUFF II NO_x Oxidation

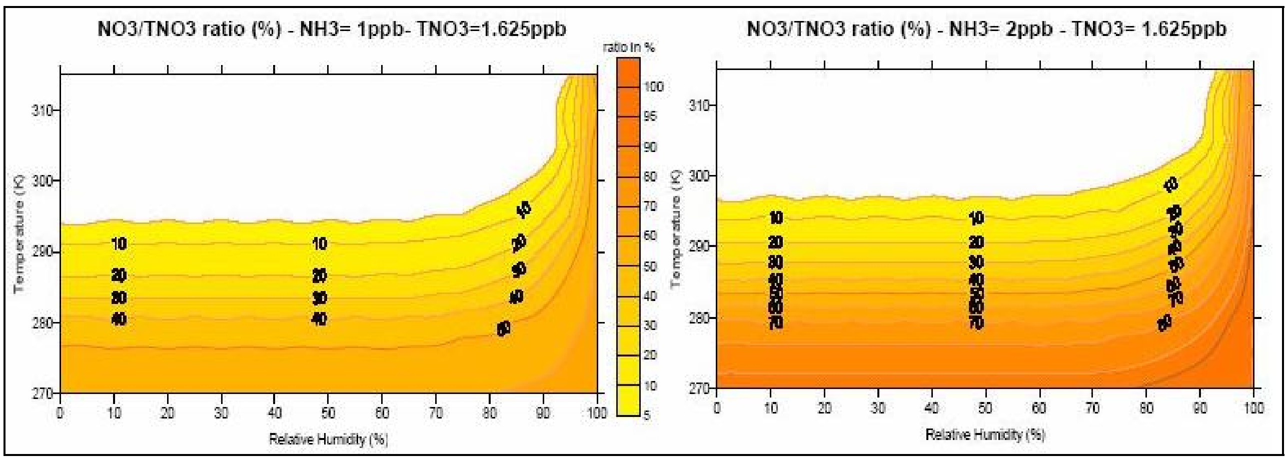


In CALPUFF, total nitrate ($TNO_3 = HNO_3 + NO_3$) is partitioned into each species according to the equilibrium relationship between gaseous HNO_3 and NO_3 aerosol. This equilibrium is a function of ambient temperature and relative humidity. Moreover, the <u>formation of nitrate strongly depends on availability and amount of NH_3 to</u>

form ammonium nitrate, as shown in Figure C-3 (from CALPUFF courses given by TRC). The figure on the left shows that with 1 ppb of available ammonia and fixed temperature and humidity (for example, 275 deg K and 80% humidity), only 50% of the total nitrate forms particulate matter. When the available ammonia is increased to 2 ppb, as shown in the figure on the right, as much as 80% of the total nitrate is in the particulate form. Figure C-3 also shows that colder temperatures and higher relative humidity significantly favor nitrate formation and vice versa. A summary of the conditions affecting nitrate formation are listed below:

- Colder temperature and higher relative humidity create favorable conditions to form nitrate particulate matter, and therefore more ammonium nitrate is formed;
- Warm temperatures and lower relative humidity create less favorable conditions to form nitrate particulate matter, and therefore less ammonium nitrate is formed;
- Sulfate preferentially scavenges ammonia over nitrates. In areas where sulfate concentrations are high and ambient ammonia concentrations are low, there is less ammonia available to react with nitrate, and therefore less ammonium nitrate is formed.

Figure C-3 NO_3/HNO_3 Equilibrium Dependency on Temperature and Humidity



Ambient Ammonia Background Concentrations

CALPUFF modeling of the baseline and BART control options emissions was conducted with the following sets of background ammonia values. The actual ammonia values used for each of the eleven Class I areas are listed in Table C-1.

- Class I areas located in areas of higher ammonia emission sources (shown in Figure B-4) and with mild winters are modeled with ammonia background of 1 ppb all year, in accordance with the WRAP BART protocol. These Class I areas are: Joshua Tree W, San Gorgonio W, Agua Tibia W, San Jacinto W, Domeland W, and Cucamonga W. The ammonia background of 1 ppb is used to model the baseline, BART option 3 (LNB/OGA/FGR) and option 5 (LNB/OFA) emissions.

- Class I areas located in the region of sparse ammonia emission sources (shown in Figure B-4) and with more substantial winter seasons are modeled with monthly variable ammonia background that have been approved for multiple PSD projects by the Federal Land Managers. The monthly ammonia background values are 0.2 ppb in January-February and December; 0.5 ppb in March-April and October-November; and 1 ppb in May-September). The Class I areas assigned these background values are Grand Canyon NP, Zion NP, Sycamore Canyon W, Pine Mountain W, and Mazatzal W.

The ammonia background values mentioned above were recently approved by the Federal Land managers for the nearby Toquop Energy Project (TEP) PSD permit application (northwest of Mesquite, Nevada) and also previously for the Desert Rock Energy Facility PSD permit application (Navajo Nation, New Mexico). These background ammonia values are based upon direct measurements (some in the Grand Canyon) as well as seasonal considerations. In general, it is important to note that the likely over-prediction by CALPUFF of nitrates in winter as noted by Morris et al. (2005) can be partially addressed by using a monthly variation of background ammonia concentrations. The default value of 1.0 ppb for arid lands as referenced in the IWAQM Phase 2 document (1998) is valid at 20°C, but the same document cites a strong dependence with ambient temperature, with variations of a factor of 3-4. This same dependence is seen at the CASTNET monitor at Bondville, Illinois (see page 5 at http://www.ladco.org/tech/monitoring/docs_gifs/NH3proposal-revised3.pdf). In addition, a study of light-affecting particles in southwest Wyoming indicated that nitrates were over-predicted by a factor of 3 for a constant ammonia concentration of 1.0 ppb, and by a factor of 2 for an ammonia concentration of 0.5 ppb (see slide 57 at http://www.air.dnr.state.ga.us/airpermit/psd/dockets/longleaf/facilitydocs/050711_CALPUFF_eval.pdf). Since there are no large sources of ammonia due to agricultural activities the Class I areas in Arizona and Utah, it is appropriate to introduce a monthly varying ammonia background concentration to the CALPUFF modeling. These ammonia background concentrations without change (ignoring additional ammonia from the plant itself) for all BART options except for SNCR operation.

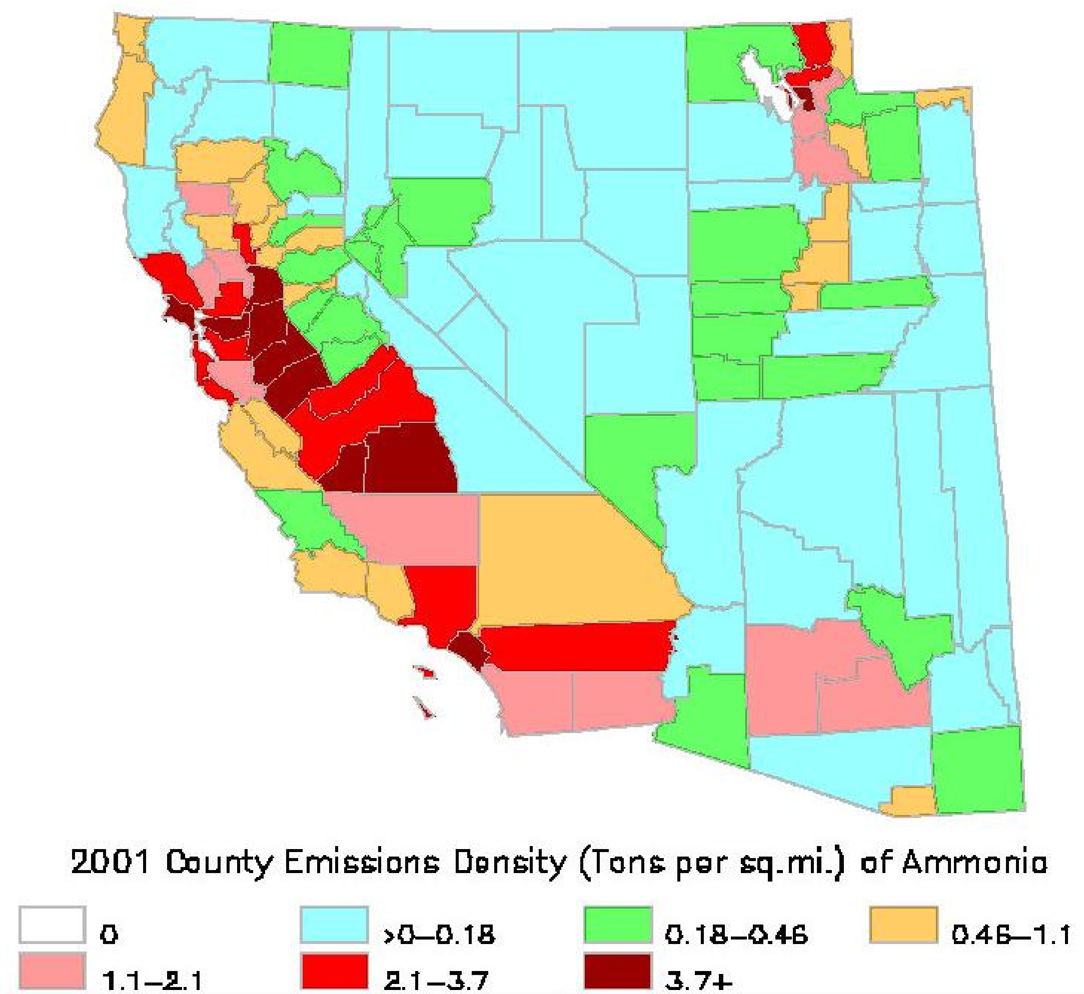
- Excess ammonia emissions associated with SCR as well as SNCR operations were modeled with CALPUFF to determine the 8^{th} highest 24-hour ammonia concentration averaged over three meteorological years in all Class I areas. Predicted ammonia concentrations were less than 10% of the background ammonia concentrations at all Class I areas except for the Grand Canyon NP (winter months only) for SNCR operation, so only the winter season background concentrations at the Grand Canyon were adjusted upward by 0.04 ppb (only for SNCR operation) to account for the additional ammonia due to plant emissions, as shown in Table C-1. The POSTUTIL program (CALPUFF post-processor) was used to re-compute regional haze impacts with the adjusted ammonia background at Grand Canyon.

As discussed above, the formation of nitrate is highly sensitive to availability of ammonia to form ammonium nitrate. Ammonium nitrate is a visibility-degrading pollutant. For the purpose of evaluating NO_x emissions control options, the ambient ammonia background concentrations at the Grand Canyon were refined to factor in excess ammonia emission increases associated with SNCR operations. The installation of SCR creates slightly higher levels of primary sulfate emissions (H_2SO_4) that were also accounted for in the CALPUFF modeling.

Table C-1 Ambient Ammonia Background Concentrations

Class I Area	January – February	March – April	May – September	October – November	December	Modeling Option
Grand Canyon NP	0.2	0.5	1	0.5	0.2	baseline, 1-3, 5
	0.24	0.5	1	0.5	0.24	4
Zion NP	0.2	0.5	1	0.5	0.2	baseline, 1-5
Sycamore Canyon W	0.2	0.5	1	0.5	0.2	baseline, 1-5
Pine Mountain W	0.2	0.5	1	0.5	0.2	baseline, 1-5
Mazatzal W	0.2	0.5	1	0.5	0.2	baseline, 1-5
Domeland W	1	1	1	1	1	baseline, 1-5
Joshua Tree W	1	1	1	1	1	baseline, 1-5
San Gorgonio W	1	1	1	1	1	baseline, 1-5
Agua Tibia W	1	1	1	1	1	baseline, 1-5
San Jacinto W	1	1	1	1	1	baseline, 1-5
Cucamonga W	1	1	1	1	1	baseline, 1-5

Figure C-4 Ammonia Emissions Density



Appendix D

Re-Calculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

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Instructions:
A Postprocessor for Recalculating CALPOST Visibility Outputs with the New IMPROVE Algorithm

Version 2
14 October 2006

Introduction

CALPOST can be used to processes outputs from CALPUFF modeling of a source's emissions to calculate the 24-hr average visibility impairments caused by primary and secondary particulate matter attributable to emissions from the modeled source. Those increments are presented in two tables, both labeled "Ranked Daily Visibility Change", in the CALPOST output (.LST) file. The table of interest to us has the subtitle "Modeled Extinction by Species" and lists the dates and locations of such incremental impacts in light extinction (b_{ext}) in ranked order, starting with the one that represents the largest percentage change in light extinction.[1]

In addition, with a different setup of the control file CALPOST.INP, the CALPOST postprocessor can be used to calculate 24-hr averages of NO_x concentrations. As described below, the outputs from that additional CALPOST run can be used to assess the visibility impact of the NO_2 gas in the source plume.

Visibility effects due to particulate matter are calculated in CALPOST from CALPUFF-modeled particulate matter component concentrations using effectively the "traditional" IMPROVE algorithm. CALPOST allows for choice of the humidity scattering enhancement function (f(RH)) to be used with the IMPROVE algorithm; for modeling in connection with the US EPA's Regional Haze Regulations (RHR), the appropriate form of f(RH) is the one described and tabulated in the EPA's 2003 guidance for tracking progress under the RHR. Visibility effects due to NO_2 are not considered in the CALPOST visibility calculation.

Recently, the IMPROVE Steering Committee developed a new algorithm for estimating light extinction from particulate matter component concentrations. This algorithm (the "new IMPROVE algorithm") provides a better correspondence between the measured visibility and

---

[1] The other table in the CALPOST visibility output file, with the subtitle "% of Modeled Extinction by Species", provides equivalent results in terms of changes in the haze index, in deciviews. The two tables represent the same results, with identical ranking of events, while just using different (but mathematically related) metrics.

that calculated from particulate matter component concentrations. The new algorithm differs in several substantive ways from the traditional one:

- The extinction efficiencies of sulfates, nitrates, and organics have been changed and are now functions of their concentrations. The extinction efficiencies of sulfate and nitrate are no longer identical, although the new hygroscopic scattering enhancement factors applied to them are the same.

- The concentration of particulate organic matter (POM; variously also labeled OCM or OMC, and sometimes just called "organics") is now taken to be 1.8 times that of the measured organic carbon (OC) concentration. (Confusingly, CALPOST labels the organics concentration as OC.)

- The contribution of fine sea salt to light extinction has been added, and is accompanied by its own hygroscopic scattering enhancement factor, $f_{ss}(RH)$.

- The light scattering by air itself (Rayleigh scattering) now varies with site elevation and mean temperature. It is to be rounded off to the nearest one Mm^{-1} when used with the new algorithm.

- The light absorption by NO_2 gas has been added.

The new IMPROVE algorithm is represented by the following formula:[2]

$$\begin{aligned} b_{ext} = \; & 2.2 \cdot f_S(RH) \cdot [small\ sulfate] + 4.8 \cdot f_L(RH) \cdot [large\ sulfate] \\ & + 2.4 \cdot f_S(RH) \cdot [small\ nitrate] + 5.1 \cdot f_L(RH) \cdot [large\ nitrate] \\ & + 2.8 \cdot [small\ organics] + 6.1 \cdot [large\ organics] \\ & + 10 \cdot [elemental\ carbon] \\ & + 1 \cdot [fine\ soil] \\ & + 1.7 \cdot f_{SS}(RH) \cdot [sea\ salt] \\ & + 0.6 \cdot [coarse\ matter] \\ & + Rayleigh\ scattering\ (site\ specific) \\ & + 0.33 \cdot [NO_2(ppb)] \end{aligned} \qquad \text{(Eq. 1)}$$

The concentrations of "large" and "small" sulfate particles are calculated as follows:

$$[large\ sulfate] = \{[total\ sulfate]/20\} \cdot [total\ sulfate]\ if\ [total\ sulfate] < 20\ \mu g^3$$

$$[large\ sulfate] = [total\ sulfate]\ if\ [total\ sulfate] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. 2)}$$

$$[small\ sulfate] = [total\ sulfate] - [large\ sulfate].$$

Identical formulas, with changes in component names, are used for nitrate and organics. In effect, these formulas conclude that low concentrations of these components are mainly in the form of "small" particles with their own extinction efficiency and $f_S(RH)$, while high

[2] Square brackets denote concentrations.

concentrations (approaching 20 $\mu g/m^3$) are mainly in the form of "large" particles with a different extinction efficiency and $f_L(RH)$. The scaling factor [total sulfate]/20 sets the fraction of total sulfate that is small.

The sea salt concentration is taken to be 1.8•[Cl^-] or, if chloride ion measurements are not available, the chlorine concentration can be used in its place. Site specific Rayleigh scattering values have been calculated for all IMPROVE sites.[3] Nitrogen dioxide concentrations are not measured at IMPROVE sites, but the ambient NO_2 concentrations under natural conditions can be expected to be negligibly small. The higher NO_2 concentration in a source plume may be great enough to cause a change in visibility, however.

In order to enable CALPOST to calculate CALPUFF-modeled source impacts on visibility using the new IMPROVE algorithm, it would have to be extensively reprogrammed. As an alternative, such a calculation could be done "off line" by adding another layer of post processing after CALPOST. To this end, I have developed a processor, in the form of an Excel workbook, that takes the CALPOST "Ranked Daily Visibility Change: Modeled Extinction by Species" output table, referenced against default annual average natural conditions concentrations, and creates an equivalent table of results based on the new algorithm. It can also incorporate the visibility impact due to light absorption by NO_2 in the plume.

The following describes the science behind the processor (which we'll call the CALPOST-IMPROVE Processor) and provides instructions for using it.

Concepts

In addition to the mechanical changes imposed by all the new terms in the new IMPROVE formula, applying the new algorithm also requires some conceptual changes. The biggest of these is that the extinction efficiencies of sulfates, nitrates, and organics now depend on the concentrations of those species. The practical implication of this is that extinction is no longer linearly additive. To calculate total extinction, you cannot take a background level of extinction and add to it CALPOST's calculation of extinction caused by the particulate matter coming from a source, because when the two aerosols mix in the atmosphere their combined mass concentration results in increases in the extinction efficiencies of both the background and the source contribution. This means that combining background particulate matter with the particulate matter from a source gives an extinction result that is greater than the sum of the two separate extinctions.

With the nonlinear behavior resulting from applying the new IMPROVE algorithm, the extinction impact of the source (i.e., the increase in extinction resulting from introducing source emissions into the atmosphere) is the sum of three parts:

1. The source impact calculated by the new IMPROVE algorithm using the CALPOST outputs for a plume in isolation;

[3] *Revised IMPROVE Algorithm for estimating Light Extinction from Particle Speciation Data.* Report to IMPROVE Steering Committee, November 2005.

2. An increase in that source impact because the extinction efficiency increases when the source's aerosol combines with the background aerosol; and correspondingly,

3. An increase in the extinction of the background aerosol because of that same mixing.

The total new extinction is the sum of the above three components plus the original background extinction. The original background extinction is just that calculated by the new IMPROVE algorithm from background concentrations of the various components, without any consideration of the effects of the plume. For this application, the background is taken to be that described by EPA's default natural conditions. The difference between the total extinction and the background is the impact of the source.

More details about the calculation are given in the appendix.

Description of Processor

The CALPOST-IMPROVE Processor is a Microsoft Excel workbook that consists of four worksheets. In Version 2 the worksheets are the following.

1. Input & Output – The output table from CALPOST is imported to here and user entries are made for the Rayleigh scattering coefficient and, if desired, for a sea salt concentration at the Class I area of interest. The NO_x concentration on each day attributable to the emissions from the source can also be entered together with an assumption of what fraction of the NO_x is in the form of NO_2. A revised table, with extinction based on the new IMPROVE algorithm is then presented on the same page. This is the only page on which user input takes place, and the results of the calculations appear on this page.

2. Calculations -- The calculations themselves are all done on this worksheet. There is no user input to this page. The variables are explained on the worksheet itself, so the user can find intermediate values if so inclined.

3. F(RH) – This worksheet tabulates the traditional IMPROVE f(RH) against RH, and then also lists values for the three new humidity growth functions, $f_S(RH)$, $f_L(RH)$, and $f_{SS}(RH)$. It serves as a lookup table for the "Calculations" worksheet.

4. Rayleigh & Sea Salt – This page tabulates the IMPROVE-recommended Rayleigh scattering coefficients for all VISTAS Class I areas and for Class I areas in adjacent states. It also lists the average sea salt concentrations for the same locations, as tabulated on the VIEWS web site, based on chloride or chlorine measurements by IMPROVE monitors between 2000 and 2004. This sheet just provides information for the user; it is not linked to the rest of the workbook. The user can obtain Rayleigh and sea salt numbers for the Class I area of interest from this table and then manually enter them in the designated spaces in worksheet 1.

Instructions for Using the CALPOST-IMPROVE Processor

These instructions apply to Version 2 of the processor. Version 2 includes the ability to calculate the light extinction effects of NO_2 resulting from the source's emissions.

Step 1. Begin by opening the output (.LST) file from a CALPOST visibility calculation run in a text editor or word processing program.[4] In the second half of the file, locate the table "Ranked Daily Visibility Change" with the subheading "Modeled Extinction by Species".[5]

Step 2. Copy this table and paste it onto a new page. Save it as a text (.txt) file, not as a formatted (e.g., MS Word .doc or .rtf) file. The final table should contain only the column headings and the data. Delete all other captions, any additional data summaries at the end, and blank lines before or after the table. The processor can handle a maximum of 22 lines of data (i.e., the highest rank in the last, unlabeled, column should be 22) plus a row of column captions. Delete any data that exceed this limit. (Fewer than 22 lines of data are OK.) The result should look like the example in Figure 1, although the line wrapping may differ.

Step 3. Open the CALPOST-IMPROVE Processor in Microsoft Excel. Save the open file under a new name so that the original empty processor will remain available for future use. The front worksheet, labeled "Input & Output" looks like Figure 2. There is a large empty box, surrounded by double lines, into which the table created above will be imported, as described below.[6] On the right is a box into which NO_x concentrations may be entered manually, and a small box below this box is provided for entry of the user's assumption of what fraction of that NO_s is in the form of NO_2. Two smaller boxes provide for user input of the Rayleigh scattering coefficient and, optionally, sea salt concentration for the Class I area, as described below. Results of the new IMPROVE algorithm calculations appear in blue in the lower half of the worksheet and some additional results, that are also useful for quality control, appear in green to the right of the large box. At the moment, many results cells will display nonsensical numbers and error messages, such as shown in Figure 2.

Step 4. Select the upper left cell (A7) in the large box. On the Excel menu bar, go to *Data>Get External Data* and click on *Import Text File*.[7] (If the large box is not empty, click on *Edit Text Import* instead.) Select the file that contains the table created in Step 2 and click on the *Get Data* button. Go through the Text Import Wizard steps, checking that all values appear correctly in separate columns. (The label "COORDINATES (km)" will be split over two columns; this is OK.) When everything appears in order, click *Finish*.

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[4] The background concentrations that were entered into CALPOST must be the EPA-prescribed default annual average natural conditions concentrations for the East. The processor will not give correct answers if other concentrations were used in CALPOST.

[5] For future reference in Step 7, this may also be a good time to locate the table with the same title but with the subtitle "% of Modeled Extinction by Species", which appears later in the output file.

[6] If the workbook has already been used, the boxes may not be empty. This does not matter.

[7] The exact wording may vary slightly between different versions of Microsoft Excel. The terminology used here is from Excel 2004 for Macintosh.

```
YEAR DAY HR  RECEPTOR    COORDINATES (km)  TYPE BEXT(Model) BEXT(BKG)
BEXT(Total) %CHANGE  F(RH)  bxSO4  bxNO3   bxOC   bxEC  bxPMC  bxPMF
2002 175  0  1027        1479.069    24.683   D      5.495      21.650      27.145
25.38   3.500  5.401  0.045  0.042  0.002  0.001  0.004     1
2002 172  0  1021        1479.244    23.778   D      4.923      21.650      26.573
22.74   3.500  4.475  0.404  0.038  0.001  0.001  0.004     2
2002 284  0  1045        1484.348    27.580   D      3.150      21.470      24.620
14.67   3.300  2.684  0.428  0.033  0.001  0.001  0.003     3
2002 353  0  1026        1482.762    24.457   D      2.594      21.290      23.884
12.18   3.100  2.017  0.557  0.018  0.001  0.000  0.002     4
2002 283  0  1026        1482.762    24.457   D      2.502      21.470      23.972
11.65   3.300  2.269  0.201  0.028  0.001  0.001  0.003     5
2002 195  0  1045        1484.348    27.580   D      2.011      21.830      23.841
9.21    3.700  1.963  0.031  0.015  0.001  0.000  0.001    6
2002  20  0  1117        1486.636    34.592   D      1.872      21.200      23.072
8.83    3.000  1.542  0.320  0.009  0.000  0.000  0.001    7
2002 173  0  1128        1479.259    35.042   D      1.649      21.650      23.299
7.62    3.500  1.625  0.012  0.010  0.000  0.000  0.001    8
2002 234  0  1021        1479.244    23.778   D      1.524      22.190      23.714
6.87    4.100  1.482  0.029  0.011  0.000  0.000  0.001    9
2002 298  0  1021        1479.244    23.778   D      1.459      21.470      22.929
6.80    3.300  1.284  0.160  0.014  0.001  0.000  0.001   10
2002 299  0  1021        1479.244    23.778   D      1.436      21.470      22.906
6.69    3.300  1.281  0.140  0.013  0.000  0.000  0.001   11
2002 275  0  1026        1482.762    24.457   D      1.270      21.470      22.740
5.92    3.300  1.202  0.058  0.009  0.000  0.000  0.001   12
2002 263  0  1045        1484.348    27.580   D      1.237      22.100      23.337
5.60    4.000  1.223  0.008  0.005  0.000  0.000  0.001   13
2002 252  0  1026        1482.762    24.457   D      1.189      22.100      23.289
5.38    4.000  1.166  0.013  0.009  0.000  0.000  0.001   14
2002 285  0  1021        1479.244    23.778   D      0.992      21.470      22.462
4.62    3.300  0.813  0.179  0.001  0.000  0.000  0.000   15
2002 161  0  1026        1482.762    24.457   D      0.873      21.650      22.523
4.03    3.500  0.842  0.020  0.009  0.000  0.000  0.001   16
2002 150  0  1026        1482.762    24.457   D      0.857      21.380      22.237
4.01    3.200  0.822  0.026  0.007  0.000  0.000  0.001   17
2002 340  0  1140        1481.017    37.258   D      0.817      21.290      22.107
3.84    3.100  0.663  0.153  0.001  0.000  0.000  0.000   18
2002 151  0  1117        1486.636    34.592   D      0.745      21.380      22.125
3.49    3.200  0.704  0.033  0.007  0.000  0.000  0.001   19
2002 160  0  1021        1479.244    23.778   D      0.735      21.650      22.385
3.40    3.500  0.710  0.014  0.010  0.000  0.000  0.001   20
2002 346  0  1021        1479.244    23.778   D      0.703      21.290      21.993
3.30    3.100  0.620  0.080  0.002  0.000  0.000  0.000   21
2002 247  0  1021        1479.244    23.778   D      0.661      22.100      22.761
2.99    4.000  0.654  0.004  0.002  0.000  0.000  0.000   22
```

Figure 1. Example of CALPOST Output Table, in Proper Format for Importing into the CALPOST-IMPROVE Processor.

Step 5.[8] The "Import Data" window will appear, with cell A7 indicated as the location at which data will be entered. Click on the *Properties* button. In the window that appears, select "Overwrite existing cells with new data, clear unused cells" and uncheck "Adjust column width", then click on *OK*. Now click on the *OK* button in the "Import Data" window.

Step 6. Assuming that your Excel application is set up to automatically recalculate whenever any entries are changed, you should now have filled the cells in the large box on the first worksheet,

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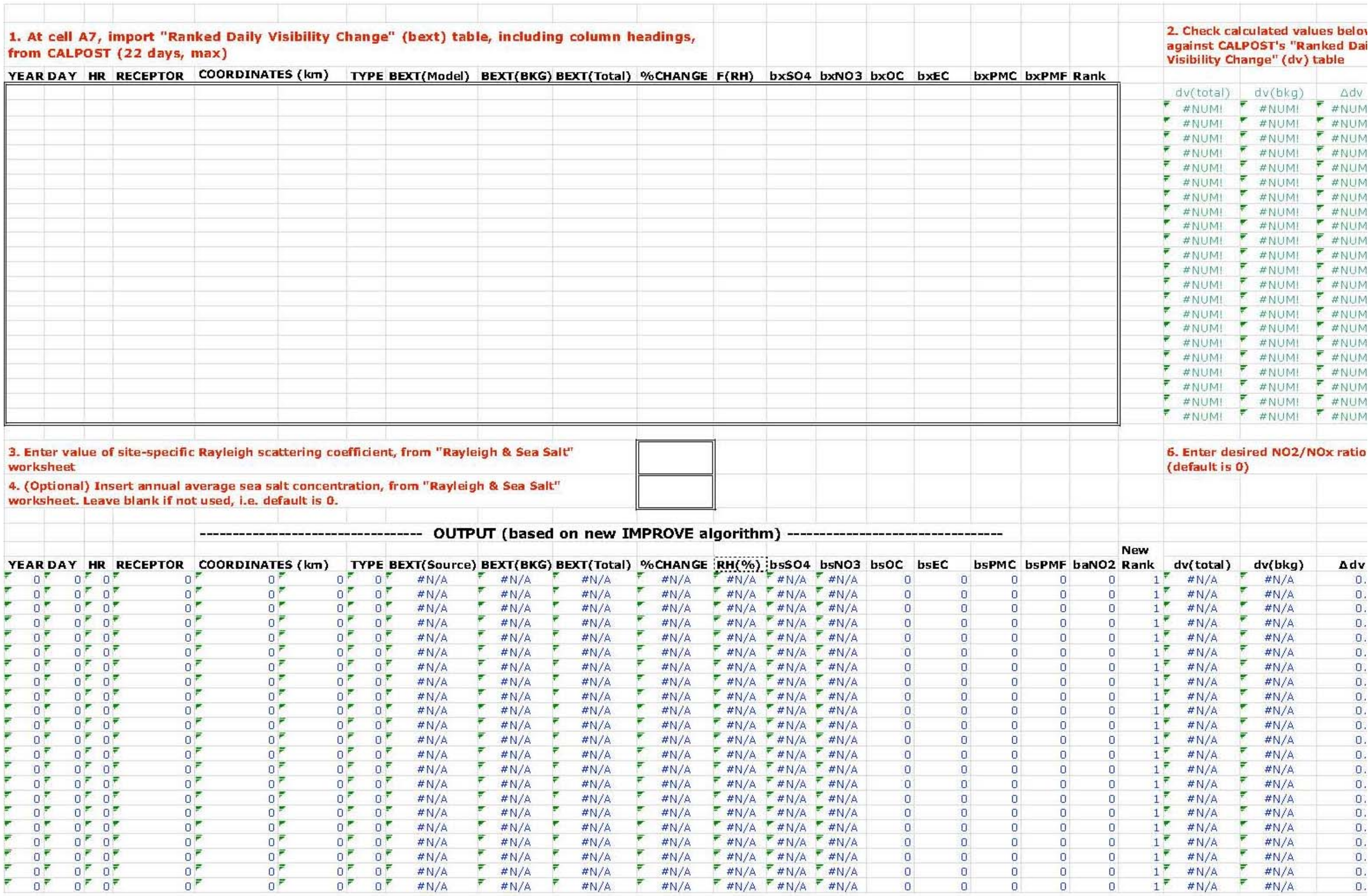
[8] If the processor already had data in it and *Edit Text Import* was clicked in Step 4, then the "Import Data" window will not appear and Step 5 can be skipped.



1. At cell A7, import "Ranked Daily Visibility Change" (bext) table, including column headings, from CALPOST (22 days, max)

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

dv(total)	dv(bkg)	Δdv
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM
#NUM!	#NUM!	#NUM

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet

4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used, i.e. default is 0.

6. Enter desired NO2/NOx ratio (default is 0)

---------------------------------- OUTPUT (based on new IMPROVE algorithm) --------------------------------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPMF	baNO2	New Rank	dv(total)	dv(bkg)	Δdv
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.
0	0	0	0	0	0	0	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	0	0	0	0	0	1	#N/A	#N/A	0.

Figure 2. Example of Appearance of Input & Output Worksheet before Data Entry.

numbers should have appeared in the green columns to the right, and some numbers will have appeared in the output table in blue on the lower half of the worksheet. If the data import worked properly, none of the imported data should have spilled out of the large box. Check that all the column captions in bold outside the large box are now duplicated on the first line in the box. (There won't be a caption for Rank.)

Step 7. As a further check on whether everything is correct so far, the dv information in the three columns to the right of the large box should be the same as that in the second CALPOST table "Ranked Daily Visibility Change: % of Modeled Extinction by Species", which was mentioned in Footnote 1.

Step 8. Beneath the large box that was just filled with imported data, enter the Rayleigh scattering coefficient for the Class I area of interest into the top small box after red instruction 3. Also, if you wish, fill in the other small box, the one after red instruction 4, with the annual average sea salt concentration. (The sea salt box may be left blank, but the Rayleigh scattering coefficient box must be filled in.) To help with filling in these two boxes, the fourth worksheet, "Rayleigh & Sea Salt", provides IMPROVE-calculated values of the Rayleigh coefficients for Class I areas in the VISTAS region and in adjacent states. Also, average sea salt concentrations for 2000-2004, calculated in accordance with the new IMPROVE procedures, can be found there.

Step 9.[9] If the impact due to NO_2 is to be considered, a second CALPOST run will be needed to provide the 24-hr average NO_x concentrations estimated by CALPUFF. For this purpose, run CALPOST using the ASPEC = NOX option in Input Group 1 of the CALPOST.INP control file. The NO_x values to insert in the NO_x input box on the Input & Output page of the processor have to be extracted manually from the CALPOST output file for each date and receptor listed in the file that was imported in Steps 1 through 5 above and are displayed in the left hand columns in the large box.

Step 10. Select a value between 0 and 1 to represent what fraction of NO_x is in the form of NO_2. Enter this value into the small box at red instruction 6 below the column where the NO_x concentrations were entered.[10]

Step 11. The blue data table at the bottom of the page represents the new IMPROVE algorithm outputs. An example is shown in Figure 3. This table can be compared with the original CALPOST table at the top of the page. All of the columns in both tables show exactly the same variables, except that the F(RH) column in the top table is replaced by just the RH in the lower table (since the new procedure has three different f(RH) functions) and a new $baNO_2$ column has been added to the bottom table to show the light absorption due to NO_2 (in Mm^{-1}). Although the events are listed in the same order in both tables, note that their rankings may have changed, as is the case for many of the lines in the blue output table in Figure 3.

[9] Steps 8 and 9 are optional. If the impact due to NO_2 is not of interest, just leave the entry fields mentioned in these steps blank.

[10] An easy way to see the effect of the NO_2 on the source's impact in the output table in the lower half of the page is to toggle this NO_2/NO_x value between the selected value and zero.

For those who are interested in more detail concerning the calculations that take place, values of the three f(RH) functions appear in columns M through O on the second, "Calculations" spreadsheet. The extinction impact of the source, including enhancement of the extinction efficiencies for sulfates, nitrates, and organics because of greater total mass concentrations, appears in columns V through AC. Extinction due to the annual average natural background appears in Columns AJ through AN; natural background extinctions for those components that are enhanced by greater total mass concentrations appear in columns AU through AX.

CALPOST Recalculation with New IMPROVE Algorithm

---------------------------- INPUT from CALPOST (based on old IMPROVE algorithm) -------------------

1. At cell A7, import "Ranked Daily Visibility Change" (bext) table, including column headings, from CALPOST (22 days, max)

2. Check calculated values below against CALPOST's "Ranked Daily Visibility Change" (dv) table

5. (Opt… Enter … NOx c…

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF	Rank	dv(total)	dv(bkg)	Δdv	NOx(p…
YEAR	DAY	HR	RECEPTOR	COORDINA	TES (km)	TYPE	BEXT(Model)	BEXT(BKG)	BEXT(Total)	%CHANGE	F(RH)	bxSO4	bxNO3	bxOC	bxEC	bxPMC	bxPMF					
2002	175	0	1027	1479.069	24.683	D	5.495	21.65	27.145	25.38	3.5	5.401	0.045	0.042	0.002	0.001	0.004	1	9.99	7.72	2.26	
2002	172	0	1021	1479.244	23.778	D	4.923	21.65	26.573	22.74	3.5	4.475	0.404	0.038	0.001	0.001	0.004	2	9.77	7.72	2.05	
2002	284	0	1045	1484.348	27.58	D	3.15	21.47	24.62	14.67	3.3	2.684	0.428	0.033	0.001	0.001	0.003	3	9.01	7.64	1.37	
2002	353	0	1026	1482.762	24.457	D	2.594	21.29	23.884	12.18	3.1	2.017	0.557	0.018	0.001	0	0.002	4	8.71	7.56	1.15	
2002	283	0	1026	1482.762	24.457	D	2.502	21.47	23.972	11.65	3.3	2.269	0.201	0.028	0.001	0.001	0.003	5	8.74	7.64	1.10	
2002	195	0	1045	1484.348	27.58	D	2.011	21.83	23.841	9.21	3.7	1.963	0.031	0.015	0.001	0	0.001	6	8.69	7.81	0.88	
2002	20	0	1117	1486.636	34.592	D	1.872	21.2	23.072	8.83	3	1.542	0.32	0.009	0	0	0.001	7	8.36	7.51	0.85	
2002	173	0	1128	1479.259	35.042	D	1.649	21.65	23.299	7.62	3.5	1.625	0.012	0.01	0	0	0.001	8	8.46	7.72	0.73	
2002	234	0	1021	1479.244	23.778	D	1.524	22.19	23.714	6.87	4.1	1.482	0.029	0.011	0	0	0.001	9	8.63	7.97	0.66	
2002	298	0	1021	1479.244	23.778	D	1.459	21.47	22.929	6.8	3.3	1.284	0.16	0.014	0.001	0	0.001	10	8.30	7.64	0.66	
2002	299	0	1021	1479.244	23.778	D	1.436	21.47	22.906	6.69	3.3	1.281	0.14	0.013	0	0	0.001	11	8.29	7.64	0.65	
2002	275	0	1026	1482.762	24.457	D	1.27	21.47	22.74	5.92	3.3	1.202	0.058	0.009	0	0	0.001	12	8.22	7.64	0.57	
2002	263	0	1045	1484.348	27.58	D	1.237	22.1	23.337	5.6	4	1.223	0.008	0.005	0	0	0.001	13	8.47	7.93	0.54	
2002	252	0	1026	1482.762	24.457	D	1.189	22.1	23.289	5.38	4	1.166	0.013	0.009	0	0	0.001	14	8.45	7.93	0.52	
2002	285	0	1021	1479.244	23.778	D	0.992	21.47	22.462	4.62	3.3	0.813	0.179	0.001	0	0	0	15	8.09	7.64	0.45	
2002	161	0	1026	1482.762	24.457	D	0.873	21.65	22.523	4.03	3.5	0.842	0.02	0.009	0	0	0.001	16	8.12	7.72	0.40	
2002	150	0	1026	1482.762	24.457	D	0.857	21.38	22.237	4.01	3.2	0.822	0.026	0.007	0	0	0.001	17	7.99	7.60	0.39	
2002	340	0	1140	1481.017	37.258	D	0.817	21.29	22.107	3.84	3.1	0.663	0.153	0.001	0	0	0	18	7.93	7.56	0.38	
2002	151	0	1117	1486.636	34.592	D	0.745	21.38	22.125	3.49	3.2	0.704	0.033	0.007	0	0	0.001	19	7.94	7.60	0.34	
2002	160	0	1021	1479.244	23.778	D	0.735	21.65	22.385	3.4	3.5	0.71	0.014	0.01	0	0	0.001	20	8.06	7.72	0.33	
2002	346	0	1021	1479.244	23.778	D	0.703	21.29	21.993	3.3	3.1	0.62	0.08	0.002	0	0	0	21	7.88	7.56	0.32	
2002	247	0	1021	1479.244	23.778	D	0.661	22.1	22.761	2.99	4	0.654	0.004	0.002	0	0	0	22	8.22	7.93	0.29	

3. Enter value of site-specific Rayleigh scattering coefficient, from "Rayleigh & Sea Salt" worksheet — 11

4. (Optional) Insert annual average sea salt concentration, from "Rayleigh & Sea Salt" worksheet. Leave blank if not used, i.e. default is 0. — 0.02

6. Enter desired NO2/NOx ratio (default is 0)

--------------------------------- OUTPUT (based on new IMPROVE algorithm) --------------------------------

YEAR	DAY	HR	RECEPTOR	COORDINATES (km)		TYPE	BEXT(Source)	BEXT(BKG)	BEXT(Total)	%CHANGE	RH(%)	bsSO4	bsNO3	bsOC	bsEC	bsPMC	bsPMF	baNO2	New Rank	dv(total)	dv(bkg)	Δdv
2002	175	0	1027	1479.069	24.683	D	4.936	22.04	27.016	22.56	86	4.363	0.039	0.033	0.002	0.001	0.004	0.495	1	9.94	7.90	2.03
2002	172	0	1021	1479.244	23.778	D	4.112	22.04	26.187	18.80	86	3.604	0.349	0.029	0.001	0.001	0.004	0.124	2	9.63	7.90	1.72
2002	284	0	1045	1484.348	27.58	D	2.563	21.78	24.363	11.86	84	2.076	0.357	0.026	0.001	0.001	0.003	0.099	3	8.90	7.78	1.12
2002	353	0	1026	1482.762	24.457	D	2.174	21.57	23.760	10.15	82	1.528	0.455	0.014	0.001	0	0.002	0.173	5	8.65	7.69	0.97
2002	283	0	1026	1482.762	24.457	D	2.293	21.78	24.090	10.61	84	1.753	0.167	0.022	0.001	0.001	0.003	0.347	4	8.79	7.78	1.01
2002	195	0	1045	1484.348	27.58	D	1.708	22.21	23.936	7.75	87	1.569	0.027	0.012	0.001	0	0.001	0.099	6	8.73	7.98	0.75
2002	20	0	1117	1486.636	34.592	D	1.625	21.48	23.114	7.62	81	1.16	0.26	0.007	0	0	0.001	0.198	7	8.38	7.64	0.73
2002	173	0	1128	1479.259	35.042	D	1.613	22.04	23.667	7.37	86	1.297	0.01	0.008	0	0	0.001	0.297	8	8.61	7.90	0.71
2002	234	0	1021	1479.244	23.778	D	1.546	22.64	24.193	6.87	89	1.213	0.026	0.009	0	0	0.001	0.297	9	8.83	8.17	0.66
2002	298	0	1021	1479.244	23.778	D	1.209	21.78	22.998	5.59	84	0.988	0.133	0.011	0.001	0	0.001	0.074	13	8.33	7.78	0.54
2002	299	0	1021	1479.244	23.778	D	1.237	21.78	23.027	5.72	84	0.986	0.117	0.01	0	0	0.001	0.124	12	8.34	7.78	0.56
2002	275	0	1026	1482.762	24.457	D	1.154	21.78	22.943	5.34	84	0.925	0.048	0.007	0	0	0.001	0.173	14	8.30	7.78	0.52
2002	263	0	1045	1484.348	27.58	D	1.137	22.64	23.783	5.06	89	1.026	0.007	0.004	0	0	0.001	0.099	16	8.66	8.17	0.49
2002	252	0	1026	1482.762	24.457	D	1.369	22.64	24.015	6.08	89	0.978	0.012	0.007	0	0	0.001	0.371	10	8.76	8.17	0.59
2002	285	0	1021	1479.244	23.778	D	1.245	21.78	23.031	5.74	84	0.625	0.149	8E-04	0	0	0	0.47	11	8.34	7.78	0.56
2002	161	0	1026	1482.762	24.457	D	1.116	22.04	23.165	5.09	86	0.67	0.017	0.007	0	0	0.001	0.421	15	8.40	7.90	0.50
2002	150	0	1026	1482.762	24.457	D	0.997	21.67	22.668	4.63	83	0.623	0.021	0.005	0	0	0.001	0.347	18	8.18	7.73	0.45
2002	340	0	1140	1481.017	37.258	D	1.071	21.57	22.646	4.99	82	0.5	0.125	8E-04	0	0	0	0.446	17	8.17	7.69	0.49
2002	151	0	1117	1486.636	34.592	D	0.913	21.67	22.584	4.24	83	0.533	0.027	0.005	0	0	0.001	0.347	20	8.15	7.73	0.42
2002	160	0	1021	1479.244	23.778	D	0.932	22.04	22.980	4.25	86	0.565	0.012	0.008	0	0	0.001	0.347	19	8.32	7.90	0.42
2002	346	0	1021	1479.244	23.778	D	0.633	21.57	22.208	2.95	82	0.467	0.065	0.002	0	0	0	0.099	21	7.98	7.69	0.29
2002	247	0	1021	1479.244	23.778	D	0.553	22.64	23.195	2.46	89	0.548	0.004	0.002	0	0	0	0	22	8.41	8.17	0.24

Figure 3. Example of Appearance of Finished Input & Output Worksheet.

Appendix
Details of Calculation Approach

As an example of the calculation steps, assume that the sulfate concentration resulting from emissions from a source is $[S_E]$ and the sulfate in the undisturbed natural background is $[S_N]$, for a total ambient sulfate concentration of $[S_T]$. According to Equations 1 and 2 in the main body of this document, the total extinction due to sulfate for this combination is

$$b_{ext}(sulfate) = 2.2 \bullet f_S(RH) \bullet [small\ sulfate] + 4.8 \bullet f_L(RH) \bullet [large\ sulfate], \qquad \text{(Eq. A-1)}$$

where

$$[large\ sulfate_T] = \{[S_T]/20\} \bullet [S_T]\ if\ [S_T] < 20\ \mu g^3$$

$$[large\ sulfate_T] = [S_T]\ if\ [S_T] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-2)}$$

$$[small\ sulfate_T] = [S_T] - [large\ sulfate_T],$$

and the subscript T denotes total sulfate

For the original background, where there is no source impact, the corresponding formulas for the terms in Equations A-2 are

$$[large\ sulfate_N] = \{[S_N]/20\} \bullet [S_N]\ if\ [S_N] < 20\ \mu g^3$$

$$[large\ sulfate_N] = [S_N]\ if\ [S_N] \geq 20\ \mu g/m^3 \qquad \text{(Eqs. A-3)}$$

$$[small\ sulfate_N] = [S_N] - [large\ sulfate_N],$$

where the subscript N denotes natural sulfate.

Similar calculations need to be carried out for nitrates. Contributions of the other particulate components are linear and can just be calculated according to Equation 1.

If the impact due to NO_2 is also to be considered, then the source impact due to this component is, according to Equation 1,

$$b_{ext}(NO_2) = 0.33 \bullet [NO_2], \qquad \text{(Eq. A-4)}$$

where $[NO_2]$ is in ppb. It is reasonable to assume that the ambient NO_2 concentrations under natural conditions would be so small as to cause negligible light absorption, so the corresponding term is not needed in the natural conditions calculation.

The contributions due to the various components are summed together as in Equation 1 to obtain the total extinction $b_{ext,T}$ and the natural background extinction $b_{ext,N}$. The fractional change in extinction is then calculated as the difference, normalized by the natural background extinction

$$(b_{ext,T} - b_{ext,N})/b_{ext,N}, \quad \text{(Eq. A-5)}$$

a result that can also be expressed in deciviews.

These formulas are used in the CALPOST-IMPROVE Processor. Similar formulas apply for nitrates and organics. There is no nonlinearity in the remaining terms in Equation 1.

Appendix E

CALPUFF Modeling Results and Graphic Charts using the New IMPROVE Equation

Table E-1 Regional Haze Results of Modeled BART Options for Each Met Year

Class I Area	BART Option	BART Controls	Met Year 2001				Met Year 2002				Met Year 2003				2001-2003 Ave		2001-2003 Total	
			Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv	Change from Baseline, dv	# of Days above 0.5 Δ dv	# of Days above 0.5 Δ dv Reduced Relative to Baseline
Grand Canyon N	-	Baseline	153	74	3.75	2.10	159	78	3.94	2.21	191	105	5.11	2.61	2.31	0.00	503	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.21	0.15	0	0	0.24	0.17	0	0	0.39	0.19	0.17	2.14	0	503
	2	LNB+OFA+SCR (In-Line)	0	0	0.33	0.18	0	0	0.28	0.20	1	0	0.50	0.23	0.20	2.10	1	502
	3	LNB+OFA+FGR	1	0	0.54	0.25	1	0	0.56	0.26	4	0	0.82	0.38	0.30	2.01	6	497
	4	LNB+OFA+SNCR	2	0	0.62	0.26	2	0	0.65	0.30	4	0	0.88	0.41	0.32	1.98	8	495
	5	LNB+OFA	2	0	0.65	0.30	0	0	0.70	0.31	6	1	1.01	0.48	0.36	1.94	8	495
Joshua Tree NM	-	Baseline	72	63	4.62	2.65	87	61	6.36	3.25	78	47	3.52	2.57	2.82	0.00	237	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.25	0.16	0	0	0.34	0.20	0	0	0.21	0.15	0.17	2.65	0	237
	2	LNB+OFA+SCR (In-Line)	0	0	0.33	0.20	0	0	0.49	0.27	0	0	0.27	0.17	0.21	2.61	0	237
	3	LNB+OFA+FGR	1	0	0.56	0.34	6	0	0.93	0.41	1	0	0.51	0.33	0.36	2.46	8	229
	4	LNB+OFA+SNCR	2	0	0.61	0.37	7	1	1.03	0.45	2	0	0.56	0.36	0.39	2.43	11	226
	5	LNB+OFA	5	0	0.71	0.44	10	3	1.22	0.54	4	0	0.66	0.41	0.46	2.36	19	218
Zion NP	-	Baseline	57	10	1.84	1.03	61	12	1.85	1.25	70	16	2.35	1.24	1.17	0.00	188	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.04	0	0	0.08	0.05	0	0	0.08	0.05	0.05	1.13	0	188
	2	LNB+OFA+SCR (In-Line)	0	0	0.06	0.04	0	0	0.13	0.05	0	0	0.13	0.06	0.05	1.12	0	188
	3	LNB+OFA+FGR	0	0	0.12	0.08	0	0	0.28	0.10	0	0	0.28	0.12	0.10	1.07	0	188
	4	LNB+OFA+SNCR	0	0	0.14	0.08	0	0	0.31	0.11	0	0	0.32	0.14	0.11	1.06	0	188
	5	LNB+OFA	0	0	0.17	0.10	0	0	0.37	0.14	0	0	0.39	0.16	0.13	1.04	0	188
Sycamore Canyon W	-	Baseline	25	7	1.73	1.00	31	5	2.44	0.89	47	7	2.16	1.00	0.96	0.00	103	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.08	0.02	0	0	0.10	0.02	0	0	0.05	0.02	0.02	0.94	0	103
	2	LNB+OFA+SCR (In-Line)	0	0	0.14	0.04	0	0	0.17	0.03	0	0	0.06	0.03	0.03	0.93	0	103
	3	LNB+OFA+FGR	0	0	0.31	0.06	0	0	0.35	0.05	0	0	0.13	0.06	0.06	0.91	0	103
	4	LNB+OFA+SNCR	0	0	0.35	0.07	0	0	0.39	0.06	0	0	0.15	0.07	0.07	0.90	0	103
	5	LNB+OFA	0	0	0.43	0.08	0	0	0.47	0.07	0	0	0.19	0.08	0.08	0.89	0	103
Agua Tibia W	-	Baseline	9	1	1.65	0.56	12	5	2.56	0.80	10	0	0.99	0.56	0.64	0.00	31	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.04	0.02	0	0	0.06	0.03	0	0	0.02	0.01	0.02	0.62	0	31
	2	LNB+OFA+SCR (In-Line)	0	0	0.06	0.02	0	0	0.08	0.03	0	0	0.03	0.02	0.02	0.62	0	31
	3	LNB+OFA+FGR	0	0	0.12	0.03	0	0	0.19	0.05	0	0	0.08	0.04	0.04	0.60	0	31
	4	LNB+OFA+SNCR	0	0	0.13	0.04	0	0	0.16	0.06	0	0	0.06	0.03	0.04	0.60	0	31
	5	LNB+OFA	0	0	0.16	0.05	0	0	0.19	0.07	0	0	0.07	0.03	0.05	0.59	0	31
Cucamonga W	-	Baseline	8	1	1.38	0.57	17	4	3.03	0.87	12	3	1.68	0.62	0.69	0.00	37	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.04	0.01	0	0	0.06	0.02	0	0	0.04	0.02	0.02	0.67	0	37
	2	LNB+OFA+SCR (In-Line)	0	0	0.07	0.01	0	0	0.10	0.03	0	0	0.06	0.02	0.02	0.67	0	37
	3	LNB+OFA+FGR	0	0	0.13	0.03	0	0	0.21	0.06	0	0	0.09	0.05	0.05	0.64	0	37
	4	LNB+OFA+SNCR	0	0	0.15	0.03	0	0	0.23	0.06	0	0	0.10	0.05	0.05	0.64	0	37
	5	LNB+OFA	0	0	0.18	0.04	0	0	0.28	0.07	0	0	0.12	0.06	0.06	0.63	0	37

Table E-1 Regional Haze Results of Modeled BART Options for Each Met Year

Class I Area	BART Option	BART Controls	Met Year 2001				Met Year 2002				Met Year 2003				2001-2003 Ave		2001-2003 Total	
			Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv	Change from Baseline, dv	# of Days above 0.5 Δ dv	# of Days above 0.5 Δ dv Reduced Relative to Baseline
San Gorgonio W	-	Baseline	15	4	1.54	0.71	22	10	4.17	1.19	15	4	1.52	0.93	0.94	0.00	52	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.02	0	0	0.12	0.03	0	0	0.04	0.03	0.03	0.92	0	52
	2	LNB+OFA+SCR (In-Line)	0	0	0.07	0.02	0	0	0.18	0.05	0	0	0.06	0.03	0.03	0.91	0	52
	3	LNB+OFA+FGR	0	0	0.13	0.04	0	0	0.36	0.08	0	0	0.10	0.06	0.06	0.88	0	52
	4	LNB+OFA+SNCR	0	0	0.15	0.04	0	0	0.40	0.09	0	0	0.12	0.06	0.06	0.88	0	52
	5	LNB+OFA	0	0	0.18	0.05	0	0	0.49	0.11	0	0	0.14	0.07	0.08	0.87	0	52
San Jacinto W	-	Baseline	15	3	1.30	0.73	22	9	3.73	1.10	19	5	1.32	0.82	0.88	0.00	56	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.04	0.02	0	0	0.12	0.04	0	0	0.06	0.03	0.03	0.85	0	56
	2	LNB+OFA+SCR (In-Line)	0	0	0.05	0.03	0	0	0.17	0.06	0	0	0.06	0.03	0.04	0.84	0	56
	3	LNB+OFA+FGR	0	0	0.10	0.05	0	0	0.33	0.10	0	0	0.09	0.05	0.07	0.82	0	56
	4	LNB+OFA+SNCR	0	0	0.11	0.05	0	0	0.37	0.11	0	0	0.10	0.05	0.07	0.81	0	56
	5	LNB+OFA	0	0	0.13	0.06	0	0	0.44	0.13	0	0	0.12	0.06	0.08	0.80	0	56
Mazatzal W	-	Baseline	18	2	1.70	0.73	9	2	1.65	0.53	22	6	1.64	0.74	0.67	0.00	49	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.02	0	0	0.03	0.02	0	0	0.04	0.02	0.02	0.65	0	49
	2	LNB+OFA+SCR (In-Line)	0	0	0.08	0.02	0	0	0.05	0.02	0	0	0.04	0.02	0.02	0.65	0	49
	3	LNB+OFA+FGR	0	0	0.20	0.04	0	0	0.09	0.03	0	0	0.05	0.03	0.03	0.63	0	49
	4	LNB+OFA+SNCR	0	0	0.23	0.04	0	0	0.10	0.03	0	0	0.06	0.03	0.03	0.63	0	49
	5	LNB+OFA	0	0	0.28	0.05	0	0	0.12	0.03	0	0	0.07	0.04	0.04	0.63	0	49
Pine Mountain W	-	Baseline	17	3	1.80	0.73	10	2	1.71	0.58	20	4	1.33	0.85	0.72	0.00	47	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.02	0	0	0.04	0.02	0	0	0.04	0.02	0.02	0.70	0	47
	2	LNB+OFA+SCR (In-Line)	0	0	0.10	0.02	0	0	0.05	0.02	0	0	0.04	0.02	0.02	0.70	0	47
	3	LNB+OFA+FGR	0	0	0.24	0.04	0	0	0.10	0.02	0	0	0.05	0.03	0.03	0.69	0	47
	4	LNB+OFA+SNCR	0	0	0.27	0.04	0	0	0.11	0.03	0	0	0.05	0.03	0.03	0.69	0	47
	5	LNB+OFA	0	0	0.33	0.05	0	0	0.13	0.03	0	0	0.06	0.03	0.04	0.68	0	47
Domeland W	-	Baseline	12	2	1.72	0.78	19	9	2.07	1.04	12	6	2.19	0.92	0.91	0.00	43	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.06	0.02	0	0	0.06	0.02	0	0	0.05	0.02	0.02	0.89	0	43
	2	LNB+OFA+SCR (In-Line)	0	0	0.09	0.02	0	0	0.10	0.03	0	0	0.09	0.04	0.03	0.88	0	43
	3	LNB+OFA+FGR	0	0	0.19	0.04	0	0	0.21	0.05	0	0	0.19	0.06	0.05	0.86	0	43
	4	LNB+OFA+SNCR	0	0	0.21	0.04	0	0	0.23	0.06	0	0	0.21	0.06	0.05	0.86	0	43
	5	LNB+OFA	0	0	0.25	0.05	0	0	0.28	0.07	0	0	0.26	0.07	0.06	0.85	0	43
11 Class I Areas	-	Baseline													1.16	0.00	1346	0
	1	LNB+OFA+SCR (Stand Alone)													0.05	1.11	0	1346
	2	LNB+OFA+SCR (In-Line)													0.06	1.09	1	1345
	3	LNB+OFA+FGR													0.10	1.05	14	1332
	4	LNB+OFA+SNCR													0.11	1.04	19	1327
	5	LNB+OFA													0.13	1.03	27	1319

Figure E-1 8th Highest Visibility Impact due to BART Option 1

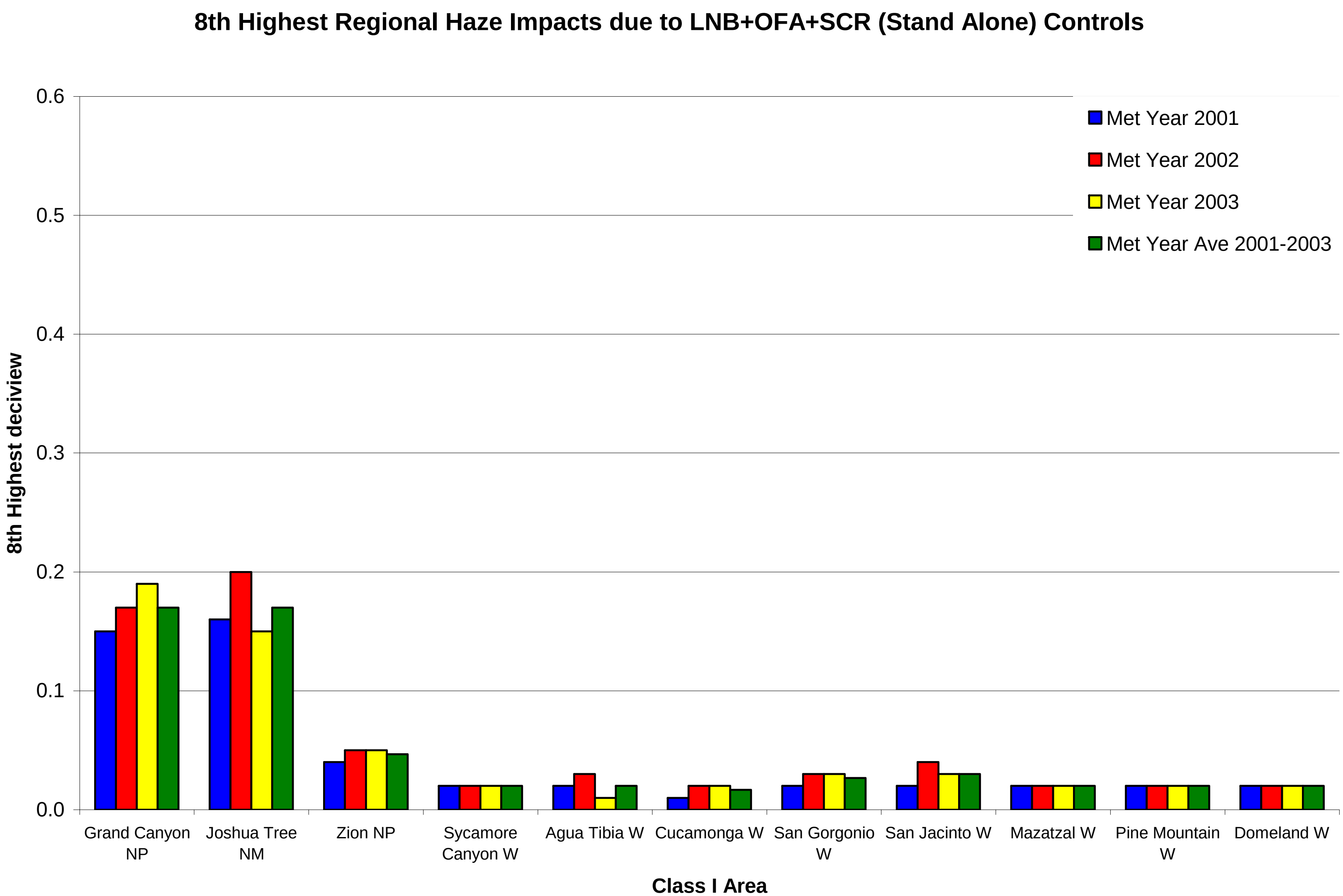


Figure E-2 8th Highest Visibility Impact due to BART Option 2

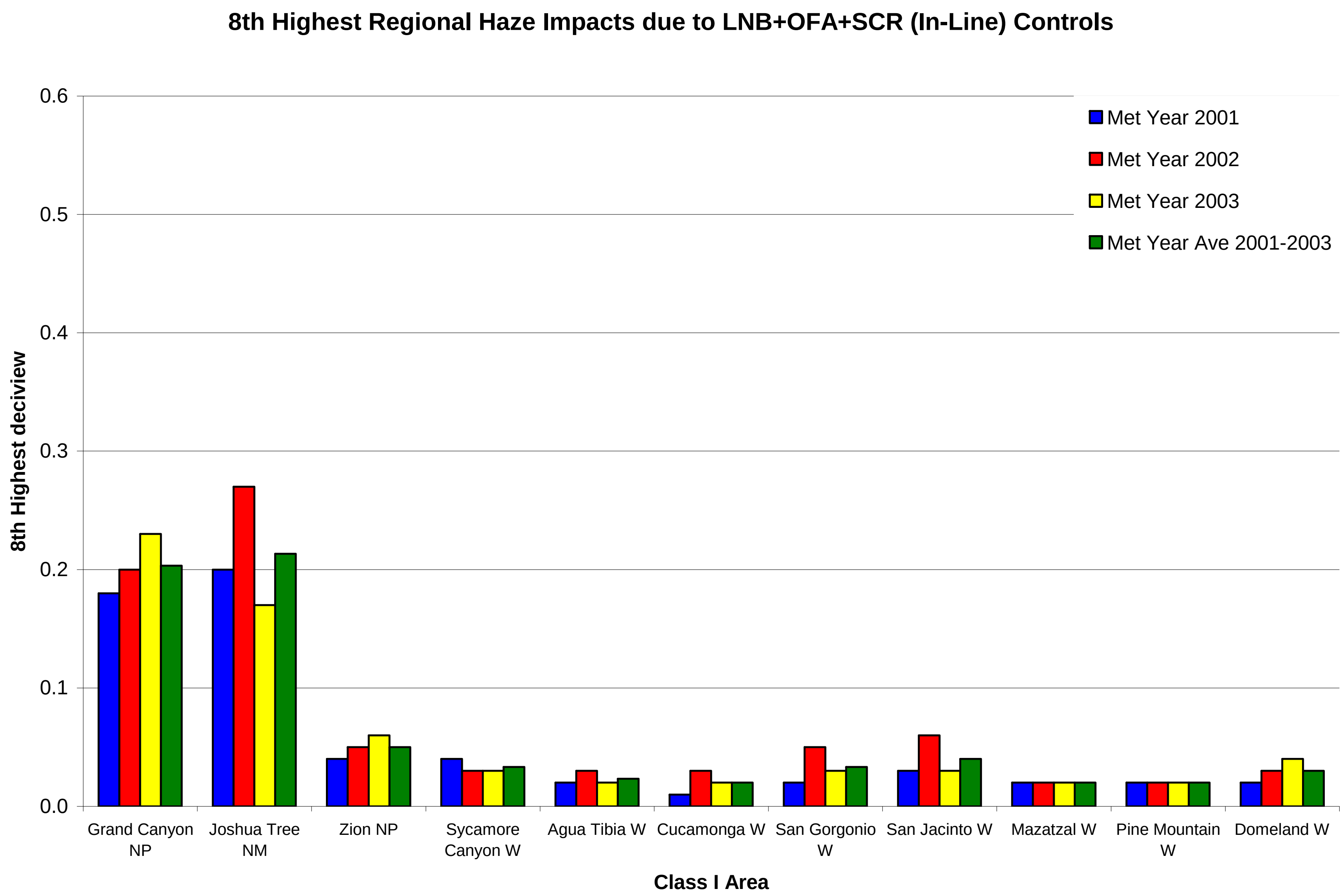


Figure E-3 8th Highest Visibility Impact due to BART Option 3

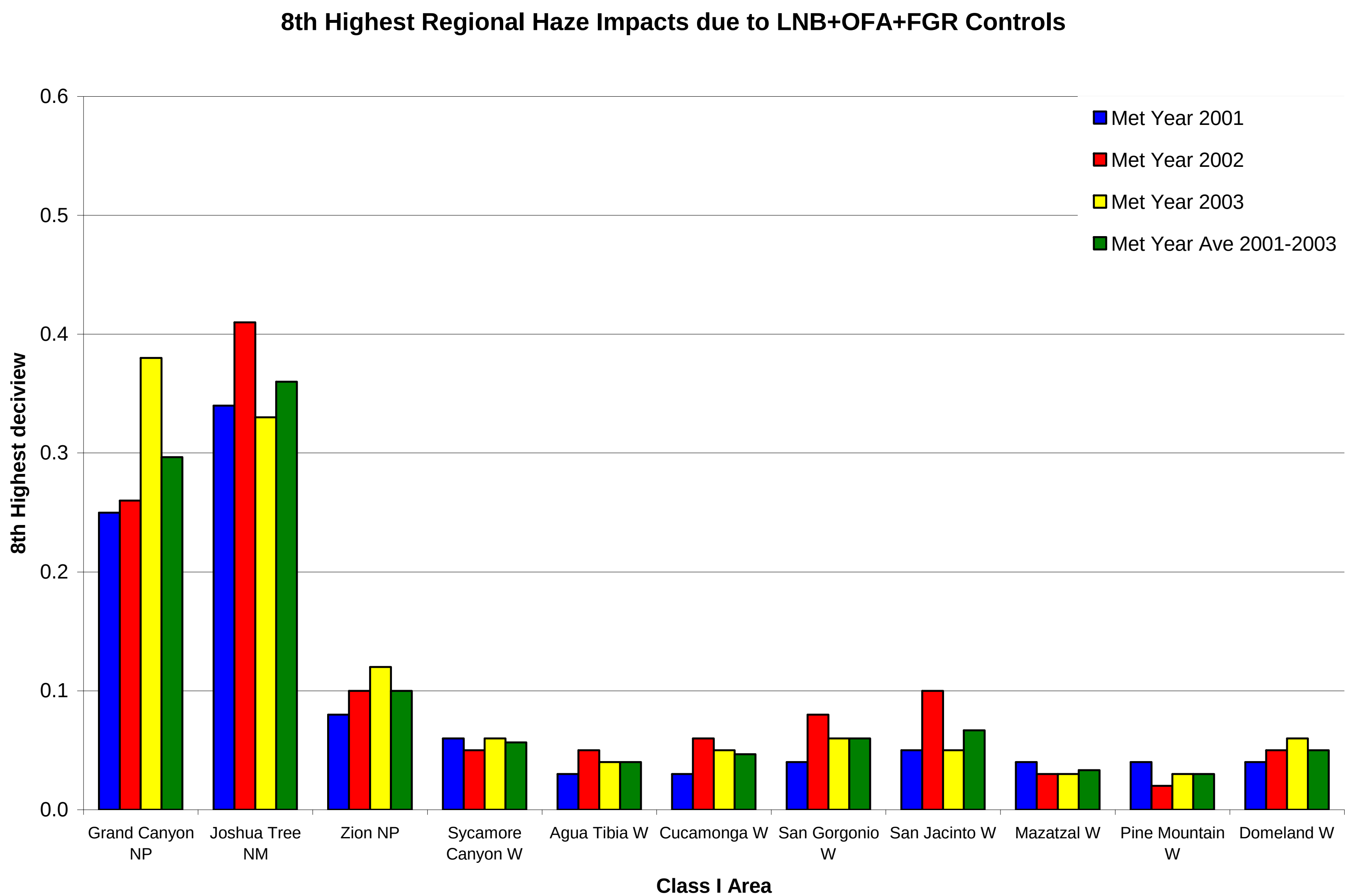


Figure E-4 8th Highest Visibility Impact due to BART Option 4

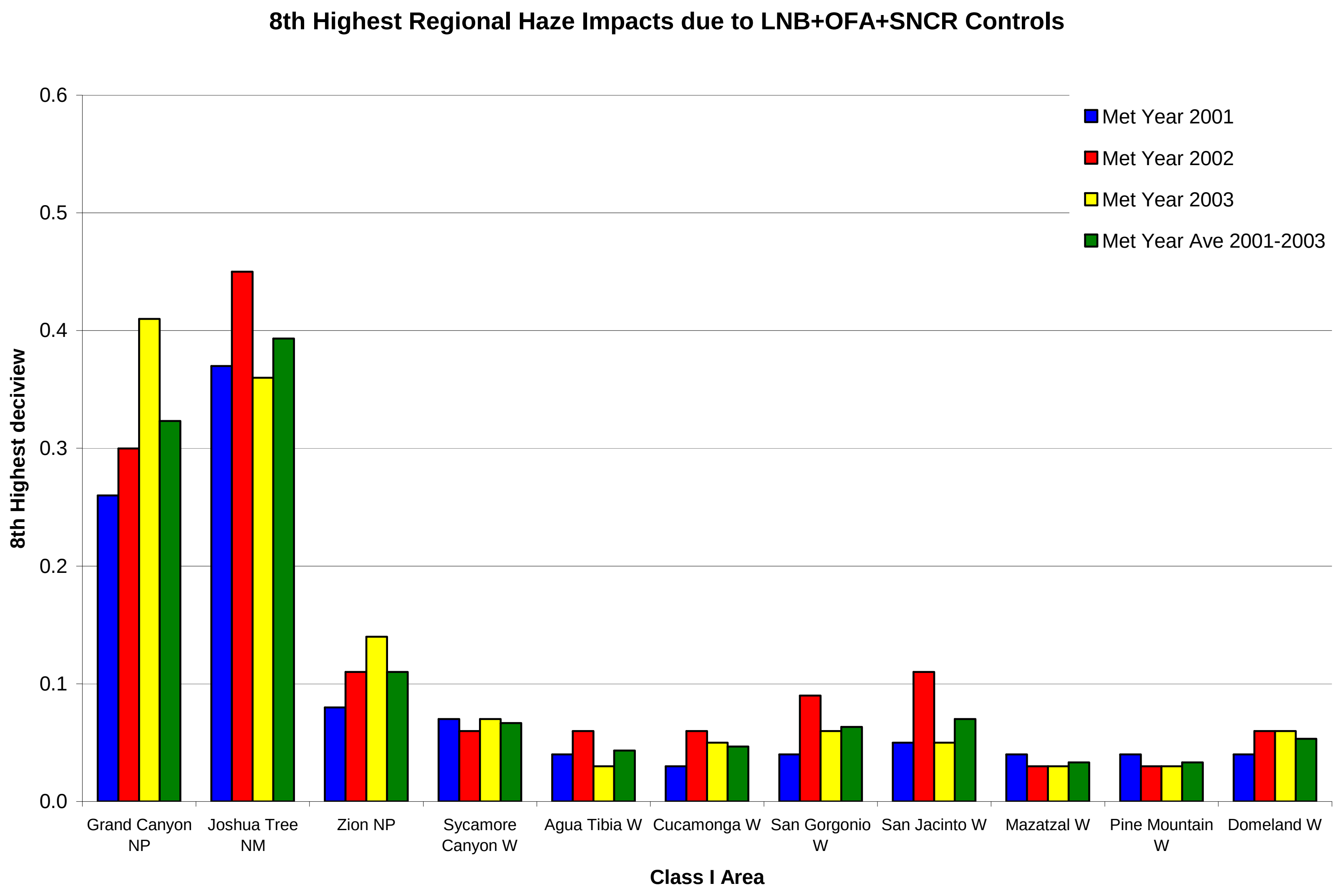
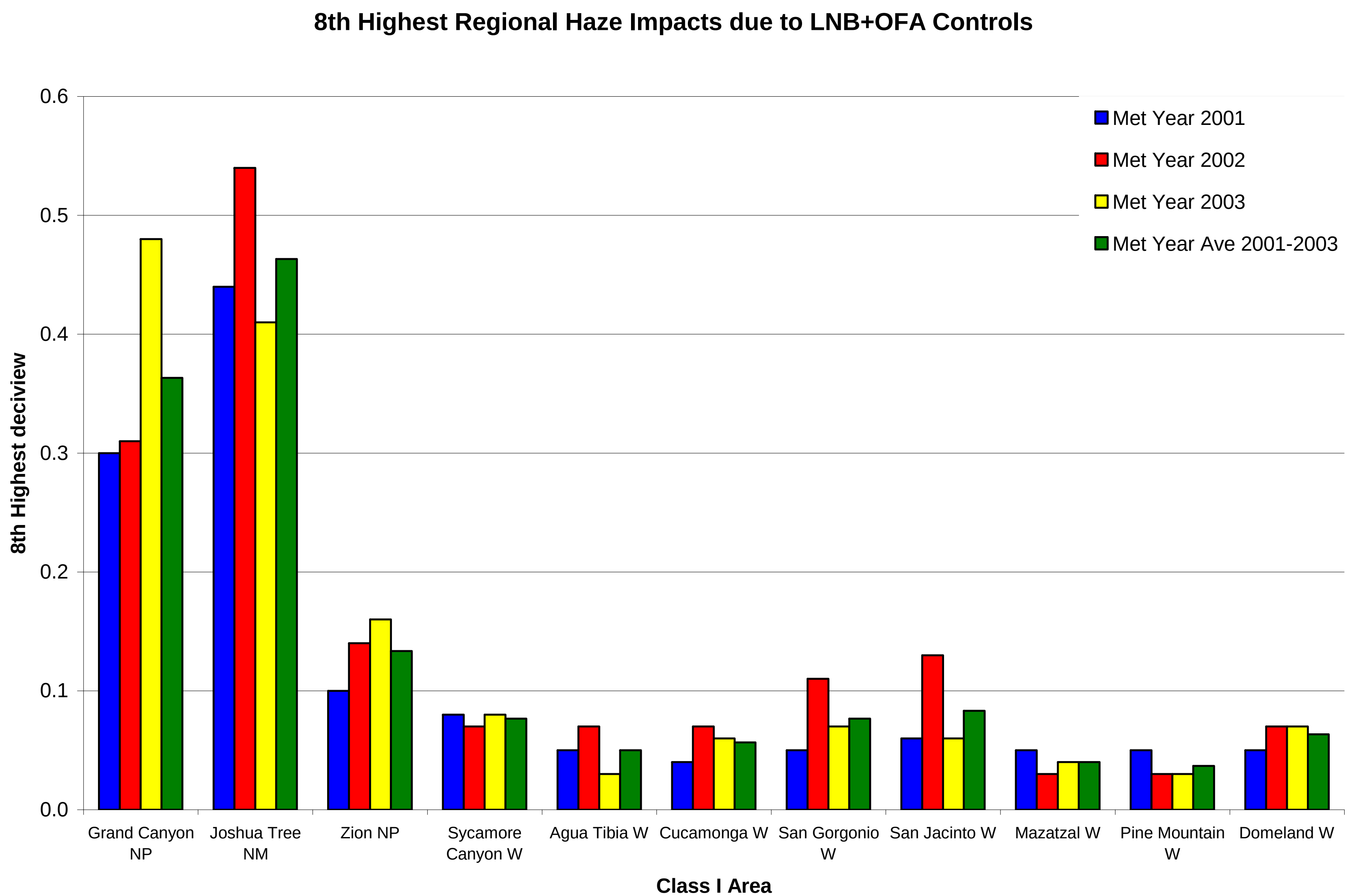


Figure E-5 8th Highest Visibility Impact due to BART Option 5



Appendix F

CALPUFF Modeling Results and Graphic Charts using the Old IMPROVE Equation

TableF-1 Regional Haze Impacts Due to Baseline Emissions

Class I Area	Met Year 2001				Met Year 2002				Met Year 2003				2001-2003 Ave
	Days above		MAX Δ dv	8th Highest Δ dv	Days above		MAX Δ dv	8th Highest Δ dv	Days above		MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv
	0.5 Δ dv	1.0 Δ dv			0.5 Δ dv	1.0 Δ dv			0.5 Δ dv	1.0 Δ dv			
Grand Canyon NP	156	85	3.87	2.31	166	86	3.98	2.42	194	111	5.44	2.91	2.55
Joshua Tree NM	77	53	5.44	3.33	90	70	7.00	3.98	85	63	4.21	3.11	3.47
Zion NP	63	19	1.93	1.22	70	16	2.10	1.38	80	19	2.69	1.45	1.35
Sycamore Canyon W	29	12	2.04	1.38	36	13	2.71	1.09	56	11	2.50	1.18	1.22
Agua Tibia W	14	5	2.21	0.87	19	8	3.30	1.11	15	3	1.37	0.83	0.93
Cucamonga W	11	1	1.64	0.71	20	8	3.50	1.05	15	5	2.00	0.81	0.86
San Gorgonio W	19	5	1.83	0.93	27	12	4.75	1.50	21	9	1.81	1.12	1.18
San Jacinto W	22	6	1.56	0.99	29	14	4.25	1.46	21	7	1.58	1.04	1.16
Mazatzal W	23	2	1.96	0.81	14	2	1.81	0.60	25	6	1.73	0.98	0.80
Pine Mountain W	20	4	2.09	0.87	11	3	1.91	0.65	23	6	1.38	0.98	0.83
Domeland W	14	6	2.17	0.99	26	11	2.47	1.34	14	8	2.69	1.22	1.18

FigureF-1 8th Highest Regional Haze Impacts for Each Modeled Year Due to Baseline Emissions

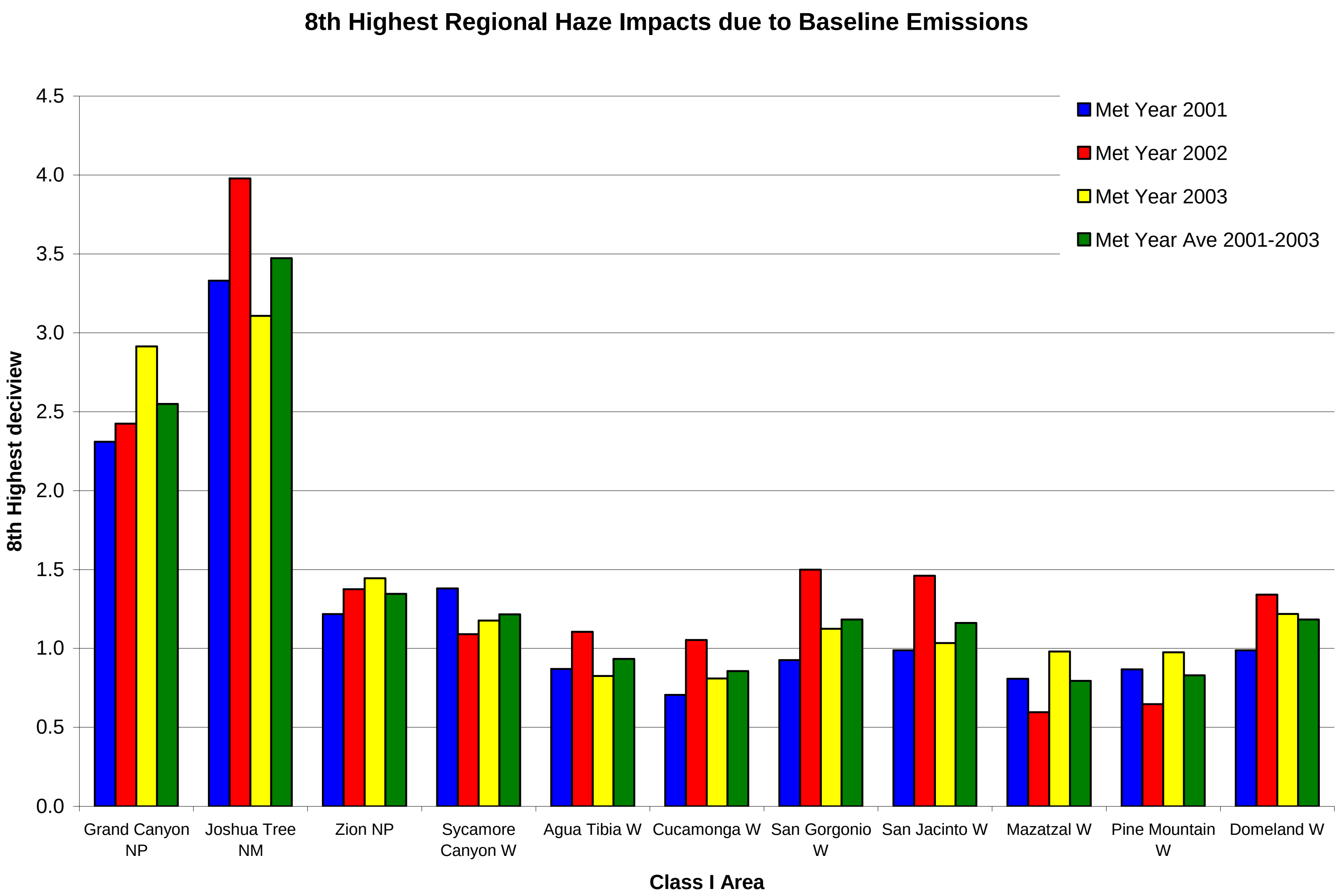


Table F-2 Regional Haze Results of Modeled BART Options for Each Met Year

Class I Area	BART Option	BART Controls	Met Year 2001				Met Year 2002				Met Year 2003				2001-2003 Ave		2001-2003 Total	
			Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	Days above 0.5 Δ dv	Days above 1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv	Change from Baseline, dv	# of Days above 0.5 Δ dv	# of Days above 0.5 Δ dv Reduced Relative to Baseline
Grand Canyon N	-	Baseline	156	85	3.87	2.31	166	86	3.98	2.42	194	111	5.44	2.91	2.55	0.00	516	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.24	0.18	0	0	0.29	0.20	0	0	0.45	0.24	0.21	2.34	0	516
	2	LNB+OFA+SCR (In-Line)	0	0	0.38	0.21	0	0	0.32	0.25	1	0	0.57	0.27	0.24	2.31	1	515
	3	LNB+OFA+FGR	2	0	0.62	0.30	2	0	0.63	0.31	4	0	0.90	0.43	0.34	2.21	8	508
	4	LNB+OFA+SNCR	4	0	0.71	0.34	2	0	0.74	0.35	6	0	0.97	0.46	0.38	2.17	12	504
	5	LNB+OFA	4	0	0.71	0.35	3	0	0.79	0.40	8	2	1.10	0.53	0.43	2.12	15	501
Joshua Tree NM	-	Baseline	77	53	5.44	3.33	90	70	7.00	3.98	85	63	4.21	3.11	3.47	0.00	252	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.32	0.22	0	0	0.42	0.27	0	0	0.26	0.20	0.23	3.24	0	252
	2	LNB+OFA+SCR (In-Line)	0	0	0.41	0.25	3	0	0.59	0.34	0	0	0.34	0.25	0.28	3.19	3	249
	3	LNB+OFA+FGR	3	0	0.68	0.43	7	2	1.09	0.59	4	0	0.61	0.42	0.48	2.99	14	238
	4	LNB+OFA+SNCR	5	0	0.74	0.46	11	3	1.20	0.65	4	0	0.68	0.45	0.52	2.95	20	232
	5	LNB+OFA	9	0	0.86	0.54	14	4	1.42	0.76	7	0	0.80	0.52	0.61	2.87	30	222
Zion NP	-	Baseline	63	19	1.93	1.22	70	16	2.10	1.38	80	19	2.69	1.45	1.35	0.00	213	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.06	0.04	0	0	0.10	0.06	0	0	0.09	0.06	0.06	1.29	0	213
	2	LNB+OFA+SCR (In-Line)	0	0	0.07	0.05	0	0	0.16	0.07	0	0	0.15	0.08	0.07	1.28	0	213
	3	LNB+OFA+FGR	0	0	0.14	0.09	0	0	0.32	0.11	0	0	0.32	0.15	0.12	1.23	0	213
	4	LNB+OFA+SNCR	0	0	0.16	0.10	0	0	0.36	0.13	0	0	0.36	0.17	0.13	1.22	0	213
	5	LNB+OFA	0	0	0.19	0.12	0	0	0.43	0.15	0	0	0.44	0.20	0.16	1.19	0	213
Sycamore Canyon W	-	Baseline	29	12	2.04	1.38	36	13	2.71	1.09	56	11	2.50	1.18	1.22	0.00	121	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.10	0.03	0	0	0.12	0.03	0	0	0.05	0.03	0.03	1.19	0	121
	2	LNB+OFA+SCR (In-Line)	0	0	0.17	0.04	0	0	0.19	0.04	0	0	0.07	0.04	0.04	1.18	0	121
	3	LNB+OFA+FGR	0	0	0.36	0.09	0	0	0.39	0.06	0	0	0.15	0.07	0.07	1.14	0	121
	4	LNB+OFA+SNCR	0	0	0.40	0.10	0	0	0.43	0.07	0	0	0.17	0.08	0.08	1.13	0	121
	5	LNB+OFA	0	0	0.49	0.12	1	0	0.51	0.08	0	0	0.21	0.09	0.10	1.12	1	120
Agua Tibia W	-	Baseline	14	5	2.21	0.87	19	8	3.30	1.11	15	3	1.37	0.83	0.93	0.00	48	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.06	0.02	0	0	0.08	0.04	0	0	0.03	0.02	0.03	0.91	0	48
	2	LNB+OFA+SCR (In-Line)	0	0	0.08	0.03	0	0	0.11	0.05	0	0	0.04	0.03	0.03	0.90	0	48
	3	LNB+OFA+FGR	0	0	0.16	0.06	0	0	0.19	0.08	0	0	0.07	0.04	0.06	0.88	0	48
	4	LNB+OFA+SNCR	0	0	0.17	0.06	0	0	0.21	0.08	0	0	0.08	0.04	0.06	0.87	0	48
	5	LNB+OFA	0	0	0.21	0.08	0	0	0.25	0.10	0	0	0.10	0.05	0.07	0.86	0	48
Cucamonga W	-	Baseline	11	1	1.64	0.71	20	8	3.50	1.05	15	5	2.00	0.81	0.86	0.00	46	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.02	0	0	0.08	0.03	0	0	0.05	0.03	0.02	0.83	0	46
	2	LNB+OFA+SCR (In-Line)	0	0	0.08	0.02	0	0	0.12	0.04	0	0	0.07	0.03	0.03	0.83	0	46
	3	LNB+OFA+FGR	0	0	0.16	0.04	0	0	0.24	0.08	0	0	0.11	0.05	0.06	0.80	0	46
	4	LNB+OFA+SNCR	0	0	0.17	0.04	0	0	0.27	0.09	0	0	0.12	0.06	0.06	0.79	0	46
	5	LNB+OFA	0	0	0.21	0.05	0	0	0.33	0.11	0	0	0.14	0.07	0.08	0.78	0	46

Table F-2 Regional Haze Results of Modeled BART Options for Each Met Year

Class I Area	BART Option	BART Controls	Met Year 2001				Met Year 2002				Met Year 2003				2001-2003 Ave		2001-2003 Total	
			Days above				Days above				Days above							
			0.5 Δ dv	1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	0.5 Δ dv	1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	0.5 Δ dv	1.0 Δ dv	MAX Δ dv	8th Highest Δ dv	8th Highest Δ dv	Change from Baseline, dv	# of Days above 0.5 Δ dv	# of Days above 0.5 Δ dv Reduced Relative to Baseline
San Gorgonio W	-	Baseline	19	5	1.83	0.93	27	12	4.75	1.50	21	9	1.81	1.12	1.18	0.00	67	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.06	0.02	0	0	0.14	0.05	0	0	0.05	0.03	0.04	1.15	0	67
	2	LNB+OFA+SCR (In-Line)	0	0	0.08	0.03	0	0	0.21	0.06	0	0	0.06	0.04	0.04	1.14	0	67
	3	LNB+OFA+FGR	0	0	0.16	0.05	0	0	0.42	0.11	0	0	0.12	0.07	0.07	1.11	0	67
	4	LNB+OFA+SNCR	0	0	0.18	0.05	0	0	0.47	0.12	0	0	0.14	0.08	0.08	1.10	0	67
	5	LNB+OFA	0	0	0.21	0.06	1	0	0.56	0.14	0	0	0.17	0.09	0.10	1.09	1	66
San Jacinto W	-	Baseline	22	6	1.56	0.99	29	14	4.25	1.46	21	7	1.58	1.04	1.16	0.00	72	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.03	0	0	0.14	0.05	0	0	0.07	0.03	0.04	1.12	0	72
	2	LNB+OFA+SCR (In-Line)	0	0	0.06	0.04	0	0	0.20	0.07	0	0	0.08	0.04	0.05	1.11	0	72
	3	LNB+OFA+FGR	0	0	0.12	0.06	0	0	0.39	0.12	0	0	0.11	0.06	0.08	1.08	0	72
	4	LNB+OFA+SNCR	0	0	0.13	0.07	0	0	0.43	0.13	0	0	0.12	0.07	0.09	1.07	0	72
	5	LNB+OFA	0	0	0.16	0.08	1	0	0.51	0.15	0	0	0.14	0.08	0.10	1.06	1	71
Mazatzal W	-	Baseline	23	2	1.96	0.81	14	2	1.81	0.60	25	6	1.73	0.98	0.80	0.00	62	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.05	0.02	0	0	0.04	0.02	0	0	0.05	0.02	0.02	0.77	0	62
	2	LNB+OFA+SCR (In-Line)	0	0	0.09	0.03	0	0	0.05	0.03	0	0	0.05	0.03	0.03	0.77	0	62
	3	LNB+OFA+FGR	0	0	0.22	0.06	0	0	0.10	0.03	0	0	0.06	0.04	0.04	0.75	0	62
	4	LNB+OFA+SNCR	0	0	0.25	0.06	0	0	0.11	0.03	0	0	0.07	0.04	0.04	0.75	0	62
	5	LNB+OFA	0	0	0.31	0.08	0	0	0.13	0.03	0	0	0.08	0.04	0.05	0.74	0	62
Pine Mountain W	-	Baseline	20	4	2.09	0.87	11	3	1.91	0.65	23	6	1.38	0.98	0.83	0.00	54	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.06	0.02	0	0	0.05	0.02	0	0	0.04	0.02	0.02	0.81	0	54
	2	LNB+OFA+SCR (In-Line)	0	0	0.11	0.02	0	0	0.06	0.03	0	0	0.04	0.02	0.02	0.81	0	54
	3	LNB+OFA+FGR	0	0	0.26	0.04	0	0	0.11	0.03	0	0	0.05	0.03	0.03	0.80	0	54
	4	LNB+OFA+SNCR	0	0	0.30	0.05	0	0	0.12	0.03	0	0	0.06	0.03	0.04	0.79	0	54
	5	LNB+OFA	0	0	0.37	0.06	0	0	0.14	0.04	0	0	0.07	0.04	0.04	0.79	0	54
Domeland W	-	Baseline	14	6	2.17	0.99	26	11	2.47	1.34	14	8	2.69	1.22	1.18	0.00	54	0
	1	LNB+OFA+SCR (Stand Alone)	0	0	0.08	0.02	0	0	0.08	0.03	0	0	0.07	0.04	0.03	1.15	0	54
	2	LNB+OFA+SCR (In-Line)	0	0	0.12	0.03	0	0	0.12	0.04	0	0	0.11	0.05	0.04	1.14	0	54
	3	LNB+OFA+FGR	0	0	0.23	0.05	0	0	0.26	0.08	0	0	0.24	0.08	0.07	1.11	0	54
	4	LNB+OFA+SNCR	0	0	0.26	0.05	0	0	0.29	0.08	0	0	0.26	0.09	0.08	1.11	0	54
	5	LNB+OFA	0	0	0.31	0.06	0	0	0.35	0.10	0	0	0.32	0.11	0.09	1.09	0	54
11 Class I Areas	-	Baseline													1.41	0.00	1505	0
	1	LNB+OFA+SCR (Stand Alone)													0.06	1.35	0	1505
	2	LNB+OFA+SCR (In-Line)													0.08	1.33	4	1501
	3	LNB+OFA+FGR													0.13	1.28	22	1483
	4	LNB+OFA+SNCR													0.14	1.27	32	1473
	5	LNB+OFA													0.17	1.25	48	1457

Figure F-2 8th Highest Visibility Impact due to BART Option 1

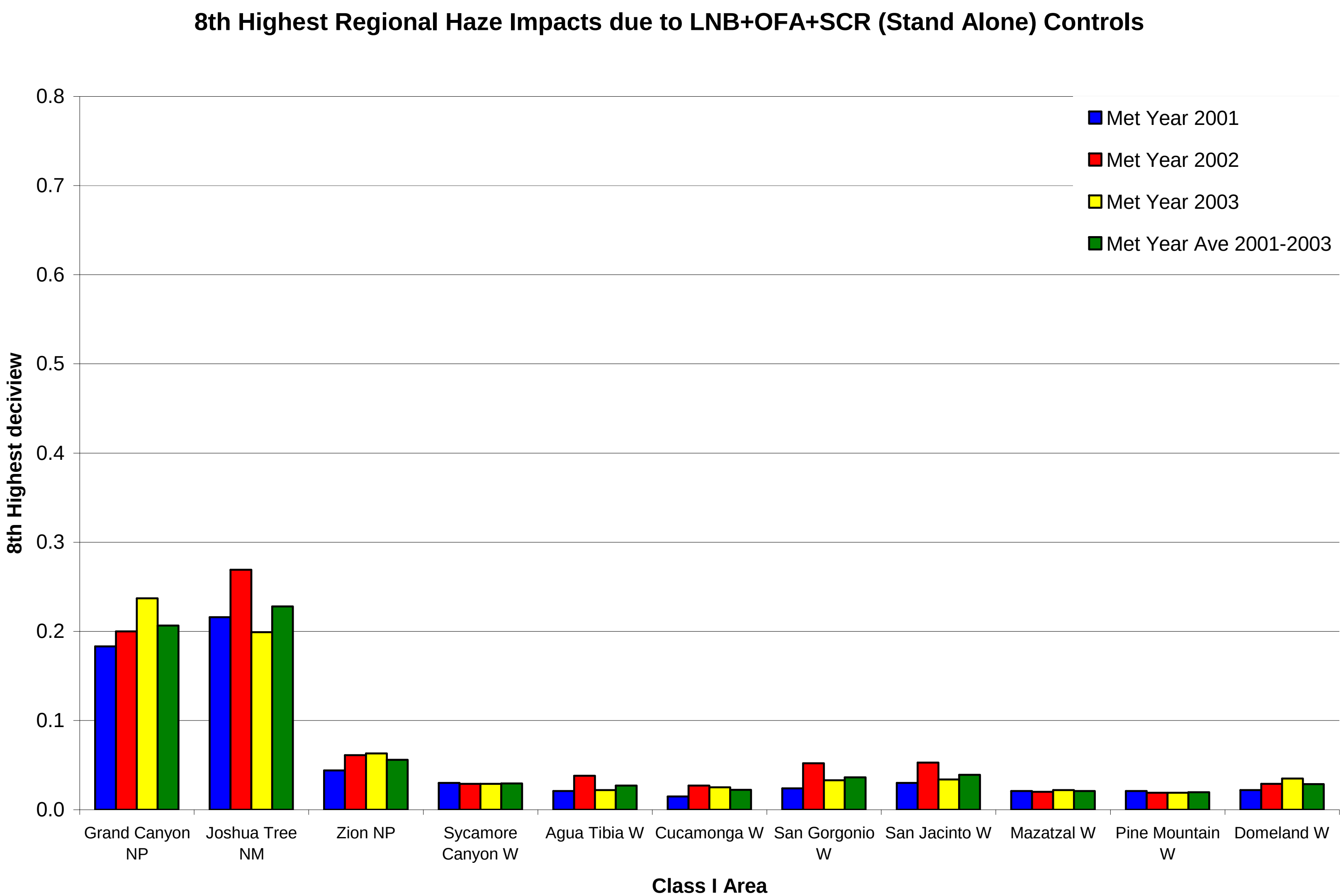


Figure F-3 8th Highest Visibility Impact due to BART Option 2

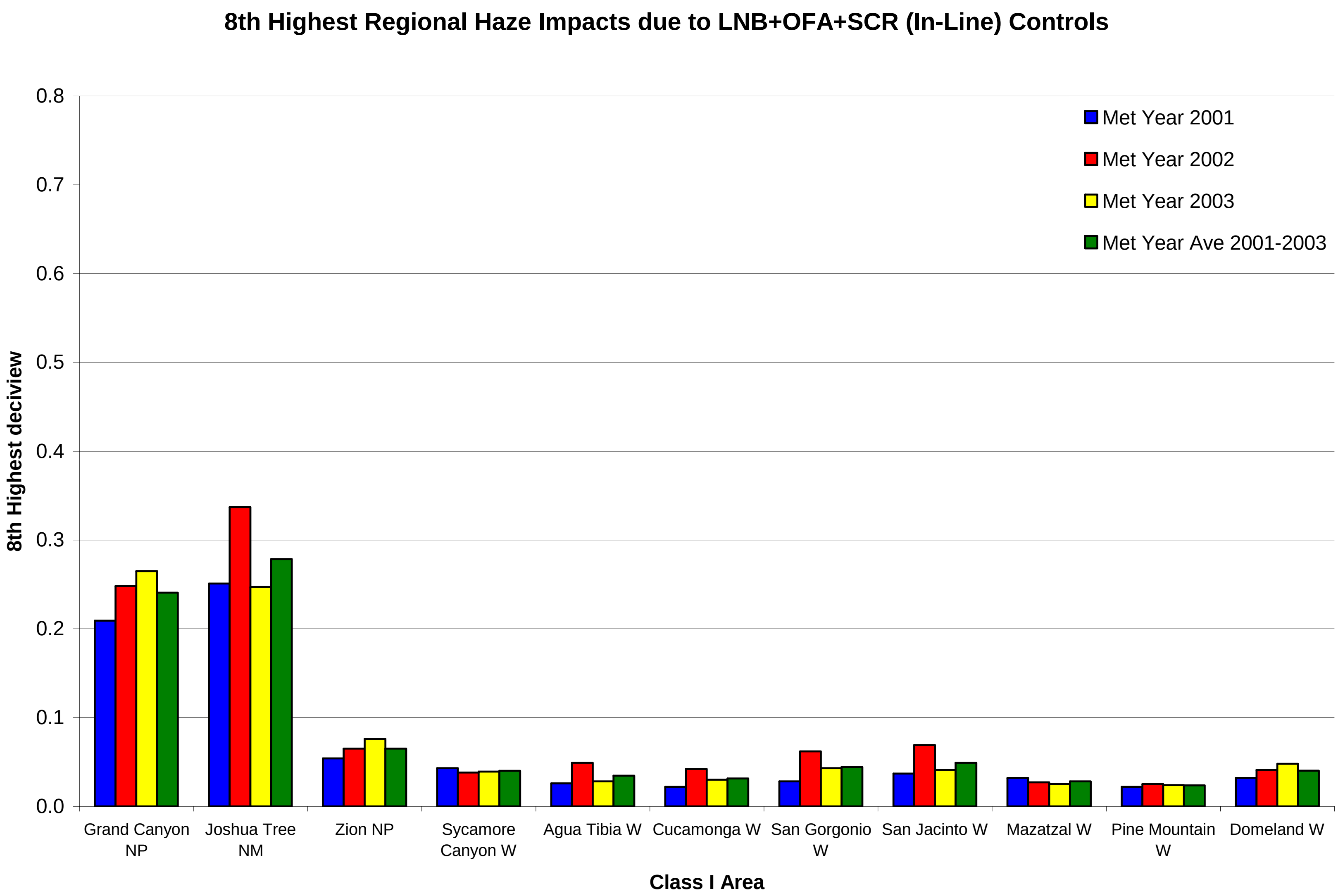


Figure F-4 8th Highest Visibility Impact due to BART Option 3

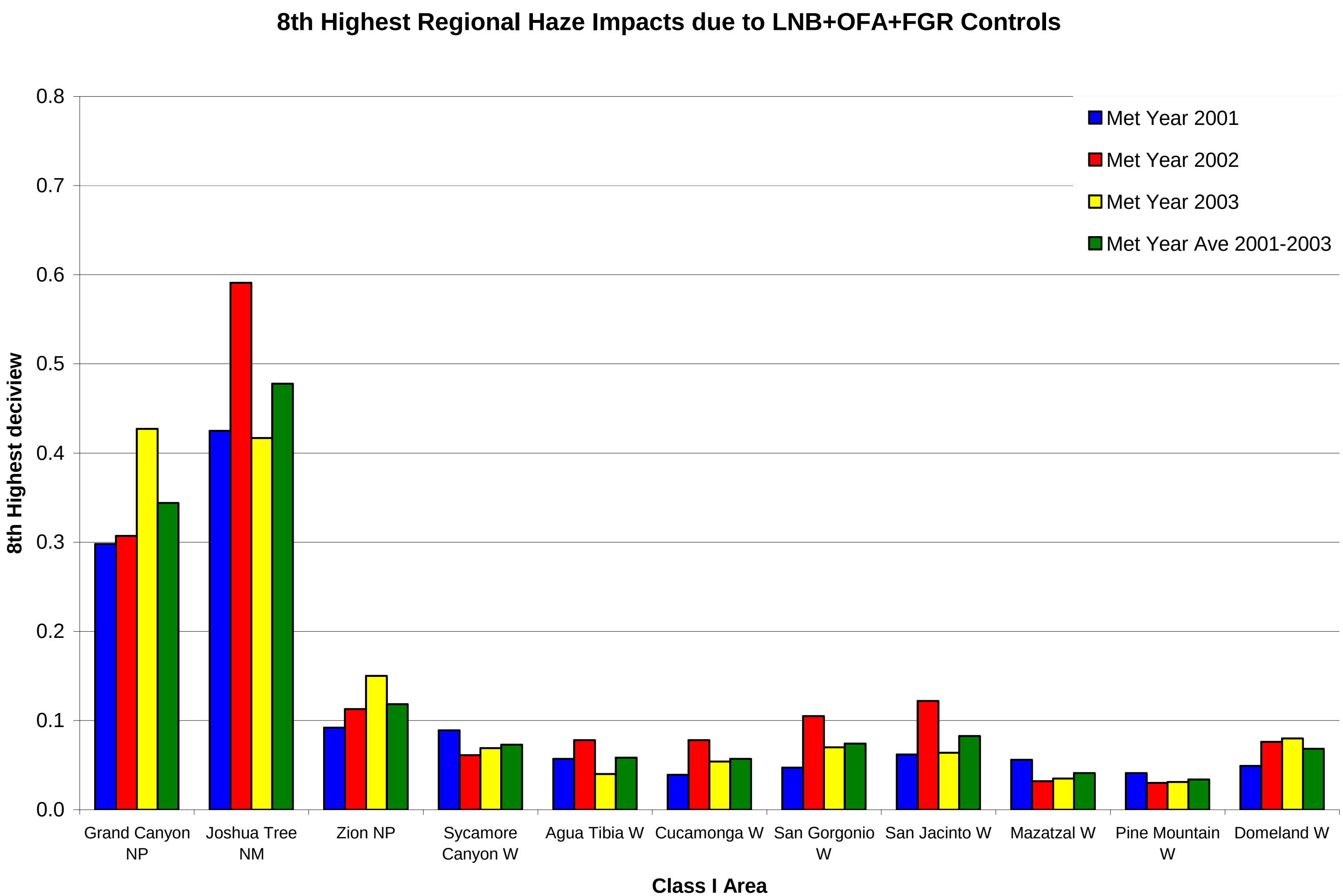


Figure F-5 8th Highest Visibility Impact due to BART Option 4

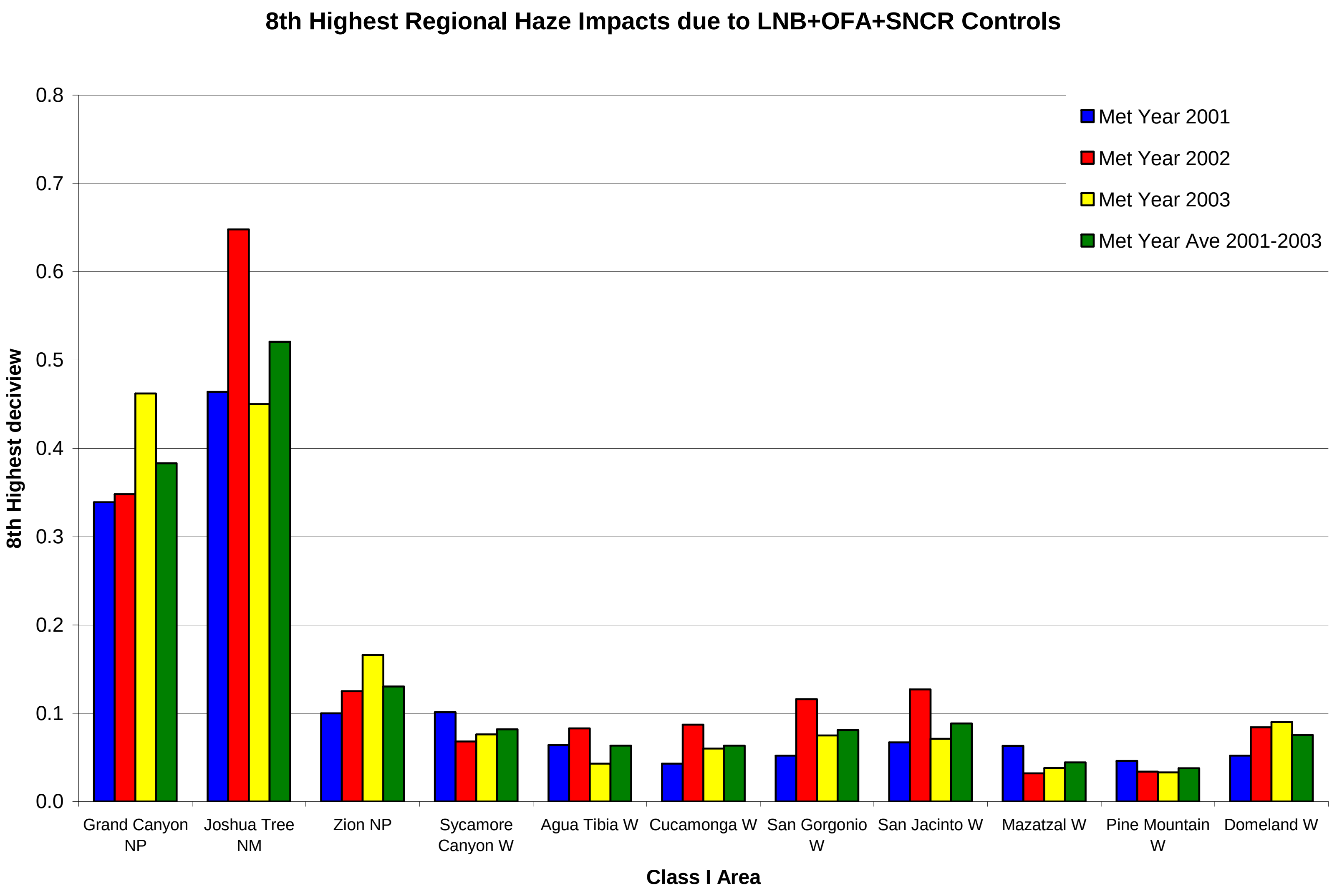


Figure F-6 8th Highest Visibility Impact due to BART Option 5

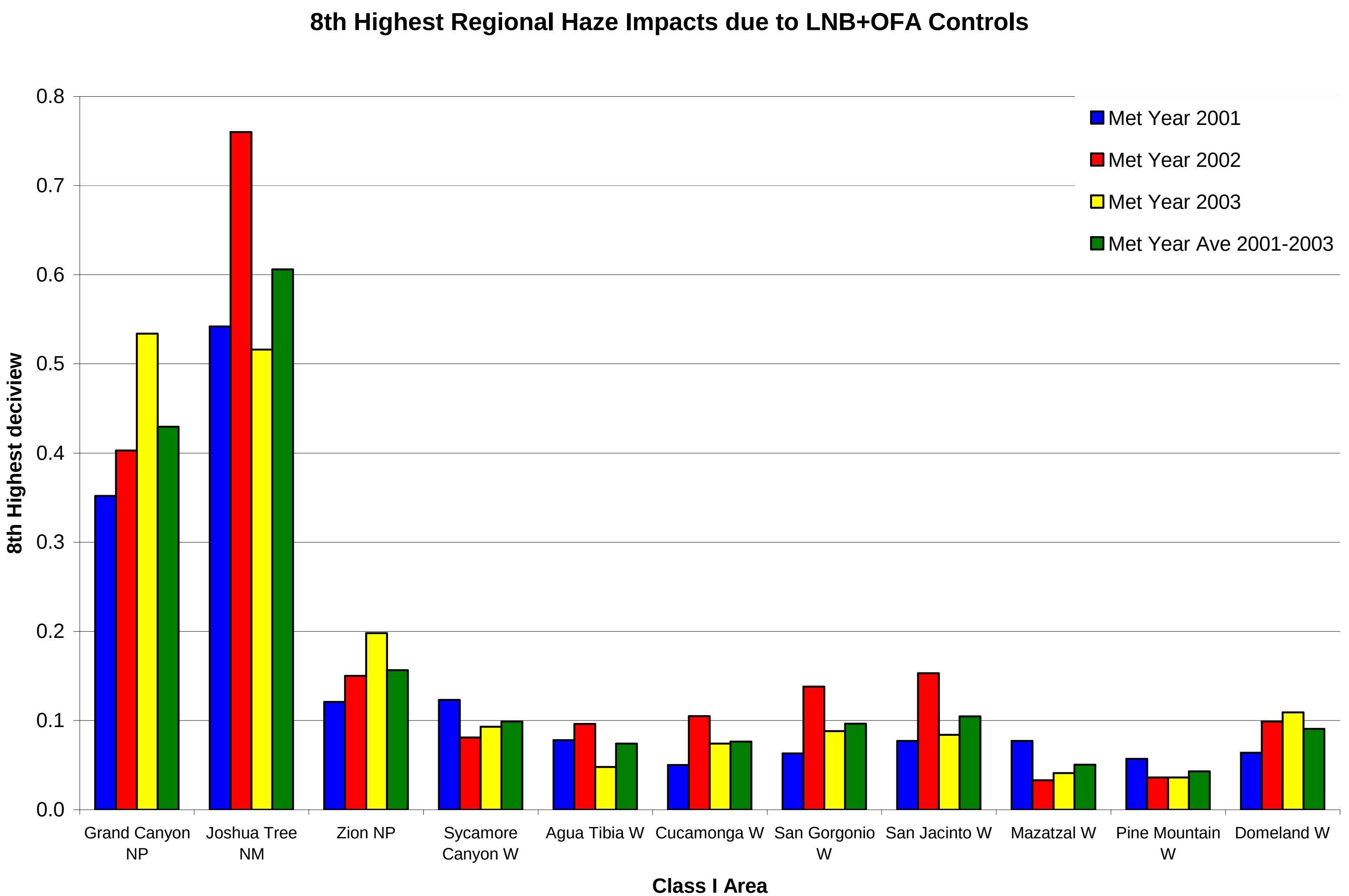


Figure F-7 8th Highest Visibility Impact due Five BART NOx Control Options

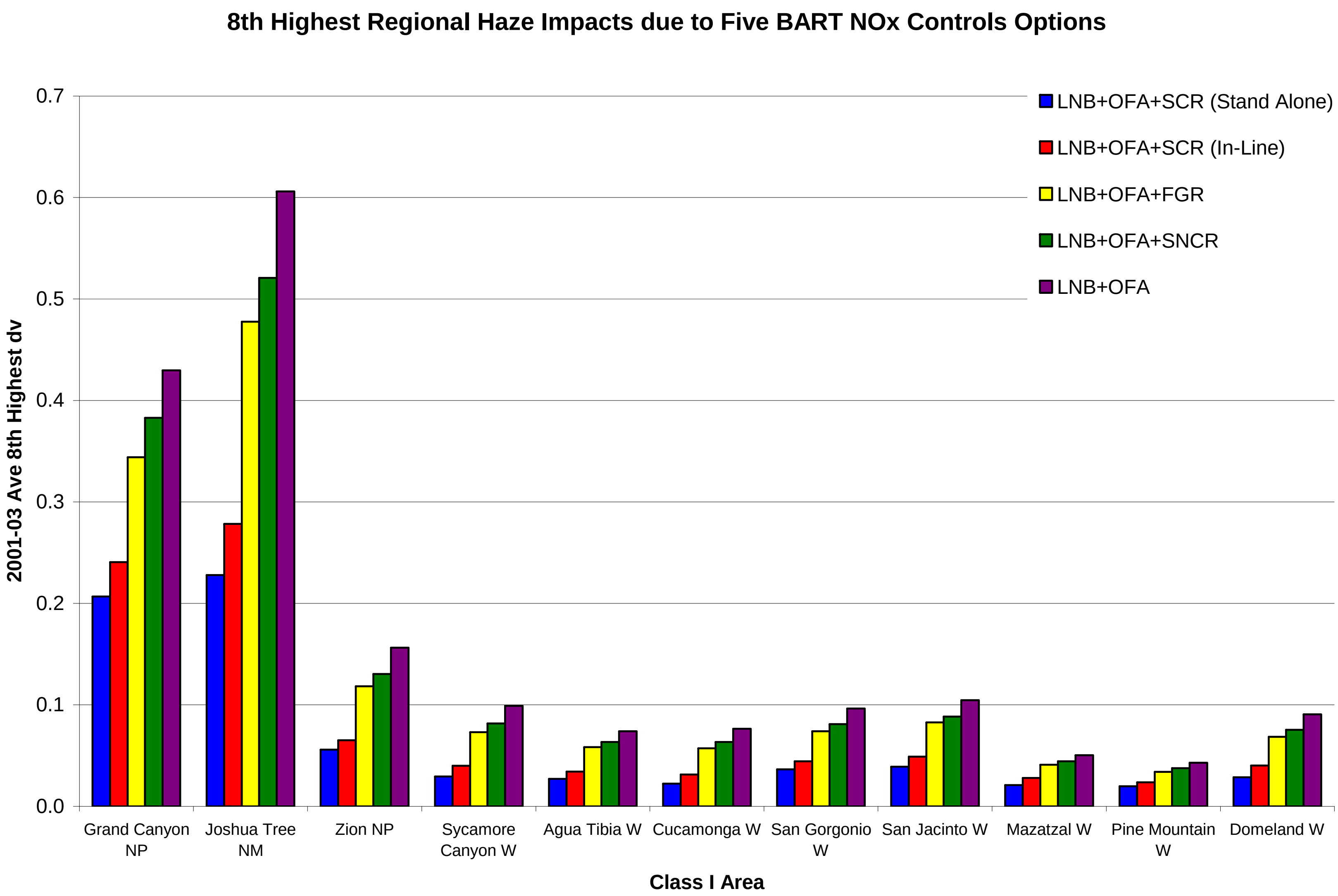


Figure F-8 Total Number of Days Removed Above 0.5 delta-dv Relative to the Baseline Case

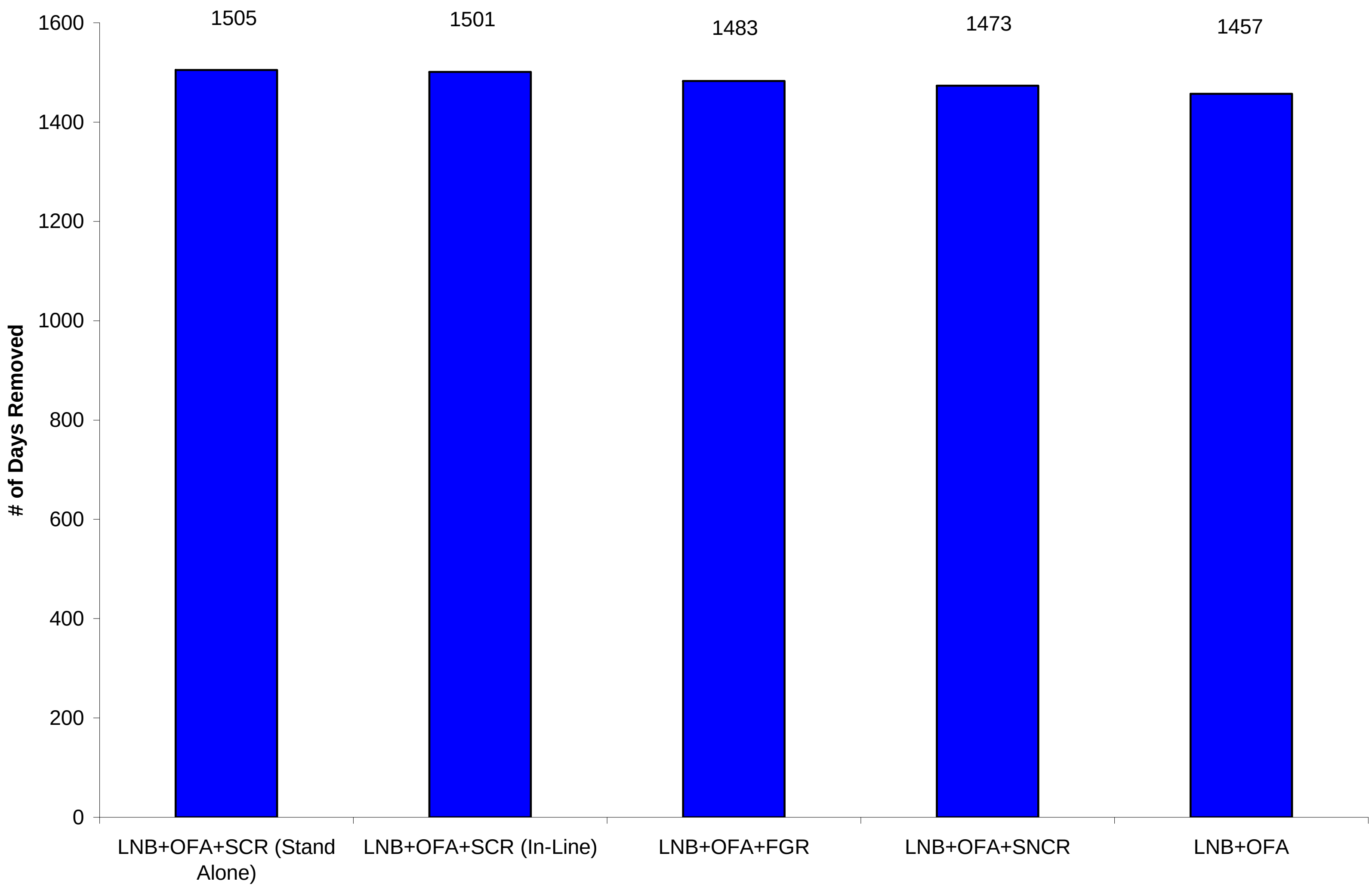


Figure F-9 Number of Days Removed at Each Class I Area Above 0.5 delta-dv Relative to the Baseline Case

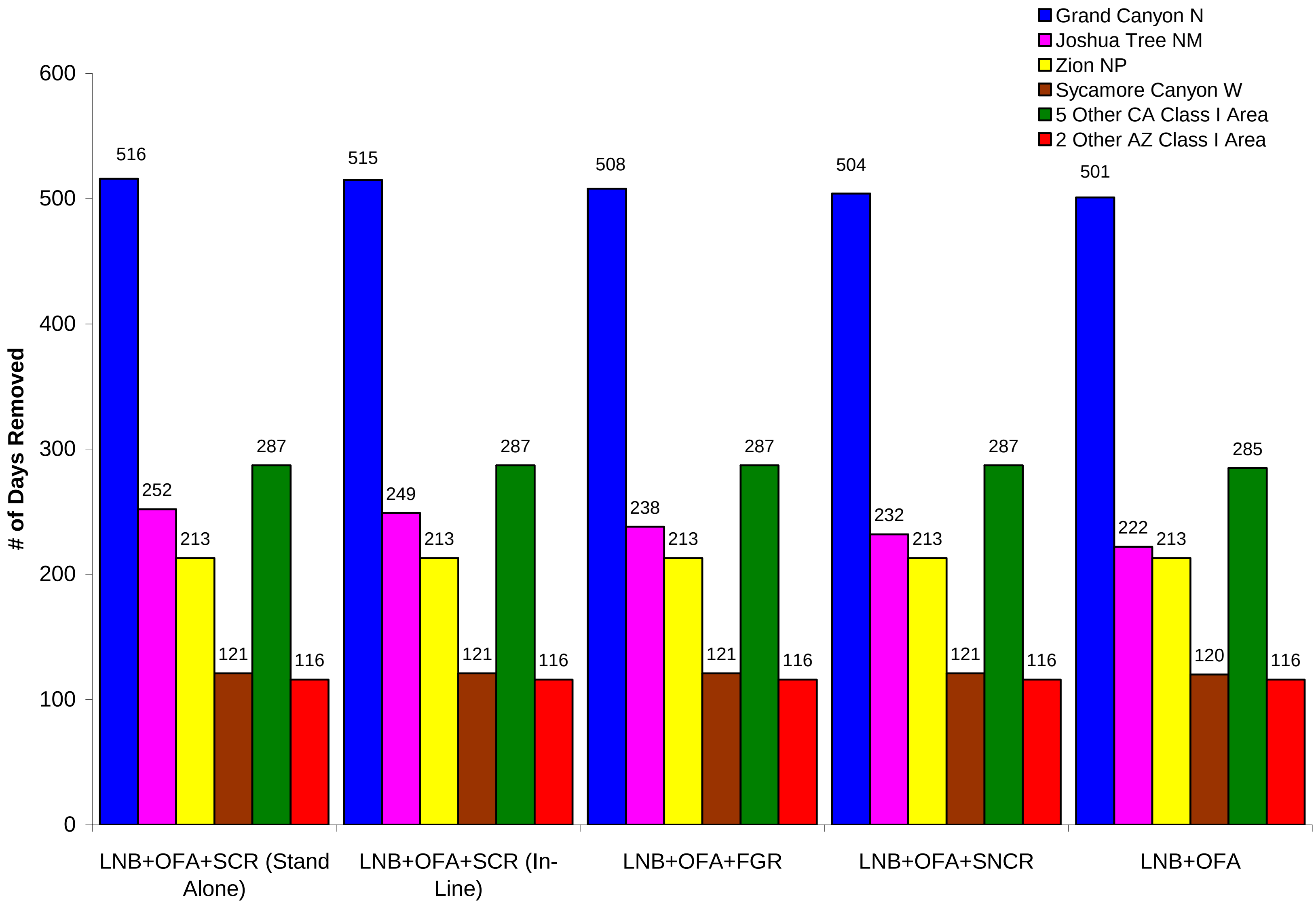


Figure F-10 Annual Cost of NOx Controls vs. Visibility Improvements at the Closest Class I Areas

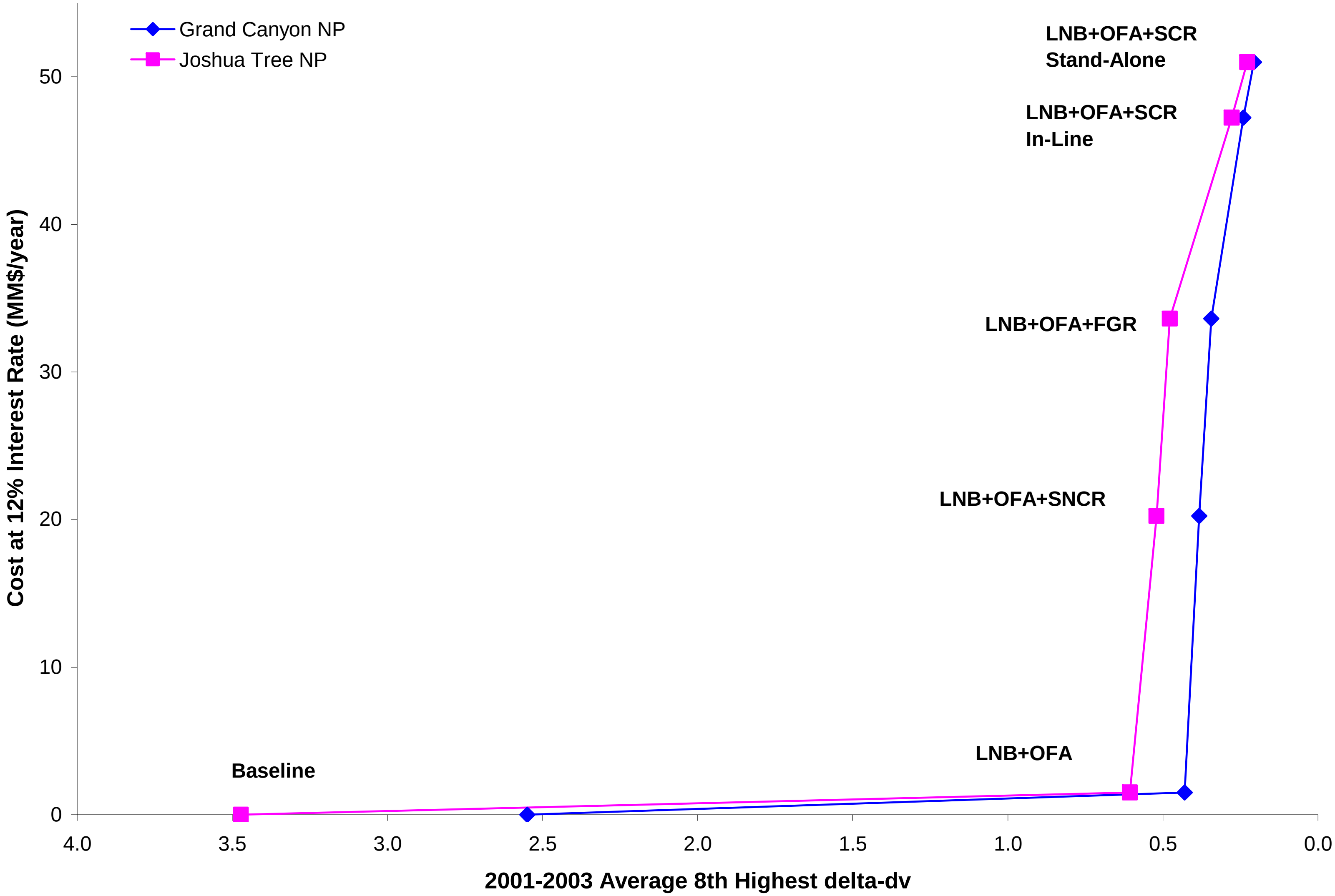


Figure F-11 Annual Cost of NOx Controls vs. Visibility Improvements at the Other California Class I Areas

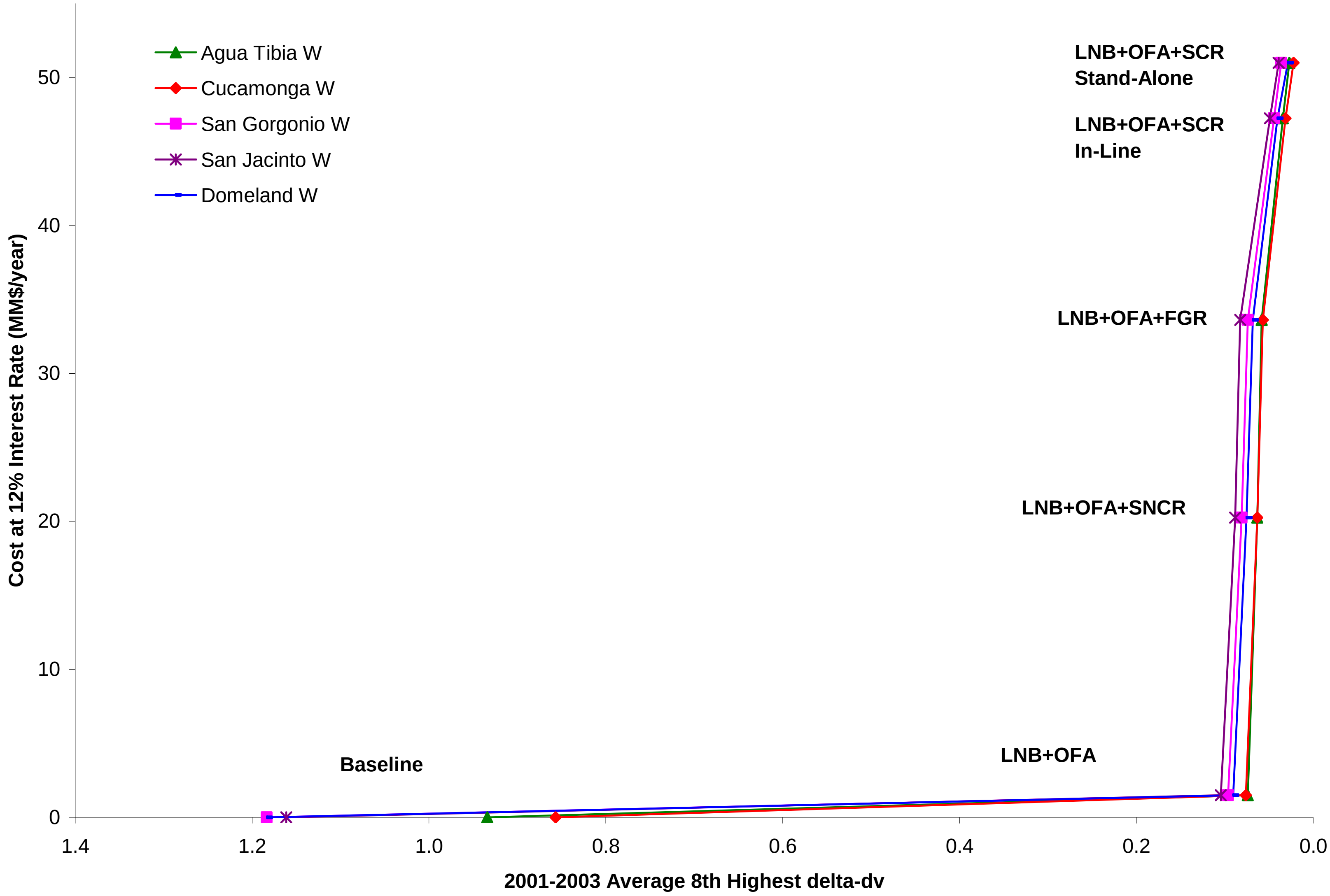
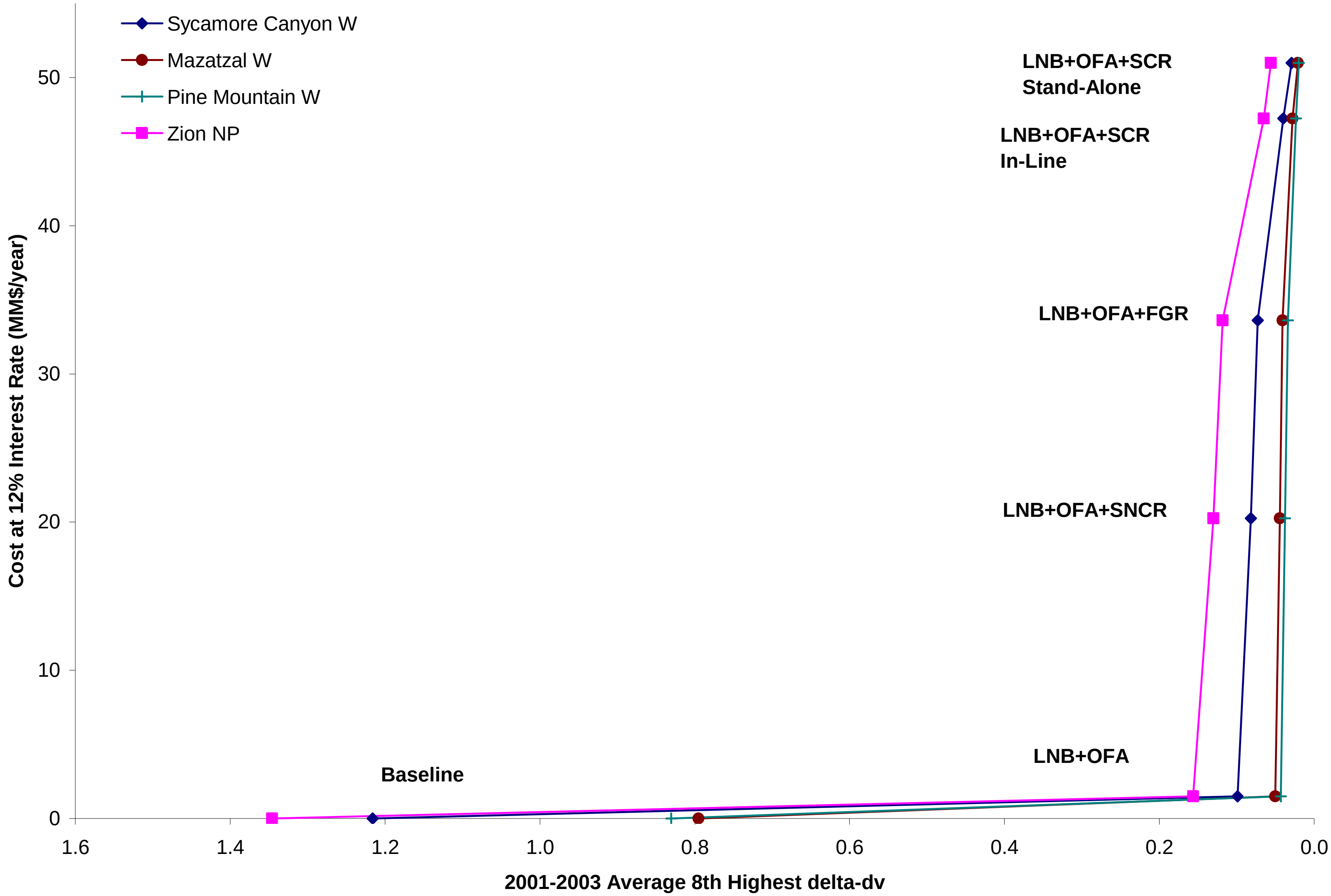


Figure F-12 Annual Cost of NOx Controls vs. Visibility Improvements at the Other Non-California Class I Areas



Appendix G

Projected NO_x Emissions on Natural Gas Over Mohave's Future Operating Range Based on 2005 Actual Reporting for the Mohave Generating Station

RILEY Power
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ANTICIPATED NOX EMISSIONS OVER THE OPERATING RANGE BASED ON 2005 ACTUAL REPORTING FOR MOHAVE GENERATING STATION

Date Issued: October 8, 2008

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APPENDIX G:

Anticipated NOx Emissions
Over the Operating Range
Based on 2005 Actual Reporting
For
Mohave Generating Station

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1. NOx Emissions

An analysis was performed comparing NOx in lb/MBtu versus lb/hr NOx, at various boiler loads. To do this the hourly EPA NOx data for 2005 Quarter 1 thru 4 was downloaded, this data is indicated as the blue data points on Figure 1 & 2 below. In order to mimic the same operating conditions while firing gas we applied a multiplier to the coal firing NOx data from 2005 to make the full load NOx average 0.10 lb/MBtu. Table 5 and Figures 1 & 2, show that there are load conditions where the unit would operate above the 0.10 lb/MBtu value. This is especially important for a unit that will be cycling as the average may be skewed by these transient operating conditions.

Table 5
Example Case Analysis
Comparing lb/MBtu and lb/hr NO_x Emissions

Load, MW	Heat Input, MBtu/hr	NOx, lb/MBtu	NOx, lb/hr
750	7500	0.1	750
500	5000	0.15	750
250	2500	0.07	175
<100	1000	0.2	200

Figure 1

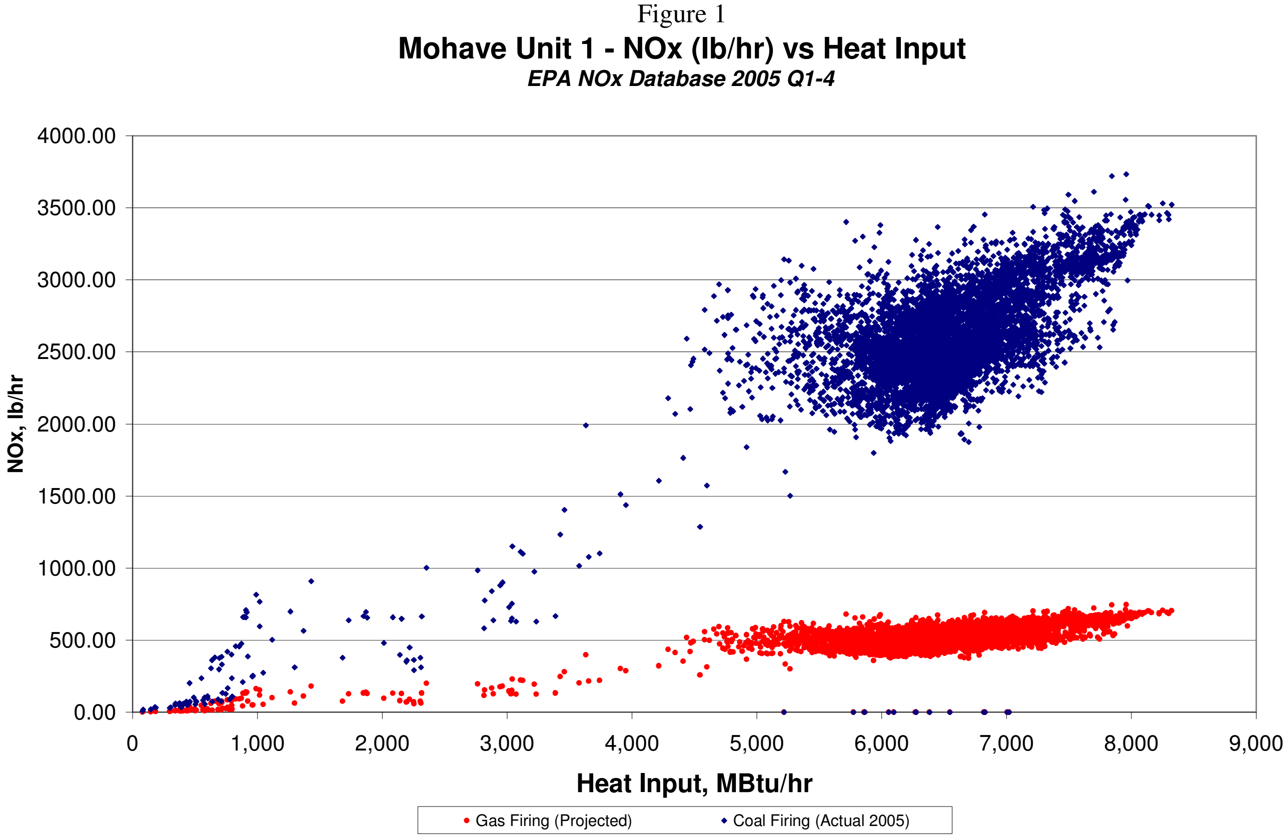

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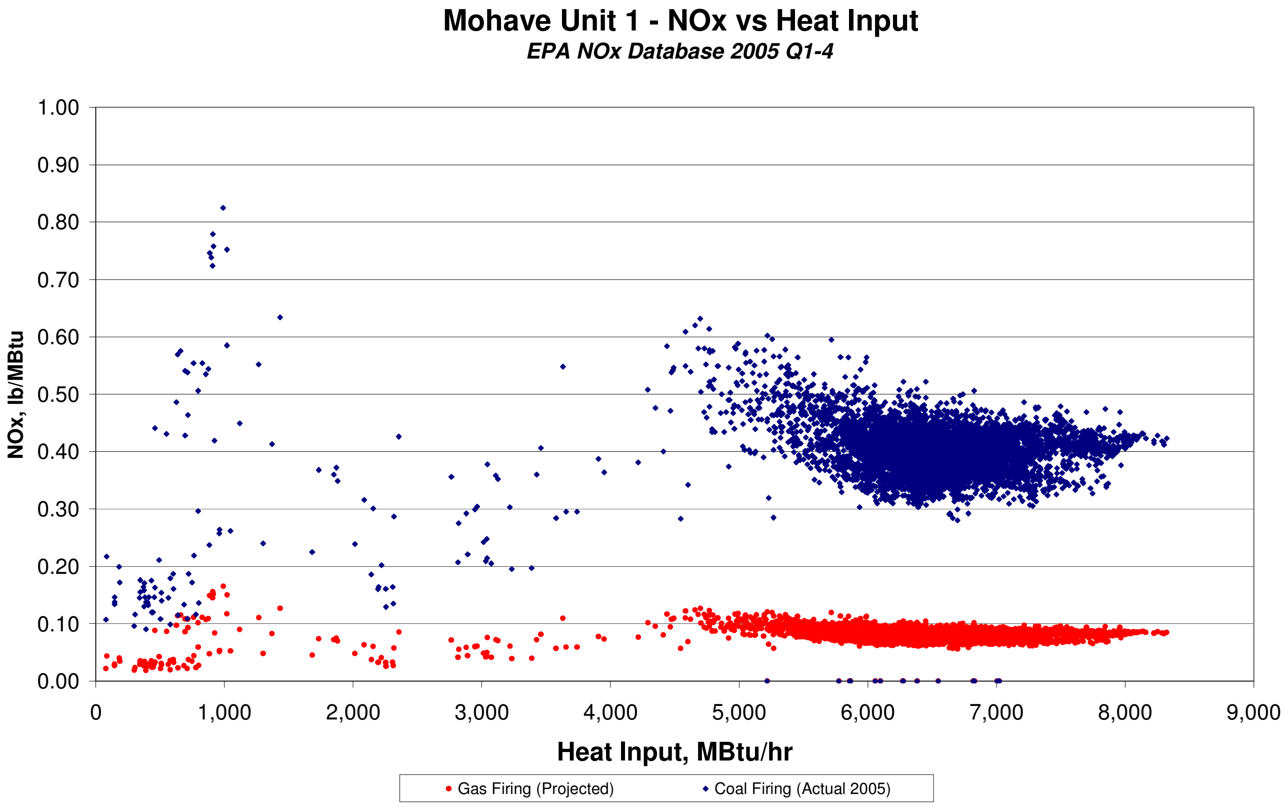
Figure 2



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