BART DETERMINATION STUDY

for

Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

October 2006

41440

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INDEX AND CERTIFICATION

BART Determination Study
Milton R. Young Station Unit 1 and 2
Minnkota Power Cooperative, Inc.

Project 41440

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Certification

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Minnkota Power Cooperative, Inc.
Milton R. Young Station
Units 1 and 2
Best Available Retrofit Technology Analysis

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EXECUTIVE SUMMARY

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

Once a source is determined to be eligible, there are five predefined steps for conducting a BART analysis for each pollutant. The result of conducting this five step analysis is a list of control technologies for regulated pollutants that provides a cost effective system of emission reduction and visibility impact reduction. However, prior to the completion of this analysis, Minnkota entered into a Consent Decree (CD) that requires the MRYS to install Best Available Control Technology-level (BACT-level) controls for NO_X, SO_2, and PM. As discussed in detail within the report, BACT is considered to be more stringent than BART. Thus, the BART analysis was reduced to an evaluation of the BACT-level control technologies and emission reductions specified by the CD. Because BACT and BART analyses have similar steps, the only remaining step for recommending BART was to perform a visibility impairment impact analysis and discern if there was an acceptable impact reduction.

Based upon an evaluation of the 90th percentile visibility impairment modeling results, the control technologies and emission reductions specified by the CD for all pollutants and both units had an acceptable impact reduction. Because there was an impact reduction in all cases, the BART recommendation consists of the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions at the modeled emission rates. The BART recommendations for each pollutant and each unit are summarized in the tables below. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

MRYS Unit 1 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Dry Flue Gas Desulfurization (FGD) Process	0.24
PM	Fabric Filter Baghouse	0.015**

* Excludes startups. See Appendix A for a detailed discussion.

** See discussion in Section 5.1

MRYS Unit 2 Recommended BART 30-Day Rolling Average

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.31
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See Appendix A for a detailed discussion.

1.0 INTRODUCTION

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

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

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

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

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

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

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

STEP 5 – Evaluate the visibility impacts.

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

1.1 BACKGROUND

Minnkota Power Cooperative, Inc. operates the Milton R. Young Station near Center, North Dakota. MRYS is a steam electric generating plant with two units. Unit No. 1 is a Babcock & Wilcox (B&W) cyclone-type coal-fired boiler burning lignite coal, serving a turbine generator with a nameplate rating of 257 MW.[2] Particulate control is provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control. Unit 1 has no sulfur dioxide (SO_2) control system and exhausts to a 300 foot tall stack. Unit No. 2 is a B&W cyclone-fired unit burning lignite coal, with a turbine-generator name plate rating of 477 MW.[2] Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi precipitator rated at approximately 99% control. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats approximately 78 percent of the flue gas with the remaining flue gas by-passed for stack gas reheat. The FGD system achieves approximately 75 percent SO_2 removal and exhausts to a 550 foot tall stack. Unit 1 began commercial operation on November 20, 1970 and Unit 2 on May 11, 1977.

[2] "Generator Nameplate Data"; Emissions & Generation Resource Integrated Database (eGRID); U.S. Environmental Protection Agency; April, 2003.

On 17 June 2002, Minnkota Power Cooperative, Inc. received a Notice of Violation (NOV) from EPA. The NOV states that Minnkota allegedly violated the Prevention of Significant Deterioration (PSD) regulations. The NOV was issued pursuant to Section 113 of the Clean Air Act. The alleged violation was caused by modifications to both Unit 1 and 2 at MRYS which allegedly resulted in a potential increase of SO_2, NO_X and PM. Without an admission of liability, Minnkota entered into a settlement in the form of a Consent Decree (CD) with the EPA and NDDH to resolve the issues. The CD requires that Minnkota install a level of control for SO_2, NO_X and PM on both Unit 1 and 2 at MRYS, equivalent to BACT. The effect of the CD on the BART analysis and the requirement to install BACT-level controls are discussed later in the report.

1.2 APPROACH

The purpose of the Regional Haze Rule is to address visibility impairment in mandatory Class 1 areas that results from the emission of SO_2, NO_X, PM, Volatile Organic Compounds (VOCs) and ammonia from certain major sources. The only control method for VOCs identified in the RACT/BACT/LAER Clearinghouse (RBLC) database is good combustion practices. This control technique is already in place at MRYS. If an analysis were performed for VOCs, good combustion practices would be the most probable method chosen for BART. The visibility impact of VOCs and ammonia are considered negligible for a BART analysis, according to the NDDH's November 2005 modeling protocol[3], and are not addressed further in this report. Before the actual BART analysis can begin for SO_2, NO_X, and PM, the approach used to conduct the analysis should be addressed. The following sections present specific subjects related to MRYS's background, which warrant mention due to their effects on the contents of the report.

1.2.1 CONTROL TECHNOLOGY EVALUATION AND BACT VS. BART

As stated above, once a source is determined to be eligible, there are general steps for conducting a BART analysis for each pollutant. All retrofit control technologies are first identified. A brief review of the processes and their capabilities is then performed to determine availability and feasibility. Subsequently, those available technologies deemed feasible for retrofit application are ranked according to control capability and an analysis then reviews the probable impacts of each technology.

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

The visibility impact is included in the impact analysis. Finally, the results of the analyses are tabulated and possible BART control options are listed.

As stated in the proposed BART guidelines dated 5 May 2004 (69 FR 25218), a BART analysis is similar to a Best Available Control Technology (BACT) analysis.

> "The process for a BART analysis is very similar to the BACT review as described in the New Source Review Workshop Manual (Draft, October 1990). Consistent with the Workshop Manual, the BART engineering analysis requires that all available control technologies be ranked in descending order of control effectiveness (i.e. percent control). You [meaning States] must examine the most stringent alternative first. That alternative is selected as the ''best'' unless you demonstrate and document that the alternative cannot be justified based upon the consideration of the five statutory factors discussed below. If you eliminate the most stringent technology in this fashion, you then consider the next most stringent alternative, and so on.
>
> Although very similar in process, BART reviews differ in several respects from the BACT review described in the NSR Draft Manual."

The proposed guidelines stated that a BART analysis is similar to a BACT review and provided a few examples of similarities and differences, but it did not explicitly state how the two analyses could be used in conjunction to obtain a determination. Because BACT and BART are similar, there are many aspects that can be combined to reduce the steps of an analysis. However, because there are some differences, a BART analysis must address some additional aspects that a BACT review does not.

A BART analysis is always conducted for existing sources and a BACT review is usually conducted for a new source. Because BACT is usually performed for a source that is a new design or reconstruction, the review must take into account all available technologies and must include the most effective controls that have been demonstrated on similar units. BACT is considered to be more stringent than BART because it usually is not limited by the design of existing equipment or current operating conditions as is required for a retrofit application. Although MRYS is eligible to perform an analysis to determine BART, the Consent Decree (CD) also requires that MRYS install levels of control equivalent to BACT. Thus, the BART analysis can be shortened to only include the BACT-level control technologies specified in the CD.

With the specification of BACT-level technologies in the CD, the first four evaluation steps of the BART analysis can be eliminated. The first four steps of BART are usually used to identify technologies, determine feasibility and evaluate cost, energy, non-air quality and useful life impacts. Because the control technologies are already specified by the CD, the visibility impacts evaluation is the only remaining step in the determination that must be performed to satisfy BART. This analysis evaluates the visibility impairment impacts of the BACT-level control technologies specified in the CD and provides a BART recommendation based upon an acceptable degree of visibility improvement in Class 1 areas.

1.2.2 CONDENSABLE PARTICULATE

Particulate matter emissions are composed of filterable and condensable particles. The filterable particles are characterized using EPA standard reference methods (i.e., Method 5, 17, 201, or 201A). The reference method used for characterization is dependent upon the size of the particle and the temperature of the flue gas, and is usually specified in the applicable permit. Solid particles are captured using a heated filter while the majority of condensable particles are not collected as they are in the gaseous form until after the flue gas has passed through the filter.

Condensable particulate matter (condensable PM) may react with atmospheric or flue gas constituents as flue gas moves through the different processes and then either condenses into a droplet, coalesces into a solid particle, or forms a solid particle as more volatile components evaporate. Condensable PM is characterized using EPA standard reference Method 202. Using Method 202, the flue gas passes through a heated filter to remove filterable PM and condensable flue gas constituents are condensed by bubbling them through water at $20^{o}C$. During post-test sample recovery, the water is evaporated and the remaining residue is weighed to determine condensable PM emissions. However, Method 202 has an inherent flaw because the means by which condensable particulate is collected differs from how particulate condenses in the stack. Method 202 can result in inaccurate measurements due to the creation of PM artifacts in the sampling water that would not normally condense in the stack plume (e.g., SO_2 and NH_3 compounds). For a fixed operating condition, Method 202 can provide inconsistent emission rate measurements and can result in overstatement of emission rates. Thus, there is considerable uncertainty surrounding emissions measured with Method 202 for the purpose of PM compliance demonstration.

Condensable PM may include both organic and inorganic constituents. Organic constituents in the flue gas can exist as a vapor at stack temperatures and a liquid or solid at ambient temperatures. Control technologies designed to minimize the formation of condensable organic emissions are the same technologies that are used to minimize carbon monoxide (CO) and volatile organic compound (VOC) emissions. A review of the RBLC database shows that good combustion practices are universally used to control CO/VOC emissions for similar units. Both MRYS units already practice good combustion practices while maintaining combustion efficiency in the boiler and controlling NO_X emissions. Because good combustion practices would likely be considered BART and are already in use at both units, the organic portion of condensable PM is not addressed further in this report.

Sulfuric acid (H_2SO_4) mist is the most widely recognized form of inorganic condensable PM emitted by combustion sources. Other inorganic condensable PM constituents may include to a lesser extent other acid gases, ammonium sulfate ($(NH_4)_2SO_4$), and unidentified inorganic species. Control technologies designed to reduce sulfuric acid mist will also reduce the other inorganic constituents. H_2SO_4 is typically generated in the flue gas when sulfur trioxide (SO_3) reacts with water. SO_3 is a by-product created during the combustion of fuels containing sulfur and is formed when sulfur dioxide (SO_2) in the flue gas is oxidized. Limited data is available on the quantity of SO_2 that will be converted to SO_3 in a lignite fired unit. Estimates of the conversion range from 0.2 to 1.0 percent.

Combustion controls commonly used to control NO_X (e.g., staged combustion and separated overfire air) provide a co-benefit of sulfuric acid mist control by limiting the oxygen available in the boiler and reducing formation of SO_3 in the boiler. The H_2SO_4 vapor will adsorb on the fly ash as the flue gas cools under appropriate temperature and moisture conditions. Consequently, when those conditions exist, H_2SO_4 is removed from the gas stream by particulate control equipment. Control technologies designed to remove SO_2 will also achieve SO_3 removal and reduce emissions of H_2SO_4. Typical SO_3 removal associated with a wet FGD process is 40 to 60 percent, and higher removal is typical for semi-dry FGD processes. The Southern Company estimates a minimum 50% reduction in H_2SO_4 emissions for use of a FGD process.[4] Thus, control technologies used to control NO_X, SO_2 and filterable PM are also able to provide H_2SO_4 control.

[4] "An Updated Method for Estimating Total Sulfuric Acid Emissions from Stationary Power Plants"; Monroe, Larry S. & Harrison, Keith E.; Southern Company Generation and Energy Marketing; Revised March, 2003.

Recommended BART for condensable PM is the co-benefit of NO_X, SO_2 and filterable PM control devices to be analyzed in this report and is not addressed further. Therefore this BART analysis for particulate emissions investigates control methods to reduce filterable PM only.

1.2.3 EMISSION SOURCE APPLICABILITY

There are two subjects within the Guidelines related to the applicability of BART to emission sources. The first subject deals with the presumptive BART emission limits and their application to power plants smaller than 750 MW in size. The Guidelines for BART Determination include the following statement with regard to presumptive BART for SO_2 (70 FR 39171):

> "You [meaning States] must require 750 MW power plants to meet specific control levels for SO_2 of either 95 percent control or 0.15 lbs/mmBtu, for each EGU greater than 200 MW that is currently uncontrolled unless you determine that an alternative control level is justified based on a careful consideration of the statutory factors. For a currently uncontrolled EGU greater than 200 MW in size, but located at a power plant smaller than 750 MW in size, such controls are generally cost effective and could be used in your BART determination….."

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

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

For power plants greater than 750 MW in size, the EPA requires state agencies to apply the presumptive limits for BART as a floor for NO_X control. However, for power plants smaller than 750 MW in size, the presumptive limits are described as being "cost-effective" but not set as a minimum performance requirement. Thus, BART for EGUs at power plants smaller than 750 MW in size, like MRYS, is not required to meet the presumptive limits. This BART analysis for MRYS will evaluate potential control options that achieve the BACT-level limits set forth in the Consent Decree.

Consequently, based upon the visibility analysis, the recommended control options may not achieve the EPA's presumptive BART limits.

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

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

According to this statement, the BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. The BART analysis for MRYS will review control options for the main boilers for Unit 1 and Unit 2. Smaller emissions sources at the facility are anticipated to provide negligible contribution to visibility impacts from MRYS in Class 1 areas. Smaller sources at MRYS are discussed in Section 1.2.4 and 1.2.5.

1.2.4 SMALL SOURCE EMISSION UNITS

The BART determination must consider any emission unit that emits the pollutant of concern (i.e., NO_x, SO_2 and PM) regardless of size. However, smaller emissions sources (e.g., auxillary boilers and emergency generators) at the facility are anticipated to provide negligible contributions to visibility impairment in Class 1 areas. The nearest Class 1 area is Theodore Roosevelt National Park (TRNP) located approximately 160 km to the west. Although technically eligible, smaller source emissions units were not reviewed because they have limited hours of operation or they are material handling sources with a level of emissions anticipated to be too small to affect visibility impact on TRNP. Consequently, small emission sources are excluded from further consideration in the study.

1.2.5 FUGITIVE DUST

The primary source of fugitive dust is from the outside coal storage area and other plant activities normally found at a coal-fired electrical generating facility. The coal stockpile, access roads and plant activities are performed and maintained with good operating practices. On the coal stockpile and on other applicable fugitive sources, dust suppression is achieved through the use of water sprays or surfactants. The level of fugitive PM emissions is not expected to affect the visibility in Class 1

areas based upon the approximate 160 km distance to the nearest Class 1 area, the large particle size and relatively small emission rates. As such, fugitive sources were not evaluated in this BART analysis for MRYS.

1.2.6 METHODOLOGY FOR VISIBILITY IMPACTS DETERMINATION

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

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

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

The approach taken in the BART analysis for MRYS incorporates the visibility impact analysis results as a verification of visibility improvement. Because the Consent Decree specifies the control level and technology that must be used for SO_2 control, the emission rate for control of PM, and the

use of a BACT "Top Down" analysis for NO_X emissions control, the visibility analysis is not used to differentiate between control technologies used to control each pollutant. Rather, the visibility analysis is used to determine if control levels and technologies specified in the Consent Decree provide visibility improvement in Class 1 areas.

1.3 THE ROLE OF MODELING AND CALPUFF IN A BART ANALYSIS

The BART guidelines list visibility impact at a Class I area as one of the factors in a BART determination. The EPA interpreted the statutory provision of Section 169A of the Clean Air Act to require that a BART-eligible source is one that is "reasonably anticipated to cause or contribute" to regional haze if it can be shown that the source emits pollutants within a geographic area from which pollutants can be emitted and transported downwind to a Class I area (70 FR 39161). A Class I area, as listed by the EPA, is an area of the country with pristine air quality that is sensitive to changes in visibility. Two Class 1 areas have been identified for inclusion in the visibility analysis for MRYS. These are the Theodore Roosevelt National Park (TRNP), and the Lostwood National Wildlife Refuge (Lostwood NWR), which are approximately 160 and 180 km (100 and 112 miles), from Milton R. Young Station, respectively. For Class I areas more than 50 km from a source, the EPA has identified CALPUFF as a guideline model for long-range transport that is suitable for predicting potential changes in visibility. CALPUFF is a non-steady-state meteorological and air quality dispersion modeling system used to access long-range transport of pollutants.

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

1.3.1 CALPUFF MODELING METHODOLOGY

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

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

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

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

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

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

The BART guideline states that a visibility improvement is based upon the modeled change in visibility impacts, measured in deciViews, for the pre-control and post-control emission scenarios. The comparison should be made for the 98th percent days (70 FR 39170). The NDDH modeling protocol provides additional clarification about BART applicability by stating, "…the context of the

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

1.3.2 MODELING SCENARIOS

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

- NDDH BART Modeling Protocol emission rates
- Post-Control emissions based upon BACT-level emission rates as required by the Consent Decree

The emission rates modeled in each scenario are presented in Table 1.3-1.

Table 1.3-1 – Milton R. Young Station Modeling Scenarios

	Unit 1			Unit 2		
Scenario	**NO_X (lb/hr)**	**SO_2 (lb/hr)**	**PM Coarse/Fine (lb/hr)**	**NO_X (lb/hr)**	**SO_2 (lb/hr)**	**PM Coarse/Fine (lb/hr)**
Screening	Protocol	Protocol	Protocol	Protocol	Protocol	Protocol
1	1,070.7	Protocol	Protocol	2,011.6	Protocol	Protocol
2	Protocol	723.1	Protocol	Protocol	1,574.4	Protocol
3	Protocol	Protocol	38.5 / 5.8	Protocol	Protocol	133.7 / 21.0
4	1,070.7	723.1	38.5 / 5.8	2,011.6	1,574.4	133.7 / 21.0
5	1,070.7	723.1	38.5 / 5.8	2,011.6	1,574.4	133.7 / 21.0

These scenarios represent the emission rates evaluated for consideration in making a BART recommendation. The emission rates presented in Table 1.3-1 correspond to control options and efficiencies required by the Consent Decree. The scenario from the NDDH BART modeling protocol is based on the historical, maximum 24-hour emission rates for MRYS between 2000 and 2002. These rates were supplied to the NDDH by Minnkota, but were based upon operations that were not

representative of stack conditions associated with new or modified retrofit control technologies. Due to analyses performed on plant operations and historical emissions data, Minnkota has determined that unit operating conditions associated with these protocol rates are not representative of future maximum 24-hour emissions and has requested NDDH to allow the use of an alternative baseline for modeled post-control emission rates. NDDH agreed to the use of an alternative baseline. The alternative baseline post-control scenarios are based upon various control technology emission reductions being applied to emissions from a maximum 24-hour average heat input of 2,955 mmBtu/hr for Unit 1 and 5,158 mmBtu/hr for Unit 2. The emission rates associated with each scenario are discussed in the section related to the controlled pollutant.

As shown in Table 1.3-1, multiple modeling scenarios were conducted to determine the specific visibility impact reduction associated with the control of each pollutant. To determine a specific visibility impact, the emission rate for the pollutant of concern was changed from the protocol rate to the post-control rate. Thus, any visibility impairment impact reduction for that modeling scenario was due solely to the application of the individual pollutant's control technology. This methodology was used for NO_X, SO_2, and PM. Additional modeling runs were conducted to determine the overall visibility impairment impact reduction caused by simultaneous application of all control technologies. In Table 1.3-1, modeling scenario 4 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for each unit individually. Modeling scenario 5 was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies for both units combined. The modeling results are summarized and discussed in the sections below.

2.0 NO_X BART EVALUATION

The BART analyses for NO_X emissions from MRYS Unit 1 and Unit 2 are described in this section. Technical descriptions of MRYS Unit 1 and Unit 2 boilers and existing air pollution control equipment are provided. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install BACT-level NO_X control technologies on both units. For NO_X, the CD required that a complete BACT analysis be performed to determine the applicable control technologies for each unit. The BACT analysis report is included as Appendix A. Because BACT is considered to be more stringent than BART, the analysis can be shortened to use control technologies identified by the NO_X BACT analysis for meeting BART. The remaining portion of the BART analysis considers visibility impairment impacts on the nearest Class 1 area.

2.1 NO_X EVALUATION BASIS – UNIT 1

Milton R. Young Station Unit 1 includes a Babcock and Wilcox steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 mmBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged "three over four" across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 253 MW gross, and has an ultimate short-term maximum gross output (URGE) rating of 278 MW. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boiler.

The modeling for Unit 1 uses two NO_X emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 2,855.2 lb NO_X/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 1,070.7 lb NO_X/hr was based upon application of Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Overfire Air (ASOFA) at a more representative maximum heat input of 2,955 mmBtu/hr. According to the BACT analysis required by

the Consent Decree, SNCR used in conjunction with ASOFA was considered the best technology and therefore was evaluated as BART for Unit 1.

2.1.1 NO_X VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART NO_X analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the BACT analysis resulted in one control technology, only one related emission rate was modeled to determine the visibility impairment impacts. The NDDH BART protocol[5] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the results predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 1 in the BACT analysis.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenario for MRYS Unit 1 was conducted with the protocol SO_2 and PM emission rates and the post-control NO_X emission rate as discussed in Section 2.1 and Table 1.3-1.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control BACT-level NO_X emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 2.1-1.

[5] "Protocol for BART-Related Visibility Impairment Modeling Analyses in North Dakota (Final)", November, 2005, North Dakota Department of Health (NDDH), Division of Air Quality.

Table 2.1-1 – NO_X Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.376	0.173
TRNP-North Unit	0.628	0.410	0.218
TRNP-Elkhorn Ranch	0.374	0.263	0.111
Lostwood NWR	0.750	0.487	0.263

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - NO_X emissions reduction by 62.5% over protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.1-2. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.1-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 17% reduction for TRNP – Elkhorn in 2001 to an approximately 40% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 53% for TRNP – South in 2000.

Table 2.1-2 – Visibility Impairment Improvements – MRYS Unit 1 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[1] Exceeding 0.5 dV in 2000	Days[1] Exceeding 0.5 dV in 2001	Days[1] Exceeding 0.5 dV in 2002	Days[1] Exceeding 1.0 dV in 2000	Days[1] Exceeding 1.0 dV in 2001	Days[1] Exceeding 1.0 dV in 2002	Consecutive Days[1] Exceeding 0.5 dV 2000	Consecutive Days[1] Exceeding 0.5 dV 2001	Consecutive Days[1] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	SNCR w/ ASOFA	23	20	35	9	11	19	2	3	3
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	SNCR w/ ASOFA	24	31	38	9	13	20	2	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	SNCR w/ ASOFA	18	20	27	6	8	17	2	3	4
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	SNCR w/ ASOFA	38	36	33	17	19	20	3	3	4

1 - Number of days for predicted visibility impairment impacts provided in Appendix B.

2.2 NO_X EVALUATION BASIS – UNIT 2

Milton R. Young Unit 2 is a Babcock and Wilcox steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 mmBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged "three over three" across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 462 MW gross, and has an ultimate short-term maximum gross output (URGE) of 512 MW. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

The modeling for Unit 2 uses two NO_X emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 5,364.2 lb NO_X/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 2,011.6 lb NO_X/hr was based upon application of Selective Non-Catalytic Reduction (SNCR) and Advanced Separated Overfire Air (ASOFA) at a more representative maximum heat input of 5,158 mmBtu/hr. According to the BACT analysis required by the Consent Decree, SNCR used in conjunction with ASOFA was considered the best technology and therefore was evaluated as BART for Unit 2.

2.2.1 NO_X VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART NO_X analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree and requisite BACT analysis, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the BACT review resulted in one control technology, only one related emission rate was modeled to determine the visibility impairment impacts. The NDDH BART protocol[6] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then

[6] Ibid, NDDH Modeling Protocol.

compared with the result predicted from a modeled post-control NO_X emission rate based upon the control technology specified for Unit 2 in the BACT analysis.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol SO_2 and PM emission rates and the post-control NO_X emission rate as discussed in Section 2.2 and Table 1.3-1.

The results of the visibility modeling at the protocol baseline NO_X emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control NO_X emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for three of the Class 1 areas at the post-control BACT- level NO_X emission rate were below the 0.50 dV threshold level. The Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.544 dV. The modeling results are presented in Table 2.2-1.

Table 2.2-1 – NO_X Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.406	0.174
TRNP-North Unit	0.619	0.438	0.181
TRNP-Elkhorn Ranch	0.360	0.277	0.083
Lostwood NWR	0.775	0.544	0.231

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - NO_X emissions reduction by 62.5% over protocol baseline case. This scenario assumes protocol emission rates for SO_2 and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 2.2-2. Similarly, the same information for the post-control NO_X emission rates is summarized and shown in Table 2.2-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control NO_X emission

rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The impact in terms of days exceeding 0.50 dV varies from an approximately 9% reduction for TRNP – Elkhorn in 2001 to an approximately 37% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 15% for TRNP – Elkhorn in 2002 to approximately 50% for TRNP – North in 2000.

Table 2.2-2 – Visibility Impairment Improvements – MRYS Unit 2 NO_X Scenarios

Class 1 Area	NO_X Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	SNCR w/ ASOFA	26	20	40	11	11	21	2	3	3
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	SNCR w/ ASOFA	24	32	40	9	13	23	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	SNCR w/ ASOFA	22	21	30	7	10	17	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	SNCR w/ ASOFA	41	39	34	19	22	20	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control NO_X emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

3.0 SO_2 BART EVALUATION

In this section, the BART analysis for Milton R. Young Station (MRYS) is described for SO_2 and a brief description of the existing control technology for MRYS Unit 2 is presented. Unit 1 does not currently use SO_2 controls. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD) that requires MRYS to install or modify SO_2 control technologies on both units to achieve BACT-level emission rates. Because BACT is considered to be more stringent than BART, the analysis can be shortened to use CD identified control technologies for meeting BART. The remaining portion of the analysis assess technologies for their potential visibility impairment impact reduction capability via visibility modeling results.

3.1 SO_2 EVALUATION BASIS – UNIT 1

Milton R. Young Station Unit 1 is a Babcock and Wilcox steam generator including a lignite-fired boiler with multiple cyclone-furnaces. The original unit design has a fuel heat input of 2,510 mmBtu/hr. The Unit 1 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The lignite significantly influences the resulting SO_2 concentration of the flue gases emitted from the boilers. Unit 1 currently does not use any SO_2 control technology.

The modeling for Unit 1 uses two SO_2 emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 7,231.2 lb SO_2/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 723.1 lb SO_2/hr was based upon application of dry Flue Gas Desulfurization (FGD) process applied to a more representative maximum heat input of 2,955 mmBtu/hr. The Consent Decree defines the BACT-level SO_2 control technology options and removal efficiencies applicable for installation on MRYS Unit 1. The control technologies included in the CD are a wet FGD process achieving 95% removal efficiency, a dry FGD process achieving 90% removal efficiency or an equivalent alternative technology to be approved by the NDDH. At the time of this report, Minnkota had not selected the SO_2 control technology for MRYS Unit 1. Thus, a dry FGD process that achieves a worst case 90% removal was selected and evaluated as BART for Unit 1. Because a dry FGD process was evaluated as worst case, this analysis will still be applicable if Minnkota chooses to utilize an equivalent or more efficient control technology.

3.1.1 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified applicable BACT-level control technologies, one technology (i.e., the dry FGD process) and related emission rate was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[7] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control SO_2 emission rate based upon the BACT-level control technology specified in the CD.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenario for MRYS Unit 1 was conducted with the protocol NO_X and PM emission rates and the post-control SO_2 emission rate as discussed in Section 3.1 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control SO_2 emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control SO_2 emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 3.1-1.

[7] Ibid, NDDH Modeling Protocol.

Table 3.1-1 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.250	0.299
TRNP-North Unit	0.628	0.269	0.359
TRNP-Elkhorn Ranch	0.374	0.160	0.214
Lostwood NWR	0.750	0.322	0.428

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - SO_2 emissions reduction by 90% over protocol baseline case. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 3.1-2. Similarly, the same information for the post-control SO_2 emission rates is summarized and shown in Table 3.1-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control SO_2 emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 17% reduction for TRNP – Elkhorn in 2001 to an approximately 74% reduction for TRNP – South in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 27% for TRNP – South in 2001 to approximately 89% for Lostwood NWR in 2000.

Table 3.1-2 – Visibility Impairment Improvements – MRYS Unit 1 SO_2 Scenarios

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Dry FGD	10	20	24	4	11	12	1	3	3
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Dry FGD	13	31	25	7	13	12	1	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Dry FGD	9	20	18	4	8	9	2	3	2
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Dry FGD	17	36	17	3	19	4	2	3	3

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

3.2 SO_2 EVALUATION BASIS – UNIT 2

Milton R. Young Station Unit 2 is a Babcock and Wilcox steam generator including a lignite-fired boiler with multiple cyclone-furnaces. Installed in 1977, the original unit design has a fuel heat input of 4,696 mmBtu/hr. The Unit 2 boiler at MRYS includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. Lignite fuel is the sole solid fuel for the plant and is supplied from a mine located adjacent to the site. The lignite significantly influences the resulting SO_2 concentration of the flue gases emitted from the boilers. Unit 2 has a Combustion Equipment Associates wet flue gas desulfurization (FGD) system (modified by Combustion Engineering) that treats the majority of the flue gas with the remaining flue gas by-passed for stack gas reheat.

The modeling for Unit 2 uses two SO_2 emission rates as a basis for the visibility impairment impacts. One emission rate was based upon the NDDH Modeling Protocol value of 6,879.0 lb SO_2/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. The second emission rate of 1,574.4 lb SO_2/hr was based upon application of wet Flue Gas Desulfurization (FGD) process at a more representative maximum heat input of 5,158 mmBtu/hr. The Consent Decree requires MRYS to modify the existing wet FGD on Unit 2 to achieve a removal efficiency of at least 90%. The modified wet FGD process that achieves at least 90% removal, considered to be BACT-level control technology by the CD, was selected and evaluated as BART for Unit 2.

3.2.1 SO_2 VISIBILITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART SO_2 analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified the applicable BACT-level control technology, one technology (i.e., the modified wet FGD process) and related emission rate was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[8] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control SO_2 emission rate based upon the BACT-level control technology specified in the CD.

[8] Ibid, NDDH Modeling Protocol.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and PM emission rates and the post-control SO_2 emission rate as discussed in Section 3.2 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline SO_2 emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control SO_2 emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for all Class 1 areas at the post-control SO_2 emission rate was below the 0.50 dV threshold level. The modeling results are presented in Table 3.2-1.

Table 3.2-1 – SO_2 Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.390	0.190
TRNP-North Unit	0.619	0.370	0.249
TRNP-Elkhorn Ranch	0.360	0.225	0.135
Lostwood NWR	0.775	0.493	0.282

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.
2 - SO_2 emissions corresponding to improvement of FGD SO_2 removal performance to 90%. This scenario assumes protocol emission rates for NO_X and PM.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 3.2-2. Similarly, the same information for the post-control SO_2 emission rates is summarized and shown in Table 3.2-2. The visibility impairment impact and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control SO_2 emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 2. The impact in terms of days exceeding 0.50 dV varies from an approximately 9% reduction for TRNP – Elkhorn in 2001 to an approximately 61% reduction for TRNP – Elkhorn in 2000. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 14% for TRNP – North in 2002 to approximately 56% for TRNP – South in 2000.

Table 3.2-2 – Visibility Impairment Improvements – MRYS Unit 2 SO_2 Scenarios

Class 1 Area	SO_2 Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Wet FGD Upgraded to 90% Control	24	20	36	8	11	23	2	3	3
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Wet FGD Upgraded to 90% Control	22	32	35	11	13	25	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Wet FGD Upgraded to 90% Control	12	21	24	8	10	16	2	3	2
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Wet FGD Upgraded to 90% Control	36	39	30	14	22	16	3	3	5

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control SO_2 emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

4.0 PARTICULATE MATTER BART EVALUATION

The BART analyses for PM emissions from MRYS Unit 1 and Unit 2 are described in this section. A brief description of MRYS Unit 1 and Unit 2 existing PM air pollution control equipment is provided. As discussed in the introduction, Minnkota has entered into a Consent Decree (CD). The CD requires MRYS to maintain or upgrade the existing PM controls on both units to achieve specified emission rates. Because the CD specified the PM controls and associated emission rate, the analysis was shortened to use the CD specified PM emission rates for meeting BART. The remaining portion of the analysis assesses potential visibility impairment impact reduction capability for the CD specified emission rates via visibility modeling results.

4.1 PM EVALUATION BASIS – UNIT 1

MRYS Unit 1 is a B&W cyclone-type coal-fired boiler. The quantity of uncontrolled PM emissions is a strong function of the type of boiler utilized. Different boiler types generate different splits between bottom ash, which is collected in the bottom of the boiler, and fly ash, which is entrained in the flue gas and becomes boiler particulate matter emissions. Unit 1 is a cyclone-type boiler that has an inherently lower percentage of fly ash due to the method of combustion. Particulate control is currently provided by a Research-Cottrell Electrostatic Precipitator rated at approximately 99% control.

The modeling for Unit 1 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One emission rate scenario was based upon the NDDH Modeling Protocol values of 36.7 lb PM_{Coarse}/hr and 5.5 lb PM_{Fine}/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.3.2, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates of 38.5 lb PM_{Coarse}/hr and 5.8 lb PM_{Fine}/hr upon application of CD specified rates applied to a more representative maximum heat input of 2,955 mmBtu/hr. The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. Because a dry FGD process is considered the worst case for SO_2 control, the associated emission rate of 0.015 lb PM/mmBtu is being used for PM.

The post-control emission rate on a lb/hr basis is slightly higher because the existing ESP performance used to derive the protocol emission rate was very good and due to the use of a higher yet more representative heat input.

4.1.1 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 1

The remaining step for the BART PM analysis was to conduct a visibility improvement determination for Unit 1. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified the PM control technology and associated emission rate, one emission rate (the 0.015 lb/mmBtu specified in the CD) was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[9] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control PM emission rate based upon the emission rate specified in the CD.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 1. The post-control CALPUFF model scenario for MRYS Unit 1 was conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rate as discussed in Section 4.1 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 1 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control PM emission rate showed a reduction in visibility impairment impact for all Class 1 areas. In addition, the modeled visibility impairment impact for two of the Class 1 areas at the post-control PM emission rate was below the 0.50 dV threshold level. The TRNP – North Class 1 area had a modeled visibility impairment impact of 0.500 dV and Lostwood NWR Class 1 area had a modeled visibility impairment impact of 0.587 dV. The modeling results are presented in Table 4.1-1.

[9] Ibid, NDDH Modeling Protocol.

Table 4.1-1 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.549	0.465	0.084
TRNP-North Unit	0.628	0.500	0.128
TRNP-Elkhorn Ranch	0.374	0.328	0.046
Lostwood NWR	0.750	0.587	0.163

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

2 - PM emissions corresponding to the 0.015 lb/mmBtu specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 1 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results are summarized and presented in Table 4.1-2. Similarly, the same information for the post-control PM emission rates is summarized and shown in Table 4.1-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in all cases. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly between years and Class 1 areas, for Unit 1. The impact in terms of days exceeding 0.50 dV varies from an approximately 3% reduction for TRNP – Elkhorn in 2002 to an approximately 27% reduction for TRNP – South in 2001. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 3% for TRNP – North in 2002 to approximately 33% for TRNP – Elkhorn in 2000.

Table 4.1-2 – Visibility Impairment Improvements – MRYS Unit 1 PM Scenarios

Class 1 Area	PM Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	38	30	48	19	15	26	3	3	4
	Fabric Filter Baghouse	31	22	43	13	11	21	3	3	4
TRNP North	Protocol	34	44	46	14	21	29	2	4	4
	Fabric Filter Baghouse	27	35	42	11	16	28	2	4	4
TRNP Elkhorn	Protocol	25	24	35	12	16	20	2	3	4
	Fabric Filter Baghouse	22	21	34	8	12	18	2	3	4
Lostwood NWR	Protocol	51	58	42	26	30	24	3	5	5
	Fabric Filter Baghouse	44	45	38	21	25	23	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control PM emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

4.2 PM EVALUATION BASIS – UNIT 2

MRYS Unit 2 is a B&W cyclone-type coal-fired boiler. The quantity of uncontrolled PM emissions is a strong function of the type of boiler utilized. Different boiler types generate different splits between bottom ash, which is collected in the bottom of the boiler, and fly ash, which is entrained in the flue gas and becomes boiler particulate matter emissions. Unit 2 is a cyclone-type boiler that has an inherently lower percentage of fly ash due to the method of combustion. Particulate control for Unit 2 is provided by a Wheelabrator-Lurgi electrostatic precipitator rated at approximately 99% control.

The modeling for Unit 2 uses two PM emission rates that distinguish between coarse and fine particulate as a basis for the visibility impairment impacts. One emission rate scenario was based upon the NDDH Modeling Protocol values of 178.7 lb PM_{Coarse}/hr and 28.1 lb PM_{Fine}/hr. The protocol rate was based upon maximum 24-hour emission rates from the 2000-2002 modeling period. However, as discussed in Section 1.3.2, the protocol emission rates are based upon actual maximum historical 24-hour emissions that are not representative of future maximum 24-hour emissions. After obtaining approval from NDDH to use alternative emission rates based upon representative stack conditions, Minnkota based the post-control emission rates of 133.7 lb PM_{Coarse}/hr and 21.0 lb PM_{Fine}/hr upon application of CD specified rates applied to a more representative maximum heat input of 5,158 mmBtu/hr. The Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 2 to achieve an emission rate of 0.030 lb PM/mmBtu.

4.2.1 PM VISIBLITY IMPAIRMENT IMPACTS ANALYSIS – UNIT 2

The remaining step for the BART PM analysis was to conduct a visibility improvement determination for Unit 2. Due to the association of the Consent Decree, the visibility analysis was the only impact evaluation necessary to establish BART. In addition, because the CD specified the PM control technology and associated emission rate, one technology (i.e., the existing ESP) and related emission rate was selected for modeling to determine the visibility impairment impacts. The NDDH BART protocol[10] emission rate was modeled to determine a baseline visibility impact. The baseline visibility impact was then compared with the result predicted from a modeled post-control PM emission rate based upon the emission rate specified in the CD.

[10] Ibid, NDDH Modeling Protocol.

Visibility impairment impact modeling was performed using the CALPUFF model with the difference between the impacts from protocol baseline and post-control hourly emission rates representing the visibility impairment impact reduction for MRYS Unit 2. The post-control CALPUFF model scenario for MRYS Unit 2 was conducted with the protocol NO_X and SO_2 emission rates and the post-control PM emission rate as discussed in Section 4.2 and Table 1.3-1.

The results of the visibility impairment modeling at the protocol baseline PM emission rate for MRYS Unit 2 showed that three of the Class 1 areas had a visibility impairment impact above the 0.50 dV threshold level for discernable impacts that contribute to visibility impairment. The visibility modeling results for the post-control PM emission rate showed a reduction in visibility impairment impact for all Class 1 areas. The modeling results are presented in Table 4.2-1.

Table 4.2-1 – PM Visibility Impairment Impacts and Reductions, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction (deciView)
	Protocol Emissions	Post-Control Emissions[2]	
TRNP-South Unit	0.580	0.563	0.017
TRNP-North Unit	0.619	0.570	0.049
TRNP-Elkhorn Ranch	0.360	0.345	0.015
Lostwood NWR	0.775	0.739	0.036

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.
2 - PM emissions corresponding to the 0.030 lb/mmBtu specified in the CD. This scenario assumes protocol emission rates for NO_X and SO_2.

The number of days predicted to have visibility impairment due to MRYS Unit 2 emissions that were greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area were determined by the visibility model for the protocol emission rates. The results were summarized and presented in Table 4.2-2. Similarly, the same information for the post-control PM emission rates was summarized and is shown in Table 4.2-2. The number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area between protocol and post-control PM emission rates were reduced in the majority of cases. The TRNP – South Class 1 area in 2001 and 2002 each had one additional day with a visibility impairment impact exceeding 0.50 dV. The number of consecutive days exceeding 0.50 dV of impact was either the same or was reduced.

The magnitude of predicted visibility impairment and number of days predicted to have visibility impairment greater than 0.50 and 1.00 deciViews at any receptor in a Class 1 area varied significantly

between years and Class 1 areas, for Unit 2. The TRNP – South Class 1 area in 2001 and 2002 each had a impact increase of one day in terms of days exceeding 0.50 dV. The approximate visibility impact increase for 2001 was 4% and for 2002 was 2%. The impact reduction in terms of days exceeding 0.50 dV varies from approximately 0% in multiple areas and years to approximately 14% for TRNP – North in 2001. The impact reduction in terms of days exceeding 1.00 dV varies from approximately 0% in multiple areas and years to approximately 13% for Lostwood NWR in 2000.

There are several plausible explanations for an increase in the number of days with a visibility impairment impact exceeding 0.50 dV for TRNP – South in 2001 and 2002. One possible cause could be the reduced exit velocity that was due to an increase in stack diameter and an increased flow rate caused by scrubbing of all of the flue gas. Because the modeling results presented in Table 4.2-1 showed a reduction in visibility impairment impacts for all Class 1 areas, additional research was not conducted to determine the cause of the increase.

Table 4.2-2 – Visibility Impairment Improvements – MRYS Unit 2 PM Scenarios

Class 1 Area	PM Control Technique	Days[2] Exceeding 0.5 dV in 2000	Days[2] Exceeding 0.5 dV in 2001	Days[2] Exceeding 0.5 dV in 2002	Days[2] Exceeding 1.0 dV in 2000	Days[2] Exceeding 1.0 dV in 2001	Days[2] Exceeding 1.0 dV in 2002	Consecutive Days[2] Exceeding 0.5 dV 2000	Consecutive Days[2] Exceeding 0.5 dV 2001	Consecutive Days[2] Exceeding 0.5 dV 2002
TRNP South	Protocol	41	28	51	18	14	27	3	3	4
	Maintain ESP	37	29	52	16	13	27	3	3	4
TRNP North	Protocol	32	43	47	18	21	29	2	4	4
	Maintain ESP	29	37	45	18	21	29	2	4	4
TRNP Elkhorn	Protocol	31	23	36	11	14	20	2	3	4
	Maintain ESP	29	23	36	11	13	19	2	3	4
Lostwood NWR	Protocol	52	51	48	30	31	25	3	3	5
	Maintain ESP	50	48	45	27	27	25	3	3	4

1 - Predicted visibility impairment impacts (90th percentile) for 2000-2002 for protocol and post-control PM emission levels.
2 - Number of days for predicted visibility impairment impacts provided in Appendix B.

5.0 BART RECOMMENDATIONS

This report presents the analysis of control technologies for each of three major pollutants (nitrogen oxides (NO_X), sulfur dioxide (SO_2), and particulate matter (PM)) for Minnkota Power Cooperative Inc.'s (Minnkota's) Milton R. Young Station (MRYS) Units 1 and 2. The final result of this analysis is a recommendation of the Best Achievable Retrofit Technology (BART) for each unit based upon "improvement in visibility which may reasonably be anticipated to result from the use of such technology" (70 FR 39163). The presented emission rates in this section are the BART recommendation.

As stated previously, this report uses the determinations made in the Consent Decree (CD) and associated NO_X BACT analysis as part of the analysis. BACT is considered to be more stringent than BART because it usually is not limited by the design of existing equipment or current operating conditions as is required for a retrofit application. Because BACT is similar to BART and BACT-level controls are required by CD, the visibility impacts evaluation was the only step in the determination performed to satisfy BART. This analysis evaluated the visibility impairment impacts of the BACT-level control technologies specified in the CD and results in a BART recommendation based upon an acceptable amount of visibility improvement in Class 1 areas. This section summarizes the visibility analysis performed for each Unit and its associated pollutants.

5.1 UNIT 1 BART RECOMMENDATIONS

The remaining step for the BART analysis was to conduct a visibility improvement determination for MRYS Unit 1. Due to the association of the Consent Decree, which required a NO_X BACT analysis, along with the specification of SO_2 and PM control technologies or emission rates for each pollutant, the visibility impairment impact analysis was the only impact evaluation necessary to establish BART. To conduct a visibility impairment impact analysis, the baseline visibility impairment impact was compared with the predicted impact from a post-control emission rate modeled separately for each pollutant. A control technology and associated emission rate are considered to meet BART requirements when the 90th percentile modeling results show a reduction in visibility impairment impact. The MRYS Unit 1 modeling results for all pollutants showed a reduction in visibility impairment impact for all Class 1 areas. Thus, the control technologies recommeded as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions along with the modeled

emission rates are recommended as BART. Table 5.1-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

Table 5.1-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 1

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.36*
SO_2	Dry Flue Gas Desulfurization (FGD) Process	0.24
PM	Fabric Filter Baghouse	0.015**

* Excludes startups. See Appendix A for a detailed discussion.
** Emission rate is associated with SO_2 control technology and applies to dry FGD process only.

The pollutant specific modeling results for MRYS Unit 1 described previously in the analysis represent the visibility impairment impact reduction attributable to a technology used to control an individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART-recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies and the results are presented in Table 5.1-2.

Table 5.1-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 1

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.549	0.091	0.458
TRNP-North Unit	0.628	0.093	0.535
TRNP-Elkhorn Ranch	0.374	0.057	0.290
Lostwood NWR	0.750	0.127	0.623

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

The simultaneous control of all pollutants for MRYS Unit 1 results in visibility impairment impacts that are approximately one fourth of the threshold the EPA designates as contributing to visibility

impairment. These modeling results provide additional support for recommending the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions as BART.

The BART analysis for MRYS was conducted before determining the SO_2 control technology for Unit 1. The Consent Decree provides the acceptable BACT-level SO_2 emission control technologies for Unit 1. SO_2 emissions were modeled using a dry FGD process at 90% control. A 90% reduction is the minimum reduction allowed by the CD and results in the worst case SO_2 post-control emission rate. Because a dry FGD process was evaluated as worst case, this analysis will still be applicable if Minnkota chose to utilize an equivalent or more efficient SO_2 emission control technology. However, if the final selection of SO_2 control technology and the corresponding post-control emission rate required by the CD changes, the post-control PM emission rate required by the CD may also change.

As discussed previously in this report, the Consent Decree requires MRYS to maintain or upgrade the PM controls on Unit 1 to achieve an emission rate of 0.015 lb PM/mmBtu if a dry FGD process is selected for SO_2 control or 0.030 lb PM/mmBtu if a wet FGD process is selected. Because a dry FGD process is considered the worst case for SO_2 control, the associated emission rate of 0.015 lb PM/mmBtu is being used for PM (only applies with utilization of dry FGD for SO_2 control). If Minnkota determines that a wet FGD process with 95% SO_2 control should be used for Unit 1, the PM emission rate dictated by the Consent Decree will increase to 0.030 lb PM/mmBtu (only applies with utilization of wet FGD for SO_2 control). Although the PM emission rate would change as a result of the SO_2 control scenario, when considering the effect of all pollutants on visibility impacts, reducing SO_2 emissions would have a greater effect. The modeling results in Appendix B provide the percent contribution of each pollutant to the visibility impact. For Unit 1, the PM contribution to the visibility impact ranges from 0.13% to 2.22%. The SO_2 contribution to the visibility impact ranges from 7.64% to 67.12%. Because the contribution of SO_2 is more than double the PM contribution in all cases, reducing SO_2 emissions by an additional 50% by going from 90% to 95% control would have a greater effect than doubling PM emissions. Thus, this analysis will still be applicable if Minnkota chooses to utilize a wet FGD process for SO_2 control and incorporate the corresponding increase in the PM emission rate as dictated by the Consent Decree.

5.2 UNIT 2 BART RECOMMENDATIONS

The remaining step for the MRYS Unit 2 BART analysis was to conduct a visibility improvement determination. Due to the association of the Consent Decree which required a NO_X BACT analysis

along with the specification of SO_2 and PM control technologies or emission rates for each pollutant, the visibility impairment impact analysis was the only subsequent impact evaluation necessary to establish BART. To conduct a visibility impairment impact analysis, the baseline visibility impairment impact was compared with the predicted impact from a post-control emission rate modeled separately for each pollutant. A control technology and associated emission rate are considered to meet BART requirements when the 90th percentile modeling results show a reduction in visibility impairment impact. The MRYS Unit 2 modeling results for all pollutants showed a reduction in visibility impairment impact for all Class 1 areas. Thus, the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions along with the modeled emission rates are recommended as BART. Table 5.2-1 summarizes the control technologies and associated emission rates that are recommended as BART for each pollutant. The recommended BART emission rates are presented as a 30-day rolling average to account for variations in boiler operation, fuel sulfur content and fly ash properties.

As discussed previously in this report, the CD required that a complete BACT analysis be performed to determine the applicable NO_X control technology for Unit 2. Due to amount of time necessary to complete a BACT analysis and a BART analysis, both reports were assembled concurrently. A preliminary BACT analysis based on historical emissions records and estimated control technology capabilities resulted in an emission rate of 0.39 lb NO_X/mmBtu to be assumed for the post-control 24-hour average emission rate for the visibility impairment impact modeling. However, further analysis conducted after the completion of the CALPUFF modeling resulted in a 30-day rolling average NO_X emission rate of 0.35 lb NO_X/mmBtu. Because the final recommended BART 30-day rolling average emission rate is lower than the modeled rate and the associated visibility impact would be reduced, dispersion modeling was not redone.

Table 5.2-1 – Recommended BART 30-Day Rolling Average, MRYS Unit 2

Pollutant	Control Technology	Emission Rate (lb/million Btu)
NO_X	Advanced Separated Over Fire Air (ASOFA) and Selective Non-Catalytic Reduction (SNCR)	0.35*
SO_2	Upgrade of Existing Wet Flue Gas Desulfurization (FGD) Process	0.31
PM	Maintain Existing Electrostatic Precipitator (ESP)	0.030

* Excludes startups. See Appendix A for a detailed discussion.

The pollutant specific modeling results for MRYS Unit 2 described previously in this analysis represent the visibility impairment impact reduction attributable to a technology used to control an

individual pollutant of concern. While this result supports an individual technology in terms of visibility impact reduction, the result is not representative of actual plant-wide operations. Application of the BART recommended technologies will result in simultaneous control of all pollutants. Thus, a comparison of the visibility impairment reduction due to reducing the protocol emission rates to post-control emission rates for all pollutants simultaneously is more representative of actual expected results. A modeling scenario was run to determine the visibility impairment impact reduction resulting from simultaneous application of all control technologies and the results are presented in Table 5.2-2.

Table 5.2-2 – Visibility Impairment Impacts for Control of all Pollutants, MRYS Unit 2

Federal Class 1 Area	Visibility Impairment Impacts[1] (deciView)		Visibility Impairment Reduction
	Protocol Emissions	Post-Control Emissions	
TRNP-South Unit	0.580	0.173	0.407
TRNP-North Unit	0.619	0.169	0.450
TRNP-Elkhorn Ranch	0.360	0.104	0.256
Lostwood NWR	0.775	0.243	0.532

1 - Average 90th percentile predicted visibility impairment impact versus background visibility. A summary of the modeling scenarios is provided in Table 1.3-1 and the modeling results are presented in Appendix B.

The simultaneous control of all pollutants for MRYS Unit 2 results in visibility impairment impacts that are approximately one half of the threshold the EPA designates as contributing to visibility impairment. These modeling results provide additional support for recommending the control technologies recommended as BACT for NO_X emissions and those specified by the CD for SO_2 and PM emissions as BART.

In addition to the visibility impairment impact modeling scenario conducted to determine the effects of simultaneous control of all pollutants for the individual units, another modeling scenario was conducted to combine the effects of both units. The modeling showed that the visibility impairment impact for all Class 1 areas was reduced to below the threshold the EPA designates as contributing to visibility impairment. Results of this scenario (labeled Run 5) are provided in Appendix B.

Appendix A

NO_X BACT Analysis Unit 1

NO_X BACT Analysis Unit 2

NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY

for

Milton R. Young Station Unit 1

Minnkota Power Cooperative, Inc.

Final Report

October 2006

31777

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NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1

prepared for

Minnkota Power Cooperative, Inc.

October 2006

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Final Report

prepared by

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Kansas City, Missouri

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INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc.
Milton R. Young Station Unit 1
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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by Minnkota Power Cooperative, Inc. or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

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10-4-06

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EXECUTIVE SUMMARY

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired steam-electric generating units (SEGUs). The units both fire North Dakota lignite supplied from the adjacent mine, near Center, North Dakota. Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 250 MW_g (gross), and has a gross design output capacity rating of 257 MW_g. Unit 1 is owned and operated entirely by Minnkota. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 460 MW_g (gross), and has a gross design output capacity rating of 477 MW_g. Unit 2 is owned by Square Butte Electric Cooperative (Square Butte), and operated by Minnkota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota Power Cooperative on June 21, 2002. The NOV alleged that modifications had been made at the Milton R. Young Station that would have required a construction permit under New Source Review (Code of Federal Regulations 40 CFR 52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree (CD) has been approved that represents a final negotiated settlement of the United States' and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average NO_X Emission Rate [Consent Decree paragraph 24, page 7, and paragraph 5, page 4].

Burns & McDonnell was retained to conduct a Top-Down BACT Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. The results of the BACT analysis are presented in this study report.

The procedures mandated by the Consent Decree for performing a Top-Down BACT Analysis are outlined in Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("EPA's NSR Manual"). The MRY Station BACT analysis was performed in accordance with this procedure. The

EPA's NSR Manual outlines five basic steps that are to be followed in this BACT analysis. These basic steps for such a BACT analysis are summarized as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

A Best Available Control Technology (BACT) analysis was performed for Milton R. Young Unit 2 for NO_X using the EPA's "top-down" approach. Best Available Control Technology is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant" (40 CFR 52.21, NSR Manual B.1).

Unit 1 at Milton R. Young Station is a cyclone-fired boiler that burns North Dakota lignite. The method of firing is very significant in analyzing control options for NO_X emissions. A cyclone boiler produces inherently higher uncontrolled NO_X levels than pulverized-coal and circulating fluidized bed boilers. There have been no new coal-burning cyclone-fired boilers built and installed in the United States since the early 1980's. Consequently, there are no examples of BACT control options listed in the RACT/BACT/LAER Clearinghouse database for consideration and direct application of published NO_X emission permit limits on the Milton R. Young cyclone-fired boilers.

Step 1 – Identify All Control Technologies

The Consent Decree requires that the NO_X Top-Down BACT Analysis for the Milton R. Young Station "include an evaluation of Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Overfire Air (OFA), Rich Reagent Injection (RRI), as well as other NO_X control technologies" potentially applicable for lignite-fired cyclone boilers [Consent Decree paragraph 65, page 19]. Other identified control techniques, such as fuel switching and fuel cleaning, and combustion-related emission control technologies, such as fuel reburn and oxygen-enhanced combustion, were also considered.

Step 2 – Eliminate Technically Infeasible Options

The BACT evaluation determined that not all the technologies identified were considered available and applicable. The technically infeasible alternatives were eliminated from further evaluation, along with feasible technologies with economic impacts that were unreasonable compared to other cost-efficient alternatives to control NO_X emissions for MRY Station Unit 1.

The technical feasibility of applying NO_X emission reduction techniques and technologies at Milton R. Young Station is dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

Both boilers include a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Ash deposition in each boiler and air preheater is a significant operational challenge for the facility. Significant equipment and manpower resources are devoted to on-going removal of fireside ash accumulations. Unit outages must be conducted at regular intervals to clean each boiler (approximately every 80-120 days). There are a number of issues that make selective catalytic reduction (SCR) technically infeasible for NO_X emission control for Milton R. Young Unit 1. The consistent long-term operation of SCR technology on lignite-fired cyclone boilers will be drastically inhibited by the susceptibility of the SCR catalyst to severe fouling, deactivation, and erosion resulting from the actions of the emitted flue gases and flyash, and ash deposit removal operations. SCR technology is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station.

Rich Reagent Injection has been demonstrated on boilers burning bituminous and subbituminous coal. However, it has not been commercially installed and placed in continuous operation on a cyclone-fired boiler burning lignite coal with high fouling and slag temperature sensitivities associated and a highly

variable heat content. RRI adds urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea, and thus creating NO_X. While RRI is specifically intended for NO_X emissions control on cyclone boilers, RRI is considered technically infeasible for application on the lignite fired cyclone boilers at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

The application of separated overfire air (SOFA) for NOx emissions control on Milton R. Young Unit 1's boiler was evaluated as part of the BACT analysis. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. This highest-performing form of SOFA can be applied alone and in combination with other technologies. Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when "starved air" (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the individual cyclone furnaces can be operated with less-than-theoretical (substoichiometric) combustion air, which corresponds to operation of a SOFA system, directly contributes to less combustion-related NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. This places great emphasis on achieving tight control over the air/fuel ratios on each cyclone during air-staged combustion operation with SOFA in order for air-staged combustion to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

In the case of MRY Station Unit 1's boiler, air-staged combustion must be sufficient to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners. Due to the short-term variability of the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND, and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control while operating the highest-performing version of SOFA system is expected to be modest.

Selective Non-Catalytic Reduction (SNCR) technology has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation.

There are significant concerns associated with effective long-term SOFA operation for Milton R. Young Station Unit1's boiler. The ability of basic combustion equipment and improvements to precisely measure the boiler's heat input rate in real-time on an individual cyclone by cyclone basis with compensation for the short-term variability of the combustible content of the Center lignite to consistently maintain substoichiometric operation of every cyclone during air-staged combustion is unproven.

Several other techniques and technologies were considered technically feasible for NOx emissions control at MRY Station: Fuel Blending/Switching; Basic Combustion Control Improvements; and various forms of Fuel Reburn. Fuel switching/blending was not evaluated further because of expected unreasonably high capital and operating costs and no additional emission reduction compared to continued lignite firing.

Other NOx emissions control techniques and technologies for MRY Station that were evaluated and determined to be technically infeasible were: Fuel Cleaning; Low NOx Burners (LNB); Flue Gas Recirculation; Oxygen-enhanced Combustion (OEC); Water/steam injection (combustion tempering); and Electro-Catalytic Oxidation (ECO®).

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the "top-down" BACT evaluation ranked the remaining control technologies by effectiveness. The purpose of ranking the control technologies was to establish a hierarchy that places at the "top" the control technology that achieves the lowest emission level. The technologies in order of their effectiveness, from highest to lowest, are: SNCR with ASOFA; Gas Reburn with ASOFA; Lignite Reburn with ASOFA; Fuel Lean Gas Reburn with ASOFA; and Advanced Separated Overfire Air (ASOFA). None of these control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application.

Step 4 – Evaluate Most Effective Controls and Document Results

Additional criteria besides technical feasibility were utilized for technology selection in this BACT analysis. These included estimates of control effectiveness (i.e. percent pollutant removed), capital plus operating and maintenance costs, annual emission reduction (tons per year), energy impacts, average and incremental cost effectiveness ($/ton), and environmental impacts (other media and emissions of toxic and hazardous air pollutants).

The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into a levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated.

Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1 were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

The two most cost-effective feasible control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology would result in any significant or unusual energy penalties or benefits. Potential increase in power plant energy consumption or net generation reductions, for ASOFA alone, or ASOFA with SNCR were relatively small.

The predicted environmental impacts from implementation of the two most cost-effective feasible NO_X emissions control alternatives from slightly higher unburned carbon in the emitted fly ash, carbon monoxide, and excess ammonia ("slip") emissions was expected to be small in comparison with the

significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reduction.

Step 5 – Select BACT

Taking into account technical feasibility, energy, environmental, and economic impacts and other costs, the recommended Best Available Control Technologies and associated emission rates for nitrogen oxides emissions produced by Milton R. Young Station Unit 1 boiler are provided in the table below.

NO_X Emission Control Technology and Rate Recommended as BACT

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**Control Method**	**12-Month Rolling Average NOx Emission Rate (lb/ million Btu)**
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.355

This recommended BACT 12-month NO_X emission rate is based upon a historic pre-control 12-month baseline average annual NO_X emission rate used in the control and cost-effectiveness analysis of 0.849 lb/mmBtu for Unit 1. The baseline emission was determined from the 12 consecutive month period with the highest historic summation of NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005.

To complete the BACT determination process, the Consent Decree (CD) requires that "specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)" must be established for each subject emission Unit [CD Paragraph 66, pg 20]. Because there are expected to be minor short term variations in operating conditions where Minnkota has not, in fact, materially changed any of their normal daily operating practices, a margin between the 12-month average operating conditions and the 30-day permit limit is proposed. This recommended emission rate should be suitably higher such that operation consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices to the extent practicable for the recommended NOx BACT alternative would not result in an exceedance (violation) of an enforceable emission permit limit.

The Consent Decree also requires that the North Dakota Department of Health's (NDDH) NO_X BACT Determination address specific emission limitations during Unit startups at Milton R. Young Station [CD Paragraph 66, pg 20]. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The SEGU startup operating period is usually not defined in emission permits. However, for the purpose of this NO_X BACT analysis, Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 2500 million BTU/hr for Unit 1; or
- the amount of time reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

For MRYS Unit 1, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation excluding such startup periods:

- The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold startup up to and including maximum continuous rated output;
- The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
- The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
- The number of startups and their range of typical durations per 30-day period time frame.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 1. The approach taken in this analysis was to establish a historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) from the 30-consecutive day period with

the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. This was then compared to the 12-month historic pre-control baseline average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 1. This is summarized below.

Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.360

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.884 lb/mmBtu for Unit 1. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.36 lb/mmBtu for Unit 1 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
1	0.36	+0.041 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.766 lb/mmBtu for Unit 1 reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
1	0.980

These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

Compliance with these emission rate would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trial period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

* * * * *

1.0 INTRODUCTION

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired boilers producing steam for electric generation. Both units fire North Dakota lignite supplied from an adjacent mine, near Center, North Dakota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota on June 21, 2002. The NOV alleged that modifications have been made at the Milton R. Young Station that would require a construction permit under New Source Review (Code of Federal Regulations 40CFR52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree[1] has been entered that represents a final negotiated settlement of the United States and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a NO_X "Top-Down" Best Available Control Technology (BACT) Analysis to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average Emission Rate (lbs/million Btu)[2].

Burns & McDonnell was retained by Minnkota to conduct a "Top-Down" Best Available Control Technology (BACT) Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services since the 1970s. As part of those services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis. The results of the BACT analysis are presented in this report.

[1] In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No. 1:06-CV-034

[2] Ibid – footnote number 1, CD paragraph 65, page 19.

The primary guidance utilized in preparation of this BACT analysis is the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990[3] ("NSR Manual").

In the next section of the report, the approach to the BACT Analysis is described. Following that, a quick summary of the plant conditions and report basis is given and then the BACT Analysis begins. The impact portion of the report is broken down into separate subsections. Within the last section, the results of all of the BACT Analysis steps are summarized for NO_X control options for Unit 1's boiler at the Milton R. Young Station.

* * * * *

[3] Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990.

2.0 "TOP-DOWN" NO_X BACT ANALYSIS APPROACH

Best Available Control Technology (BACT) is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[4]. A BACT review does not result in an emissions removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station Unit 1's boiler NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps are as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The predefined steps of a BACT analysis are described in this section, and results presented. Available NO_X control techniques and technologies are defined, identified, and a technical description of the emission reduction process and capabilities are reviewed in the following section. Subsequently, those techniques and technologies deemed feasible for retrofit application are ranked according to nominal NO_X control capability. An engineering analysis reviews the estimated capital and operations and maintenance (O&M) costs for each feasible alternative, including taking a look at Balance of Plant (BOP) requirements. Following the cost impact determination, the energy and environmental impacts are reviewed for each feasible technology. Finally, the results of the engineering analyses are tabulated and a NO_X BACT selection is recommended for each unit.

2.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" NO_X BACT analysis is to identify, for the emissions unit in question, a comprehensive list of all "available" control options. In the EPA's draft NSR Manual,

> "available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of

[4] Ibid footnote number 2, NSR Manual B.1

production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant"[5].

According to the EPA's draft NSR Manual, "a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term"[6]. Also, "a control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development"[7].

In order to identify available NO_X emission control technologies and techniques appropriate for potential application to MRY Station units, the following information sources were reviewed for coal-fired electric generating unit powerplants:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and Control Technology Center (website).
- Federal (EPA) and State, including North Dakota Department of Health internet websites for air emission permits and recently-submitted applications, including BACT Evaluations following New Source Review procedures.
- Federal (EPA and Department of Justice) and State, including North Dakota Department of Health internet websites for Consent Decrees issued as a result of legal actions taken by the United States government for alleged violations of the Prevention of Significant Deterioration (PSD) provisions and New Source Review provisions of the Clean Air Act, and/or federally-approved and enforceable State Implementation Plans.
- Control technology vendor information.
- Published and available information from technical, engineering, and environmental consultants.
- Technical literature found in journals, reports, internet websites, newsletters, proceedings of technical seminars and conferences pertaining to studies, engineering, designs, and testing of air pollution controls.

[5] Ibid, NSR Manual B.5
[6] Ibid, NSR Manual B.17
[7] Ibid, NSR Manual B.18

2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The second step of the "top-down" BACT process is to evaluate the available NO_X control technologies and techniques identified in Step 1 in terms of the specific factors that apply to the emissions unit in question. In accordance with EPA's draft NSR Manual, "an available technology is "applicable" if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible[8]".

The EPA's NSR Manual states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique"[9]. Also, a "showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source)"[10]. After a determination is made that any of the processes are technically infeasible, options are eliminated if technical challenges would preclude or prevent the successful long-term use of the control option or technique on the emission unit under consideration. This is performed prior to any economic analysis.

However, the EPA's NSR Manual also states "…control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis"[11]. Also, it states "An NSPS simply defines the minimum level of control to be considered in the BACT analysis"[12]. The NSR Manual further states "When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emission level less stringent than the NSPS. If so, the option is unacceptable"[13]. New Source Performance Standards (NSPS) for NO_X emissions from EGUs firing North Dakota lignite are 0.8 lb/mmBtu. The EPA Acid Rain Program's Title IV NO_X emission limit for Group 2, cyclone-fired coal boilers with outputs greater than 155 MWe is 0.86 lb/mmBtu.

[8] Ibid, NSR Manual B.17
[9] Ibid, NSR Manual B.20
[10] Ibid, NSR Manual B.19
[11] Ibid, NSR Manual B.12
[12] Ibid, NSR Manual B.12
[13] Ibid, NSR Manual B.12

EPA's draft NSR Manual also states "A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review"[14].

Also in the EPA's draft NSR Manual is a qualification for technical feasibility, as described by the statement "Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration"[15].

2.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The third step in the "top-down" BACT evaluation is to rank the control technologies remaining after the feasibility analysis by control effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that "places at the "top", the control technology that achieves the lowest emission level"[16].

Selecting common units in order to compare emissions performance levels amongst options is one of the two key issues that must be addressed in a BACT analysis. EPA's draft NSR Manual states "it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed"[17]. For fossil fuel-fired boilers, pounds of nitrogen oxides per unit of fuel heat input (i.e. lb/mmBtu), is a common means of comparing and calculating NO_X emissions.

Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would

[14] Ibid, NSR Manual B.18
[15] Ibid, NSR Manual B.18
[16] Ibid, NSR Manual B.25
[17] Ibid, NSR Manual B.22

result in a large number of options"[18]. Also, "manufacturer's data, engineering estimates, and the experience of other sources provide the basis for determining achievable limits"[19].

2.4 STEP 4 – EVALUATE THE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

The fourth step of a "top-down" BACT review is to evaluate the technically-feasible emission controls, beginning with the most effective. Economic, energy, and environmental impacts are to be assessed and quantified, where possible, in the control technology analysis. The purpose of the evaluation is to determine if there are any identified impacts that would eliminate the top control technology from consideration. In the case where the most effective control alternative is determined to incur or produce adverse energy, economic or environmental impacts, the basis of the determination is documented, and the next most stringent control alternative is evaluated. This analysis process continues until the control technology under consideration cannot be eliminated by identification of any source-specific adverse energy, economic or environmental impacts.

The economic impacts are based on estimates of capital equipment pricing, procurement, installation and estimated operating and maintenance costs. The total installed capital costs along with the operating costs for each control technology are summarized in the economics of each respective section. The Levelized Total Annual Cost (LTAC) represents the levelized cost of procurement, construction, operation and maintenance over an assumed service life. Cost effectiveness ($/ton) of a control technique or technology is calculated by dividing the LTAC ($/yr) by the annual amount of NO_X removed (tons/yr). Baseline pre-control emissions are calculated using realistic upper boundary operating assumptions, considering inherent physical or operational constraints on the source. Plotting of the annual amount of NO_X removed (tons/yr) versus the levelized total annual control cost ($/yr) for the various control options on an x-y graph allows visualization of the cost-effectiveness. A "least-cost envelope" can be readily identified to indicate the inferior control options which should not be considered in the subsequent analyses. The incremental cost-effectiveness (difference in $/ton) between control techniques or technologies can also be calculated and compared. This allows evaluation of the dominant controls included on the least-cost envelope (curve).

[18] Ibid, NSR Manual B.23
[19] Ibid, NSR Manual B.24

2.5 STEP 5 – SELECT BACT

The final step in the "top-down" evaluation process is to select BACT for the applicable pollutant and emission unit. Per the EPA guidance document, BACT is "the most effective control technology not eliminated in Step 4"[20]. The methodology described above was applied to the Milton R. Young Station Unit 1's boiler for emissions of nitrogen oxides.

* * * * *

[20] Ibid, NSR Manual B.53

3.0 BACT ANALYSIS for MRY STATION UNIT 1 NO_X EMISSIONS

The approach taken in this BACT analysis for Milton R. Young Station included a technical analysis of demonstrated control alternatives for NO_X emissions. This approach followed the predefined steps of a BACT analysis process as generally described in Section 2. Potential NO_X control techniques and technologies were identified, and a technical description of the emission reduction process and capabilities were provided. Subsequently, those techniques and technologies deemed available and feasible for retrofit application were ranked according to nominal NO_X control capability. The engineering analysis then developed the estimated capital and O&M costs for each alternative, including taking a look at Balance of Plant (BOP) requirements. Finally, the cost effectiveness points for each feasible technology were plotted, and those that comprise the dominant controls curve were identified.

For the feasible techniques and technologies considered for determining NO_X control cost-effectiveness for the two steam electric generating units at the MRY Station, estimates were produced for predicted NOx reductions that represent achievable long-term expectations of the alternative reduction techniques and technologies being presented in the technical analysis. Each were tabulated and graphed.

3.0.1 EMISSION UNIT DESCRIPTION

Milton R. Young Station Unit 1 is owned and operated entirely by Minnkota. MRY Station Unit 1 includes a Babcock and Wilcox steam generator installed in 1970. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation. Original unit design steam generating capacity is 1.714 million lbs/hr at 1,920 psi with a fuel heat input of 2,510 mmBtu/hr. The boiler is fired by seven ten-foot diameter cyclone burners, arranged “three over four” across the front wall of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the electrostatic precipitator (ESP). Exhaust gases leave the air heater and pass through an ESP for particulate collection and removal prior to the two induced draft fans (installed in parallel) which discharge to the stack. Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 253 MW gross, and has an ultimate short-term maximum gross output (URGE) rating of 278 MW.

The EPA's Technical Support Document[21] published in the Edocket (EPA's internet website) for the Final BART Guidelines lists nameplate steam turbine-generator capacity of MRY Station Unit 1 as 257 MW (gross), which was assumed for calculating capital cost estimates for control alternatives.

The Unit 1 boiler at M.R. Young Station includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Milton R. Young Station Unit 1's boiler design, combustion performance, and NO_X emissions are dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

The design unit operating conditions for this study are presented in Table 3-1. The historical average lignite coal analysis is shown in Table 3-2.

Table 3-1 – Unit Design Parameters

Design Unit Operating Characteristics	Unit 1 Design
Boiler Type	Subcritical(1)
Combustion System	Cyclone
Number of Cyclones; arrangement, location	7; 3 over 4, front
Unit Design Capacity Electrical Output(2), MW (net/gross)	235 / 257

(1) – Balanced draft, single drum, superheated steam with single stage of steam reheat.
(2) – These values were established by the original equipment manufacturers, prior to construction.

[21] EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b; this is associated with EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445
[23] Ibid, footnote number 2, NSR Manual page B.11

Table 3-2 – Historical Average Lignite Coal Analysis

Lignite - Center Mine Ultimate Coal Analysis: (as received)	**Average % by mass**
Moisture	37.29
Carbon	38.69
Hydrogen	2.50
Nitrogen	0.57
Sulfur	0.81
Ash	8.74
Oxygen	11.40
Total	100.00
Higher Heating Value, Btu/lb	6,662

3.0.2 NITROGEN OXIDES EMISSION FORMATION

Nitrogen oxides (NO_X) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. There are two primary sources of NO_X emissions, referred to as "thermal" NO_X and "fuel" NO_X. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of the fuel containing nitrogen compounds. For most coal-fired units, thermal NO_X emission typically represents approximately 20% and fuel NO_X about 80% of the total NO_X formed. Nitrogen oxide (NO) is typically the most predominant form of NO_X emissions from fossil fuel combustion, along with nitrogen dioxide (NO_2). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces high temperature flue gases and results in very high uncontrolled NO_X emissions. The amount of thermal NO_X emissions produced by cyclone boilers can be considerably higher than fuel NO_X emissions.

3.1 IDENTIFICATION OF NO_X CONTROL OPTIONS FOR MILTON R. YOUNG STATION

The first step in the BACT evaluation is to identify all "demonstrated and potentially applicable control technology alternatives"[23] according to the EPA's draft NSR Manual. In identifying control technologies, "the applicant needs to survey the range of potentially available control options"[24].

[24] Ibid, NSR Manual page B.11

3.1.1 REVIEW OF RETROFIT INSTALLATIONS

The BACT determinations listed in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database are for new facilities. The Milton R. Young Station is an existing powerplant facility with two coal-fired EGUs. A BACT evaluation for retrofitting control equipment to coal-fired EGUs in an existing facility will be substantially different than an analysis for installing control equipment on coal-fired EGUs in a new facility. Consequently, in performing the BACT analysis for existing boilers at Milton R. Young Station, it is important to review powerplant facilities, especially cyclone-fired coal boilers, which have retrofitted NO_X control equipment in recent years.

In 1998, EPA issued a NO_X SIP (State Implementation Plan) call. Under the SIP call, utility boilers in the eastern United States were required to substantially reduce NO_X emissions during the "ozone season". The compliance date for the NO_X SIP call is May 31, 2004. A high percentage of the fired electric generation facilities in the eastern United States have or are in the process of retrofitting NO_X controls to comply with the NO_X SIP call. The EPA's NO_X SIP call was not applicable to North Dakota utility boilers.

There are a number of fossil fuel-fired EGU powerplants around the United States that have implemented or are planning to implement modifications to reduce NO_X emissions. The NO_X emission control system installations are in response to Acid Rain requirements, EPA's NO_X SIP call, the Clean Air Interstate Rule (CAIR), the Regional Haze Rule (RHR), and local regulations.

In addition to the facilities that have had to retrofit emissions controls as a result of the Title IV Part 76 Acid Rain requirements and/or EPA's NO_X SIP call, a few installations have had to retrofit controls in recent years as the result of court decisions resulting from litigation and regulatory action. None of the boilers associated with identified consent decrees are cyclone-fired. They are also located in a region requiring compliance with an EPA-approved State Implementation Plan for nitrogen oxides emissions controls (i.e. NO_X SIP call). As mentioned above, North Dakota utility boilers were not subject to the EPA's NO_X SIP call.

3.1.2 POTENTIALLY FEASIBLE NOx CONTROL OPTIONS FOR MILTON R. YOUNG STATION

A review of available information on retrofit installations performed at utility and industrial coal-fired powerplants during the past fifteen years was undertaken. NO_X emission control technologies and techniques with potential application to Milton R. Young Station boilers were identified, and are listed in Table 3-3.

TABLE 3-3 – Potentially Available NO_X Control Technologies Identified for BACT Analysis

NOx Control Technology
Pre-Combustion Controls
Fuel Cleaning/Blending/Switching
Combustion Controls
Basic Combustion Control Improvements
Low NOx Burners (LNB)
Separated Overfire Air (SOFA)(1)
Flue Gas Recirculation
Fuel Reburn
Oxygen-enhanced combustion (OEC)
Water/steam injection (combustion tempering)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)(2)
Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)(3)

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

A comprehensive literature search, with sources including technical papers and presentations made at conferences by nationally-recognized technical organizations, utilities and other parties involved with design, construction, and testing of NO_X control techniques, plus hardware supplier experience lists, was performed. The results of this search are presented in Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2 FEASIBILITY ANALYSIS

The second step of the "top-down" BACT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible.

An available technology is "applicable" if it can be reasonably be installed and operated on the source type under consideration. Also, a control technique is considered available if it has reached the stage of licensing and commercial availability. For the purposes of this analysis, the term "commercial" is further defined to mean "capable of establishing a full contractual agreement with commercial and performance guarantees supported by appropriate financial backing" for the implementation of full-scale, full-time systems of the technique or technology application. A technology that is available and applicable is technically feasible.

There are three basic categories of NO_X emission control techniques and technologies:

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

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

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

Most of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent coal-fired utility boiler installations in the United States for five years or more.

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

Combustion controls, such as low-NO_X burners (LNBs) and overfire air systems, are very commonly applied to reduce NO_X emissions from fossil fuel-fired powerplants. Low-NO_X Burners are typically applied to pulverized coal, gaseous and liquid fuel-fired boilers. They are not applicable to cyclone-fired boilers. Flue gas recirculation (FGR) has been practiced and performed at numerous natural gas and fuel oil-fired utility and industrial powerplants for NO_X emissions control reasons. On large coal-fired utility boilers, FGR has primarily been applied for steam temperature control purposes, not for emissions control. Conventional Gas Reburn (CGR) with overfire air has been installed and placed in commercial operation on several cyclone-fired boilers, primarily in the eastern region of the United States. Coal Reburn (CR) with overfire air has been successfully demonstrated on two cyclone-fired boilers and commercially installed on three pulverized coal-fired boilers in the United States. Combustion tempering (water/steam injection) has been tested but has not been continuously practiced on cyclone-fired coal boilers. Oxygen-enhanced combustion has only been demonstrated and/or installed on a limited number of pulverized coal-fired powerplants, not on any coal-fired cyclone boilers.

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

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

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

- a full-scale basis, but only with temporary equipment; or
- a full-scale basis, with permanent equipment but in a limited number of installations; or

- with less than full-scale and full-time application.

3.2.1 SUMMARY OF RETROFIT INSTALLATIONS OF NO_X CONTROL TECHNOLOGIES

There are a number of facilities around the country that have implemented or are planning to implement modifications to reduce NO_X emissions. Table 3-4 summarizes the various NO_X emission control system installations currently installed, or that have been demonstrated on a full-scale, short-term basis, in response to Acid Rain requirements, EPA's NO_X SIP call and local regulations, or a utility investigating the technology.

TABLE 3-4 – Identified NO_X Control System Retrofits on Cyclone Coal-fired Boilers

No. of Units(1)	Cyclone NO_X Control Technology Description
1	Fuel Switching/Blending
39(2)	Separated Overfire Air (SOFA)
2	Selective Non-Catalytic Reduction, with or without SOFA
2(3)	Rich Reagent Injection, with SOFA
7(4)	Conventional fuel reburn (pulverized or micronized coal, gas), w/ SOFA
1(5)	Fuel lean gas reburn, with or without SOFA
22(6)	High-dust or low-dust SCR, with or without other technologies
1(6)	Tail-gas SCR, with or without other technologies

(1) – This list of known NOx control retrofit installations is primarily focused on units in the United States. There may be other installations that are similar but were not identified.
(2) – Installed for NOx control (without fuel reburn). A list of known cyclone boiler SOFA installations is included in Appendix A2.
(3) – RRI has only been demonstrated with temporary equipment for testing. See technical literature references in Appendix A1 and A2 for details.
(4) – Several conventional coal and gas reburn retrofits have discontinued reburn demonstration or routine operation. See Technical Literature Reference list and Appendix A3 for further details.
(5) – Only one example of fuel lean gas reburn retrofit (without OFA) on a cyclone-fired boiler has been demonstrated. This system was installed for short-term reburn testing and has been removed.
(6) – High-dust SCR technology has been retrofitted on sixteen U.S. cyclone-fired boilers, all believed to have SOFA. Low-dust SCRs in U.S. have only been installed only on pulverized coal-fired boilers, none on cyclones. One tail-gas SCR installation on a coal-fired cyclone boiler found in Germany; none in the U.S. See technical literature references in Appendix A1 and A2 for details.

A more detailed description of the various control technology retrofits and their claimed effectiveness is included in the technical descriptions and reference literature in the technical feasibility assessment of

Appendix A1, and Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2.2 SUMMARY OF FEASIBLE NO_X CONTROL TECHNOLOGIES FOR MRY STATION

One example of fuel switching applied to a cyclone-fired boiler was identified. Ottertail's Big Stone Unit 1 was originally designed to burn North Dakota lignite and was switched to western subbituminous (PRB) coal for reasons unrelated to NO_X emissions reduction. Big Stone Unit 1 and M.R. Young Station Unit 2 have similar boiler designs, and MRYS Unit 1's boiler is approximately 60% as large as MRYS Unit 2's boiler. Thus, conversion of Milton R. Young Station Unit 1's boiler to fire PRB coal or a lignite/PRB blend is technically possible. There are no railroad facilities provided to service the Milton R. Young plant. Additional operational and capital costs to bring in large quantities of PRB coal will be significant. Based on a comparison of available emission data between Ottertail's Big Stone Unit 1 and M.R. Station Young Unit 1, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station. Although fuel switching at Milton R. Young Station is technically feasible, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. For these reasons, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 1 boiler.

Separated Overfire Air (SOFA) is the most commonly-applied, combustion-related NO_X emission reduction technology that has been proven effective on cyclone-fired boilers. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated overfire air are expected to limit the control effectiveness of this technique, alone and in combination with other feasible NO_X control options.

Selective Non-Catalytic Reduction (SNCR) technology is a form of post-combustion NO_X emission control that has been successfully applied on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal to reduce NO_X emissions. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be

dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation. This control technology adds urea (or ammonia) reagent to the hot furnace gases in the upper furnace to chemically reduce nitrogen oxides. SNCR was considered technically feasible for application on both units at M.R. Young Station. SNCR can be operated with and without SOFA. Variations of SNCR technologies such as Hydrocarbon-enhanced SNCR (HE-SNCR) and "Rotamix" have been installed on pulverized coal-fired boilers but are not proven on cyclone boilers. This is described in detail in Appendix A1.

Rich Reagent Injection (RRI) is a form of SNCR under development specifically intended for NOx emissions control on cyclone boilers. As of October 2006, RRI has been demonstrated but has not been commercially installed and placed in continuous operation on a cyclone-fired boiler, especially one burning coal with high fouling and slag temperature sensitivities associated with lignite supplied from the Center mine. RRI adds aqueous urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea which will increase NOx emissions. RRI is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station at the present time. This is described in detail in Appendix A1.

Various forms of fuel reburn with and without overfire air are types of combustion-related technologies that have been demonstrated and commercially installed on pulverized coal, fuel oil-fired, and cyclone utility and industrial boilers. Natural gas-consuming variations such as Conventional Gas Reburn (CGR) and Fuel-Lean Gas Reburn (FLGR™) have been applied to cyclone boilers burning bituminous and subbituminous coals. High capital costs expected for installing a natural gas pipeline and high operating costs from consumption of large volumes of such fuel make these alternatives economically unfavorable for both units at M.R. Young Station. Pulverized or micronized coal reburn, in combination with SOFA, are technically feasible but will require extensive capital, operating and maintenance costs for fuel grinding equipment and facilities when installed and operated for both units at M.R. Young Station. This is described in detail in Appendix A1.

Fuel cleaning is a technique normally applied to reduce the sulfur or ash content of a fossil fuel prior to combustion. No examples of fuel cleaning of North Dakota lignite or western subbituminous coal strictly for NO_X emissions reduction were found in available technical literature. This technique is considered infeasible for NO_X emissions control of M.R. Young Station boilers at the present time.

High-dust, low-dust, and tail-gas variations of selective catalytic reduction (SCR) technology have been applied on pulverized coal and cyclone boilers as a post-combustion type of NO_X emission control throughout the world and in the United States, except on units firing North Dakota lignite. The severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technology on the EGUs at the Milton R. Young Station. This is described in detail in Appendix A1 with supporting documentation in Appendix B.

The results of Step 2 of the NO_X BACT Analysis for determining the technical feasibility of potential control technologies, including various "layered" combinations, are listed in Tables 3-5 and 3-6.

TABLE 3-5 – Technically-Feasible Potential NO_X Control Technologies for M.R. Young Station Cyclone Boilers

Control Technology(1)	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on M.R. Young Station Unit 1 boiler?
Selective Non-Catalytic Reduction (SNCR)	Yes(2)	Yes
Conventional Gas Reburn	Yes(3)	Yes(3); Requires SOFA or ASOFA
Coal Reburn	Yes(4)	Yes(4); Requires SOFA or ASOFA
Fuel Lean Gas Reburn	No(5)	Yes(5) (w/ or w/out SOFA or ASOFA)
Advanced SOFA	No(6)	Yes(6). Includes relocated lignite drying vent ports
Separated OFA (basic SOFA)	Yes(6)	Yes(6)
Combustion Improvements	Yes	Yes(7); typically included with separated OFA
Flue Gas Recirculation	Not for NOx control	Yes(8) (not expected to reduce NOx further)
Fuel Switching / Blending	Yes	Yes(9) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.
(1) – All potential combinations of technologies not listed. See discussion of "layered" technologies.
(2) – Assumes use of urea for reagent. Limited number of active installations on cyclone-fired boilers burning western subbituminous (i.e. Powder River Basin or PRB coal).
(3) – Limited number of active conventional gas reburn (CGR) installations on cyclone-fired boilers burning PRB coal.
(4) – Limited number of demonstrations or active installations of pulverized or micronized coal reburn on cyclone-fired boilers. One demonstration of pulverized coal reburning with PRB coal has been performed on a cyclone-fired boiler, no longer active. Only one active permanent coal reburn installation on cyclone-fired boiler burning eastern bituminous coal, none burning western subbituminous coal or lignite.
(5) – Only one short-term test demonstration of FLGR™ on a cyclone-fired boiler burning coal with separated overfire air.
(6) – No cyclone boilers firing North Dakota lignite have installed basic or advanced SOFA. See Appendix A.
(7) – Considered part of SOFA installation for coal boilers without combustion controls for NOx reduction.
(8) – No examples of using recirculated flue gas on coal-fired boilers for NOx emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for MRY Station Unit 1 / 2. Potential NO_X reduction improvement on MRY Unit 1 / 2 considered part of "advanced" SOFA.
(9) – Zero additional NO_X reduction potential expected from this technique (switching from lignite to lignite/PRB blends or 100% PRB) alone for MRY Station Unit 1 / 2.

TABLE 3-6 – Technically Infeasible Potential NO_X Control Technologies for M.R. Young Station Cyclone Boilers

Control Technology(1)	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on M.R. Young Station Unit 1 boiler?
Selective Catalytic Reduction (SCR): conventional (high dust); Low-dust; Tail-gas	Yes(2) / No / Yes(3)	No(4) - Unresolvable fouling and catalyst deactivation problems expected. See discussion of SCR feasibility for ND lignite.
Electro-Catalytic Oxidation (ECO®)	No	No, has not been demonstrated full-scale nor reached commercial availability
HE-SNCR (using ammonia)	No(5)	No(5). Has not been demonstrated on cyclone.
Rotamix (ROFA + SNCR)	No(6)	No(6). Has not been demonstrated on cyclone.
Rich Reagent Injection (RRI) with ASOFA	No(7)	No(7). Requires oxygen-free furnace environment, varying air/fuel would increase NOx emissions.
RRI + SNCR with ASOFA	No(7)	No(7). See footnote and feasibility discussion.
Advanced Conventional Gas Reburn (ACGR) + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Coal Reburn + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Fuel Lean Gas Reburn + SNCR	No(8)	No. Has not been demonstrated on cyclone.
Rotating Opposed-Fired Air	No(6)	No. Has not been demonstrated on cyclone.
Oxygen Enhanced Combustion	No(9)	No. Has not been demonstrated on cyclone.
Water Injection	No(10)	No(10)
Fuel Cleaning	Not for NOx control	No(11) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.

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

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

(3) – No identified installations on coal-fired boilers in the United States. One tail-end SCR on cyclone boiler in Germany.

(4) – See discussion of SCR feasibility for ND lignite in Appendix A1 and Appendix B.

(5) – Hydrocarbon-enhanced SNCR has not been demonstrated on a cyclone-fired boiler, nor any boiler firing western subbituminous coal or lignite.

(6) – Rotating Opposed-Fired Air with or without SNCR has not been demonstrated on a cyclone-fired boiler. No apparent significant advantages over SOFA on cyclone-fired boilers.

(7) – Rich Reagent Injection has been successfully demonstrated for brief periods with SOFA with and without SNCR at two cyclone powerplants. There are no permanent RRI installations completed and operational as of May 2006. Difficulties in maintaining an oxygen-free furnace environment in MRY Station boilers where the urea reagent would be injected due to cyclone air/fuel imbalances during air-starved combustion would increase NOx emissions.

(8) – No known demonstrations or permanent installations of Advanced conventional gas reburn (CGR) or FLGR™ or pulverized/micronized coal reburn (PCR/mCR) in combination with SNCR on cyclone-fired boilers. CGR and PCR/mCR require separated overfire air. FLGR™ has been applied to pulverized coal firing with and without SOFA, with and without SNCR; FLGR™ with SNCR is also called amine-enhanced fuel lean gas reburn (AEFLGR™).

(9) – No known demonstrations or permanent installations of oxygen-enhanced combustion (OEC) on cyclone-fired boilers.

(10) – No permanently installed examples of using this technique continuously on coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.

(11) – No known demonstrations or permanent installations of using this technique continuously on coal-fired boilers for NOx emissions control were found in available technical literature.

Additional criteria besides technical feasibility are utilized for technology selection in a BACT analysis have been included in the following sections summarizing control effectiveness estimates, capital plus operating and maintenance cost estimates, energy impacts, and environmental impacts:

- Control effectiveness (i.e. percent pollutant removed)
- Expected emission rate (see Tables 3-7, 3-8) and emission reduction (tons per year)
- Economic impacts (total cost and incremental cost effectiveness)
- Energy impacts
- Environmental impacts (other media and emissions of toxic and hazardous air pollutants)

3.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the "top-down" BACT evaluation is to rank the remaining control technologies by effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that "places at the "top" the control technology that achieves the lowest emission level."

The emission reduction (control effectiveness) percentages developed for ranking the available NO_X emission control options considered feasible for Milton R. Young Station Unit 1 are shown in Table 3-7. These are estimates based upon engineering judgments with considerations of:

- Boiler heat input rates associated with realistic upper boundary operating assumptions;
- baseline emission rates corresponding to the realistic upper boundary operating assumptions;
- the general combustion properties of North Dakota lignite;
- published and available emission reduction performance achieved at other similar utility powerplants (cyclone-fired boilers);
- computer-derived predictions; and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

These NO_X emission level and reduction percentage estimates include adjustments of previously demonstrated or predicted performance that reflect differences between North Dakota lignite and eastern or midwestern bituminous and western subbituminous coals.

The numbers assume the estimated capability of the employed technique is achievable and sustainable (long-term) and that potential operational limitations mentioned in the feasibility discussions allow the successful practice of the technique or technology. None of the remaining control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application. This is particularly pertinent to all control options that involve air-staged combustion associated with various forms of separated overfire air. SOFA-based controls for cyclone-fired coal-burning boilers have typically reduced NO_X emission levels significantly from the precontrol baseline, and which allow or enhance further reductions when combined with other control techniques and technologies.

3.3.1 ESTABLISHING BASELINE NO_X EMISSIONS FOR RANKING CONTROL OPTIONS

Before the various feasible NO_X emission control alternatives can be estimated and ranked in order of effectiveness, the precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual provides general guidance for establishing estimated baseline emissions to be used for the purpose of calculating and comparing the control and cost-effectiveness of a control option:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of added post-process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for the use of inherently lower polluting processes"[25].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true

[25] Ibid, NSR Manual B.37

upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[26].

Establishing estimated baseline NO_X emissions for a new or existing source involves determining the design or operational basis of the emission rate. A useful means of comparing such emission rates is to establish the unit emission rate, expressed in pounds of pollutant per unit of process output. For processes such as steam-electric generating powerplants utilizing combustion in boilers, the desired process output (kilowatts or megawatts) can be related to the pollutant-bearing flue gas created by the combustion of fuel. Units of fuel heat input (millions of BTUs) required to create a unit of desired electrical output (kW) and thus the efficiency of converting the fuel heat to such electrical output (unit heat rate, Btu/kW-hr) are important.

A review of reported hourly NO_X emissions for MRY Station Unit 1 boiler, including unit mass rates (lb/mmBtu and lb/hr), boiler heat input (mmBtu/hr), and gross electrical output in megawatts (MW_g), was performed for the operating periods in years 2001-2005 inclusive. A realistic upper bound emission case scenario for each boiler's baseline emissions at Milton R. Young Station determined the highest summation of any rolling 12-month period NO_X mass emissions (pounds), along with the summation of the gross heat input (mmBtus) and the boiler operating hours for the same rolling 12-month period corresponding to the highest NO_X pounds. Dividing the summation of the rolling 12-month NO_X pounds by heat input results in a average unit emission rates (lb/mmBtu). Likewise, the summation of the rolling 12-month gross heat input (mmBtus) divided by the boiler operating hours yields an average gross heat input rate (mmBtu/hr). This emission evaluation revealed that:

- Unit 1 at Milton R. Young Station is typically operated in a base-loaded manner;
- MRYS Unit 1's highest 12-month NO_X mass emissions summation divided by the summation of the same 12-month period's heat input averaged 0.849 lb/mmBtu at a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MW_g.

3.3.2 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The degree of success in operation of separated overfire air alone and in combination with the other selected feasible alternatives is important to the amount of NO_X emission reduction achieved. The emission control performance from the advanced version of separated overfire air (ASOFA) is highly

[26] Ibid, NSR Manual B.37

dependent on the degree of success in admitting combustion air insufficient for complete combustion in the cyclones without causing related negative impacts. The control percentages estimated for firing North Dakota lignite in the MRY Station boilers reflect the belief that operating the existing cyclones much below an average cyclone stoichiometric ratio of approximately 0.95 (95% of the theoretical amount of combustion air required for complete combustion) will not be successful. This is due primarily to the expected "starved air" combustion causing a reduction in cyclone furnace gas temperatures, thus creating a strong potential for molten slag solidifying in the cyclone barrels, slag taps, and lower furnace floor openings. This would impose a great interruption to steam production since forced outages would be required to remove this physical obstruction before full load boiler operation could be reestablished. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options"[27].

The potential operational limitations for deeply air-staged cyclones associated with separated overfire air and coal reburn alternatives are expected to limit the amount of NO_X control potential possible from successful practice of the particular technique or technology. This is described in the detailed feasibility discussions included in Appendix A1.

The advanced form of separated overfire air is expected to be effective in NO_X emission reduction and can be combined with other feasible combustion-related and post-combustion control alternatives for these lignite-fired cyclone boilers. The basic form of SOFA in combination with coal reburn, gas reburn options, and SNCR, was not included in the detailed control effectiveness analysis in order to limit the number of options that were evaluated.

Using an advanced form of SOFA system, M.R. Young Station's Unit 1's boiler operating at MCR is expected to achieve a NO_X emission level of 0.51 lb/mmBtu when operating modestly air-staged cyclone furnaces with suitable combustion controls. This level of NO_X reduction from ASOFA operation, approximately forty percent, is based on the expected ability to reduce emissions without incurring potential significant negative impacts of this technique. This reduction estimate includes the additional amounts of control potential available from operating with relocated lignite drying system vent ports associated with ASOFA operation with modestly air-staged cyclone furnaces.

[27] Ibid, NSR Manual B.37

Coal reburn with ASOFA is estimated to reduce NO_X emissions for M.R. Young Station's Unit 1's boiler operating at MCR slightly less than 55 percent from the pre-control baseline NO_X emission rate, considering similar control levels demonstrated by previous coal-reburn retrofits on cyclone-fired boilers and limitations previously discussed with ASOFA.

Conventional Gas Reburn and Fuel Lean Gas Reburn options were both assumed to be installed with ASOFA. NO_X reduction from CGR with ASOFA operation is expected to be approximately fifty six percent. FLGR with ASOFA is expected to reduce NO_X emissions approximately forty six percent. Estimates for NO_X emissions for M.R. Young Station's Unit 1's boiler considered similar control levels demonstrated by previous gas-reburn retrofits on cyclone-fired boilers with modestly air-staged cyclone furnaces and limitations previously discussed with ASOFA.

The NO_X emission rate for Selective Non-Catalytic Reduction (SNCR) (using urea) with ASOFA is expected to be approximately 0.355 / 0.33, resulting from a reduction in NO_X emissions of approximately 58 percent from the 12-month average pre-control baseline NO_X emission rate.

Included in the feasible control option ranking of Table 3-7 are layered alternatives that were shown in Table 3-5. The highest-performing NO_X control alternatives remaining in consideration are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" SOFA, which is expected to have significantly lower NO_X emissions than a typical SOFA system as applied to the Milton R. Young cyclone boilers.

TABLE 3-7 – Ranked NO_X Control Options Feasible for MRY Station Unit 1 Boiler with Expected Control Performance

Alt. Label(1)	NO_X Control Technique	Emission Rate (lb/mmBtu)	Control Percentage(2)
E	SNCR (using urea) w/ ASOFA	0.355	58.1
D	Gas Reburn with ASOFA	0.374	56.0
C	Lignite Reburn w/ ASOFA	0.385	54.6
B	Fuel Lean Gas Reburn with ASOFA	0.460	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	39.5
-	Baseline	0.849	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.
(2) - Control percentages are relative to an average pre-control emission baseline of 0.849 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

The annual emission levels developed for Table 3-7's ranking the feasible alternatives assume that the highest 12-month average pre-retrofit level of unit NO_X emissions for M.R. Young Station's Unit 1's boiler is a baseline of 0.849 lb/mmBtu. This was determined from the highest reported rolling 12 consecutive month period's summation of hourly NO_X emissions (lbs).

The hourly gross fuel heat input (mmBtu) was summed over that same 12-month time period, and divided by the number of boiler operating hours to yield an annual average gross fuel heat input rate (mmBtu/hr). Multiplying the 12-month average heat input rate (mmBtu/hr) by the baseline or control alternative's 12-month average unit emission rate (lb/mmBtu) equals a 12-month average hourly NO_X emissions rate (lb/hr). Annual NO_X emissions (tons) for the baseline pre-control condition were calculated by multiplying the 12-month summation for boiler operating hours during the same period as the highest NO_X emissions by the 12-month average emission rate (lb/hr). The annual tons for the control options were calculated by multiplying the alternative's average annual emission rate (lb/yr) by a reduction factor (if applicable) for heat input or running plant capacity and adjusting boiler operating hours by an annual uptime (availability) factor. Details for these adjustments are included in Appendix C3. Based on these calculations, the annual emissions for M.R. Young Station's Unit 1's boiler are shown in Table 3-8.

TABLE 3-8 – Expected Annual NO_X Control Performance for MRY Station Unit 1 Alternatives

		EMISSIONS				NOx Removal Efficiency(5) %
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission(2) lbs/hr	Annual Emission(3) tons/yr	Emission Reduction(4) tons/yr	
E	SNCR (using urea) w/ ASOFA	0.355	975	4,025	5,909	58.1
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6
B	Fuel Lean Gas Reburn w/ ASOFA	0.460	1,261	5,260	4,674	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	1,409	5,874	4,060	39.5
-	Baseline	0.849	2,330	9,934	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 2,744 mmBtu/hr heat input.
(3) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 94.1% was assumed for the baseline case.
(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).
(5) - Estimated NO_X control level percentage reductions relative to 0.849 lb/mmBtu emission baseline at 2,744 mmBtu/hr MCR heat input.

3.4 NO_X CONTROLS ANALYSIS AND IMPACTS EVALUATION

The fourth step of a "top-down" BACT review is to evaluate the most effective emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

3.4.1 NO_X CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 1

An evaluation was performed to determine the various cost impacts of installing feasible NO_X control alternatives on Milton R. Young Unit 1. This evaluation includes estimated:

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

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 3-9 through 3-13.

3.4.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

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

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the NO_X control technologies capital cost estimate basis was 257 MW_g for MRY Station Unit 1[28].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 1 NO_X control technologies are presented in Table 3-9. The estimated installed and levelized capital costs for the highest-performing form of the various feasible NO_X emission reduction technologies evaluated for cost-effectiveness are shown in Table 3.10. These are listed in order of control effectiveness, with the highest ranked option at the top.

[28] Ibid footnote number 23.

TABLE 3-9 – Unit Capital Cost Factors of Feasible NO_X Control Options for MRY Station Unit 1

Alt. Label[1]	NO_X Control Technique	Range[2] ($/kW)	Single Point Unit Capital Cost Factor[3], ($/kW) MRYS Unit 1
E	SNCR (using urea) w/ ASOFA	20-35[4]	31.6[4],[5]
D	Gas Reburn w/ ASOFA	15-30[6]	70.1[5],[6],[7]
C	Lignite Reburn w/ ASOFA	30-60[6]	181.5[5],[8]
B	Fuel Lean Gas Reburn w/ ASOFA	--[9]	41.4[4],[5],[9]
A	Advanced Separated Overfire Air (ASOFA)	5-10[6]	16.6[5]

(1) – Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.
(4) – Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix C2 for details.
(5) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(6) – NESCAUM 2005 Technical Paper, posted at their website. See technical references in Appendix A1 for details.
(7) – The single point unit capital cost factor shown for a conventional gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.
(8) – The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 for details.
(9) – The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. The single point unit capital cost factor shown for a fuel lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (15.7 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.

TABLE 3-10 – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(4)	18,006	1,570
C	Lignite Reburn w/ ASOFA(5)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(4)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.
(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.
(4) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnotes #8 and 10 under Table 3-9.
(5) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

3.4.1.2 Operating and Maintenance Cost Estimates for MRY Station NO_X Controls

The operational and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[29], and from published in technical papers discussing those control technologies. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.

[29] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

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

For economic evaluation purposes, an annual average running plant capacity factor of 96.6 percent compared to a nominal unit output capacity of 253 MW_g combined with an average annual availability (uptime) of 8,528 operating hours (97.3 percent of 8760 hours per year) resulting in an annual unit capacity factor of 94.1% were assumed for Unit 1's pre-control baseline annual operation. A heat input rate of 2,744 mmBtu/hr and a NO_X emission rate of 0.849 lb/mmBtu were assumed for calculating control and cost-effectiveness from pre-control maximum rolling 12 month summation of nitrogen oxides' mass emissions for MRY Station Unit 1.

Table 3-11 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 3-11 – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(3) $1,000
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

3.4.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

In order to compare a particular NO_X emission reduction alternative during the initial engineering analysis portion of the BACT selection process, the sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal by implementing that alternative was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Appendix C1 for methodology). The unit control cost was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The control alternatives were also compared by calculating the change in unit cost (incremental cost) per incremental ton removed for the next most stringent alternative. This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average annual cost increment compared with the baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted.

The comparison of the cost-effectiveness of the remaining NO_X emission reduction technologies was made and is shown in Table 3-12 and Figures 3-1 and 3-2 for MRY Station Unit 1. These figures plot estimated annual amount of NO_X removal (emission reduction) in tons per year on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis), for each of the remaining NO_X control technologies. Points on the graph that are farthest to the right and closest to the horizontal axis are deemed more cost-effective, since they represent controls that achieve more NO_X removal per dollar required for total annual costs of operation, maintenance, and capital recovery (depreciation).

Although the NSR Manual repeatedly prescribes following a "top down" analysis approach for BACT determination, the development of a least cost envelope with dominant controls (as seen in NSR Manual Figure B-1, page B.42) clearly labels points with lower emissions reductions and total annual costs first, i.e. "A", "B", etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NOx control technique alternative has followed this approach.

TABLE 3-12 – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(6)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(7)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(6)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 94.1% was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

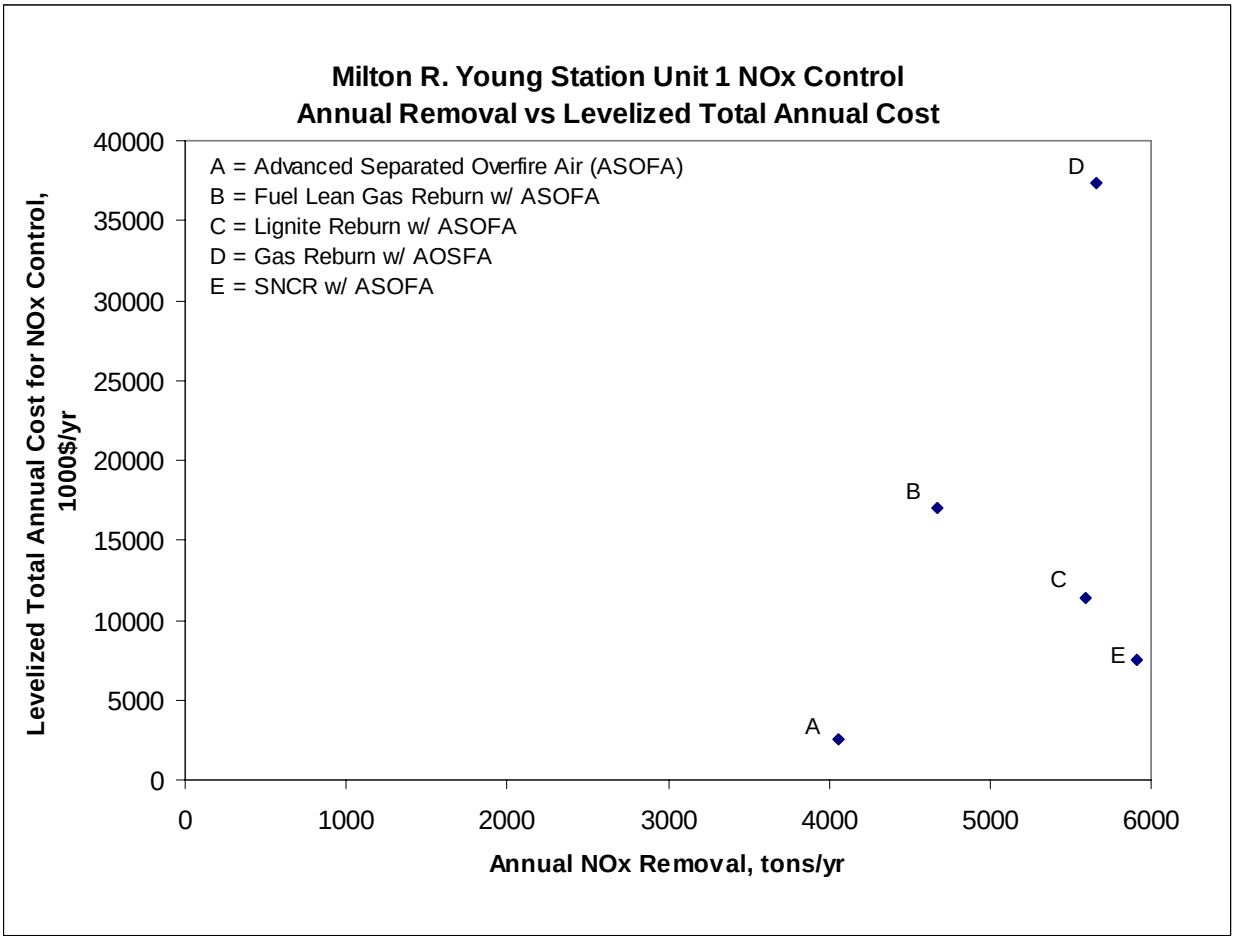
(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note #3 for Tables 3-10 and 3-11 for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at highest allowable pre-control NOx emission rate.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnotes #8 and 10 under Table 3-9.1

(7) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $2,054,000 for annualized capital cost plus $2,527,000/yr for annualized O&M cost, for a LTAC subtotal of $4,581,000/yr.

Figure 3-1 – NO_X Control Cost Effectiveness - MRY Station Unit 1(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-12.

The purpose of Figure 3-1 is to show the range of control and cost for all feasible NO_X reduction alternatives evaluated. A dominant set of control alternatives were determined by generating what is called the "envelope of least-cost alternatives". The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope are inferior control alternatives per the NSR Manual and should be excluded from further analysis on a cost efficiency basis.

Of the technically feasible NO_X control alternatives considered for MRY Station Unit 1, data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), lay distinctly left and above the other points of the control cost points' scatter plot of Figure 3-1. These control options are inferior and therefore were eliminated from further control cost-effectiveness analysis.

Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Table 3-13. The annual NO_X control tons per year, divided by the total levelized annual cost, yields an average unit cost ($/ton). Incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. The additional tons per year of NO_X control relative to the previous apparent least-cost curve point, divided by the increase in levelized annual cost, yields an incremental unit cost ($/ton). Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the envelope of least-cost control alternatives, also called the dominant controls cost curve or DCCC) between successively more effective alternatives which are considered technically feasible for Milton R. Young Station boilers.

TABLE 3-13 – Dominant Controls Cost Curve Points for Feasible BACT NO_X Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

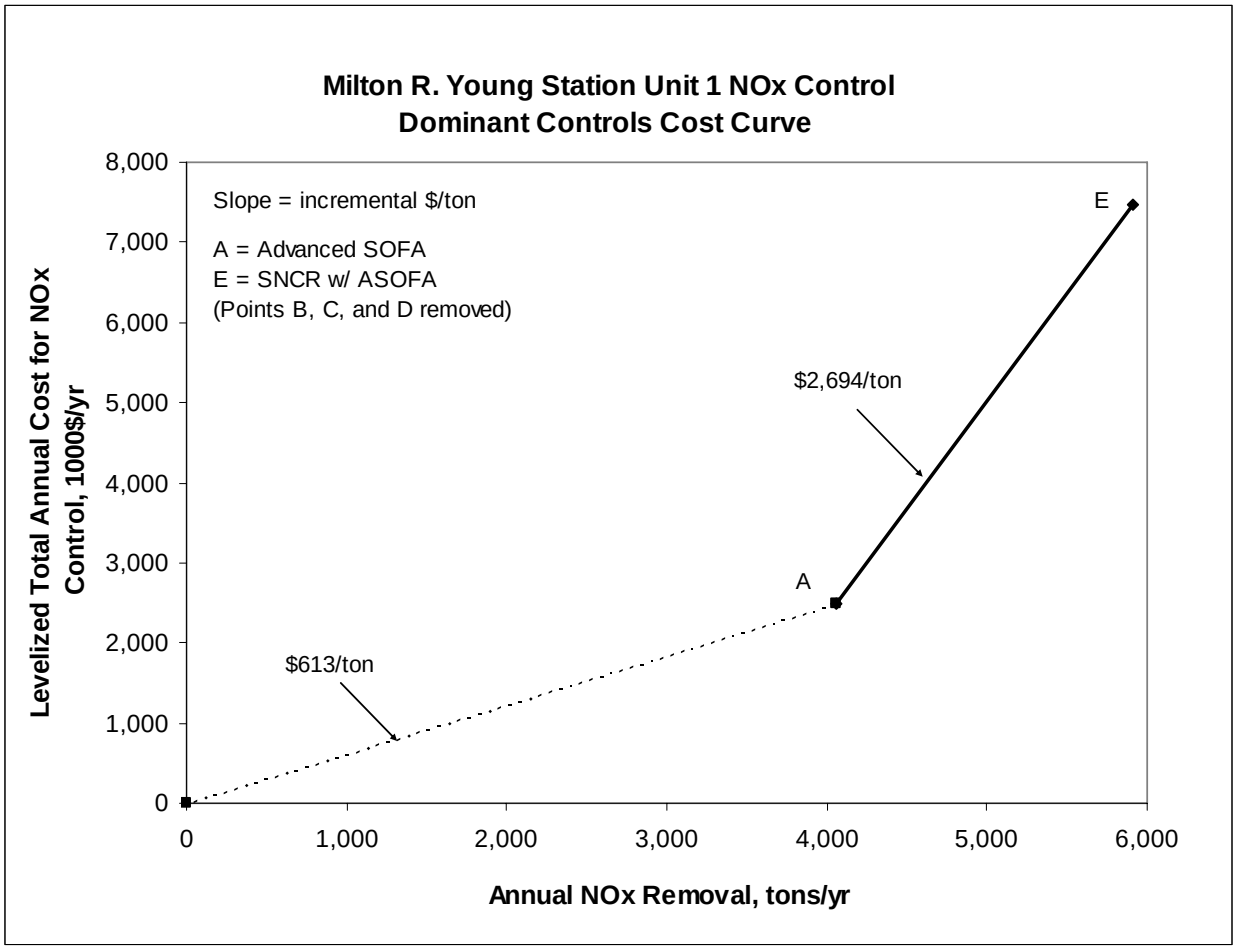
(1) – Dominant controls cost curve points from lowest (ASOFA) to highest (SNCR w/ ASOFA) are labeled the same as in Table 3-12, and on the graphs that accompany this table (Points B, C, and D were eliminated).
(2) – All cost figures in 2006 dollars.
(3) – Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.
(4) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest, except as noted.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control

technique (slope from zero baseline to ASOFA, Point A was $613/ton for MRYS Unit 1; the incremental cost (slope) from ASOFA, Point A to SNCR with ASOFA, Point E was $2,694/ton for MRYS Unit 1.

Figure 3-2 contains a repetition of the levelized total annual cost and NO_X control information from Figure 3-1 for MRY Station Unit 1, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 1 NO_X emissions alternatives.

Figure 3-2 – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-13.

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. As can be seen from a review of Table 3-14, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from approximately $613/ton to $6,597/ton of MRYS Unit 1's NO_X emissions removed. It should be noted,

however, that the highest estimated average control costs involve gas reburn technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the least-cost envelope of dominant control alternatives or dominant controls cost curve) between successively more effective alternatives. The economic impact analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is SNCR with ASOFA (Point E). This control option is considered technically feasible for Milton R. Young Station Unit 1 boiler but incurs a significant annual (levelized) incremental cost relative to the next highest feasible NO_X control technique, ASOFA (Point A) when ASOFA is compared against the pre-control baseline. The Advanced Separated Overfire Air alternative has an average unit control cost ($613/ton) approximately 48% of the highest performing feasible alternative on the dominant controls cost curve (SNCR with ASOFA, $1,265/ton). ASOFA also has a much lower incremental cost per ton relative to the pre-control baseline (slope from zero to Point A, $613/ton) compared to SNCR with ASOFA (Point E) versus ASOFA (Point A); the slope from Point A to Point E was $2,694/ton.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The environmental impacts.

TABLE 3-14 – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 1

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1

Alt. Label(1)	NOx Control Alternative	EMISSIONS(2) Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency(2) %	ECONOMIC IMPACTS Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388(7)	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 96.6% average running plant capacity factor compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.
(7) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

3.4.2 ENERGY IMPACTS OF MRY STATION NO_X CONTROLS

Operation of the most cost-effective NO_X control technologies considered feasible for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various NO_X control alternatives are summarized in Appendix C3.

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

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

3.4.2.1 ENERGY IMPACTS OF SOFA TECHNOLOGY

There should not be a major impact on energy consumption resulting from the operation of the advanced variation of a separated overfire air system. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Damper resistance and supply pressure impacts of the SOFA system on fan power consumption should be insignificant. The amount of flyash emitted from the boiler is expected to be reduced (less than five percent) from the baseline level

when the SOFA system is in full operation. Slightly higher levels of unburned carbon in the flyash may occur with the operation of a SOFA system. This could have a small negative impact on the plant heat rate (higher Btu/kw-hr). These changes are expected to be within the typical range of current operation.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a separated overfire air system. Typical SOFA operation on bituminous or western subbituminous coal-fired cyclone boilers does not carry a significant additional risk of causing insufficient or excessive accumulation of slag within the cyclone barrels or furnace bottom compared with non air-staged combustion. Reliable boiler operation depends on avoiding such adverse conditions in the cyclones and lower furnace, which could require a forced outage to remove the solidified slag prior to returning the boiler to generation production service.

The challenges of maintaining adequate slag layer development and flow while firing lignite in MRY Unit 1's cyclones under excess air conditions have been significant during the operating history of the powerplant. Minimizing forced outages resulting from cyclone slag issues have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of combustion characteristics of lignite supplied from the Center mine, and the dependency of the slag flow on the temperature within the cyclone barrels or furnace bottom, conditions may occur during ASOFA operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the solidified slag.

The potential impact on annual unit operating time due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation was estimated to be approximately 2% reduction from the assumed pre-control baseline availability, i.e. 0.97-0.02=0.95. The estimated electrical generation production lost due to the reduction in MRY Unit 1's annual availability is shown in Table 3-16.

3.4.2.2 ENERGY IMPACTS OF SNCR TECHNOLOGY

For SNCR, the injection of a diluted urea solution will require some additional auxiliary power for heating and pumping the liquid and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 70 to 200 kW. The injection of water (used for urea dilution) into the boiler flue gas also will have a small negative impact on the plant heat rate (higher Btu/kw-hr), although the vendor of SNCR systems advises that the heat released from the oxidation of a portion of the

injected urea compensates for this impact. The impact of additional flue gas created by operation of an SNCR-related system on fan power consumption should be small.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a SNCR-related system. Typical SNCR operation with low ammonia slip when firing low-sulfur western subbituminous coal in cyclone-fired boilers does not carry a significant additional risk of causing excessive fouling of the tubular air preheater compared with non-SNCR operation. Reliable boiler operation depends on avoiding adverse fouling conditions in the air preheater, which could require a forced outage to remove the ash deposits prior to returning the boiler to generation production service.

The challenges of maintaining open passages through the air preheater tubes while firing lignite in MRY Unit 1's cyclones under typical conditions have been minor during the operating history of the powerplant. Minimizing forced outages resulting from ash deposits within the air preheater have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of fouling characteristics of lignite supplied from the Center mine, and the dependency of the fouling within the air preheater on sodium, sulfur, and ammonia slip emission levels, conditions may occur during SNCR operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the air preheater deposits.

The potential impact on annual unit operating time due to air preheater fouling and other potential issues associated with SNCR system operation was estimated to be an incremental 1% reduction from the assumed pre-control baseline or ASOFA availability. The estimated electrical generation production lost due to the reduction in MRY Unit 1's annual availability is shown in Table 3-16.

TABLE 3-15 – Expected Auxiliary Electrical Power Impacts for NO_X Controls - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Auxiliary Electrical Power Demand and Consumption for NOx Control Equipment	
		Gross Demand(2) kW	Power Usage(3) kW-hrs/yr
E	SNCR w/ ASOFA	73	582,411
A	Advanced SOFA (ASOFA)	1	8,058

(1) – Alternative number has been previously assigned from highest to lowest unit NOx emission rate.
(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.
(3) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

TABLE 3-16 – Expected Electrical Power Generation Availability and Capacity Impacts for NO_X Controls - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Availability(2)	Estimated Annual Average Operating Time Reduction, hrs/yr(3)	Estimated Annual Average Running Plant Capacity Factor(4)	Estimated Annual Average Electricity Generation Reduction kW-hrs/yr(5)
E	SNCR w/ ASOFA	0.956	273	0.965	67,660,606
A	Advanced SOFA (ASOFA)	0.952	188	0.966	46,586.546

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – Baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(3) – Annual lost operating time resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.
(4) – Baseline running plant capacity factor is assumed at 96.6 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(5) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 253 MW (MCR gross unit electrical output capacity).

TABLE 3-17 – Expected Total Electrical Power Generation Impacts for NO_X Controls - MRY Station Unit 1

Alt. Label(1)	NOx Control Technique	Power Usage(2) kW-hrs/yr	Estimated Annual Average Electricity Generation Reduction(3) kW-hrs/yr	Est. Total Annual Change in Net Electrical Power Generation Available for Sale(4) kW-hrs/yr
E	SNCR w/ ASOFA	582,411	67,660.606	68,243,017
A	Advanced SOFA (ASOFA)	8,058	46,586.546	46,594,605

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(3) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 253 MW (MCR gross unit electrical output capacity).
(4) – Annual change in net electrical power generation available for sale is arithmetic sum of annual power generation reduction due to a change in the auxiliary electrical power consumed plus the annual generation reduction from a decrease in annual operating time and average annual running plant capacity factor resulting from the implementation of the individual NOx control technique, compared with baseline.

3.4.3 ENVIRONMENTAL IMPACTS OF NOx CONTROLS - MRY STATION

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

3.4.3.1 ENVIRONMENTAL IMPACTS OF SOFA TECHNOLOGY

The operation of a separated overfire air system is expected to slightly increase carbon monoxide concentrations in the stack flue gas. The advanced form of SOFA alternative is expected to slightly lower the amount of particulate matter emitted from the boiler and may raise the amount of unburned carbon in the flyash collected for land disposal and emitted to the atmosphere by small increments. Alternatives involving forms of gas reburn should experience lower particulate emissions, and a reduction in the amount of boiler bottom and flyash requiring disposal.

The environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons removed will increase, by approximately two percent.

3.4.3.2 ENVIRONMENTAL IMPACTS OF SNCR TECHNOLOGY

Operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of an SNCR system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR depends on the amount of reagent utilization and location of the injection points. Higher SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

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

Delivery of the urea reagent to the powerplant facility and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable. Emergency planning and community communications are part of the management plan requirements for such reagent usage.

The environmental impact from potential reduction of annual unit operating time by approximately one percent due to air preheater fouling issues associated with SNCR system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons eliminated relative to the constant pre-control emission baseline will increase by approximately one percent.

3.4.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF MRY STATION NO_X CONTROLS

The economic, energy, and environmental impacts of each feasible BACT alternative evaluated for this study is summarized in this Section. Table 3-18 summarizes the various impacts discussed in Sections 3.4.1 through 3.4.3. The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated. Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1 were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

TABLE 3-18 – Summary of Top-Down BACT Impact Analysis Results for Dominant NO_X Control Alternatives - MRY Station Unit 1

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
E	SNCR w/ ASOFA	0.355	975	4,275	5,659	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.
(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.
(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr).
(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations likely will increase with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology.

3.5 BACT RECOMMENDATIONS AND CONTROL LEVELS – MRY STATION UNIT 1

This report presents the analysis of control technologies for nitrogen oxides (NO_X) for Minnkota Power Cooperative's (MPC's) Milton R. Young Station Unit 1 using the EPA's "top-down" BACT approach. BACT is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[30]. A BACT review does not result in a percent removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps were as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The final result of this analysis is a recommendation of the BACT alternative and the associated NO_X emission rate for Minnkota Power Cooperative's Milton R. Young Station Unit 1. The emission limitations for a generation facility are expressed in a pounds per million British Thermal Units (lb/mmBtu) basis.

3.5.1 UNIT 1 NO_X BACT

In step one of the technology evaluation, three basic categories of NO_X controls for EGUs were-identified: pre-combustion, combustion, and post-combustion. Eleven basic types of NO_X control processes were identified within these three categories. Twenty four variations of these eleven processes were reviewed for availability and applicability to cyclone-fired EGUs burning North Dakota lignite. An "advanced" form of Separated Overfire Air, alone and in various combinations with Lignite Reburn, Selective Non-Catalytic Reduction (SNCR), Conventional Gas Reburn and

[30] Ibid, NSR Manual B.1

Fuel Lean Gas Reburn™, was evaluated for cost-effectiveness. The cost-effectiveness analysis indicated that ASOFA alone, and ASOFA with SNCR were cost effective alternatives for MRY Station Unit 1 NO_X control. The energy and environmental impacts analysis for MRY Station Unit 1's cost-effective NO_X control alternatives were generally insignificant.

Based upon the definition of BACT and the results of the BACT analysis, Selective Non-Catalytic Reduction (SNCR) in combination with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA) is recommended as the Best Available Control Technology for nitrogen oxides emissions from Minnkota Power Cooperative's Milton R. Young Station Unit 1. The unit BACT NO_X emissions rate for MRYS Unit 1 is 0.355 lb/mmBtu , determined as a rolling 12-month average. This is shown in Table 3-19.

TABLE 3-19 – NO_X Emission Control Technology and Rate Recommended as BACT for Milton R. Young Station Unit 1

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**BACT Control Method**	**12-Month Rolling Average BACT NOx Emission Rate (lb/mmBtu)**
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.355

3.5.2 EMISSION RATE LIMITATION RECOMMENDATION

To complete the BACT determination process, the Consent Decree (CD) requires that "specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)"[31] (pounds per million Btu) must be established for each subject emission Unit. The CD also states that "a "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lbs/MMBtu for the current Operating Day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-day Rolling Average Emission Rate shall include startup, shutdown, and Malfunction periods within each Operating Day"[32].

[31] Ibid footnote number 1, Paragraph 66, page 20.
[32] Ibid footnote number 1, Paragraph 5, page 4.

The Consent Decree also states that the North Dakota Department of Health's (NDDH) NO_X "BACT Determination shall address specific emission limitations during Unit startups"[33] at Milton R. Young Station. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 1.

In keeping with the establishment of a specific CD Phase II 30-day Rolling Average NO_X Emission Rate limitation, a relevant precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual states:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions"[34].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[35].

[33] Ibid footnote number 1, Paragraph 66, page 20.
[34] Ibid footnote number 2, NSR Manual page B.37
[35] Ibid footnote number 2, NSR Manual page B.37.

The BACT Analysis was conducted based upon the highest historical 12-month rolling NO_X emission summation operating conditions for Milton R. Young Station boilers during years 2001-2005. However, a baseline reflecting a realistic upper bound case scenario based upon the highest historical 30-day rolling NO_X emission operating conditions during years 2001-2005 was established prior to recommending enforceable permit conditions for BACT to be applied to each Milton R. Young Station boiler.

The approach taken in this analysis was to identify pre-control 30-day baseline operating conditions from the 30-consecutive day period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1, 2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. MRYS Unit 1's highest reported 30-day rolling average NO_X unit emission rate during years 2001-2005 was 0.884 lb/mmBtu for the period ending January 15, 2004. The corresponding MRYS Unit 1 30-day average hourly NO_X mass emission rate was 2,642 lb/hr. The average unit heat input rate for MRYS Unit 1 was 2,990 mmBtu/hr, and the average gross unit electrical power output was 246.7 MW_g for the same 30-day period.

The operating conditions during the highest historical 30-day rolling NO_X emission for years 2001-2005 were then compared to the highest 12-month historic pre-control baseline conditions. The average unit NO_X emission rate (lb/mmBtu) from the highest historic pre-control 30-day baseline period was compared with the average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 1. This is explained below.

NO_X emissions for cyclone-fired boilers are typically higher in pounds per million BTUs during start up events than during steady-state operation at maximum continuous rating (MCR) conditions. This is because hourly heat and combustion air input rates required to establish adequate molten

slag formation within the cyclone barrels and promote slag tapping are typically produced from firing conditions that create high flame temperatures. NO_X emissions are sensitive to peak furnace gas temperatures, thus uncontrolled NO_X emissions can be high during cyclone boiler startups. Furnace exit flue gas temperatures (FEGTs) during cyclone boiler startups are less than those occurring during conditions of steady state MCR firing rates due to the high heat absorption of the boiler metal and water being raised from ambient or near-ambient temperatures. Until sufficient FEGT exists for a feasible and available post-combustion technology, such as SNCR, to be effective, NO_X emissions will be basically uncontrolled. There is a practical lower limit of boiler heat input for conventional combustion-based NO_X emission control techniques, such as the advanced version of separated overfire air, to be operated beyond the amount required for cooling the SOFA injection nozzles when it can be diverted from the cyclone burners and significantly control NO_X emissions. These limitations of the effectiveness of BACT controls on Milton R. Young Station boilers during startups and other reduced-load operating periods influence the recommended 24-hour and 30-day rolling average NO_X emission rate limits.

Startup procedures for steam electric generating units (SEGUs) comprising a fossil fuel-fired boiler and steam turbine-generator are specified by the original equipment manufacturers to follow guidelines for heat and pressure increases to provide protection of boiler and turbine equipment. Initial start up duration after an outage may be dictated by the need to gradually warm up burner port/cyclone refractory materials, steam drum shell, steam headers, and other boiler metal surfaces exposed directly or indirectly to furnace gases, and the steam turbine's multiple casings and rotor shafts. This is normally accomplished with easy-to-ignite fossil fuel firing (such as natural gas, distillate fuel oil, or propane) of the boiler combined with coal to gradually increase firing until recommended boiler steam outlet temperature and pressure are reached. This is followed by supplying the steam turbine with sufficient inlet steam flow to reach conditions that allow the coupled generator to be synchronized and electricity to be generated above zero megawatts. From this point, boiler fuel firing is increased within prescribed rates until the desired operating load is achieved.

The SEGU startup operating period is usually not defined in emission permits. Startup is the period beginning with initiation of fuel ignition, and continuing until the powerplant equipment has reached operating conditions that include continuous fuel firing and sustained operating steam pressure and temperature levels within the guidelines of the designs for the boiler and turbine and their auxiliary systems for minimum sustainable levels without causing damage to the equipment.

A recent SEGU proposed PSD permit has included a definition of startup as "the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits"[36]. Similarly, a shutdown is defined as "the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the boiler and combustion has ceased"[37]. Based on the referenced definitions of a startup period and a shutdown period, the amount of time required for a SEGU's load (boiler steam output or generator electrical output) to increase beyond such minimum sustainable operating levels can be considered part of startup events if the SEGU is typically base-loaded at full load or MCR output. This is the case with both MRY Station SEGUs.

Startups of SEGUs may be labeled as cold, warm, and hot to account for the amount of residual heat remaining in the boiler and steam turbine equipment. The various types of starts are dependent upon the amount of time the SEGU has been out-of-service (i.e. without boiler fuel firing or generator megawatt output). Cold starts have been defined as starts after the boiler has been without fuel firing for more than 72 hours, warm starts are more than 8 hours and less than 72 hours, and hot starts are less than 8 hours[38].

Although the definition of a startup event and the corresponding startup period is not required by the Consent Decree, defining start-ups is recommended. This helps to address the specific emission limitations during Unit startups at Milton R. Young Station and determine the impact of such operations on 30-day rolling average NO_X emissions. For the purpose of this NO_X BACT analysis, a Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 2500 million BTU/hr for Unit 1; or
- the amount of time reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

This startup definition for MRY Station Unit 1 accounts for conditions where cyclone refractory materials replaced during boiler overhauls must be cured by extended low-firing heating cycles,

[36] Desert Rock Energy Center (AZP04-01) Proposed PSD Permit Conditions, page 7. (http://www.epa.gov/region09/air/permit/desertrock/#permit)
[37] Ibid, page 7.
[38] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, Document Number 09417-360-250R1, May 2004, page 5-1.

unit controls are upgraded and must be adjusted during low-load operation, or for boiler feedwater quality to improve after boiler maintenance has been performed that affects the insides of the waterwall and superheated steam tubes. It also allows for a failed or interrupted start sequence which can require considerably less or more time to elapse than an average startup duration.

Analysis of MRY Station Unit 1 operations data from 2001 through 2005 revealed:

- There were 60 total startups in the five year period;
- Minimum startup was 10 hours for a "hot" start following a boiler master fuel interruption (Unit "trip");
- Maximum startup with an extended ramp-up period until full load was reached was 61 hours.

Unit 1 had a start-up that began on June 27, 2005 that lasted for 61 hours. This startup included initial firing in the 5th hour of 6/27 (0500 hours being the beginning of the startup period), and which ended at the end of the 17th hour (i.e. at 1800 hours) on June 29th, 2005 upon reaching a generator output of 245 MW (gross) rather than a 6-hour average heat input rate of more than 2500 million Btu per hour.

There are certain boiler operating conditions that need to exist before the BACT NOx control techniques and technologies can be effectively operated:

1. The furnace gas temperature in the region where a urea reagent solution is injected for SNCR-based NO_X control must be between 1700°F and 2100°F. This region is expected to be in the vicinity of the furnace exit, which is commonly defined as either the horizontal plane extending from the furnace rear wall arch ("nose") to the front wall of the boiler, or the vertical plane from the nose up to the furnace roof, upstream of the gas inlet to the superheater tube banks. The gas temperature (FEGT) range in this furnace region is dependent on boiler heat input rate and cleanliness of the firesides of the furnace walls, which affects the amount of radiant energy absorbed by the wall tubes and transferred to the water within.
2. The numbers of active cyclones and continuous coal firing rates must be enough to establish sufficient:
    a. coverage of molten slag on the actively-fired cyclone barrel surfaces and drainage of the slag from the bottom of the boiler; and

b. combustion airflow through the actively-fired cyclones to allow a portion to be diverted to the separated overfire air system above the amount required for idle cyclone cooling and SOFA nozzle cooling.

As previously discussed, furnace exit flue gas temperatures (FEGTs) will need to be measured or determined empirically during operation of the MRY Station boilers in order to be able to effectively control NO_X emissions using SNCR technology. The design and operation of the SNCR systems at MRYS for CD Phase II emissions control should include features that accommodate cyclone boiler startups and low-load operation with "clean" or "dirty" boiler heat transfer surfaces as soon as conditions occur that are technically practicable, i.e. within the SNCR system vendor's recommended operating guidelines, as well as full-load conditions in order to minimize NO_X emissions.

The amount and duration of sustained boiler heat input required to establish the operating conditions described in item 2 above is more difficult to precisely determine. Lignite heat content variability and inability to accurately determine the actual air/fuel ratio on a cyclone-by-cyclone basis in real-time, and the slagging and fouling characteristics of the lignite ash, cause (and are expected to continue to cause) difficulties with stable combustion performance. The minimum firing rates of the MRY Station boilers required to successfully initiate the effective operation of the SOFA system are specific to each individual boiler, and are not currently known. Due to such operating problems and emission control limitations, the ability to effectively limit NO_X emissions during startup periods and low-load operation following implementation of advanced SOFA (CD Phase I control) and/or an SNCR system (CD Phase II control) is uncertain.

Because there are expected to be minor short term variations in operating conditions during startups where Minnkota has not, in fact, materially changed any of their normal startup operating practices and criteria, a margin between the 30-day rolling average steady-state NO_X emission rate (which does not include the impacts of startups) and the proposed 30-day rolling average NO_X emission permit limit that includes startup emissions is recommended. This rate considered recognized operational factors and equipment designs applied to steady state conditions with sustained output close to maximum continuous capacity ratings. The recommended 30-day Rolling Average NO_X Emission Rate permit limitation excluding the impact of startups that reflects BACT for Milton R. Young Station Unit 1 is shown in the table below.

TABLE 3-20 – Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
1	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.360

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.884 lb/mmBtu for Unit 1. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

A recommended BACT 30-day NO_X emission rate limit that includes the impact of startup emissions should be suitably higher such that operation consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices to the extent practicable for the MRY Station boilers would not result in an exceedance (violation) of an enforceable 30-day rolling average NO_X emission permit limit.

For MRYS Unit 1, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation without or excluding such startup periods:

1. The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold, warm, or hot startup up to and including maximum continuous rated output;
2. The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
3. The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
4. The number of startups and their range of typical durations per 30-day period time frame.

The June 27-29, 2005 startup was chosen for additional evaluation as the start-up for MRY Station Unit 1.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.36 lb/mmBtu for Unit 1 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

TABLE 3-21 – Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
1	0.36	+0.041 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.766 lb/mmBtu for Unit 1 reported for the longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

TABLE 3-22 – Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
1	0.980

These emissions occurred during the 61-hour June 27-29, 2005 startup for Unit 1.

Compliance with these emission rates would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration operating period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trail period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

References:

1. In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

3. EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b; this is associated with EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445.

4. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

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APPENDIX A

Technical Feasibility Assessment Details for NO_X Control Technologies (A1)

U.S. Coal Cyclone NO_X Reduction Projects Summary

With Retrofit NO_X Control Projects' Technical Literature Summary (A2)

A.1 Technical Feasibility Assessment of NO_X Control Alternatives

A.1.1 Pre-Combustion Fuel Treatment/Switching

Fuel switching can be a viable method of NO_X emission reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of MRY Station, the Unit 1 and 2 boilers were designed and constructed specifically for firing North Dakota lignite, which has a fuel higher heating value (Btu/lb) approximately 20% lower than typical Powder River Basin (PRB) coal. A cyclone–fired boiler (Ottertail's Big Stone Unit 1) that is similar in geometry and steam generation design to MRY Station Unit 2 fires PRB coal. Based on a comparison of available emission data between Big Stone Unit 1 and MR Young Unit 2, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station.

Conversion of Milton R. Young Station Unit 1 boiler to fire PRB coal is technically possible. It is expected that major plant modifications will be required. Rail service is not presently installed at this site, so the additional operational and capital costs to bring in large quantities of PRB coal will be significant. Investigation of the specific source, distance, and costs for supplying necessary quantities of PRB coal via rail or trucks to M.R. Young station has not been performed. With zero baseline NO_X emissions reduction expected from application of fuel switching, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. Although fuel switching is technically feasible, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 1 boiler.

A.1.2 Combustion Controls

Combustion controls comprise the most numerous category of NO_X emission reduction technologies. These techniques employ methods that reduce the amount of NO_X emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). These controls result in fewer emissions to atmosphere or that may require subsequent reduction from additional applicable combustion and/or post-combustion techniques.

As the boilers in question were designed for firing North Dakota lignite fuel, they were furnished with suitably-sized furnaces and limited back-end economizer heat transfer surfaces upstream of the air preheaters. This provides high temperature air to aid the evaporation of excess moisture from the crushed coal particles in the pre-combustion drying systems, and long residence times for solid and gaseous fuel

particles to burn essentially to completion prior to leaving the furnaces. The latter feature is especially advantageous for applying various forms of combustion modifications which are conducive in reducing NO_X emissions.

A.1.2.1 Basic Combustion Improvements

Combustion improvements are commonly-applied techniques which may produce modest incremental NO_X emissions reductions. In their most basic form, these typically provide improvements to combustion air flow distribution, measurement, and pressure, together with fuel flow measurement and metering, to promote consistent combustion performance by burning fuel with more accuracy in maintaining a desired fuel/air ratio.

These improvements may allow, or be combined with, the practice of several other NO_X control techniques. Separated overfire air (discussed below), with or without "low excess air" (LEA), burners out-of-service (BOOS) and biased firing (BF) operation of the cyclones, cause a decrease in the ratio of combustion air to fuel supplied to the cyclones (burners), thus reducing the amount of thermal NO_X emissions produced during combustion. The amount of potential NO_X emission reduction achievable from these basic techniques is highly-dependent on the specific type of firing, fuel, and conditions which apply to the boiler(s) being reviewed.

Making lignite drying system air adjustments and adding improvements to the boiler combustion controls and reducing combustion air inputs have already reduced uncontrolled NO_X emissions at Milton R. Young Station boilers approximately 10%. Further incremental improvements from additional combustion controls that allow operation with modest amounts of cyclone air staging, similar to the effect of a separated overfire air system, are possible. Incremental NO_X emissions reductions are expected from such improvements being incorporated into another feasible alternative, such as separated overfire air. This alternative was not considered as a stand-alone option for additional NO_X reduction at Milton R. Young Station for the Unit 1 boiler.

A.1.2.2 Low NO_X Burners (LNB)

Low NO_X burners (LNBs) of various designs have been commonly applied to pulverized coal-fired utility and industrial boilers for more than ten years. However, they are not installed on cyclone-fired boilers. This technology is infeasible on cyclone boilers[1], and was eliminated from consideration for additional NO_X reduction at Milton R. Young Station Unit 1's boiler.

A.1.2.3 Separated Overfire Air (SOFA)

Separated overfire air (SOFA) is a combustion-related NO_X emission reduction technology frequently-applied with and without low NO_X burners to utility and industrial boilers for more than twenty five years. Separated Overfire Air (SOFA) is an air-staging NO_X emission reduction combustion technique that is typically based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. The diverted combustion air is then injected in the upper furnace, where combustion is completed. For typical cyclone coal-fired boilers, this involves diverting approximately 20 percent of the secondary combustion air, forcing the cyclones to operate fuel-rich. Starved-air combustion causes fewer NO_X emissions to be produced.

At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous ("Powder River Basin") coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998. A summary of several of the first SOFA (and reburn) retrofits to cyclone-fired boilers is described in published technical papers[1,2]. Cyclone boiler retrofit SOFA installations are included in the EPA's BART technical support document[3] and listed later in Appendix A2.

A basic form of separated overfire air (SOFA) can be applied and installed on MRY Station Units 1. There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application.

Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when "starved air" (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the cyclone furnaces can be operated with less than theoretical (substoichiometric) combustion air directly contributes to less NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. In the case of MRY Station Unit 1 boiler, cyclone combustion must be sufficiently air-staged to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners.

In the case of MRY Station boilers, there is a significant amount of variability in the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND. Analysis of several hundred coal feed samples taken simultaneously from multiple cyclones of MRY Station Unit 2's boiler revealed that the maximum differential of the lignite heating values from cyclone-to-cyclone was just over 12% of the average heating value of all the samples. Assuming an operating case occurred where the maximum cyclone-to-cyclone differential heating value was for two cyclones at the opposite ends of the fuel heat content range, there would be a plus or minus 6% variation in fuel heat content for either of the individual cyclones from the overall average. If the desired average cyclone air/fuel (stoichiometric) ratio was 0.95 when operating with air-staged cyclones associated with separated overfire air, and the amount of secondary combustion air to each cyclone was equal, there would be a stoichiometric ratio of approximately 1.01 in one cyclone and a stoichiometric ratio around 0.89 in another cyclone at the same time. The modestly air-staged cyclone would produce higher than average NOx emissions. The deeply staged cyclone would produce less than average NOx emissions and potentially insufficient amounts of heat release, and raise the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil in the deeply-staged cyclone or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in lower emissions removal performance and higher operating costs. Thus, due to the variability of the fuel heat content and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control in MRY Station boilers is expected to be modest while firing lignite coals.

In order to potentially achieve lower NO_X emission rates with modestly air-staged combustion for MRY Station boilers, additional combustion improvements can be installed. One potential improvement is to implement a unique form of SOFA for North Dakota-lignite–fired cyclone boilers. This includes relocated lignite drying system vent ports. This will be referred to as "Advanced SOFA" (ASOFA). There are several design challenges anticipated for implementing the advanced version (with the described port relocations) of separated OFA. These are believed to be solvable.

Both forms of separated overfire air as a combustion-related NO_X control technique are considered feasible for application to Milton R. Young Station cyclone boilers. Since the advanced SOFA is the highest-performing form of this technology, only this ASOFA version of the alternative was considered for additional NO_X reduction at Milton R. Young Station boilers.

Another form of separated overfire air being marketed commercially is "Rotating Opposed Fire Air" (ROFA). For utility applications in the United States, this has only been applied to pulverized coal-fired boilers, primarily tangentially-fired units[4]. It is different than basic SOFA in that it includes a hot air booster fan, and injects the overfire air in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. The vendor (Mobotec USA) claims ROFA maximizes air-staged in-furnace combustion NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon.

While this variation of separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Because cyclone boilers do not require the addition of hot air booster fans for SOFA, this technique is not distinct enough from basic SOFA from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration. ROFA technology lacks demonstrated cyclone-fired boiler experience, and thus was considered infeasible and not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.2.4 Oxygen-Enhanced Combustion

A supplier of liquid oxygen (Praxair) has developed a method of replacing some of the combustion air supplied to the burners with pure oxygen. Combustion air, which is normally input through the secondary air system ductwork downstream of the forced draft (FD) fan and air heater, is supplemented with pure oxygen directly injected into the burners. Oxygen-enhanced combustion (OEC) can reduce boiler NO_X emissions resulting from " thermal NO_X", a reaction of the nitrogen in the combustion air admitted to the burners with the available oxygen in the air in the flame or peak temperature regions of the fuel combustion process. The use of pure oxygen instead of air reduces the availability of nitrogen from the air to be oxidized in the high temperature regions, thus reducing formation of thermal NO_X. This technique has only been demonstrated in a boiler with pulverized fuel burners firing bituminous coal[5].

The lack of adequate experience on any cyclone-fired coal-burning boiler, on a temporary demonstration or permanent full-scale basis, and for a coal-fired facility of this size, precludes consideration of oxygen-enhanced combustion at MRY Station Unit 1's boiler. This is deemed to be infeasible technology at this location at the present time.

A.1.2.5 Flue Gas Recirculation

Flue gas recirculation (FGR) has been commonly applied to coal-fired boilers, primarily to inject into the lower furnace, just above the burners, supplied from the boiler's economizer flue gas outlet via a hot gas booster fan. This modifies the amount and temperature of hot furnace gas either in the lower-middle or upper furnace and convection heat transfer zones. As this flue gas typically has an oxygen content around 2-5%, it limits the availability of oxygen in a high temperature, possibly fuel-rich lower furnace zone. Flue gas recirculation for NO_X control is most commonly applied with gaseous or liquid fossil fuels to reduce the high temperatures which convert nitrogen in the combustion air to nitrogen oxides. No examples of using or installing FGR on cyclone-fired boilers strictly for NO_X emissions control were found in available technical literature.

For MRY Station Unit 1's boiler, FGR was originally supplied from the outlet of the induced draft fans, but has since been discontinued and removed. Since it is not operational on Unit 1, and therefore does not affect the potential performance of separated overfire air (in an "advanced" form), it would not be expected to reduce NO_X emissions if reinstalled alone or in combination with SOFA. Although FGR is technically feasible, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 1's boiler.

A.1.2.6 Water/Steam Injection (Combustion Tempering)

When applied to older gas-fired and oil-fired utility and industrial boilers, water and/or steam injection adds moisture into the lower furnace, concurrent with or near (to the side or slightly above) the burners, supplied from the boiler's treated feedwater or auxiliary steam systems via a metering pump or valve. There has been some limited testing of water injection for NO_X emissions control on natural gas-fired and coal-fired cyclone boilers[6,1]. For coal-fired cyclones, this technique is most effective on boilers burning bituminous coal; however, it has not been permanently installed and continuously operated in such applications. Successful long-term operation of water injection would be difficult for lignite-fired cyclone boilers, due to the high moisture levels in the coal and the need to readily ignite and sustain stable combustion and molten slag formation in the cyclone furnaces. For these reasons, water/steam injection is considered technically infeasible for NO_X control application at Milton R. Young Station.

A.1.2.7 Fuel Reburn

Another combustion technology that may be applicable to control NO_X emissions from the Milton R. Young Station units is fuel reburn. In a similar manner that overfire air diverts a portion of the combustion air input to the main firing zone, the reburning process involves supplying a portion of the fuel heat input to the boiler at a higher elevation in the furnace. This creates an upper furnace atmosphere where the reburn fuel's combustion products causes some of the NO_X formed in the main burner combustion zone and reburn zone to be converted into molecular nitrogen. Depending on the amount of reburn fuel added and the amount of oxygen available in the furnace gases to combine with the reburn fuel introduced, additional combustion air may be supplied as supplemental or overfire air. Downstream of the air injection elevation, the intention is to complete the reaction of any remaining carbon monoxide (CO) to carbon dioxide (CO_2), plus reduce the amount of combustible matter remaining in the entrained flyash.

The most common forms of reburn technology applied to utility powerplant boilers are:

- Pulverized or micronized coal reburn (PCR or MiCR); and
- Gas reburn (GR).

Pulverized coal reburning and micronized coal reburning have been applied to pulverized coal and cyclone-fired boilers. NO_X reduction efficiencies of 50 to 60 percent have been demonstrated on eastern bituminous coal and midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone[7,8].

For utility powerplant boiler applications, natural gas has been utilized as reburn fuel most often, demonstrated in two basic approaches:

- Conventional gas reburn (CGR); and
- Fuel-lean gas reburn (FLGR™).

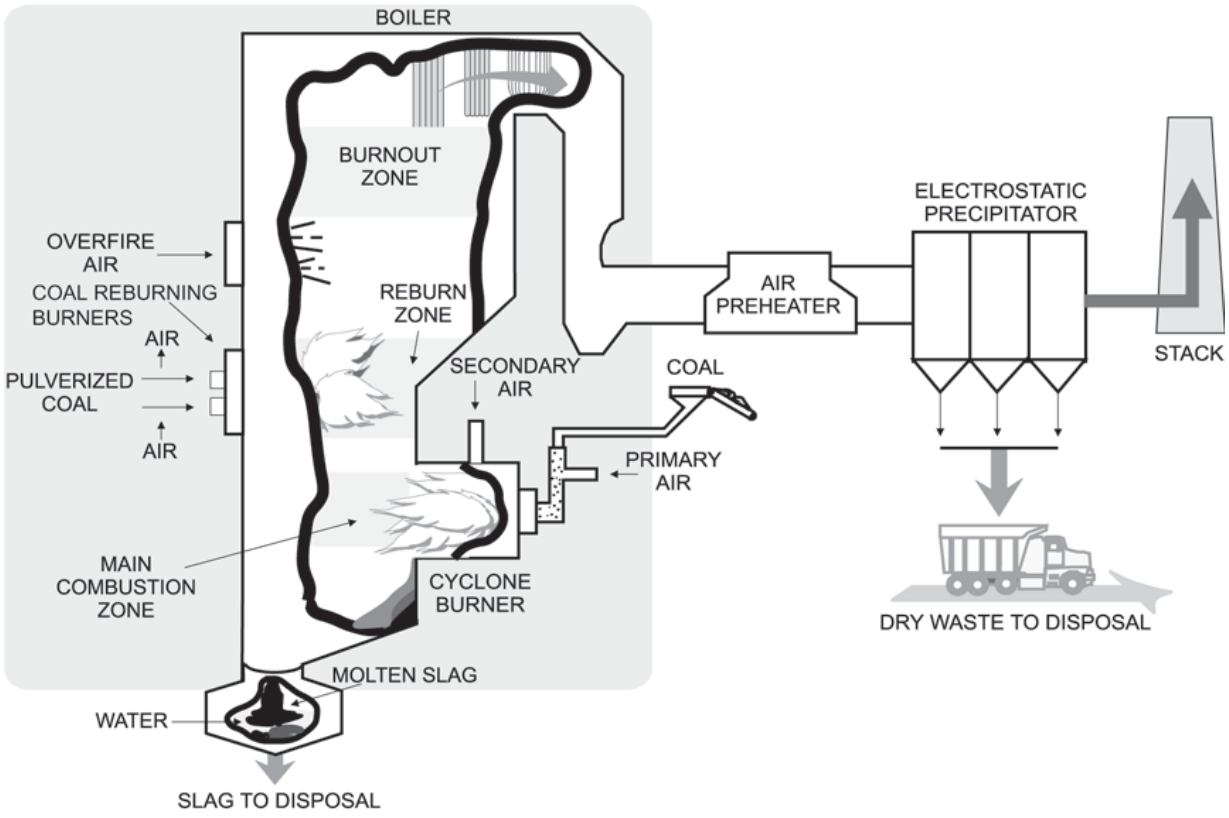
Either natural gas or pulverized coal (lignite) can be used as the reburn fuel. A sufficient quantity of natural gas is not currently available at the Milton R. Young Station plant site. Supplying enough natural gas to provide 6 to 25% of the total heat input to either or both boilers at MRY Station is expected to be technically feasible, although transport pipeline installation capital costs, and current and predicted unit natural gas costs and operating economics, are likely to be unfavorable.

Various forms of fuel reburning have been demonstrated and operated routinely on cyclone boilers for NO_X emission controls. This has been applied to units firing eastern bituminous coal, and western subbituminous or PRB/bituminous coal blends, using pulverized or micronized coal or natural gas as the most common reburn fuel. Reburning for NO_X emissions reduction has not been demonstrated on a unit firing high moisture, low heat content North Dakota lignite. Pulverized/micronized coal, along with conventional and fuel lean gas reburn technologies, are discussed below.

A.1.2.7.1 Coal Reburn

In the case of applying conventional coal reburn to cyclone boilers, the existing cyclones are supplied with the majority of the fuel, with either natural gas or pulverized coal (lignite) used as the reburn fuel such that the total heat input to the boiler is essentially the same as without fuel reburn. Separated OFA ports are located above the reburn fuel injection section of the furnace. These SOFA ports provide sufficient oxygen in a conventional fuel reburn installation to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones. This is shown schematically for a pulverized coal reburn application on a cyclone-fired boiler with SOFA in Figure A.1-1.

Figure A.1-1 Pulverized Coal Reburn Application on Cyclone Boiler With Overfire Air[8]



In the United States, pulverized coal reburning and micronized coal reburning techniques for utility powerplant NO_X emissions reduction have been applied on a very limited full-scale, full-time basis to cyclone-fired boilers in field demonstration tests and longer-term demonstration operation, respectively. There have been only two known pulverized or micronized coal reburn installations in the United States on cyclone boilers, one on a utility boiler in Wisconsin, and one on a small industrial-size cyclone boiler in New York state[7,8,9,10,11,12,13,14]. NO_X emissions reduction efficiencies of 57 percent have been demonstrated on cyclone boilers firing eastern bituminous coal, or midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone. With the exception of the U.S. Department of Energy's (DOE) Clean Coal Technology Program demonstration projects[7,8,9], no known commercially-available coal reburn systems have been installed and are routinely operated on cyclone boilers in the United States to date. The DOE-CCTP projects for coal reburn applied to cyclone boilers are described below.

Pulverized coal reburning for NO_X emissions reduction in a cyclone-fired boiler was demonstrated on the 110 MW Nelson Dewey Unit 2 for Wisconsin Power & Light in 1991-1992. Reburn fuel preparation and handling, reburn burners with flue gas recirculation, and a separated overfire air system were added. Coal reburn tests were conducted on this unit while firing bituminous and PRB coals. NO_X emission control efficiencies of 50 to 60 percent, with reductions from 0.75-0.83 lb/mmBtu baselines to around 0.38 lb/mmBtu, but as low as 0.29 to 0.32 lb/mmBtu, with PRB coal at full load with approximately 25-30% of the total fuel heat input from reburn fuel were demonstrated[9,11,12]. The reburn system is no longer operated on Nelson Dewey Unit 2.

Micronized coal reburning has been demonstrated in 1997-1998, and continues to operate year-round on a small industrial cyclone boiler (400,000 lb/hr steam output, 50 MW gross equivalent) for Eastman Kodak Company at their Kodak Park facility in Rochester, NY. This unit (Boiler #15) achieves a NO_X reduction efficiency of approximately 57 percent on eastern bituminous coal, involving limited cyclone air-staging (cyclones believed to be slightly above 0% excess air) and a modest amount of overfire air injection downstream of the micronized reburn fuel input nozzles. Approximately 17% of the boiler's total fuel heat input is typically supplied to the reburn zone. This coal reburn system continues to operate routinely at this facility. This installation is reported to use a Fuller MicroMill to produce micronized coal with 80% passing through a 325 mesh screen[7,9,13].

If a coal reburn system was applied to MRY Station boilers, the existing cyclones would be supplied with the majority of the fuel in the form of crushed coal, and the balance of fuel would be supplied to a pair of dedicated pulverizers to feed the reburn injection ports, such that the total heat input to the boiler is essentially the same as without fuel reburn. In a conventional fuel reburn installation, OFA ports located above the reburn section of the furnace provide sufficient oxygen to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, lignite is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO_X emissions. The concerns are that the diversion of a significant amount of heat input from the cyclone barrels to use as a source of reburn fuel in the form of pulverized or micronized lignite may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems.

Potential NO_X emissions reduction performance is expected to be limited on lignite-fired cyclone boilers with a basic form of separated overfire air system, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to any conventional reburn process in that it would require much higher reburn fuel injection rates to create a substoichiometric atmosphere in the lower secondary furnace that is conducive to promoting in-furnace NO_X reduction.

Significant additions to the fuel preparation equipment in the existing plant facilities will be required. The coal reburn system expected to be applied to MRY Station boilers may use two new fine-grind pulverizers and dynamic classifiers to achieve the level of coal particle size distribution required.

Higher unburned carbon levels in the flyash exhausted from the boiler may occur, especially when the reburn fuel is coal, and the regular burners are fired with less than theoretical amounts or combustion air commonly practiced with the use of overfire air. Lowering the reburn fuel injection elevation, decreasing

the amount of reburn fuel, and grinding the reburn coal to a greater degree of fineness can help to offset some of the increase in flyash unburned carbon content. Flue gas opacity from the stack may increase if the particulate removal equipment is an electrostatic precipitator, due primarily to reduced resistivity and smaller particle sizes of the flyash.

An issue that affects the feasibility of lignite reburning is the uptime required for the lignite reburn fuel pulverizing system, and impact of the reburn system on effectiveness in reducing NO_X emissions during load changes and lower loads. Typically, one new pulverizer is dedicated to prepare reburn fuel in existing pulverized fuel-fired boiler applications. Cyclones may be fired with less fuel or deactivated during boiler operation in order to accommodate changes in fuel combustion characteristics, boiler load, and for scheduled or unscheduled individual crusher maintenance. Milton R. Young Station Unit 1 has seven crushers for cyclone coal grinding, each dedicated to one of the seven cyclone furnaces. Diverting as much as 30% of the total heat input as reburn fuel could require two of the existing cyclones to be deactivated, and two new MPS-89 pulverizers to be dedicated to reburn fuel preparation. As each of these mills requires periodic maintenance, boiler emissions and/or load could be negatively impacted during individual reburn mill outage periods while the boiler remained in service. A high level of fineness of coal particles from the reburn mills is important to achieve and maintain in order to limit increases in flyash combustibles. A minimum of 60 percent passing through 200 mesh fineness is recommended by one of the reburn technology vendors (B&W) for pulverized lignite reburn. Micronized coal reburn requires even greater fineness: 70-80 percent passing through a 325 mesh screen.

Pulverized or micronized coal reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on MRY Station Unit 1's boiler. These combined techniques are expected to reduce NO_X emissions approximately 54% from current pre-control baseline levels (down to 0.385 lb/mmBtu) for the MRY Station Unit 1 boiler. These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers, which may not be successful given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 1's boiler.

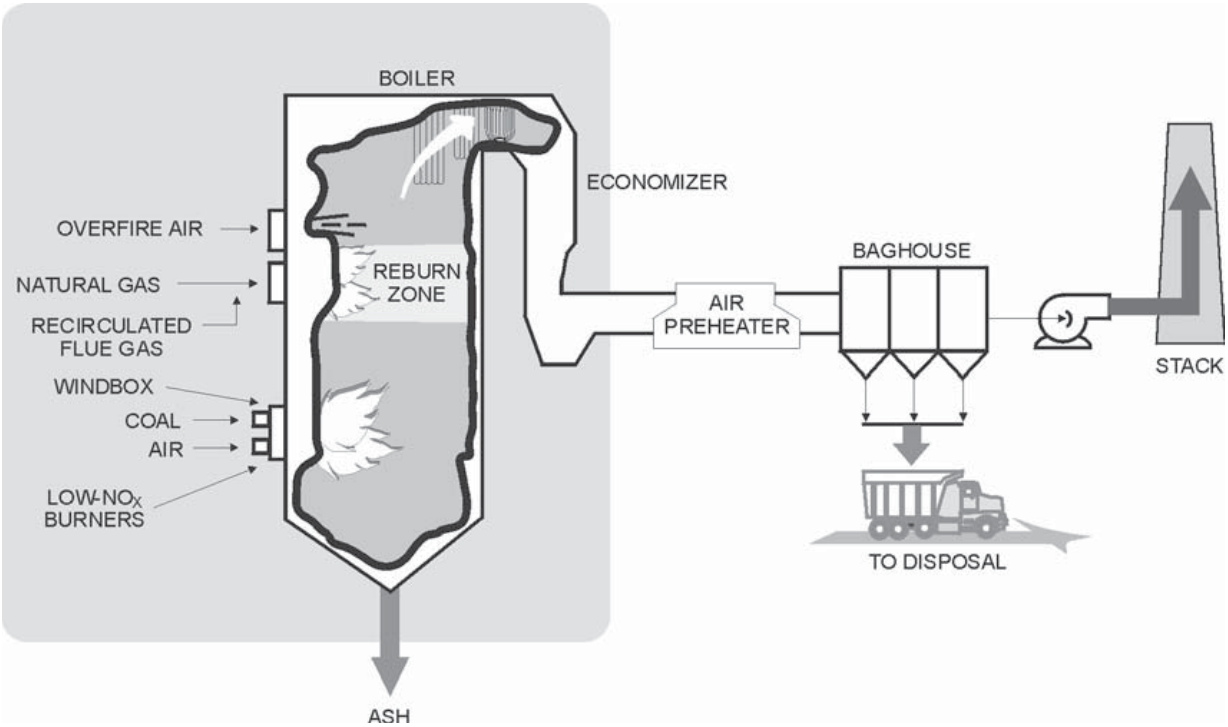
A.1.2.7.2 Conventional Gas Reburn

Natural gas has been preferred as the reburn fuel of choice. Natural gas has been utilized for reburn fuel in two basic approaches: conventional reburn and fuel-lean gas reburn. In the conventional approach, up to 30% of the boiler's total fuel heat input is supplied to the reburn zone, followed by a significant amount of overfire air for completion of combustion prior to flue gases exiting the boiler.

Conventional gas reburning in a cyclone-fired boiler has been available at Tennessee Valley Authority's Allen Station Boiler #1 (300 MW) since 1998. The reburn technology provider (vendor) claims NO_X emissions were reduced 67% from a full-load baseline of 1.29 (down to 0.42) lb/mmBtu when firing a blend of western bituminous and PRB coals[14]. Conventional gas reburn fuel input rates were not available from the technology vendor's literature. Another reference source of information stated NO_X emissions were reduced 65% from a full-load baseline of 0.86 (down to 0.30) lb/mmBtu with 7 percent of the total fuel heat input supplied as reburn fuel[9].

A schematic graphic of conventional gas reburn on a pulverized coal-fired boiler is shown in Figure A.1-2.

Figure A.1-2 Natural Gas Reburn Application on Wall-Fired Pulverized Coal Boiler with Overfire Air[8]



Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. For the most effective NO_X reduction by applying the various available forms of fuel reburn, the injection of fuel is usually performed using recirculated flue gas as a diluent and carrier media to aid dispersion and avoid completely oxidizing the carbon and nitrogen components in the fuel and furnace gases from staged burners/cyclones. Improved gas reburn designs have reduced or eliminated FGR with higher gas injection pressures. For lignite-fired cyclone boilers, reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reburn fuel will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture will disrupt the desired in-furnace nitrogen oxides reduction process.

It should be recognized that application of air-staged cyclones with basic or advanced forms of SOFA with reburn techniques will require the overfire air injection ports to be located at a somewhat lower elevation of the furnace compared with air-staged cyclones without reburning. This means that less air-staging of the cyclones may be practiced, or that less residence time will be available for the in-furnace NO_X reduction process to occur.

Similar to coal reburning, there are concerns that withholding a significant amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones for use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with conventional reburn and separated overfire air systems is the typical approach to avoid slag tapping problems. Natural gas reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Milton R. Young Station's Unit 1 boiler.

Although the unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages, using high-pressure natural gas for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 1's boiler.

A.1.2.7.3 Fuel Lean Gas Reburn

Another approach to gas reburning is "fuel-lean gas reburn" (FLGR™) technology, which injects limited amounts of natural gas (approximately 3-10 percent of the total fuel heat input) above the burners (or cyclones) with or without significant air-staging of the burners (cyclones) or the addition of overfire air upstream of the fuel injection elevation. FLGR's first field-test on a cyclone-fired boiler was at Commonwealth Edison's Joliet Unit 6 (327 MW), a 9-cyclone-furnace boiler[15]. NO_X emissions reduction with FLGR (without SOFA) was believed to be approximately 35-40% with 7% of the boiler's total fuel heat input supplied in the reburn zone. This test yielded 0.59 lb/mmBtu NO_X emissions from a baseline of 0.98[16]. One other cyclone boiler has been modeled using computational fluid dynamics (CFD) as part of a study looking at applying FLGR at Owensboro Municipal Utilities' Elmer Smith Station Unit 1 (150 MW single-wall, eastern bituminous coal-fired boiler). This model predicted that NO_X emissions could be reduced by 25-30% over that achievable from overfire air and SNCR[17].

More commonly, FLGR™ has been applied on medium to large pulverized coal wall-fired boilers burning eastern bituminous or western subbituminous coals. On Wisconsin Electric Power Company's (WEPCO's) Pleasant Prairie Unit 1, a 620 MWg Riley turbo-fired wet-bottom (slagging) boiler, FLGR™ alone was predicted to reduce NO_X emissions by 35-39 percent at a gas reburn rate of 7-8 percent but only achieved 20% from a baseline of 0.45 lb/mmBtu[16,18]. This is presumably without burner air-staging or SOFA. It has also been applied in combination with SNCR at this WEPCO site.

A potential advantage of FLGR™ over conventional gas reburn is that the former is generally compatible with, but does not require, the installation and operation of SOFA. The staged reburn fuel is introduced into an oxygen-rich atmosphere downstream of the burners and any OFA injection points. The amount of reburn fuel injected is typically limited by acceptable carbon monoxide levels in the boiler exit flue gas.

There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. This is significant, especially for alternatives with FLGR™ technology when combined with basic or advanced SOFA to allow the natural gas introduced above the SOFA ports to burn completely prior to the furnace exit plane. In either case, the amount of additional potential NOx reduction possible with FLGR™ is limited, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to the fuel-lean

reburn process in that it would require much higher reburn fuel injection rates in the lower secondary furnace to promote in-furnace NO_X reduction. There are reduced concerns that the withholding of a modest amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this reburn technique which will further risk slag "freezing" in the barrels and lower furnace.

Fuel lean gas reburn can be applied and installed on MRY Station Unit 1's boiler with or without SOFA/ASOFA. This technique is considered technically feasible for application to MRY Station Unit 1's boiler. Expected NO_X reduction will be modest for FLGR™ without SOFA and FLGR™ with a basic form of SOFA. Unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages. Because of these factors, these variations of this technology will not be cost-effective compared to other alternatives with similar control effectiveness. FLGR™ without SOFA and FLGR™ with a basic form of SOFA were not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of fuel lean gas reburning in combination with post-combustion technologies, such as amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.2.7.4 Fuel Oil Reburn

Fuel oil has been substituted for natural gas in a conventional reburn application. This is much less common in the United States than using natural gas as a reburn fuel, due to the general lack of demand and difficulties in supplying the volume of fuel oil which would be required. It has been installed commercially on three 350 MW oil-fired boilers in New Brunswick (Canada) at the Coleson Cove plant. NO_X emissions reduction with reburn and SOFA was 78% with 25% of the boiler's total fuel heat input supplied in the reburn zone. This yielded 0.22 lb/mmBtu NO_X emissions from a baseline of 1.0 lb/mmBtu[9]. No examples of conventional fuel oil reburn applied to a coal-fired cyclone boiler were found in available literature.

Fuel oil reburn could potentially be considered for application to MRY Station Unit 1 and Unit 2 boilers. Investigation of the specific source, distance, and costs for supplying significantly increased quantities of fuel oil via transport trucks hauling tanker trailers or underground pipeline to M.R. Young station has not

been performed. The unit operating and capital costs to supply large quantities of high-volume liquid fossil fuel at this site are economic disadvantages. The concerns regarding potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application are similar to those expressed for conventional gas reburn. It is believed that potential NO_X control with oil reburn would be slightly less than comparable conventional gas reburn systems.

Although fuel oil reburn could potentially be considered for application to MRY Station Unit 1's boiler, the lack of any distinct potential NO_X reduction advantages and demonstration on cyclone-fired boilers does not appear to support its consideration. This alternative was not included in the NO_X control and cost-effectiveness analysis.

A.1.3 Post-Combustion Controls

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO_X emissions after they have exited the boiler's lower furnace. In the case of Milton R. Young Station Unit 1, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic reduction (SCR) technologies. Another emerging technology that has recently entered the commercial market is Powerspan's Electro Catalytic Oxidation®, which treats utility boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury. Another emerging technology that has recently entered the commercial utility air pollution control market is Powerspan's Electro Catalytic Oxidation®, which treats boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury.

A.1.3.1 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR), and variations such as hydrocarbon-enhanced SNCR (sold under the trade name of NOxStar™), and Rich Reagent Injection (RRI), are all post-combustion types of boiler NO_X emission controls. While these technologies are insensitive to the specific fuel types whose combustion products are being treated, the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels. SNCR has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to cyclone boilers with or without the use of a SOFA system. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has

been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO_X emissions as much as 15-40% at full load, most typically between 25-35 percent[19].

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [$CO(NH_2)_2$] or ammonia [NH_3] reacts with the NO_X, forming N_2 and water, reducing NO_X emissions.

Long-term examples where SNCR has been used to reduce NO_X emissions on two cyclone-fired boilers are on a 138 MW unit and 160 MW unit burning eastern bituminous coal at Conectiv's B.L England Station (Units 1 and 2) since 1995 and 1996, respectively. Tests at these plants demonstrated that SNCR can decrease NO_X emissions as much as 30-36% at full load, from around 1.3-1.4 lb/mmBtu respectively to as low as 0.85 lb/mmBtu (without overfire air)[18,19,20]. These boilers, located near Atlantic City, New Jersey, continue to operate SNCR (with OFA) for annual NOx emissions around 0.55 and 0.45 lb/mmBtu, respectively.

SNCR can be applied and installed on MRY Station boilers. Estimated NO_X emission rates for using SNCR with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor predictions. SNCR alone is expected to reduce NO_X emissions approximately 37% from MCR baseline levels (down to around 0.5 lb/mmBtu) for the MRY Station Unit 1 boiler with ammonia slip limited to approximately 5 ppmvd. Because of the operating costs of the consumed reagent, this technology will not be cost-effective compared to other alternatives with similar control effectiveness (i.e. SOFA), SNCR alone was not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of SNCR-related technologies, such as Rich Reagent Injection with SNCR, and amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.3.2 Hydrocarbon-enhanced SNCR (NOxStar™)

Hydrocarbon-enhanced SNCR technology, commercially marketed as NO_XStar™, is offered by a single vendor (Mitsui Babcock) as a post-combustion type of enhanced SNCR technology, whereby an

ammonia-based reagent is continuously injected into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (typically either natural gas or propane) and air or steam to provide lance cooling and aid reagent dispersion. The targeted combustion gas temperature range is between 1500°F and 2000°F. The amount of gaseous hydrocarbon introduced is small enough (0.1 to 0.2% of total fuel heat input) that this is not intended to act as a form of reburn or staged fuel combustion. An array of permanently-installed injection lances are located within the boiler convection pass, divided into numerous discrete zones across the full width and height of the duct. The hydrocarbon auto-ignites, forming hydroxyl (OH) radicals which react with the NO_X and ammonia to produce elemental nitrogen (N_2) and water vapor (H_2O).

NO_XStar™ was demonstrated at Tennessee Valley Authority's Kingston Power Station Unit 9 (tangentially-fired 200 MW twin-furnace boiler firing eastern bituminous coal) in 2002[21]. This technology was subsequently permanently-installed at TVA's Colbert Station Unit 4 in late 2003 on a 192 MW wall-fired boiler burning eastern bituminous coal[22]. NO_X reduction was stated as 68-80% for these applications, which included the impact of overfire air and air-staged combustion upstream of the ammonia and propane injection locations.

An example of a hydrocarbon-enhanced SNCR installation on a wall-fired pulverized fuel boiler is shown as a sectional side elevation view of the upper furnace in Figure A.1-3.

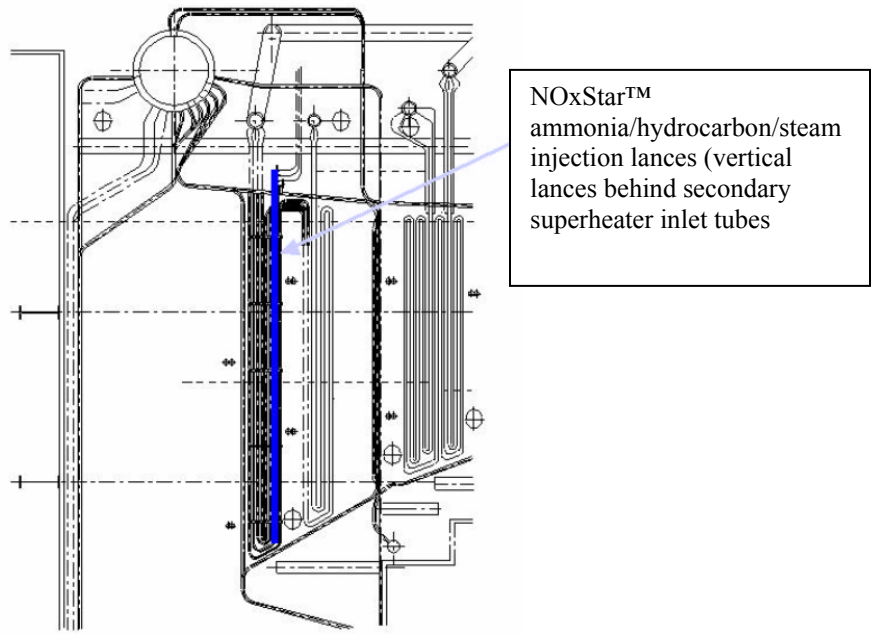


Figure A.1-3 Hydrocarbon-enhanced SNCR Application on PC-fired Boiler[22]

The supplier (Mitsui Babcock) of hydrocarbon-enhanced SNCR technology claims there is little sensitivity to the type fuel (coal) or burners this technique can be potentially applied to in order to reduce NO_X emissions. The chemical reagent injection for hydrocarbon-enhanced SNCR (NO_XStar™) NO_X control technology must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) model simulations are needed to determine the optimum injection points and spray patterns. Boiler operating conditions change with unit load and varying fuel characteristics. The NO_XStar™ process control system must be able to adjust for these changing conditions in order to be effective throughout the intended load range and firing conditions encountered. Non-retractable ammonia injection lances arranged in a parallel-series manner are permanently mounted inside the upper furnace zone, attached to convective tube elements. Different sections of the injection "grid" can be turned off or on, depending on load and firing conditions and amount of NO_X reduction required. Injection nozzles are continuously purged and cooled by extracted superheated steam from the boiler's main steam outlet, whether ammonia reagent is being introduced into the flue gas stream or not. Ammonia slip can be minimized by injecting less reagent, although NO_X control performance will be reduced.

There are a number of issues with firing North Dakota lignite that make the applicability of hydrocarbon-enhanced SNCR infeasible compared to previous experience in other coal-fired powerplants. These issues include:

- Hydrocarbon-enhanced SNCR (NOxStar™) technology has not been applied to cyclone boilers (with or without the use of a SOFA system). It has been only applied to date on pulverized coal-fired boilers burning eastern bituminous fuels.
- There is no successful demonstrated full-scale experience in continuous service of hydrocarbon-enhanced SNCR (NO_XStar™) technology on units firing high-slagging coals such as western subbituminous (PRB) and lignite. The heat transfer surfaces in the convective heat transfer zone where the reagent mixture is injected are prone to severe fouling from flyash constituents common in North Dakota lignite coals. Flyash deposit accumulation on the outside of the NO_XStar™ lances in Milton R. Young Station Unit 1 boiler's upper furnace is expected to be significant, potentially occurring within a matter of a few weeks from startup and nearly impossible to prevent or remove effectively during boiler operation. Such buildup is expected to cause maldistribution of the NO_X reduction chemical reagent from the injection nozzles. Effective on-line removal of these deposits from the injection nozzles is anticipated to be insufficient to maintain effective injection distribution and volume control. It is anticipated that this would significantly reduce the NO_X emission reduction performance consistently achieved on a sustainable basis.

The lack of experience with cyclone boilers, especially those firing coal with severe deposition characteristics such as North Dakota lignite, makes this technology technically infeasible for application on the Milton R. Young Station Unit 1 boiler.

A.1.3.3 Rich Reagent Injection (RRI)

Rich Reagent Injection (RRI) is a NO_X control process that has been developed and demonstrated specifically for use on cyclone boilers. Rich Reagent Injection is an SNCR process that involves the injection of aqueous urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace in Figure A.1-4.

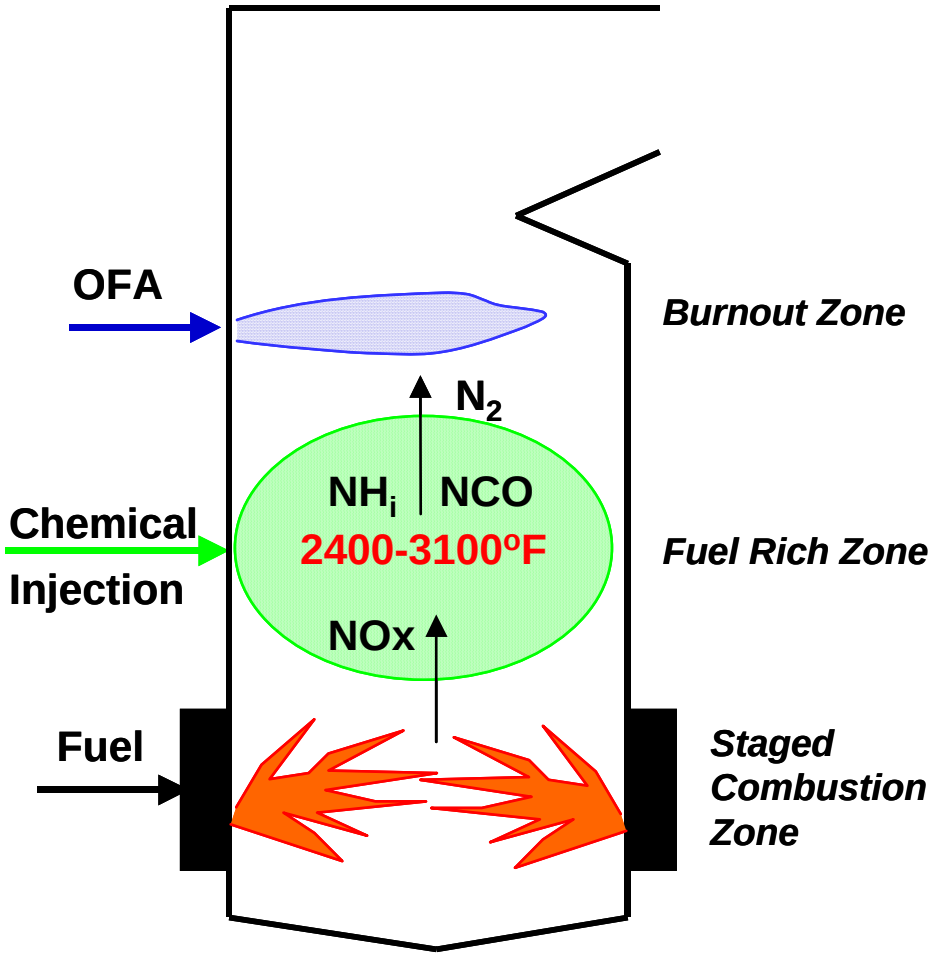


Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air[23]

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit 1, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals. Generally, the heat content of these coals typically varies very little. Short-term testing of the RRI process has been performed alone and in combination with SNCR on B.L. England Unit 1 in 1999[24,25], and more recently at Ameren's Sioux Unit 1 in 2002[23,25], in 2004[26] (alone), and in the first half of 2005[27] (alone, and with SNCR).

The RRI process is intended to be used only with air-starved (substoichiometric staged-air) cyclone combustion, in conjunction with the installation and operation of an OFA system. The RRI process has not been demonstrated on any unit that fires North Dakota lignite. As of May 2006, no commercial installation of a permanent Rich Reagent Injection system has been made at any cyclone-fired boiler.

There is only one holder of a commercial license for modeling and conceptually designing RRI (Reaction Engineering International), with two vendors sub-licensed to design and sell RRI equipment (Fuel Tech and Combustion Components Associates). Since these license agreements are in place, and considering that successful demonstration testing has been performed at two cyclone-fired boiler powerplants, this technology is considered to be applicable and commercially available for potential application on cyclone boilers which burn coals with heat contents that are relatively constant. However, due to the variable heat content of lignite coal, RRI is considered to be technically-infeasible for application on North Dakota lignite-fired boilers. Technical feasibility and expected NO_X emissions from RRI for application on the Milton R. Young Station Unit 1 boiler are included in the "Layered NO_X Reduction Technologies" section.

A.1.3.4 Selective Catalytic Reduction (SCR)

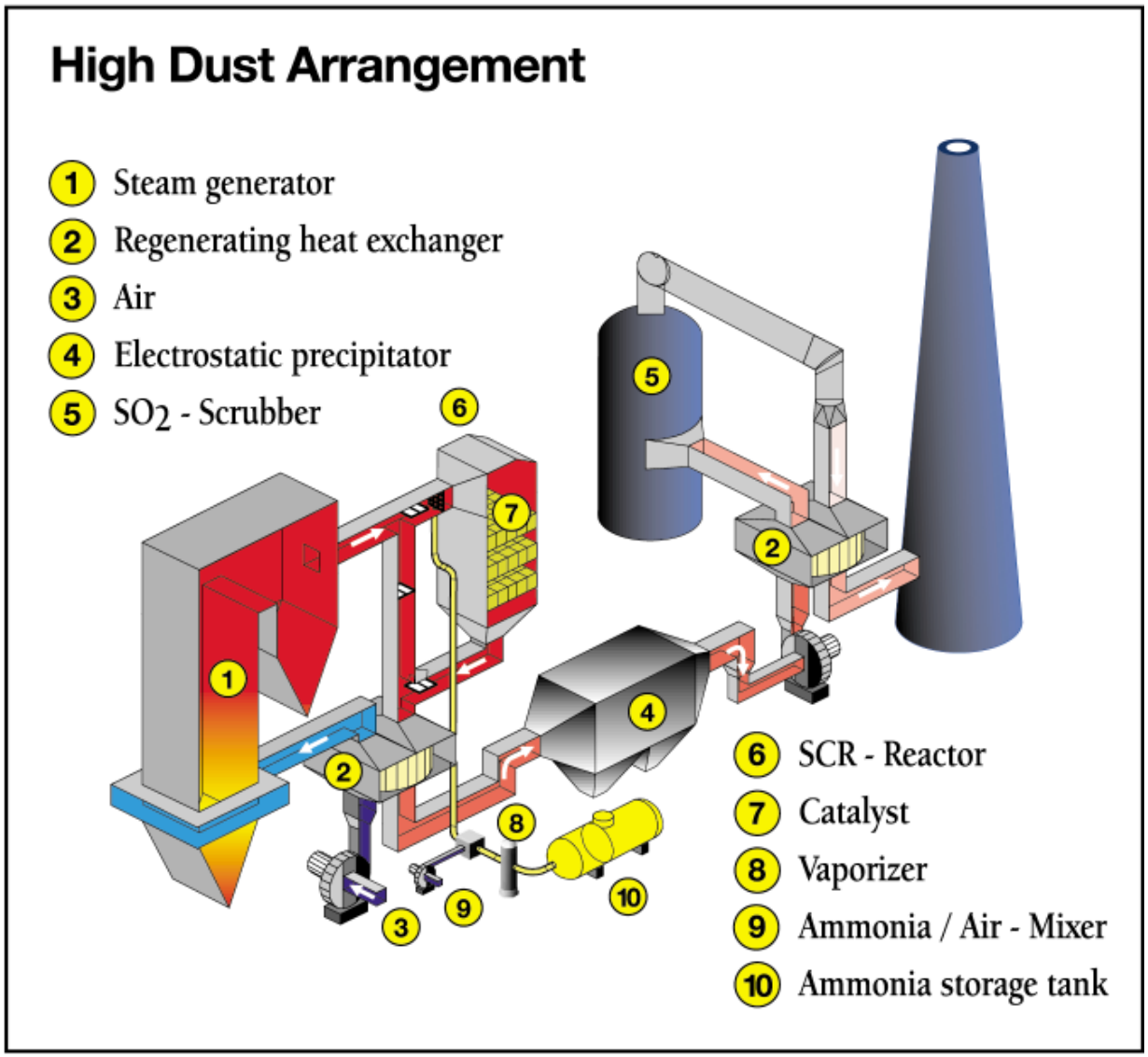
The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_X to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A catalyst is used to enhance NO_X reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. These are described below.

A.1.3.4.1 High-Dust Selective Catalytic Reduction (HD-SCR)

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst. The conventional SCR reactor arrangement is preferred for most coal-fired applications in utility boilers because it avoids the added expense of reheating the flue gas if placed after the air heaters which cool the flue gas, and downstream of any flue gas treatment to remove acid gases. Conventional SCR technology uses an ammonia injection grid (AIG), which consists of multiple nozzles, for distributing the reagent into the flue gas at the boiler's economizer flue gas outlet.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

Figure A.1-5 Conventional High-Dust SCR Arrangement with FGD Scrubber Outlet Reheat



(figure copied from Wheelabrator Air Pollution Control literature)

Conventional high-dust, hot-side SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. There are also a limited number of European SCR installations on steam electric generating units (SEGUs) firing lower grade (brown) coal. There are, however, no existing full-scale SCR installations on units that fire North Dakota

lignite. There are approximately 50 cyclone-fired units located in the states affected by EPA's NO_X SIP call. Over half of these units are planning to install conventional high-dust, hot-side SCR systems in response to the SIP call. The installation of conventional high-dust, hot-side SCR systems has been completed on approximately 22 of these units. Appendix A2 lists several conventional high-dust hot-side U.S. SCR installations on pulverized coal and cyclone-fired utility boilers, along with measured NO_X emissions. Initial data from these units indicate that conventional high-dust, hot-side SCR systems operated on suitable cyclone-fired units may be able to reduce NO_X emissions to as low as 0.07 lbs/mmBtu. Several SCR installations have been retrofit on existing cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

The EPA NO_X SIP call only applies to units in the eastern United States. There are no facilities firing North Dakota lignite in the EPA NO_X SIP call region. SCR system operation is currently only needed during the ozone season (June – September) for units installing control equipment solely to meet the EPA NO_X SIP call requirements. Limited annual operation is a significant factor with respect to SCR equipment reliability, maintenance, operational costs, and catalyst life. The demands on the SCR system are much more severe if the equipment is required to operate on a full-time, annual basis.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO_3:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO_x emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 5 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period.
- SO_3: Due to the composition of typical SCR catalysts, a small percentage of inherent SO_2 will be oxidized to SO_3. This oxidation can be controlled by catalyst selection and can be less than one percent. SO_2 to SO_3 oxidation must be carefully controlled to avoid creating SO_3 levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO_3 oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ($(NH_4)_2SO_4$) and liquid ammonium bisulfate (NH_4HSO_4). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO_X emissions, control ammonia slip, and minimize SO_2 oxidation.

Recent technology has allowed catalyst suppliers to make more rigorous and lengthy guarantees. A reasonable initial operating period for conventional catalysts in high-dust reactor arrangements on boilers firing eastern or midwestern bituminous coal is around 24,000 active operating hours (i.e. when ammonia reagent is being injected). Factors that need to be taken into account in design of a high-dust, hot-side SCR application that affect the need for catalyst replacement are:

- Pressure drop: The amount of restriction to flue gas flow through the SCR inlet, ammonia injection grid, SCR reactor, and downstream ductwork directly increases induced draft fan horsepower required to maintain adequate boiler draft. This is an important parameter to consider and minimize during the design stage. Pressure drop is a function of the average and maximum SCR reactor duct velocities, the amount of restriction caused by flow distribution correction devices (baffles or vanes), and the number and geometrical aspects of the catalyst layers. Many retrofit SCR installations require a booster fan or upgraded induced draft fan to overcome the added flow resistance. This increases operating cost for the increase in auxiliary power consumption and loss of saleable electric power. The type and pitch of the catalyst are factors most influential in determining the amount of pressure drop.
    - Catalyst type: The most common types or forms of catalyst material are honeycomb or plate. The former offers more surface area per volume, but can be more restrictive and prone to pluggage from ash deposits. The latter is usually less restrictive but requires more catalyst per layer or more layers to achieve the active surface needed to achieve the intended NO_X emission reduction.
    - Catalyst pitch: The pitch of the catalyst, a term used to describe the size of the gas path openings through the catalyst, varies depending on the manufacturer and design dust loading. Pitch is generally on the order of 5 to 7 millimeters. Potential pluggage of flow channels within the catalysts layers is therefore an issue that must be dealt with during design.
- Catalyst performance: The amount of NO_X emission reduction expected is a function of the specific activity level of the catalyst material and the amount of catalyst installed, over a given period of time. Catalyst formulation selection and features of construction have a significant impact on long-term NO_X emission reduction and subsequent costs for reagent and catalysts replacement. The frequency of catalyst replacement is influenced strongly by:
    - Catalyst erosion: Erosion of the catalyst material in coal fired units from entrained flyash or sootblowing action reduces the amount of active surface available for reacting with the reagent and flue gas, and can cause distortions in gas distribution ("channeling") through the

SCR reactor. Catalyst material is fragile and can be easily damaged. Some catalyst is provided with erosion-resistant top edges to mitigate this tendency.

- Moisture absorption: Many types of catalyst are damaged by absorption of moisture. The reactor must be kept above ambient dewpoint temperatures or protected from freezing during outages in order to protect the catalyst from moisture damage. Spare catalyst must be carefully packaged to keep it dry and must be handled delicately to prevent damage.
- Thermal degradation: The specific active elements of the catalyst surface, or the matrix structure itself upon which the catalyst material is applied, can degrade when exposed to flue gas temperatures greater than the intended design of the formulation. High flue gas temperatures within the reactor causes sintering, leading to a permanent loss of catalyst activity due to a change in the pore structure of the catalyst. Proper selection and manufacturing control of the catalyst structure and formulation can minimize thermal degradation.
- Catalyst poisoning: The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Two elements especially detrimental to the life of common titanium-supported vanadium pentoxide SCR catalyst are arsenic and zinc. Vanadia/tungsten-based catalysts are particularly susceptible to rapid deactivation due to gaseous arsenic poisoning. In some German SCR installations, a 50% loss of activity has been reported within 10,000-15,000 operating hours. Addition of molybdenum to a vanadia-titanium SCR catalyst on similar applications shows relative activity reductions of 20-25%. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to poisoning is not possible to restore without effective cleaning to remove the deposits, or eventual replacement.
- Catalyst fouling: The surface area potentially exposed to the reagent (ammonia) and nitrogen oxides in the flue gas can become fouled with flyash or sulfur-related compounds. The presence of excess calcium oxide in the presence of sulfur in the flue gas can form a calcium sulfate surface coating that can be extremely dense, masking the pores of the catalyst. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to fouling is difficult to restore without effective cleaning to remove the deposits, or eventual replacement.

SCR technology has been installed on numerous coal-fired utility boiler facilities around the world and there are a large number of manufacturers that market the catalysts. The question is whether SCR is a

feasible technology for a unit firing North Dakota lignite. There are serious concerns whether installation of SCR technology on a North Dakota lignite-fired unit can be successful, especially in a conventional "hot-side, high-dust" configuration. The effectiveness of the SCR process is highly dependent upon the ability of the nitrogen oxides in the flue gas being able to contact the active sites within microscopic pores of the catalyst in the presence of ammonia reagent with minimal interference from contaminants.

A recent technical paper "Ash and Mercury Behavior in SCR Catalysts When Firing Subbituminous and Lignite Coals" by the Energy & Environmental Research Center (EERC) of the University of North Dakota was published in the February 2005 issue of Fuel Processing Technology magazine[28]. This paper summarized the results of SCR slipstream testing at two PRB-fired plants and one North Dakota lignite-fired powerplant. The evaluation included determination of impacts of ash on SCR plugging and blinding. Flue gas was isokinetically extracted from the convective pass of the boiler upstream of the air heater. Pressure drop across the catalyst was measured during the initial two-month test period, and the two consecutive two-month test periods following the initial trial, while holding flue gas flow and temperatures constant. Ammonia was injected downstream of a screen, upstream of a flow straightener and air pulse section. Compressed air was injected ahead of the reactor, and was periodically pulsed to simulate sootblowing to minimize ash deposit accumulation.

This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels. Very small flyash particles were found bonded together by a matrix of sodium-, calcium-, and sulfur-rich materials, likely in the form of calcium sulfate. North Dakota lignite coal contains many alkali and alkaline-earth elements, and sulfur. The firing of lignite coal which produces fine (less than 5-µm diameter) flyash particles creates conditions that enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

As posted on Electric Power Research Institute Inc.'s (EPRI's) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study[29] produced field data analyzed from an "In-Situ Mini SCR Reactor" system installed in a typical "high-dust" location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas

temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one of the PRB-fired sites with two different catalysts, deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

North Dakota lignite produces an ash that is very sticky and creates severe ash deposition problems. There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite. A technical assessment was conducted for the installation of SCR technology on a North Dakota lignite unit. In order to further evaluate the feasibility of installing a conventional SCR system on a North Dakota lignite fired unit, the Energy & Environmental Research Center (EERC) at the University of North Dakota was consulted. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash.

Technical difficulties and anticipated operating problems that are unresolved with respect to installing conventional SCR technology at Milton R. Young Station include the impacts of erosion, severe ash deposition, and "popcorn ash" on the catalyst. According the EERC's study (see Appendix B), "the most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium-calcium-magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency". For these reasons, application of available conventional high-dust SCR technology is considered technically infeasible for Milton R. Young Station Unit 1 and Unit 2 boilers. These concerns can be divided into four categories. Each category is addressed below. An explanation of the factors that make conventional SCR technology infeasible for these boilers follows:

1. Ash Deposition: North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. This fuel produces ash with severe deposition characteristics that are not typical with other coals. When exposed to the heat of the combustion process inside the cyclone burners, the majority of the fuel ash becomes molten and flows into the bottom of the furnace. A significant portion of the fuel ash is entrained into the flue gas exiting the cyclone barrels at high velocity, where it comes into contact with the lower furnace waterwalls. The portion that is carried with the rising flue gas cools and some is deposited on heat transfer surfaces in the upper furnace and boiler convection pass. Ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite. The problem is so severe at Milton R. Young that the Unit 1 boiler must be shut down at 120-day intervals to

allow for cleaning of ash deposits from the boiler heat transfer surfaces in order to restore reasonable furnace exit gas velocities and temperatures.

Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. Sodium content of the lignite ash averages approximately 4.4%, and can nearly double this value for some of the lignite produced from the Center mine. PRB coal typically averages around 1.5% sodium content. Boilers firing North Dakota lignite typically have a 2.5% higher heat rate (million Btu per kilowatt of electric generation) than a typical boiler firing PRB coal, thus requiring more heat input and firing more fuel per megawatt of electricity output. A cyclone boiler firing North Dakota lignite also converts approximately 50% of the fuel ash to flyash, compared with a 35% conversion rate for PRB coal-fired cyclone boilers. Overall, this results in an amount of sodium emitted from a cyclone boiler firing North Dakota lignite of approximately 7.3 lbs/MW-hr compared with 0.9 lbs/MW-hr for a PRB-fired cyclone boiler.

The catalysts in coal-fired boiler SCR reactors are highly susceptible to ash deposition. In a typical conventional high-dust SCR reactor, the flue gas typically passes through two to four layers of catalyst modules. The catalyst modules have numerous narrow passages to provide intimate contact between the flue gas, ammonia and catalyst. The clearance (pitch) in these passages is typically 6-10 millimeters. A typical catalyst layer is approximately 1 to 1.5 meters deep. The catalysts in coal-fired boiler SCR reactors must be cleaned frequently using soot blowers and/or sonic horns. This is true even on units firing fuels that do not produce a sticky ash that contributes to ash deposition. Ash deposition on the catalyst in a high-dust SCR application would be severe for a unit firing North Dakota lignite.

Sulfur in the coal is oxidized during excess air combustion to form sulfur dioxide (SO_2), and a small amount of sulfur trioxide (SO_3). Some of the ammonia-based reagent injected upstream of the SCR reactor will combine with SO_3 to form ammonium bisulfate. The catalyst in the SCR reactor will also oxidize a portion of the SO_2 to SO_3. Excess unreacted ammonia reagent carryover ("ammonia slip") from the SCR reactor will also react with these sulfuric acid compounds in a similar fashion. The deposition characteristics for a unit burning North Dakota lignite will create difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst, and increase the probability that the air preheater downstream and flue gas ductwork will be prone to accumulations which could be severe. High-dust SCR performance and catalyst life

will be severely impacted. It is anticipated that a high-dust SCR's catalyst life will be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement.

Hot-side air preheaters are susceptible to fouling. Tubular air pre heaters originally supplied with all cyclone boilers also tolerate moderate dust loadings, since their height and size make them difficult to maintain cleanliness. Leak tightness of the air preheater is important on cyclone-fired boilers with relatively high forced draft fan discharge (combustion air supply) pressures. A high-dust SCR installation will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

2. "Popcorn Ash": A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. Boilers firing North Dakota lignite have severe problems with ash deposition on boiler surfaces. North Dakota lignite has a high propensity to form deposits on the boiler's furnace and convection pass fireside surfaces. For lignite-fired units, the boiler's heat transfer surfaces must be cleaned by sootblowing and other methods (e.g. water lances) frequently to maintain satisfactory boiler operation. Some of the removed deposits released by the cleaning action within the boiler and convection passes form "popcorn ash", which will be entrained in the flue gas. Carry over of boiler ash deposits will contribute to pluggage of the "popcorn ash" screen ahead of the top layer of SCR reactor catalyst. This can cause distortions in gas distribution ("channeling") through the SCR reactor, which will aggravate erosion in the high velocity areas and ineffective performance of the catalyst.

3. Temperature: A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units is catalyst operating temperature. The performance of any SCR catalyst is highly dependent on the temperature of the flue gas passing through the reactor. Typically, a temperature of 600 – 750 degrees F is required to obtain satisfactory operation of an SCR reactor. Operation of commonly supplied catalyst suitable for a high-dust SCR reactor at temperatures above 750 degrees results in severe and rapid deterioration of the catalyst and SCR reactor's NO_X emission reduction performance. For bituminous and sub-bituminous coal-fired units, boiler flue gas passing between the economizer outlet and air heater inlet is generally

within a temperature range acceptable for conventional SCR catalysts without additional heating or cooling of the flow stream.

North Dakota lignite-fired cyclone boilers, including those at Milton R. Young Station, have high temperatures at the economizer's flue gas outlet by design. The highest gas temperatures downstream of the convection pass economizer sections and upstream of the air heater inlets in Milton R. Young Unit 1's boiler are much higher than 750 degrees.

High gas temperatures at the air heater inlet are required to produce the high air temperatures (700°F) needed for the pre-combustion lignite drying system, along with primary and secondary combustion air supplied to the cyclones. Such air preheater arrangements and capabilities have been taken into account in the design of the North Dakota lignite-fired cyclone boilers. Reducing this high gas temperature to accommodate conventional catalysts for a conventional high-dust SCR reactor would result in pre-combustion air temperatures that are too low to provide satisfactory drying and rapid ignition of the high-moisture fuel. This will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, it is not feasible to modify the Milton R. Young Unit 1's boiler to operate with the lower economizer outlet flue gas temperature.

Catalysts for a conventional high-dust, hot-side SCR system have not been installed nor successfully demonstrated in a full-scale installation of an operating solid fuel-fired unit that are designed to continuously operate at the high temperatures (above 750 degrees F) that exist between the convection pass economizer and air heater on the Milton R. Young Unit 1's boiler.

4. Erosion: A final consideration on whether hot-side, high-dust SCR technology can be successful on a North Dakota lignite-fired unit is the potential for erosion of the SCR catalyst. North Dakota lignite supplied from the Center mine has an average fuel ash content of 10.5%, and can have an ash content up to 25.5 percent. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MW-hr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream can result in physical erosion of the catalyst. In addition, effective on-line cleaning of the

high-dust catalyst will likely require steam or compressed air sootblowing. Cleaning cycles of the catalyst will be required much more frequently than a typical conventional SCR installation due to the ash deposition characteristics of the North Dakota lignite and the expected buildup and pluggage resulting from the carry over of "popcorn ash". Frequent sootblowing of the catalyst to remove fouling deposits and ash accumulations will contribute to erosion and decreased catalyst life. There is some European experience with high ash brown coals that catalyst manufacturers will be able to draw upon. This experience, however, will not be directly applicable to these United States units because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

The EPA's NSR Manual states that for a technology to be feasible it must "available and applicable". SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is "applicable" for a unit firing North Dakota lignite.

In accordance with EPA's NSR Manual, a technology is "applicable" if it has been installed on a "similar unit". Hot-side, high-dust SCR technology has been retrofit on coal-fired units featuring cyclone boilers. However, there are no SCR installations in operation or planned on units that include cyclone burners firing North Dakota lignite with severe slagging and fouling tendencies combined with such high boiler economizer outlet gas temperatures (over 750°F) required for high-moisture fuel pre-drying systems and tubular air preheaters.

The EPA's NSR Manual also states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique." In this SCR technology application, it appears that a facility utility powerplant firing North Dakota lignite would experience extended time delays or be required to devote significant internal resources and engage outside research, followed by extended field trials to learn how to apply a conventional high-dust, hot-side SCR technology on a such a fuel source.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology on a North Dakota lignite-fired steam-electric

generating unit, this control option is considered technically infeasible for Unit 1's boiler at Milton R. Young Station.

A.1.3.4.2 Low-Dust Selective Catalytic Reduction (LD-SCR)

Low-dust SCR (LD SCR) technology could potentially be applicable to North Dakota lignite-fired boilers for NOx emission control. Low-dust SCR refers to the location of the SCR system downstream of a particulate collection system, such as an electrostatic precipitator or a fabric filter. If the low-dust SCR is downstream of a hot-side electrostatic precipitator and prior to the air preheater, flue gas reheating is unnecessary. This has been the prevalent form of alternative retrofit SCRs in the United States for coal-fired utility boilers. There are ten known hot-side low-dust SCR installations (without flue gas reheat) operating in the United States as of July 2005. These are listed in Appendix A2. If applied to MRY Station Unit 1's boiler, the low-dust SCR equipment would be downstream of a cold-side electrostatic precipitator; flue gas reheat prior to the LD SCR reactor inlet would be required for proper NO_X emission reduction performance.

For a cold-side LD SCR, the ESP outlet flue gas passes through a low-dust gas-to-gas heat exchanger (LD GTG-HE), prior to passing to the low-dust SCR reactor. After the LD GTG-HE, the flue gas will travel through the new duct, receiving hot flue gases from a direct-fired gas burner or set of high-pressure steam coils, leading to an ammonia injection grid, turning vanes and then into the LD SCR reactor. The flue gas entering the inlet to the LD GTG HE is expected to be near the air heater outlet temperature (330-340°F) in a cold-side LD SCR application. The supplemental heat added downstream of the LD GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the LD SCR NO_X–ammonia reaction to be effective. The LD gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the FGD system (if applicable) and stack. The use of rotary regenerative-type heat exchangers has been applied in European LD SCRs. With this design, there will be leakage between the untreated and treated gas streams such that the exit flue gas has higher NO_X concentrations than the LD SCR outlet gas. The direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the LD SCR reactor. The LD SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

The factors that make low-dust SCR technology infeasible for the Milton R. Young Station Unit 1's boiler with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: An existing electrostatic precipitator upstream of a low dust SCR reactor will still expose the catalyst to the acid gas content and fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the LD-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the low-dust SCR catalyst life will still be unacceptably short. The small particle flyash passing into the reactor will be sufficient to cause pluggage of the catalyst pores, resulting in deactivation of the catalyst. The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of a low-dust SCR. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. One catalyst vendor's has stated it is their "experience that low-dust catalyst is more difficult to clean than that from high-dust"[30]. Low-dust SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.
- Site Space Constraints: The installation of a low-dust SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A low-dust SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the SCR reactor outlet to the flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the cold-side low-dust SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where low-dust SCR systems must be located. The situation is particularly severe for Unit No. 2. Equipment that impacts the feasibility of installing a low-dust SCR system on Units 1 and 2 includes the Unit 2 absorbers, Unit 2 flue gas desulfurization (FGD) dewatering equipment, fly ash handling equipment, fuel storage and transfer equipment, stacks, fans and ductwork. It would be extremely

disruptive to the continued economic operation of both boilers to relocate all the mentioned equipment to create space for the low-dust SCR systems at the M.R. Young Station. Stacks, fans and ductwork and the Unit 2 FGD system cannot be readily relocated due to adjacent structures and the need to continue operation while constructing the retrofit installations. The fuel handling equipment includes a coal storage barn and the main conveyors supplying lignite to the units. Relocating the coal handling equipment currently occupying space needed for the low dust SCR systems would be quite difficult given the site configuration. It is conceivable that the fly ash equipment located west of Unit 1 could be relocated to provide some of the space needed for the low-dust SCR. However, the availability of this space is doubtful, since avoiding the likelihood of severe SCR catalyst sulfate fouling will require a new Unit 1 FGD system to be installed. If a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a low-dust SCR system.

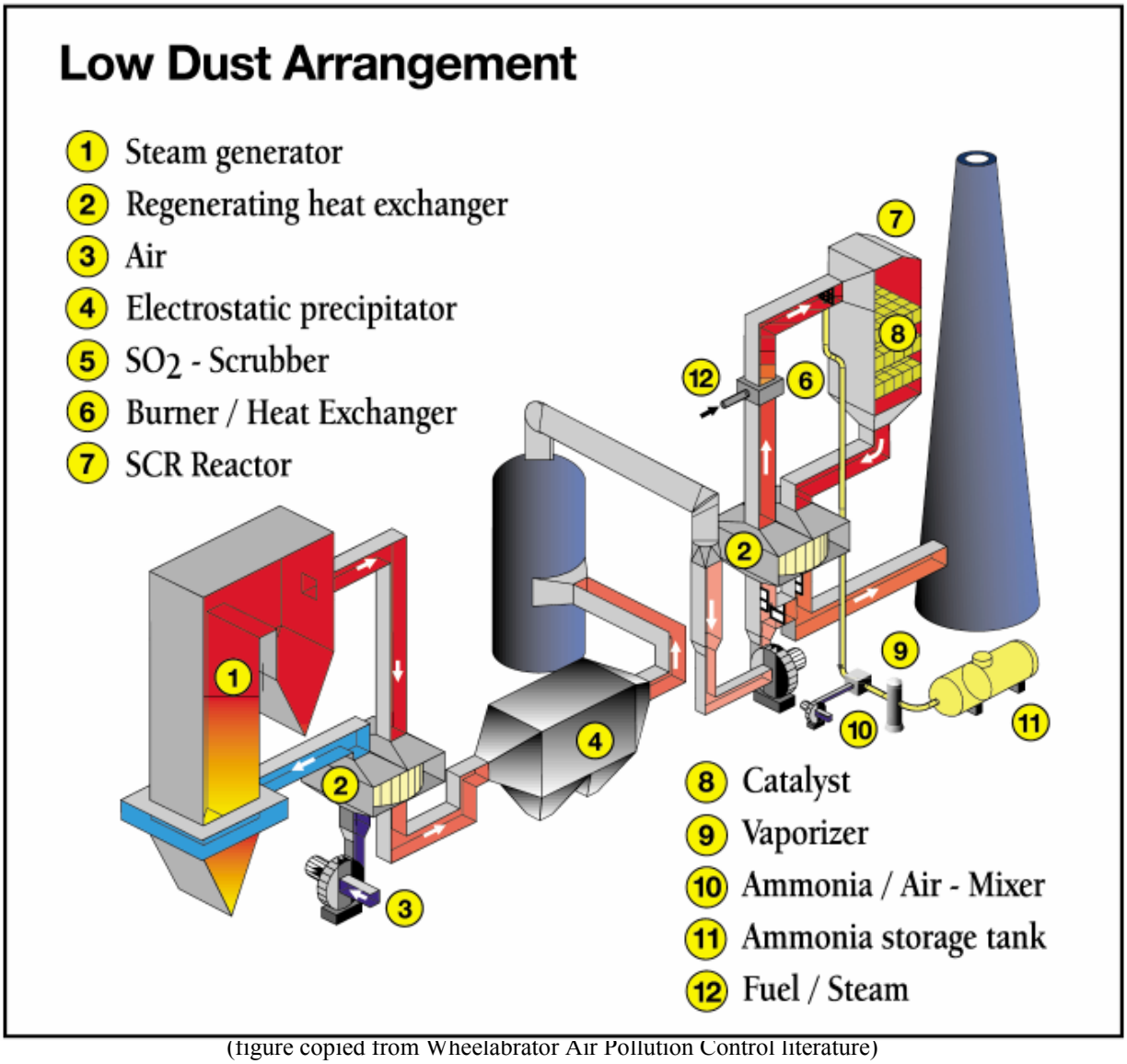
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of low-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for the Milton R. Young Station Unit 1's boiler.

A.1.3.4.3 Tail-Gas Selective Catalytic Reduction (LD-SCR)

A tail-gas (TG) SCR is a low-dust SCR system where the LD SCR reactor is installed downstream of a FGD scrubber. The FGD outlet flue gas passes through a gas-to-gas heat exchanger (GTG-HE), prior to passing to the tail-gas SCR reactor. The flue gas will travel through new or modified ductwork leading to an ammonia injection grid, turning vanes and then into the TG SCR reactor. The TG SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

A schematic graphic diagram for a low dust arrangement is shown in Figure A.1-6.

Figure A.1-6 Tail-Gas SCR Arrangement



(figure copied from Wheelabrator Air Pollution Control literature)

The flue gas from a wet FGD scrubber outlet entering the inlet to the gas-to-gas heat exchanger is expected to be near the saturation temperature (140°F) in a cold-side TG SCR application. The supplemental heat added downstream of the TG GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the TG SCR NO_X– ammonia reaction to be effective. The TG gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the stack. With a rotary regenerative-type gas-to-gas heat exchanger, there will be internal leakage between the untreated and treated gas streams such that the stack exit flue gas has higher NO_X concentrations than the

TG SCR reactor outlet gas. Using direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the TG SCR reactor.

There is limited technical information published in English for coal-fired steam-electric generating units (SEGU) with low-dust/tail-gas SCR technology in applications requiring full flue gas reheat prior to the reactor inlet. There is no experience with TG SCR on eastern bituminous, western subbituminous coal or lignite-fired SEGUs in the United States. As of 1997, there was one low-dust/tail-gas SCR on a 220 MWe German cyclone-fired boiler with a 1988 retrofit installation. This boiler was reported to be operating without combustion controls or FGD, burning low sulfur, low ash, moderate moisture bituminous coal with an average pre-SCR NO_X emission rate of approximately 1.07 lb/mmBtu, and was meeting a 30-day rolling average emission limit of approximately 0.16 lb/mmBtu (85% reduction)[31].

Milton R. Young Station Unit 1 does not currently incorporate any flue gas desulfurization equipment, which would place the reactor catalyst in a low-dust SCR configuration, which is considered infeasible when burning North Dakota lignite. A new FGD system for Unit 1 would be required in order to avoid or significantly reduce expected sulfate formation within the catalyst and gas-to-gas heat exchanger when combined with ammonia required for the TG SCR. Unit 2 currently employs a wet scrubber which currently treats approximately 83% of the total flue gas flow from the boiler. Flue gas reheat is currently provided by the FGD bypass (i.e. warm, untreated flue gas is mixed with the cool scrubbed gas).

The factors that make tail-gas SCR technology infeasible for both Milton R. Young Station boilers with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: The TG SCR reactor downstream of a flue gas desulfurization (FGD) scrubber will still be susceptible to fouling, contamination, pluggage, and catalyst deactivation.
    - An existing electrostatic precipitator (ESP) upstream of a tail-gas SCR reactor will still expose the catalyst to fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the TG-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the tail-gas SCR catalyst life will still be unacceptably short.
    - The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of

a TG-SCR. Flue gas with entrained fine particulate matter, including some involving sodium and sulfur-containing compounds, will pass through and be carried-over from a wet FGD scrubber. This treated gas stream will carry sodium sulfate particles, formed by homogenous condensation after exiting the boiler and not removed by the FGD system, into the catalyst layers of the TG-SCR reactor. A dry FGD system followed by a fabric filter upstream of the TG-SCR will still allow sulfur-bearing flue gas and fine particles to enter the catalyst. There is serious concern that fine particles passing into the reactor will accumulate within the catalyst, and be resistant to removal by conventional sootblowers and other cleaning technologies. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_2 and/or SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. Catalyst that is exposed to such conditions will be ineffective at maintaining adequate activity upon which the performance of the TG-SCR's NO_X removal is based.

- These entrained particles will also deposit on the gas-to-gas heat exchanger ahead of the tail gas SCR reactor. This deposition will decrease heat transfer between the incoming (cool) flue gas and the outgoing (warm) flue gas. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the SCR reactor could still suffer catalyst fouling from the deposits dislodged from the GTG HE cleaning cycle becoming reentrained in the reheated flue gas. Tail-gas SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the TG SCR catalyst will require premature, extended, frequent outages for replacement.

- Site Space Constraints: The installation of a tail-gas SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A tail-gas SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the TG SCR reactor outlet to the scrubbed flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the TG SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR system is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where TG SCR systems must be located. A flue gas desulfurization system will be needed for Unit 1 in the

near future to comply with the Consent Decree. When a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a tail-gas SCR system. Thus, the availability of adequate space for all the new FGD and TG-SCR system equipment and structures while accommodating existing coal storage and handling needs for both existing boilers at Milton R. Young Station is doubtful.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment and the lack of pertinent experience with all aspects of design, construction, operation and maintenance of tail-gas SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the TG-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, tail-gas SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

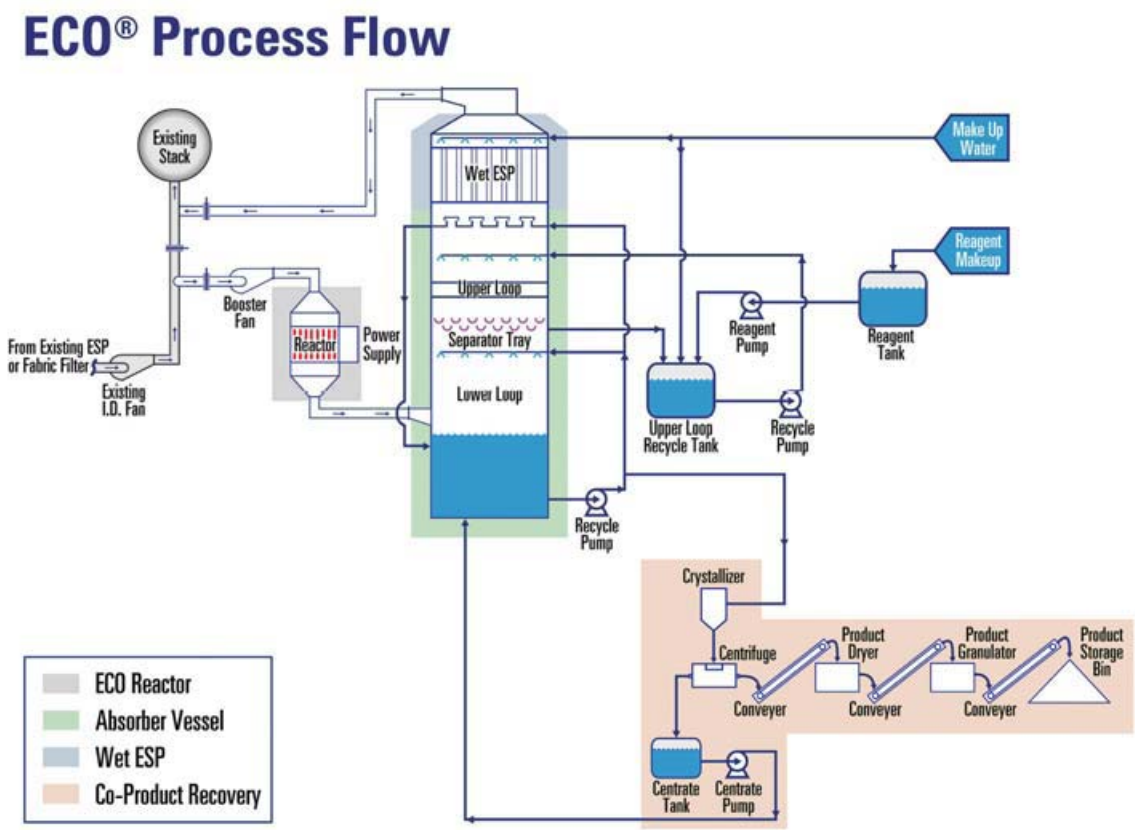
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of tail-gas SCR technology on a North Dakota lignite-fired steam-electric generating unit including a cyclone boiler, this control option is considered technically infeasible for the Milton R. Young Station Unit 1's boiler.

A.1.3.5 Electro-Catalytic Oxidation (ECO®)

Powerspan's Electro-Catalytic Oxidation (ECO®) system is a multi-pollutant technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO® process has two main process vessels, a barrier discharge reactor, and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO_X, and other constituents in the flue gas stream. The flue gas stream then enters the bottom of the ECO® scrubber where the lower loop cools the flue gas and removes a portion of the acid gasses [sulfur trioxide (SO_3), sulfuric acid (H_2SO_4), nitric acid (HNO_3)] produced in the barrier reactor and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO_2, NO_2, acid gases and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final

step in the ECO® process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury. An updated schematic process flow diagram for the basic ECO® process is shown in Figure A.1-7.

Figure A.1-7 – Electro-Catalytic Oxidation (ECO®) Process Flow Diagram
(copied from http://www.epa.gov/appcdwww/aptb/EPA600R03110.pdf)



Powerspan has been involved in an extended ECO® process demonstration using a 28 MW Commercial Demonstration Unit (CDU) at R.E. Burger Station Units 4&5. The ECO® CDU project treated a slipstream and demonstrated performance, reliability and economics for approximately one year. The demonstration program started in January, 2004. NO_X removal is stated to be up to 90% with a claimed 0.05 lb NO_X/mmBtu outlet condition achievable for the front-end of the ECO® process. Further sustained operational tests of the ECO® CDU are underway during the second and third quarters of 2005.

As this is a post-combustion multi-pollutant control technology, it is claimed that there is little sensitivity to the type boiler or burners that Powerspan's Electro-Catalytic Oxidation (ECO®) process can be

potentially applied to in order to reduce NO_X emissions. The effectiveness of this ECO® process for NO_X control has been demonstrated on a slip-stream commercial demonstration unit (CDU) associated with pulverized fuel boilers firing midwestern or eastern bituminous coal.

Powerspan's published data from the commercial demonstration unit's performance of up to 90% when treating flue gas with an inlet NO_X concentration around 0.5 lb/mmBtu. This would result in a stack NO_X emission around 0.05 lb/mmBtu.

The ECO® process has not been demonstrated in a full-scale configuration on any unit, nor tested in a slipstream configuration on any boiler that fires western subbituminous coals or North Dakota lignite. It has also not been applied to emissions from a cyclone-fired boiler. According the EPA's Draft NSR Manual, "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available: an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice".

There are a number of issues with firing North Dakota lignite that make the applicability of the ECO® process technically infeasible for MRY Station boilers. These issues include:

- Deposits and Pluggage: The flyash deposition characteristics of the North Dakota lignite are extremely severe. Anything that contributes to flyash deposition and pluggage within the barrier reactor is expected to have a detrimental impact on the multi-pollutant control performance of the ECO® process, and thus could have a serious impact on MRY Station operations. The lack of demonstrated operation on treating the emissions from a boiler firing coal with a high slagging index precludes the use of the ECO® process as technically feasible for BACT as applied to a boiler firing North Dakota lignite.
- Reliability and Availability: Milton R. Young Station's major planned outages for each unit are scheduled to occur once every three years. Any NO_X control technology selected as BACT will need to operate year-round, year in and year out, on a routine basis, while performing at high levels of pollutant reduction. The Powerspan ECO® system is a new technology and is not as highly developed as other more common NO_X and SO_2 control technologies such as SCR or SNCR plus wet or semi-dry flue gas desulfurization (FGD). It is expected to require a full-time, full-scale application with sustained continuous operation to confirm levels of currently demonstrated reliability and availability from the ECO® CDU are acceptable to meet the

expectation of infrequent major outages over long time periods while maintaining high levels of control.

There are additional factors that make the application of the ECO® process potentially more difficult than other established emission control technologies available for coal-fired powerplants:

- There is a lack of experience with the ECO® downstream ammonia scrubber's coproduct crystallization and granulization equipment design, operation, and maintenance, which was not included with the initial commercial demonstration unit. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during CDU operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a technical feasibility deficiency. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO_2 scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. However, at MRY Station, considerable costs would be incurred for interim storage and shipment of the ECO® process scrubber's liquid bleedstream until sufficient experience has identified and eliminated potential failures and repairs for the crystallization and granulation equipment should it prove to be unreliable.

- Size of the barrier reactor: Powerspan recently indicated that they would scale the reactor for optimum cost and space arrangement based upon lessons learned from the CDU plant operation. The number of individual passages within a barrier reactor sized for either of MRY Station boilers' maximum flue gas flow and gas stream constituents is expected to require a cross-sectional area comparable to half of a large electrostatic precipitator. Although this has not been closely examined for all aspects of design, construction, operation and maintenance, the amount of physical space required to hold the barrier reactor and inlet and outlet ductwork is believed to not be available for potential retrofit to MRY Station units. Site space constraints are considered to be a barrier to technical feasibility for potential application of the ECO® process at Milton R. Young Station for Unit 1 and Unit 2's boilers.

- Additional station auxiliary power consumption: The barrier reactor, plus the ammonia scrubber and wet electrostatic precipitator additions by an ECO™ system, require an increase in station

auxiliary power consumption. For NO_X control, this includes more horsepower required by the booster fan needed to compensate for the flue gas pressure drop created across the barrier reactor. It also includes the power consumed by the electrodes of the barrier reactor itself.

Because of the technical feasibility issues and lack of commercial availability and full-scale experience, especially on such high fouling coals, the ECO® system was considered technically infeasible as a BACT alternative for Milton R. Young Station for Unit 1's boiler.

A.1.4 "Layered" NOx Reduction Technologies

Many of the NO_X emission reduction technologies which involve furnace or convection pass areas for their introduction into the flue gas stream have been, or can potentially be, applied in combinations so as to result in an overall higher level of removal. Separated overfire air, various types of fuel reburn, and various forms of SNCR could potentially be combined in series to reduce NO_X emissions prior to boiler's flue gas exit. However, all the possible NO_X control technology combinations have not been installed on coal-fired powerplants, so actual feasibility of some combinations have not been demonstrated as viable, particularly in consideration of the special challenges posed by cyclone boilers firing lignite coal.

A.1.4.1 SOFA Combined With Other NO_X Reduction Technologies

Separated Overfire Air can be favorably combined with every other method in order to reduce the amount of reagent or reburn fuel required to achieve the resulting level of NO_X emission reduction. Some control technologies, especially conventional fuel reburn systems, require overfire air to complete the combustion of the staged fuel admitted to the upper furnace. Fuel lean gas reburn can be applied with or without SOFA, as this limited amount of staged fuel is introduced into an oxygen-rich atmosphere downstream of the cyclone burners and any overfire air injection points.

A.1.4.1.1 SOFA with SNCR

Selective non catalytic reduction technologies are post-combustion, in-furnace NO_X control alternatives that have been installed in numerous boilers of various designs, fuel types, with and without overfire air. It is usually advantageous to apply overfire air so that the amount of chemical reagent consumption can be minimized in order to achieve the targeted NO_X emission rate from the boiler outlet.

Tests at Conectiv's B.L England Station (Units 1 and 2) demonstrated that SNCR can decrease NO_X emissions as much as 31% at full load, from 0.55 to 0.38 lb/mmBtu, over and above the reduction possible from overfire air alone (approximately 60% drop, from 1.3 to 1.4 down to 0.55) in full operation. This is an overall NO_X emission reduction of 72% from pre-retrofit baseline[24].

SNCR can be applied alone or combined with either the basic or the advanced forms of separated overfire air (ASOFA) on MRY Station boilers. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this technique. However, as previously explained in the discussion of SOFA alternatives, this will risk slag "freezing" in the barrels and lower furnace. Estimated NO_X emission rates for using SNCR techniques with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor estimates. SNCR with ASOFA is expected to reduce NO_X emissions approximately 31% below NO_X levels predicted for ASOFA operation, and potentially 58% overall from current baseline level for the MRY Station Unit 1 boiler with ammonia slip limited to approximately 5 ppmvd. This highest performing basic SNCR system is potentially able to achieve a NO_X emission rate of 0.355 lb/mmBtu, when combined with the advanced form of SOFA on MRY Station Units 1 boiler during operation at the pre-control baseline (near MCR load). These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers.

Another form of SNCR is combined with separated overfire air. This is currently being marketed commercially as "Rotating Mixing" (Rotamix). In the United States' utilities industry, this has only been applied to pulverized coal-fired boilers. It is different than basic SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects the ammonia (or urea) reagent into the high-pressure overfire air flow stream ahead of the ROFA nozzles' outlets. This mixture is imparted into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. This vendor (Mobotec USA) claims that Rotamix (rotating opposed fire air or ROFA + SNCR) helps to distribute the reagent across the furnace cross section, which maximizes in-furnace NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. Three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal were retrofitted with Rotamix, each achieving a NO_X reduction of approximately zero to 55 percent beyond the levels produced by ROFA alone, from pre-SNCR baselines of 0.22 to 0.28 lb/mmBtu down to 0.10 to 0.23 lb/mmBtu without low-NO_X burners[4,32,33,34].

While this variation of SNCR combined with separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Since cyclone boilers do not require the addition of hot air booster fans for SOFA, and optimum injection locations for both SOFA and SNCR reagent may not coincide, Rotamix may not perform as well as, or significantly better than, a well-designed combination of conventional SOFA and SNCR. This technique is not distinct enough from basic SNCR from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration for Milton R. Young Station boilers. Because of a lack of cyclone-fired boiler experience with ROFA and Rotamix, the latter was considered infeasible and thus was not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.4.1.2 SOFA with RRI

Rich Reagent Injection must be used in an oxygen-deprived atmosphere in order to effectively reduce nitrogen oxide emissions. This requires air-staged cyclones and separated overfire air operation.
The NO_X emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO_X reduction on coal-fired boilers. Data from B.L. England and Sioux plants show this technology can reduce NO_X emissions between zero and 39 percent beyond the amount attributable to overfire air system operation[23,24,25,26,27]. During initial demonstration testing of RRI at Ameren's Sioux Unit 1 boiler, a 500 MW unit firing a blend of PRB and midwestern bituminous coals (without SNCR), with SOFA in August 2001 at a lower furnace SR of approximately 0.99, NO_X emissions were reduced approximately 55% to 0.55 lb/mmBtu w/ SOFA only, with zero to 15% additional NO_X reduction from RRI (down to 0.47 lb/mmBtu) with zero ammonia slip[25]. Results of this initial RRI testing at Sioux plant were poor at cyclone stoichiometric ratios close to 0.99 because inconsistent, sporadic, and non-repeatable NO_X emissions reductions between zero and 15% were measured. Subsequent RRI testing at Sioux Unit 1 in March 2002 with SOFA at an average cyclone stoichiometric ratio around 0.95 showed NO_X emissions reduction of 29 percent (down to 0.27 lb/mmBtu) beyond those achieved with a modest amount of cyclone air-staging with SOFA (68% drop down to 0.38 lb/mmBtu from SOFA alone), for an 80% overall decrease from uncontrolled baseline; RRI CFD model

predictions for these conditions were NO_X emissions reduction of 31% with FGR and 37% without FGR operation. Tested NO_X emissions with RRI+SOFA in 2002 were with a reagent normalized stoichiometric ratio (NSR) of 3 (lbs NH_3 per lb NO_X)[25].

Parametric testing at Sioux Unit 1 in May 2005 reduced NO_X emissions between 15-38% with RRI, down to 0.15 to 0.20 lb/mmBtu. Reagent NSR between 1.0 and 4.0 and low ammonia slip levels less than 2 ppm from an established baseline condition of 0.20 to 0.285 lb/mmBtu level achieved NO_X emissions as low as 0.12 lb/mmBtu with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output[27].

The intent of the RRI process for NO_X reduction is that it must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system, with or without SNCR. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. The combustion gases in the vicinity of the RRI urea injection ports must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which will increase NO_X emissions. For lignite-fired cyclone boilers, the basic form of separated overfire air (without relocated lignite drying system vent ports) is incompatible with RRI. Reagent injection will be near the elevation of the existing lignite drying system vent ports in the lower front and rear walls of a lignite-fired cyclone boiler located immediately above the top rows of cyclones. The oxygen introduced with the lignite drying system's vented moisture-laden airstreams will cause the urea to be oxidized, creating NO_X emissions.

The advanced form of SOFA relocates these lignite drying system vent ports from the lower to the middle furnace, enhancing the desired in-furnace nitrogen oxides reduction process. Therefore, in order for RRI to be even moderately effective in reducing NO_X emissions from a lignite-fired cyclone boiler, this technology must be combined with an advanced form of separated overfire air, whether installed with or without SNCR.

As mentioned in the feasibility discussion of applying separated overfire air to lignite-fired cyclone boilers, the degree to which each and every individual cyclone furnace can be successfully operated with less than theoretical (substoichiometric) combustion air directly impacts potential NO_X formation and further in-furnace emission reduction. Because the heat content of lignite from the Center mine is not

consistent from hour to hour, there can be substantial deviations in air/fuel ratios for individual cyclones from the overall average.

In the case of MRY Station boilers, Minnkota has simultaneously sampled the unprepared lignite feed to several cyclones' lignite drying systems in order to determine the variability in the combustible and ash components of North Dakota lignite. This investigation found that fuel quality variations can result in individual samples' heating values to have a maximum differential of over 12% of the lignite samples' average.

TABLE A1-1 – Lignite Heating Values and Variations for Milton R. Young Station (Unit 2)

M.R. Young Station Individual Cyclone Lignite Samples		Differences Between Individual Cyclone Lignite Samples	
Higher Heating Values, Btu/lb	Percentage of Average HHV	HHV Differential, Btu/lb	Percentage of Average HHV
Minimum HHV: 5,852	88.9%	Minimum : 4	0.06%
Maximum HHV: 7,101	1.08%	Maximum : 797	12.1%
Average HHV: 6,584	100%	Average: 165	2.51%

When operating with air-staged conditions associated with separated overfire air, any individual cyclone with lignite heat input lower than average can allow significant amounts of oxygen to oxidize the urea reagent at high temperatures, thus increasing NOx emissions in that zone at that time. Cyclones with lignite heat inputs higher than average would produce lower stoichiometric air/fuel ratios and less NOx emissions. Less complete combustion in the deeply staged cyclones may release insufficient amounts of heat, thus raising the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in increased emissions, lower performance, and higher operating costs.

The MRY Station Unit 1 boiler's cyclone air/fuel ratios vary in real-time based on significant changes in combustible content on an individual cyclone by cyclone basis. Adjustment of individual cyclone combustion air inputs to compensate for the variability in individual cyclone lignite heat input rates for Unit 1's boiler would be necessary to maintain consistent substoichiometric operation of every cyclone during air-staged combustion. This places great emphasis on achieving tight control over the air/fuel

ratios on each cyclone during air-staged combustion operation in order for ASOFA to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

There is no equipment available for coal-fired boilers that can measure the fuel heat input at the prepared feed injection point on such a variable fuel to allow the determination of reasonably accurate air/fuel ratios on individual cyclones in real time. Without being able to measure the cyclone air and heat inputs to allow for control of air/fuel proportions and emissions, the stoichiometric ratios of individual cyclones can not be established accurately to produce combustion products essentially devoid of free oxygen. This requirement is especially necessary when employing RRI to avoid increasing, rather than reducing, NO_X emissions on the Milton R. Young Station Unit 1 boiler.

Because of the significant insurmountable problems discussed above which would increase NOx emission rates, RRI is considered technically infeasible for application on the Unit 1 cyclone boiler at the Milton R. Young Station.

A.1.4.1.3 SOFA with RRI and SNCR

When RRI is combined with separated overfire air and SNCR, it has demonstrated very high NO_X emissions reduction at Conectiv's B.L. England Unit 1 boiler during short-term testing firing eastern bituminous coal, on the order of 80% from an uncontrolled baseline around 1.2 lb/mmBtu[24]. In May 2005, testing RRI+SNCR+SOFA at Ameren's Sioux Unit 1 boiler firing a high PRB-blend coal demonstrated NO_X emissions as low as 0.12 lb/mmBtu. This was from an established baseline condition of 0.20 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation. These testing results when firing an 80%:20% PRB/Illinois coal blend at 480 MWg unit output with a reagent NSR of 4 and ammonia slip limited to less than 5 ppmvd, showed an overall 90% reduction with no apparent adverse short-term impacts of deeper air-staged combustion together with overfire air, RRI and SNCR applications[27].

Because of the significant insurmountable problems regarding RRI as mentioned above, RRI with SNCR and ASOFA is considered technically infeasible for application on the Unit 1 cyclone boiler at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

A.1.4.2 SNCR and Reburn

Various forms of SNCR could potentially be installed downstream of separated overfire air and various types of fuel reburn, to reduce NO_X emissions prior to a boiler's flue gas exit. Several of these examples were already described[7,8,9,10,11,1213,14]. Conventional gas (CGR) or coal reburn systems, by and large, have not been combined with forms of SNCR, although at least one vendor (GE Energy) has promoted a combination of conventional gas reburn with SNCR and overfire air systems as "advanced" gas reburn. Only one example of permanent installation of SNCR with conventional gas reburn (and overfire air) on a tangentially-fired boiler was found in available technical literature[10] and vendor experience lists[14]. The vendor (GE Energy) that provided the advanced gas reburn system at 120 MW NRG Somerset Station claimed NO_X emissions were reduced by 44% from a baseline of 0.45 down to 0.25 lb/mmBtu with overfire air alone; an additional reduction of 20% resulting from conventional gas reburn with overfire air, down to 0.20 lb/mmBtu; and further decrease of 45% down to 0.11 lb/mmBtu using gas reburn with SNCR with an unstated amount of ammonia slip, for an overall reduction of 75% from uncontrolled baseline[14].

No examples of actual demonstration or permanent installation of SNCR with conventional gas or coal reburn (and overfire air) on cyclone-fired boilers were found in a search of published and proprietary technical literature. The lack of experience with these combinations on a cyclone-fired boiler, especially for lignite-firing, makes the application for MRY Station's boilers infeasible.

FLGR™ has been installed with SNCR for NO_X emission reduction on several pulverized coal boilers, as discussed in the following subsection. A potential advantage of FLGR™ over conventional coal or gas reburn techniques is that the former is generally compatible with, but does not require, the installation and operation of SOFA.

Rich Reagent Injection would appear to be less capable of being combined with fuel reburn, especially conventional fuel reburn alternatives with high amounts of reburn fuel injection. This is due to the expected need to idle (e.g. not fire) up to two of the seven cyclones when operating the reburn system at full boiler load. In this case, the cooling air introduced into the idle cyclones, and any conveying air injected with pulverized reburn coal (or if natural gas is injected with recirculated flue gas), are expected to counteract the fuel-rich conditions of the air-and fuel-staged cyclones operating substoichiometrically. This will cause a portion of the amine reagent to be oxidized in the lower furnace, creating NO_X emissions instead of converting them to nitrogen and water. No example of actual demonstration or permanent installation of RRI with reburn (and overfire air) on cyclone-fired boilers was found in

available technical literature or vendor experience lists. This combination is considered infeasible at the present time.

Hydrocarbon-enhanced SNCR (e.g. NO_XStar™) may potentially be combined with all types and forms of reburn previously discussed, since the location of the enhanced ammonia injection nozzles will be above (beyond) the elevation in the middle furnace where any reburn fuel should be reacted. No example of actual demonstration or permanent installation of HE-SNCR with reburn (and overfire air) on any coal-fired utility boilers, especially cyclone-fired units, was found in available technical literature or vendor experience lists. The advantage that HE-SNCR presents is the potential for greater-than-SNCR-levels of NOx reduction without significant amounts of gaseous hydrocarbon being required. Because of a lack of experience with HE SNCR applied to cyclone boilers, and none with significant amounts of fuel reburn, this combination has not been investigated further, and was not included in the control and cost-effectiveness analysis for NO_X controls.

A.1.4.2.1 Amine-Enhanced FLGR™ (AEFLGR™) or FLGR™ + SNCR

Fuel-lean gas reburn has been combined with SNCR as a hybrid form of amine reagent technologies on at least five pulverized coal-fired utility powerplants retrofit installations within the United States. This combination of technologies allows the boiler to be operated with FLGR™ alone, FLGR™ and SNCR simultaneously, or SNCR only (without SOFA) for the specific level of control desired or required.

No examples of actual demonstration or permanent installation of FLGR™ + SNCR (with or without overfire air) applied to a cyclone-fired boiler were found in available technical literature or vendor experience lists. The vendor (Fuel Tech) that provided the AEFLGR™ system at Mercer Station claimed NO_X emissions were reduced by 60% (from a baseline of 1.4 down to 0.56 lb/mmBtu) with 5 ppm ammonia slip without overfire air. A technical paper provides more details[18]. Another technical paper stated that FLGR™ alone only reduced NO_X emissions approximately 27% from the 1.4 lb/mmBtu baseline, down to 1.03 lb/mmBtu[35].

An AEFLGR™ system (with or without SOFA or ASOFA) may be potentially applied to a cyclone-fired boiler. The high capital and operating costs associated with applying fuel lean gas reburn is expected to make this economically unattractive, and the existing lignite pre-drying vent ports will likely limit the NO_X emission reduction potential of the FLGR™ component if installed without the advanced form of

SOFA. The lack of experience with this combination on any cyclone-fired boiler, especially for lignite-firing, makes this combination infeasible for MRY Station Unit 1 boiler.

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A.2.1 - U.S. Cyclone NOx Reduction Projects Summary

SELECTIVE NON-CATALYTIC REDUCTION/ RICH REAGENT INJECTION
Cyclone-Fired Boilers

Conectiv (formerly Atlantic Electric)
BL England Unit 1 Crushed Coal, single-wall cyclone-fired 1962 vintage
138 MW B&W boiler aqueous urea SNCR, 1995 startup eastern bituminous coal
Boiler has only 3 cyclone burners, arranged "1 over 2" style.
RJM implemented commercial Fuel Tech urea-based SNCR system installation in 1995 after short-term (3-month demonstration test) in 1993-1994. 31 % NOx reduction claimed, from 1.31 lb/mmBtu NOx baseline[(1)] for SNCR only; RJM claimed 35% reduction from 1.31 lb/mmBtu down to 0.85 lb/mmBtu (without overfire air) with urea-to-NOx NSR = 0.85 (RJM experience list).

Added eight temporary RRI ports (three nozzles on each lower sidewall, and two nozzles on the upper rear wall, and performed one month demonstration parametric testing of overfire air only (without SNCR or RRI), at 120 MW nominal boiler load and cyclone S.R. = 0.90 in 1999. REI claimed 55% NOx reduction from a 1.2 lb/mmBtu uncontrolled NOx baseline to 0.55 lb/mmBtu with OFA only, with stack CO emissions below 50 ppm. For Rich Reagent Injection; REI claimed 25-30% NOx reduction for RRI down to 0.38 lb/mmBtu from controlled baseline w/ OFA alone of 0.55 lb/mmBtu NOx and a RRI urea-to-NOx NSR = 2; also showed RRI+SNCR w/ OFA reduced NOx 55% to 0.25 lb/mmBtu (34% beyond RRI w/ OFA), for an overall 79% NOx reduction with a SNCR urea-to-NOx NSR = 1. Measured less than 1 ppm ammonia slip during RRI testing, < 5 ppm slip for RRI + SNCR. No significant increase in CO emissions during RRI testing[(2)].
Source: [(1)] ICAC White Paper; RJM experience list; [(2)] REI 2001 Technical Paper.

Conectiv (formerly Atlantic Electric)
BL England Unit 2 Crushed Coal, cyclone-fired, single-wall-fired 1964 vintage
160 MW B&W boiler SNCR, 1996 startup eastern bituminous coal
RJM implemented commercial Fuel Tech urea-based SNCR system in 1996, claimed 36% reduction from 1.36 lb/mmBtu down to 0.85 lb/mmBtu, urea-to-NOx NSR = 0.85 (without overfire air) [(1)].
An OFA system was added in 1998, resulting in NOx emissions of 0.33 lb/mmBtu, for an overall NOx reduction of 76%.
Source: RJM experience list. (Also listed in [(1)] ICAC White Paper).

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler Rich Reagent Injection demonstration testing in 2001
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.

Installed twenty temporary RRI ports (six nozzles on each lower sidewall, and four nozzles on each front and rear wall), and performed one month demonstration parametric testing of overfire air only and initial testing with RRI in August 2001, followed by additional testing in March 2002, and the second quarter of 2004. Added 8 RRI ports (1 in each sidewall, 4 in each front and rear wall) and 14 SNCR ports (5 on upper front wall, 9 on upper rear wall) to the furnace in early 2005, followed by three weeks of parametric testing and 3 days of continuous testing of RRI with SNCR and deeper-staged OFA.
Tested in August 2001 at lower furnace SR approx.=1.0, 0.55 lb/mmBtu w/ OFA only, only 15% NOx reduction w/ RRI, zero ammonia slip.

Tested in March 2002 at lower furnace SR approx.=0.95, from 0.38 lb/mmBtu baseline w/ OFA only, achieved 29% NOx reduction w/ RRI down to 0.27 lb/mmBtu, NSR=3, zero ammonia slip[3].
(assume blend of PRB and Illinois bituminous coal w/ tire-derived fuel and petroleum coke)[3].
Operation in the second quarter 2004 showed actual stack NOx averaged around of 0.30 lb/mmBtu with OFA only and lower furnace at a cyclone SR around 0.88 burning a 85% PRB, 15% Illinois #6 bituminous coal blend, presumably at 440 MW. This is a 75% NOx reduction from a 1.19 lb/mmBtu pre-control baseline. REI using CFD modeling predicted NOx down to 0.18 lb/mmBtu with RRI+OFA, and below 0.15 with RRI+SNCR under similar deep cyclone air-staging (1.19 to 0.28 lb/mmBtu is 76% reduction, 0.18 vs 0.28 is an additional 36% reduction w/ RRI, and 0.14 vs 0.28 is a 50% reduction w/ RRI+SNCR, for an overall reduction of 88%)[4].
Tested in May 2005 at 480 MWg with lower furnace SR approx. = 0.85-0.88, 76-83% reduction from 1.2 lb/mmBtu baseline down to as low as 0.20 lb/mmBtu w/ SOFA only firing 80% PRB, 20% Illinois #6 bituminous coal blend; additional 15-39% NOx reduction w/ RRI, to as low as 0.15 lb/mmBtu from 0.20-0.28 lb/mmBtu baseline w/ SOFA only at urea NSR varied between 1 and 4, with one ppm ammonia slip; achieved additional NOx reduction w/ RRI +SNCR down to 0.12 lb/mmBtu, NSR=4, ammonia slip10 ppm or less. RRI+SNCR w/ SOFA NOx reduction percentage varied from 15% to 50% below SOFA-only levels, with NSRs between 1 and 4.5. SNCR alone had 13% (NSR=1) to 32% (NSR=1) NOx reduction with ammonia slip around 1-2 ppm*.
Source: [3] REI 2002 and 2003 Technical Papers; [4] REI 2004 Technical paper;* REI 2005 Technical paper.

REBURN – GAS, CONVENTIONAL
Cyclone-Fired Boilers
Constellation Energy (formerly Baltimore Gas & Electric)
C.P. Crane Station, Units 1 & 2 (MD) Crushed Coal, cyclone-fired, eastern bituminous coal
2 x 200 MW B&W boilers (four cyclones each) 1961, 1963 vintage
GE-EER Conventional Gas Reburn, 1999 startup
Added gas supply piping, metering, hangers, supports; reburn injectors and cooling air ductwork, OFA ductwork, injection nozzles and wall ports, field (assume eastern bituminous coal)
GE-EER claimed Gas Reburn with OFA lowered NOx between 60% and 65% from baselines of 1.50 lb/mmBtu to between 0.60 and 0.52 lb/mmBtu, at full load with reburn operation. No claims of percent reburn fuel or percent OFA included in GE-EER's experience list.
Another technical paper showed this installation of CGR operated with 25 percent reburn fuel[5].
Source: Sept. 2005 GE-EER experience list; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

City Water, Light & Power
Lakeside Unit 7 Crushed Coal, front-wall cyclone-fired, midwestern bituminous coal
300,000 lb/hr steam B&W boiler (approx. 33 MWe equivalent, two cyclones) 1961 vintage
Springfield, IL DOE Clean Coal demonstration project (included sorbent injection)
GE-EER conventional gas reburn w/ OFA 1992 startup (CGR not currently operating)
Vendor claimed to lower NOx by 66% from 0.95 lb/mmBtu baseline to 0.32 lb/mmBtu. A GE-EER 2004 technical paper showed 25% reburn fuel yielded minimum NOx emissions[6].
A DOE NETL technical paper showed this demonstration of CGR from 5/93-10/94 (assume with OFA) with 23 percent reburn fuel reduced NOx 60% from 0.97 to 0.39 lb/mmBtu [5].
Source: Sept. 2005 GE-EER experience list; [6] GE-EER 2004 Technical paper; [5] DOE-NETL 2004 Reburn Conference Technical paper.

Eastman Kodak Company
Kodak Park Boilers 41 & 42 Crushed Coal, front-wall cyclone-fired, 1964 & 1966 vintage

400,000 lb/hr steam B&W boilers (approx. 50 MWe equivalent, two 8-ft dia. cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn w/ OFA December 1998, July 1998 startups (still operating)
Commercial installation of CGR, with (1) gas burner added to each sidewall + (2) large and (2) small OFA ports added to front wall above cyclones, utilizing higher reburn gas pressure (vs. Boiler #43) requires no flue gas recirculation; {Very small furnace w/ cyclone SR not <1.0}.
B&W claimed reburn with OFA lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 10-12% percent reburn fuel to achieve 0.6 lb/mmBtu and 23-24% reburn gas input to reach 0.33 lb/mmBtu NOx (73% reduction) [7].
Another technical paper showed NOx lowered by 52% from 1.25 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel[5].
Source: [7] B&W Technical Paper; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL
Cyclone-Fired Boilers, continued
Eastman Kodak Company
Kodak Park Boiler 43 Crushed Coal, front-wall cyclone-fired 1968 vintage
600,000 lb/hr steam B&W boiler (approx. 60 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn 1995 startup (still operating)
Commercial installation of CGR, with flue gas recirculation (FGR) for injection mass momentum w/ (1) FGR fan; (1) gas burner added to each sidewall + (2) OFA ports added front wall above cyclones. {Very small furnace/low residence time w/ cyclone SR not <1.0}
B&W claimed reburn with OFA & FGR lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 18% percent reburn fuel to achieve 0.6 lb/mmBtu and 29% reburn gas input to reach 0.36 lb/mmBtu NOx (70% reduction) [7].
Another technical paper showed NOx lowered by 56% from 1.35 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel[5].
Source: [7] B&W Technical Paper; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Tennessee Valley Authority (TVA)
Allen Station Unit 1 (TN) Crushed Coal, cyclone-fired (seven cyclones) 1959 vintage
300 MW B&W boiler PRB &western bituminous coal blend fired
GE-EER Conventional Gas Reburn, 1998 startup
Commercial installation added gas supply piping, metering, hangers, supports; reburn injectors and cooling air piping, OFA ductwork, injection nozzles and wall ports, field I&C devices.
Reburn with OFA claimed to lower NOx 65% from baseline 1.20 lb/mmBtu to 0.42 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included. (TVA also installed duplicate OFA systems on Allen Units 2 & 3 boilers).
Another technical paper showed NOx lowered by 65% from 0.86 lb/mmBtu baseline (to 0.30 lb/mmBtu) with 7 percent reburn fuel[5].
Source: Sept. 2005 GE-EER experience list; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, CONVENTIONAL
Cyclone-Fired Boilers
Alliant Energy (formerly Wisconsin Power & Light)
Nelson Dewey Station Unit 2 Crushed Coal, cyclone-fired, PRB coal 1962 vintage

110 MW B&W boiler 3-cyclones across front wall, 4 reburn burners +
4 OFA ports across rear wall, aligned vertically in columns.
US DOE Clean Coal Demonstration project of B&W's Conventional Coal Reburn, 1991 startup (since discontinued) added coal supply piping, reburn burners with flue gas recirculation, OFA ductwork + dual zone ports; coal feeder, pulverizer & PA fan, tested with PRB and bituminous coals. (western subbituminous coal)
B&W claimed reburn operation lowered NOx by 57% from baseline of 0.83 mmBtu to 0.38 lb/mmBtu at full load[7]. Approx. 30% percent of total fuel input supplied as reburn fuel. Increased unit output by 10 MW, increased flyash unburned carbon by 4% (13-22% vs 9-18%), decreased furnace exit gas temperature (FEGT). OFA ports listed in B&W experience list.
B&W shows full load NOx w/o reburn was 0.75 lb/mmBtu, and 0.29-0.32 lb/mmBtu w/ PRB fuel during reburn operation (57% decrease). At 75% load, 0.64 vs 0.29-0.32 lb/mmBtu. At 55% load, 0.62 vs 0.29-0.31 lb/mmBtu without and with reburn activated[8].
Another technical paper showed NOx lowered by 52-55% from 0.82 lb/mmBtu baseline (to 0.39-0.34 lb/mmBtu) with 25-30 percent reburn fuel[5].
Source: [7] 2004 B&W Technical Paper; [5] DOE-NETL 2004 Reburn Conference Technical paper; [8] B&W case history (from website, dated 1997).

REBURN – COAL, MICRONIZED, CONVENTIONAL
Cyclone-Fired Boilers
Eastman Kodak Company
Kodak Park #15 Boiler Crushed Coal, front-wall cyclone-fired, 1956 vintage
400,000 lb/hr steam B&W boiler (approx. 50 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
GE-EER micronized coal reburn 1996 initial startup (operating since 1997)
Demonstration project performed with Dept. of Energy's US Clean Coal Technology Program. Project added flue gas recirculation for injection mass momentum, FGR fan and two micronized coal pulverizers; (6) reburn coal injectors added to rear wall + (1) reburn coal injector on each of the sidewalls, with (4) OFA ports added across front wall above cyclones[9]. GE-EER designed and fabricated the coal injectors and OFA ports. {Extremely small furnace and low residence time}.
GE-EER claimed reburn + OFA w/ FGR reduced NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. No claims of percent reburn fuel included.
Another technical paper showed this demonstration of micronized coal reburn from 4/97-10/98 lowered NOx by 57% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 17 percent reburn fuel[5].
Source: [9] DOE Topical Report Number 14 (May 1999); GE-EER experience list; [5] DOE-NETL 2004 Reburn Conference Technical paper.

REBURN – FUEL LEAN GAS REBURN
Cyclone-Fired Boilers
Midwest Generation (formerly Commonwealth Edison)
Joliet Station 9, Unit 6 Crushed Coal, opposed-wall cyclone-fired (nine cyclones)
340 MW B&W boiler 1959 vintage, 1997 startup (FLGR has since been decommissioned)
Energy Systems Associates demonstrated 25-30% NOx reduction using 5-10% of total heat input as reburn natural gas injected (without OFA)[5].
Another technical paper showed this demonstration in collaboration with Gas Research Institute of FLGR lowered NOx by 28-43% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 7 percent reburn fuel[10].
Source: [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); [10] NGB Technologies Technical Paper.

REBURN – FUEL LEAN GAS REBURN w/ SNCR continued

Cyclone-Fired Boilers

Owensboro Municipal Utilities (KY) Crushed Coal, front-wall cyclone-fired
Elmer Smith Unit 1 (three cyclones) 1965 vintage
150 MW B&W boiler
CFD model study only predicted NOx reductions from 1.59 to 0.39 lb/mmBtu with OFA only (75% reduction, 0.90 SR); 25-30% NOx reduction using 6% of total heat input as reburn natural gas injected above OFA; 40-45% NOx reduction from SNCR with <5 ppm ammonia slip[11].
Source: [11] REI Technical paper.

Separated OVERFIRE AIR

Cyclone-Fired Boilers

Tennessee Valley Authority (TVA) Crushed Coal, cyclone-fired, 1959 vintage
Allen Station Units 2 & 3 (TN) (seven cyclones)
300 MW B&W boilers PRB &western bituminous coal blend
GE-EER Overfire air (duplicate of Allen 1), 1999 startup
GE-EER claimed to lower NOx with OFA alone up to 29% from baseline 1.20 lb/mmBtu to 0.85 lb/mmBtu on Units #2 and 3 at full load.
Source: Sept. 2005 GE-EER experience list.

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler PRB/Illinois Coal blend
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.
A ten-port OFA system (five ports on each front and rear wall) began operation in mid-2001, which reduced NOx emissions approx. 40-50% reduction from 1.1-1.3 (assume average of 1.19) down to 0.7 lb/mmBtu with moderate cyclone air-staging (cyclone SR from 1.19 to 1.0).[3] Subsequent testing and full load operation at deeper cyclone air-staging (SRs ≤ 0.90) has dropped NO_X with SOFA alone to around 0.3 lb/mmBtu in 2004[4].
Source: [3] REI 2002 and 2003 Technical Papers; [4] REI 2004 Technical paper;* REI 2005 Technical paper

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with Separated Overfire Air CR technology are listed in Table A.2-1. A large majority of the cyclone-fired boilers listed burn western subbituminous coal (or PRB blended with midwestern bituminous coal).

TABLE A.2-1 – Cyclone-Fired Boiler Overfire Air Retrofit Installations[12]

Facility Name	Installation Date	Comments
Allen Station Units 1	Installed 1998*	OFA w/ CGR retrofit; has SCR
Allen Station Unit 2	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Allen Station Unit 3	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Asbury Unit 1	Installed 5/10/1999	Empire District, BART-eligible
Bailly Unit 7	Installed 2003[13]	SCR to be installed in 2006-7
Bailly Unit 8	Installed 5/31/2000	SCR retrofit 5/11/2004
Baldwin Unit 1	Installed 12/31/1999	SCR retrofit 4/28/2003
Baldwin Unit 2	Installed 5/8/2000	SCR retrofit 4/12/2002
Big Stone Unit 1	Installed 10/22/1997	part of conversion to PRB
BL England Unit 2	Installed 1998*	previous SNCR retrofit in 1996
CP Crane Unit 2	Installed 2/1/1999	OFA w/ CGR retrofit
Coffeen Unit 1	Installed 2/1/2001	SCR retrofit 4/21/2003
Coffeen Unit 2	Installed 2/9/2000	SCR retrofit 4/09/2002
Edgewater Unit 3	Installed 11/2001[13]	
Edgewater Unit 4	Installed 6/19/2001	
Joliet 9 Unit 6	Installed 2000[13]	
Kincaid Unit 1	Installed 4/28/2000	SCR retrofit 12/17/2002
Kincaid Unit 2	Installed 5/24/2000	SCR retrofit 6/07/2002
Allen S. King Unit 1	Installed 11/30/1999	
LaCygne Unit 1	Installed 2/28/2000	
Lake Road Unit 6	Installed 6/01/2002	
Michigan City Unit 12	Installed 4/1998[13]	SCR retrofit 5/01/2003
Nelson Dewey Unit 1	Installed 2002[13]	
Nelson Dewey Unit 2	Installed 2002[13]	
Paradise Unit 1	Installed 11/14/1998	SCR retrofit 5/01/2001
Paradise Unit 2	Installed 12/8/1999	SCR retrofit 5/01/2000
Paradise Unit 3	Installed 5/4/2000	SCR retrofit 3/10/2004
Powerton Unit 5-1	Installed 6/1/2003	
Powerton Unit 5-2	Installed 6/1/2003	
Powerton Unit 6-1	Installed 6/1/2002	
Powerton Unit 6-2	Installed 5/4/1999	
Schahfer Unit 14	Installed early 2000[13]	SCR retrofit 5/11/2004
Sibley Unit 2	Installed 5/24/2002	
Sibley Unit 3	Installed 5/4/1999	
Sioux Unit 1	Installed 4/30/2001	SNCR demo May 2005
Sioux Unit 2	Installed 4/30/1997	
State Line Unit 4	Installed 11/2001[13]	Similar to Joliet 9 Unit 6
Tanners Creek Unit 4	Installed 5/12/2002	
Thomas Hill Unit 1	Installed June 2004[13]	
Thomas Hill Unit 2	Installed November 2000[13]	

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project.
Source: [12] US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)
* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)
[13] Burns & McDonnell internal database.

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with SCR technology are listed in Table A.2-2. This list includes at least eighteen cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). The highest emission

reductions listed in Table A.2-2 for SCR systems are for clean reactor catalyst and ideal operating conditions.

TABLE A.2-2 – Cyclone-Fired Boiler High-Dust SCR Installations

Facility[1]	Unit Size[2],MW	Tested Control Efficiency[3]	Tested Outlet NO_X Emission Rate (lb/mmBtu)[3]	2003 Ozone Season Average NO_X Emission Rate[4] (lb/mmBtu)
Allen 1, 2, & 3[5,6]	330 ea.	91.1/NAD[7]/88.7	0.070/NAD[7]/0.088	0.088/0.077/0.086
Baldwin 1[5,6]	600[3]	82.9	0.072	0.238
Baldwin 2[5,6]	605[3]	83.5	0.067	0.286
Bailly 8[5,6]	422	NAD[7]	NAD[7]	0.84
Coffeen 1[5,6]	389	NAD[7]	NAD[7]	0.114
Coffeen 2[5,6]	617	NAD[7]	NAD[7]	0.120
Dallman 31 & 32	207	NAD[6]	NAD[6]	0.149/0.146
Kincaid 1 & 2[5,6]	660[3] ea.	89/89	0.079/0.079	0.181/1.198
Marion 4	173	94.3	0.067	0.252
Merrimack 1[5,8]	114	50.5[9]	0.148	0.158
Merrimack 2	346	51.3[9]	0.155	0.171
Michigan City 12[5,10]	540	84.2	0.109	0.418
New Madrid 1 & 2[8,10]	600 ea.	87.4/88.1	0.149/0.147	0.319/1.172
Paradise 1 & 2[5,6]	704 ea.	87.7/87.7	0.102/0.101	0.124/0.113
Paradise 3[5,6]	1150	89.1	0.088	0.658
Schahfer 14[5,10]	540	83.5	0.106	0.478

[1] – original design fuel for all listed cyclone boilers was bituminous coal
[2] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.
[3] – Burns & McDonnell internal database.
[4] – as reported to US EPA, available from their website at http://cfpub.epa.gov/gdm/index.cfm
[5] – includes application of separated overfire air for combustion NO_X control
[6] – current fuel believed to be a blend of subbituminous and bituminous coals
[7] – NAD = no published data from SCR emission testing found on these units.
[8] – original air preheaters were tubular-type; changed to rotary-type during SCR retrofit
[9] – Design NO_X removal efficiency is higher, approx. 90%.
[10] – current fuel believed to be subbituminous coal

For Merrimack Unit 1's SCR, inlet (i.e. uncontrolled) NO_X was 1.34 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. The catalyst was designed for 88.9% NO_X removal efficiency

and 5 ppm ammonia slip. SCR commercial service date July 20, 1999. [(14) Babcock Borsig Power 2000 technical paper on SCRs].

For Merrimack Unit 2's SCR, inlet (i.e. uncontrolled) NO_X was 2.66 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. Initial testing demonstrated 70% removal(15), which exceeded the 65% requirement to achieve a 0.92 lb/mmBtu permit limit. The catalyst was designed for 85-95% NO_X removal efficiency and 5 ppm ammonia slip(16).

(15)NETL-DOE Clean Coal Technology 1997 technical paper on SCRs; (16) 1997 ICAC White Paper on SCRs.

Northern Indiana Public Service Company (NIPSCO)
Bailly Unit 8 Crushed Coal, cyclone-fired, opposed-wall-fired 1968 vintage
360 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires a blend of 85% western subbituminous (PRB) coal, with Illinois bituminous coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Michigan City Unit 12 Crushed Coal, cyclone-fired, opposed-wall-fired 1974 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2003 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2003 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 1998(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Schahfer Unit 14 Crushed Coal, cyclone-fired, opposed-wall-fired 1975 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

TABLE A-3 – Low-Dust Pulverized Coal-Fired Boiler SCR Installations

Operator/Facility[1,2]	SCR Startup Date[3]	Average NO_X Emission Rates[4] (lb/mmBtu)	Unit Size[5], MW
AEP/Cardinal Unit 3[6]	5/01/03	0.74 / 0.34 / 0.135	650
Carolina P&L/Mayo Unit 1[7]		- / (0.36) / N/A	368 x 2
Carolina P&L/Roxboro Unit 4[7,8]	5/07/01	0.57 / 0.26 / 0.081	372 x 2
Cinergy/East Bend Unit 1	4/01/02	- / (0.28) / 0.067	648
Constellation/Brandon Shores Unit 1[8]	(2001)	0.47 /0.33 / 0.126	685
Constellation/Brandon Shores Unit 2[8]	(2000)	0.45 / 0.31 / 0.094	685
Dayton P&L/Killen Station Unit 2	11/01/03	- / (0.48) / 0.06[9]	666
Dynegy Midwest Gen/Havana Unit 6[10]	(2000)	0.46 /0.20 / 0.102[9]	488
PSEG Power LLC / Mercer Unit 1[11]	(2005)	- / (0.63) / N/A	320
PSEG Power LLC / Mercer Unit 2[11]	(2004)	- / (0.76) / N/A	320

[1] – Burns & McDonnell internal database.
[2] – Current fuel is eastern or midwestern bituminous coal, except Havana
[3] – US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, except where noted. Dates in () are believed to be accurate but have not been confirmed.
[4] – The three values are "Pre-control average", "2004 annual average", and "2003 ozone season average" NO_X emission rates, as reported to US EPA. Pre-control and year 2004 annual average data as shown in US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b. Values shown in parentheses are year 2003 annual average where 2004 data is not available. Year 2003 and 2003 ozone season data is available from the EPA's website at http://cfpub.epa.gov/gdm/index.cfm, includes application of separated overfire air for combustion NO_X control where applicable.
[5] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.
[6] – This boiler has low-NOx burners for combustion controls.
[7] – Carolina Power & Light plants listed here have two boilers per unit, total nameplate for Mayo is 736 MW, Roxboro is 745 MW; emission numbers are the average of both boilers.
[8] – This boiler has low-NOx burners and overfire air for combustion controls.
[9] – This is preliminary data reported to the US EPA for 2004 ozone season average emission rate.
[10] – This boiler's current fuel is believed to be subbituminous coal.
[11] – Mercer boilers listed have low-dust SCR with flue gas reheat. Unit size is approximate, not nameplate.
N/A = complete 2004 ozone season data is not available, and 2003 ozone season data is not representative of the post-SCR installation emission rate.

SELECTIVE NON-CATALYTIC REDUCTION

Pulverized coal-fired boilers

American Electric Power (AEP) Pulverized Coal, cell-burner, opposed wall-fired B&W boiler
Cardinal Unit 1 1967 vintage; Low NO_x burners installed in October 1998
600 MW (nominal) Brilliant, Ohio
Fuel Tech urea-based SNCR installed in October 1998.
Fuel Tech, DOE, EPRI-member utilities SNCR demonstration project. Tested in March-April 1999, claimed 65% reduction with LNBs + SNCR w/ 5 ppm NH_3 slip, (from pre-LNB retrofit baseline of 1.20 lb/mmBtu*) down to 0.52 lb/mmBtu at 620 MW (100% MCR). SNCR reduced NO_X 31% below LNBs alone (0.75 lb/mmBtu baseline), at 620 MWg (100% MCR), 34% reduction at 75% MCR (450 MWg), and 42% reduction at minimum load (340 MWg, 55% MCR) ≤ 5% ammonia slip[17], burning eastern bituminous coal. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005; [1]ICAC White Paper, [17] 2000 Fuel Tech technical paper, *Riley Power (Babcock Power Inc.) experience list 8/16/04.

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 SNCR startup
Fuel Tech commercial SNCR installation claimed 25% NOx reduction from low-NO_X burner w/o OFA baseline of 0.58 lb/mmBtu (down to 0.44 lb/mmBtu on SNCR alone). Urea-to-NOx NSR not stated.
(Also see FLGR + SNCR installation summaries for pulverized coal boilers).
Source: Fuel Tech experience list dated 1/28/2005.

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler SNCR startup in 2002
Mobotec USA "Rotamix" ammonia-based SNCR system injects aqueous ammonia liquid into a high velocity boosted separated overfire air (ROFA) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.28 lb/mmBtu baseline by 43% to 0.16 lb/mmBtu in 2002 with 5 ppm NH_3 slip following the installation of ROFA in 2000.
Overall reduction 73% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.16 lb/mmBtu[18].
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.13 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 54% decrease from 0.28 lb/mmBtu with ROFA alone, or 78% overall decrease[19]. Ammonia-to-NOx NSR not stated.
Source: [18] CP&L 2002 Technical paper; [19] Mobotec 2003 technical paper.

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler SNCR startup in 2001
Mobotec USA "Rotamix" ammonia-based SNCR system, injects aqueous ammonia liquid into a high velocity boosted separated overfire air ("ROFA") system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.23 lb/mmBtu baseline by 22% to 0.18 lb/mmBtu with 5 ppm NH_3 slip following the installation of ROFA+SNCR in 2001[18]. Presentation slide graph shows no reduction for Rotamix beyond ROFA alone at full load NO_X emission rate of 0.23 lb/mmBtu. Ammonia-to-NOx NSR not stated.
Overall reduction 67% from full-load pre-ROFA baseline 0.54 lb/mmBtu to 0.18 lb/mmBtu.
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.10 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 56% decrease from 0.23 lb/mmBtu with ROFA alone, or 81% overall decrease[19]. Urea-to-NOx NSR not stated.
Source: [18] CP&L 2002 Technical paper; [19] Mobotec 2003 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Cinergy (formerly Cincinnati G&E) Pulverized Coal, Tangentially-fired,
Miami Fort Unit 6 (Ohio) 1960 vintage; startup prior to 2000
163 MW CE boiler
Fuel Tech urea-based SNCR system, claimed to lower NOx by 35% from 0.55 lb/mmBtu baseline[(1)].(assume eastern bituminous coal). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [(1)] ICAC White Paper.

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 3 Pulverized Coal, Tangentially-fired, 1954 vintage
84 MW CE boiler mid-March 1996 startup; (assume eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system. HRC claimed 35% NOx reduction with less than 10 ppm ammonia slip. Urea-to-NOx NSR not stated.
Another source shows a 30% reduction from 0.54 lb/mmBtu baseline[(1)].
Source: Hamon experience list (not listed by Fuel Tech); [(1)] ICAC White Paper.

Conectiv (formerly Delmarva Power & Light) Pulverized Coal
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers Spring 2000 startup (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system (not listed by Fuel Tech) on both units.
HRC claimed 35% NO_X reduction with less than 5 ppm ammonia slip. Urea-to-NOx NSR not stated.
An REI 1999 technical paper shows a pre-SNCR baseline of 0.37 and 0.44 lb/mmBtu, respectively. [(20)]
Another source listed these units as having a pre-control NO_X baseline of 0.97 and 0.57 lb/mmBtu, and 2004 post-SNCR startup average of 0.32 and 0.33 lb/mmBtu, respectively. [(12)]
Source: Hamon experience list (not listed by Fuel Tech); [(20)] REI 1999 technical paper;
[(12)] US EPA Docket OAR-2002-0076-0446 Excel Spreadsheet 6/15/2005.

Dominion Generation (Virginia E&P Co.) Pulverized Coal, Tangentially-fired
Clover Station, Units 1 & 2 (VA) ABB/CE boilers, 1995, 1996 vintage
2 x 465 MW (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) 1995, 1996 startup (initial commercial)
Fuel Tech claimed NOx reduced by 25% from 0.32 lb/mmBtu baseline (to 0.24 lb/mmBtu).
Source: Fuel Tech experience list dated 1/28/2005. Urea-to-NOx NSR not stated.

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
Mobotec USA "Rotamix" urea-based SNCR system with rotating opposed fired air (ROFA).
Mobotec 2004 technical paper claimed to lower NO_X by 55% from 0.22 lb/mmBtu baseline to 0.10 lb/mmBtu in April 2004 with urea-based Rotamix SNCR and < 5 ppm CO. NH_3 slip not mentioned.
Overall reduction 83% from full-load pre-ROFA baseline 0.58 lb/mmBtu to 0.10 lb/mmBtu [(21)]. Urea-to-NOx NSR not stated.
Source: [(21)] Mobotec 2004 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Eastern Utilities Associates, Pulverized Coal, Tangentially-fired
Montaup Electric Company 1959 vintage
Somerset Unit 8 (Massachusetts) Summer 1995 startup
112 MW CE boiler (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR (Fuel Tech system), claimed to lower NOx below 0.38 lb/mmBtu (Mass. RACT). Urea-to-NOx NSR not stated.
Another source listed 28-60% NOx reduction from a 0.49-0.89 lb/mmBtu baseline[(1)].
Source: Hamon experience list, Fuel Tech experience list dated 1/28/2005, [(1)]ICAC White Paper.

First Energy Pulverized Coal, Tangentially-fired,
Eastlake Unit 3 (Ohio) 1954 vintage
130 MW CE boiler (w/ division wall) (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Fuel Tech claimed to lower NOx from 20-32.5% from 0.34-0.40 lb/mmBtu baseline[(1)]. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [(1)] ICAC White Paper.

First Energy Pulverized Coal, wall-fired,
Sammis Unit 2 (Ohio) 1960 vintage
180 MW Foster Wheeler boiler SNCR startup Fall 1999
Urea-based SNCR (Fuel Tech system) (eastern bituminous coal)
Fuel Tech claimed to lower NOx from 25-30% from 0.45 lb/mmBtu baseline [(1)]. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [(1)] ICAC White Paper.

First Energy Pulverized Coal, wall-fired,
Sammis Units 6 & 7 (Ohio) 1969 & 1971 vintage
680 MW B&W Universal Pressure boilers (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) SNCR startup after 1999
Fuel Tech claimed to lower NOx from 25% from 0.38 lb/mmBtu baseline. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers SNCR startup prior to 2000
Urea-based SNCR (Fuel Tech system)
Fuel Tech claimed 66% (50-75%) NOx reduction from baseline of 1.0 ± 0.1 (range 0.85-1.12) lb/mmBtu, (which would lower NOx to around 0.34±0.07 lb/mmBtu). Urea-to-NOx NSR not stated. {These NOx reduction percentages may include impact of low-NOx burners}.
Source: Fuel Tech experience list dated 1/28/2005, [(1)]ICAC White Paper.
(Also see LNB installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Schiller Units 4, 5, & 6 Pulverized Coal/#6 Fuel oil, front-wall-fired
50 MWe x 3Foster Wheeler boilers 1952, 1955, 1957 vintage
Urea-based SNCR (Fuel Tech system) Colombian bituminous coal
August 1999 startup
RJM implemented Fuel Tech urea-based commercial SNCR installation on all three boilers.

RJM claimed 50% reduction from 0.50 lb/mmBtu pre-SNCR baseline to 0.25 lb/mmBtu for SNCR coal-firing operation; NO_X baseline 0.82 lb/mmBtu prior to RJM's LNB modifications installed in 1994, 1992, & 1994 (39% reduction); Urea-to-NOx NSR not stated.
Fuel Tech claimed 30% NO_X reduction for SNCR from baseline of 153 ppm firing #6 fuel oil on Units 4 & 6 only.
Source: RJM experience list, Fuel Tech experience list dated 1/28/2005.

SELECTIVE NON-CATALYTIC REDUCTION continued
Pulverized coal-fired boilers
Owensboro Municipal Utilities (KY) Pulverized Coal, Tangentially-fired,
Elmer Smith Unit 2 1974 vintage
300 MW CE boiler eastern bituminous coal
Hamon Research-Cottrell supplied an ammonia-based SNCR system but stated no claims for NOx reduction; (this project is not listed in ICAC White Paper[(1)]). Ammonia-to-NOx NSR not stated.
Source: Hamon experience list.

PECO Energy (formerly Philadelphia Electric Company)
Cromby Unit 1 Pulverized Coal, front wall-fired divided furnace
160 MWe B&W boiler 1954 vintage eastern bituminous coal
RJM installed Fuel Tech urea-based SNCR with low NO_X burner modifications & OFA in 1999, June 1999 startup.
RJM claimed 29% SNCR NO_X reduction from baseline of 0.35 lb/mmBtu, down to 0.25 lb/mmBtu with urea NSR = 0.8; RJM provided burner modifications of B&W XCL low-NOx burners installed in 1994 + OFA; this reduced NO_X from 0.50 to 0.35 lb/mmBtu (30% reduction) without SNCR. Urea-to-NOx NSR not stated.
Source: RJM experience list; [(1)]ICAC White Paper.

Exelon (formerly PECO Energy/ Pennsylvania Electric Company)
Eddystone Units 1 & 2 Pulverized Coal Tangentially-fired, 1954 vintage
318, 333 MW each CE boilers 1999 SNCR startup, eastern bituminous coal
Fuel Tech claimed 30% NOx reduction from baseline of 0.26 lb/mmBtu.
Source: Fuel Tech experience list dated 1/28/2005.

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 25% (initial) NOx reduction for SNCR alone from baseline of 0.65 lb/mmBtu (down to 0.49 lb/mmBtu). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, also listed in [(1)]ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage April 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 30-35% NOx reduction from baseline of 2.0 lb/mmBtu on SNCR alone, down to 1.4 lb/mmBtu. Urea-to-NOx NSR not stated.

Source: Fuel Tech experience list dated 1/28/2005; also listed in [1]ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers)

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Reliant Energy (formerly GPU Genco) Pulverized Coal
(formerly Sithe, formerly Penelec) Tangentially-fired
Seward # 15 (PA) mid-1990's SNCR startup
Units 4 & 5 eastern bituminous coal
62 & 156 MW CE boilers 1950 & 1957 vintage
Urea-based SNCR (Fuel Tech system), later installed an in-duct SCR to reduce NH_3 slip.
Fuel Tech claimed to lower NOx 35% for SNCR only (55% for combined SNCR/SCR from 0.78 lb/mmBtu baseline). Boilers have since been demolished and replaced with CFBs. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [1]ICAC White Paper.

Rochester Gas & Electric Pulverized Coal, Tangentially-fired
Russell Station, Units 1-4 (NY) 1948, 1950, 1953, 1957 vintage
1 x 50 MW, 2 x 65 MW, 1 x 85 MW CE boilers eastern bituminous coal
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Vendor claimed to lower NOx by 15-27.5% from 0.28 – 0.42 lb/mmBtu baselines. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

HYDROCARBON-ENHANCED AMMONIA SNCR (NOxStar™)

Pulverized coal-fired boilers

Tennessee Valley Authority (TVA) Pulverized Coal twin-furnace, tangentially-fired,
Kingston Power Station (TN) 1955 vintage eastern bituminous coal
Unit 9, 200 MWe CE boiler NOxStar™ startup January 2002
Demonstration of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR installation.
Mitsui Babcock claimed 68% NOx reduction from baseline of 0.55 lb/mmBtu down to 0.17 lb/mmBtu with boosted OFA and NOxStar™ with < 5 ppm ammonia slip; NOxStar™ alone reduced NOx by 53%[22]; boosted OFA only reduced NOx from 0.55 to 0.45 lb/mmBtu (18% reduction). Ammonia-to-NOx NSR not stated.
TVA's website reported that "an earlier version of NOxStar was installed at Kingston Fossil Plant Unit 9 in 2002 with mixed results. NOx reductions were achieved, but the boiler was damaged" (http://www.tva.gov/environment/repotrs/envreports/aer/2003/env_compliance.htm)
Source: [22] Mitsui Babcock Technical paper, October 2003.

Tennessee Valley Authority (TVA) Pulverized Coal, wall-fired
Colbert Station (AL) 1955 vintage
Unit 4, 192 MWe twin-furnace B&W boiler w/ FGR eastern bituminous coal
First commercial installation of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR technology.
Mitsui Babcock showed 80% NOx reduction from baseline of 0.50 to 0.10 lb/mmBtu; using < 0.1% of total boiler heat input for propane input and 1% of total steam flow generated in the boiler for lance cooling[23]; 2004 SNCR system startup. Ammonia-to-NOx NSR not stated.
Source: [23] Mitsui Babcock 2004 Technical paper.

REBURN – GAS, CONVENTIONAL
Pulverized coal-fired boilers

Allegheny Power (formerly West Pennsylvania Power) Pulverized Coal, opposed wall-fired
Hatfield's Ferry Station cell-burner, 1969 & 1972 vintage
Units 2 & 3, 600 MW (nominal) each (B&W boilers) eastern bituminous coal
GE-EER Gas Reburn; 1999 startup (Unit 2) & 2003 (Unit 3)
GE-EER Low NOx burners, boosted OFA, gas reburn system.
GE-EER claimed to lower NOx up to 67% from baseline of 0.60 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation on Unit 2, 68% from 0.62 lb/mmBtu to 0.20 lb/mmBtu on Unit 3. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 35% NOx reduction at 600 MW load with LNB + OFA w/o reburn fuel, and an additional 50% reduction to 0.20 lb/mmBtu with reburn fuel[24].
B&W added 20 OFA ports in 1994 per B&W's experience list. No NOx reduction claims. Source: Sept. 2005 GE-EER experience list; [24] GE-EER 2004 Technical paper. Unit 2 and Unit 3 listed in [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL continued
Pulverized coal-fired boilers)

Conectiv (formerly Delmarva Power & Light) Pulverized Coal, Tangentially-fired
Edgemoor Unit 4 1966 vintage, eastern bituminous coal
160 MW CE boiler 1999 startup
GE-EER Gas Reburn project added gas supply piping, metering, hangers, supports, reburn injectors and cooling air piping; OFA ductwork, injection nozzles and wall ports, field instrumentation. No FGR or OFA booster fans.
Vendor claimed to lower NOx up to 48% from baseline of 0.32 lb/mmBtu to 0.16 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 32% NOx reduction for gas reburn with 4-mill operation at 160 MW load from 0.31 lb/mmBtu LNB + OFA baseline w/o reburn fuel (down to 0.21 lb/mmBtu), and 48% NOx reduction for gas reburn with 3-mill operation, to 0.16 lb/mmBtu [24].
Source: Sept. 2005 GE-EER experience list; [24] GE-EER 2004 Technical paper. Listed in [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)

Dynegy (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Hennepin Unit 1 1966 vintage
71 MW CE boiler eastern bituminous coal
GE-EER Gas Reburn, 1990 startup (not currently operating); GE-EER Orimulsion Reburn, 1997.
DOE Clean Coal demonstration project (included sorbent injection).
Vendor claimed gas reburn w/ OFA lowered NOx up to 67% from baseline of 0.75 lb/mmBtu to 0.25 lb/mmBtu) at full load; 65% reduction from baseline of 0.75 lb/mmBtu down to 0.26 lb/mmBtu with subsequent Orimulsion reburn operation.
GE-EER 2004 technical paper shows 18% gas reburn fuel yielded minimum NOx emissions[6].
Another technical paper showed this 80 MW US DOE Clean Coal demonstration project in January 1991-January 1993 lowered NOx by 67% from 0.75 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 18 percent reburn fuel[5].
Source: Sept. 2005 GE-EER experience list; [6] GE-EER 2004 Technical paper; [5] DOE-NETL 2004 Reburn Conference technical paper, and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Oil reburn installation summaries for pulverized coal boilers).

REBURN – GAS, CONVENTIONAL continued

Pulverized coal-fired boilers)

AES (formerly New York State Gas & Electric (NYSEG)

Greenidge #6 (NY)	Pulverized Coal, Tangentially-fired,	1953 vintage
100 MW CE boiler	GE-EER Conventional Gas Reburn, 1996 startup	

Vendor claimed to lower NOx 55% from 0.63 lb/mmBtu baseline to 0.28 lb/mmBtu at full load with reburn operation burning eastern bituminous coal. Gas Research Institute predicted would achieve 76% (down to 0.15 lb/mmBtu) w/ advanced gas reburn.
GE-EER 2004 technical paper shows 23% reburn fuel yielded minimum NOx emissions around 0.23 lb/mmBtu[(6)].
EPA's "Scorecard on Reburning 6/1/2004" shows a 109 MW t-fired boiler (listed as Greenidge Unit 4) lowered NOx by 50% from 0.50 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 10 percent reburn fuel (no longer operating) [(5)].
Source: Sept. 2005 GE-EER experience list; [(6)] GE-EER 2004 Technical paper; [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired B&W boilers
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	GE-EER Gas Reburn, 2000 startup	

Vendor claimed to lower NOx up to 43% and 45% from 0.60 lb/mmBtu baseline to 0.34 and 0.33 lb/mmBtu) at full load with reburn operation, respectively. No claims of percent reburn fuel included.
Source: 2002 GE-EER experience list. Listed in [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, 1962 vintage
175 MW B&W boiler	western bituminous coal
DOE Clean Coal demonstration project	November 1992-January 1995

Gas reburn demonstration performed with Dept. of Energy and Gas Research Institute 1992-1995.
Existing boiler with 16 burners was retrofitted with low NO_X burners and GE-EER gas reburn OFA, FGR, and reburn injectors. Added OFA booster fan, 800 hp flue gas recirculation fan for injection mass momentum, for increased gas injection mass momentum (which was subsequently removed). The CGR installation portion has since been decommissioned.
Vendor claimed to lower NOx up to 64% from baseline of 0.73 lb/mmBtu to 0.26 lb/mmBtu) at full load with reburn operation.
GE-EER 2004 technical paper shows 15-20% reburn fuel yielded minimum NOx emissions[(6)].
A 2004 DOE-NETL technical paper showed this project achieved 0.46 lb/mmBtu NO_X emissions with low NO_X burners alone (37% reduction), further reduced NO_X by 44% with 12.5 percent reburn fuel[(5)].
A 2001 DOE-NETL technical paper claimed a NOx reduction of 65% at an average reburn gas heat input of 18% of total boiler fuel input, with and without FGR. Demonstrated 70% NOx reduction at higher reburn input rates. Referred to technology as GR-LNB. FGR was added for gas injection momentum but was subsequently removed to reduce fuel input. [(25)]
Source: Sept. 2005 GE-EER experience list; [(6)] GE-EER 2004 Technical paper; [(5)] DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); [(25)] DOE-NETL 2001 Technical paper; also in [(9)] DOE 1999 Topical Report Number 14.

REBURN – OIL, CONVENTIONAL

Pulverized coal-fired boilers

Dynegy (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Hennepin Unit 1 1966 vintage, eastern bituminous coal
71 MW CE boiler 1997 startup
GE-EER Orimulsion Reburn system w/ OFA, claimed orimulsion reburn lowered NOx up to 65% from baseline of 0.75 lb/mmBtu to 0.26 lb/mmBtu at full load with Orimulsion reburn operation (installed after gas reburn was demonstrated in early 1990's). No claims for percent reburn fuel included.
GE-EER 2004 technical paper shows 60% reduction with subsequent Orimulsion reburn [(6)].
Source: GE-EER experience list; [(6)] GE-EER 2004 Technical paper. Orimulsion not mentioned in [(5)] DOE-NETL 2004 Reburn Conference technical paper or DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

New Brunswick Power
Coleson Cove, Bunker C/Orimulsion–fired, opposed-wall
St. John, New Brunswick, Canada
3x 350 MW B&W Boilers
Sixteen new low-NO_X oil/Orimulsion burners, eight reburn burners, nine SOFA ports, two combustion air booster fans, reburn and OFA wall penetration openings, OFA windboxes, ductwork, dampers, and accessories were added[(7)].
Another technical paper showed this reburn system lowered NOx by 78% from 1.0 lb/mmBtu baseline to 0.22 lb/mmBtu at 25 percent reburn fuel input[(5)].
Source: [(7)] B&W 2004 Technical Paper;[(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Georgia Power Pulverized Coal, Tangentially-fired
Scherer Unit 1 1982 vintage
887 MW CE boiler 2000 oil reburn startup
GE-EER Oil Reburn system, claimed to lower NOx from baseline of 0.36 lb/mmBtu.
GE-EER 2004 Technical paper shows reduction up to 48% (to 0.19 lb/mmBtu) at 800 MW load with oil reburn operation. No claims of percent reburn fuel included[(24)].
Source: Sept. 2005 GE-EER experience list shows this as a coal reburn project with eastern bituminous coal, reducing NO_X emissions 33% from 0.36 to 0.24 lb/mmBtu;
[(24)] GE-EER 2004 Technical paper. Not listed in [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Pulverized coal-fired boilers

AES (formerly New York State Electric and Gas Milliken Station Unit 1)
Cayuga tangentially-fired, pulverized coal, 1956 vintage
148 MWe, CE boiler eastern bituminous coal
GE-EER micronized coal reburn system 1996 startup (still operating)
US DOE Clean Coal demonstration project from March 1997-April 1999 lowered NOx with this reburn system by 29% from 0.35 lb/mmBtu baseline to 0.25 lb/mmBtu at 14 percent reburn fuel input[(5)]. Not listed in GE-EER's experience list nor in their 2004 technical paper.
Source: [(5)] DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL continued

Pulverized coal-fired boilers

E. ON US Holdings (formerly Louisville Gas and Electric)
R.D. Green Station Units 1 & 2 (KY) wall-fired, pulverized coal, vintage unknown
293 MWe, 2 boilers eastern bituminous coal
GE-EER coal reburn system Startup dates: 2003 & 2002, respectively
Vendor claimed to lower NOx up to 57% from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation.
Reburn system listed on EPA's "Scorecard on Reburning 6/1/2004" shows NOx lowered by 44% from baseline of 0.45 lb/mmBtu down to 0.25 lb/mmBtu (with unknown reburn fuel input[(5)]).
Another technical paper showed baseline NOx with existing low-NOx burners was 0.45 lb/mmBtu, and reduced NOx emission 40% to 0.27 lb/mmBtu with OFA, and further reduced NOx emissions 22% down to 0.21 lb/mmBtu with the coal reburn system in operation[26].
Source: [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
[(24)] GE Energy 2004 Technical paper, and [(26)] March 2004 Modern Power Systems issue.

Cheng Loong (not in United States)
Unit #1, 250 MWe wall-fired, bituminous pulverized coal, vintage & mfr unknown
GE-EER coal reburn system 2000 Startup (still operating)
Source: GE-EER experience list
Vendor claimed to lower NOx 44% from baseline 0.45 lb/mmBtu to 0.25 lb/mmBtu) at full load with OFA alone; further reduced NOx 28% to 0.18 lb/mmBtu, for 60% overall reduction. Recent (2004) data shows NOx down to 0.14 lb/mmBtu (69% overall) with up to 30 percent reburn fuel[(24)].
Source: [(24)] GE Energy 2004 Technical paper; GE-EER experience list. Listed in [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL w SNCR

Pulverized coal-fired boilers)

NRG Somerset Pulverized Coal, Tangentially-fired, vintage
Unit 6 Boiler 8 (NY) GE-EER Conventional Gas Reburn,
120 MW CE boiler Fuel Tech SNCR, 2003 startup
Reburn vendor claimed to lower NOx 55% from 0.45 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with reburn operation burning Venezuelan coal. The SNCR system further reduced NOx emissions 45% down to 0.11 lb/mmBtu, for an overall reduction of 77%.[(26)].
Source: Sept. 2005 GE Energy experience list; [(26)] March 2004 Modern Power Systems issue.

REBURN – FUEL LEAN GAS REBURN (FLGR)

Pulverized coal-fired boilers

Duke Power Company tangentially-fired, pulverized coal
Riverbend Unit 7 eastern bituminous coal 1954 vintage
140 MWe, CE boiler 1998 FLGR startup, gas reburn decommissioned since then
Previously installed ABB/CE's Low NOx Concentric Firing System (LNCFS-1) with Close-Coupled Overfire Air (CCOFA); (pre-mod NOx + combustion mods date not known).
Commercial FLGR installation claimed 34% NOx reduction from full-load baseline of 0.42 lb/mmBtu down to 0.29 lb/mmBtu w/ the combustion modifications and FLGR gas reburn fuel at 7% of total boiler heat input. CO emissions were above 1000 ppm corrected to 3% O_2.[(27)]
Vendor claimed to lower NOx 57% from 0.47 lb/mmBtu baseline to 0.20 lb/mmBtu) at full load with separated OFA alone; further reduced NOx 45% to 0.11 lb/mmBtu with low-NOx burners, OFA, gas reburn, and SNCR, for 77% overall reduction; no claims for amount of reburn fuel[(24)].

EPA's "Scorecard on Reburning 6/1/2004" showed this reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input[5].
Source: [27] ESA, GRI, NGB 1998 Technical paper; [24] GE Energy 2004 Technical paper; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – FUEL LEAN GAS REBURN (FLGR) continued
Pulverized coal-fired boilers
Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech listed FLGR installation and claimed 20% NOx reduction from baseline of 0.45 lb/mmBtu (to 0.36 lb/mmBtu). No claims of percent reburn fuel input included.
Source: Fuel Tech experience list dated 1/28/2005. [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see FLGR + SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR)
Pulverized coal-fired boilers
Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Commercial urea-based Fuel Tech SNCR +FLGR installation claimed 50% NOx reduction from baseline of 0.58 lb/mmBtu (426 ppm) down to 0.29 lb./mmBtu w/ 5 ppm ammonia slip[1]. Low NO_X burners were previously retrofitted in 1997 without separated overfire air[28]. This is 33 % lower than 0.44 lb/mmBtu baseline for SNCR alone. (Also see SNCR installation summaries for pulverized coal boilers). Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating[5].
Another technical paper showed 52% NOx reduction down to 0.28 lb/mmBtu at all loads, from 99 MWg to 207 MWg (48% to 100% MCR) with an average NH_3 slip of 3 ppm. FLGR alone achieved 23% NOx reduction with 6% reburn fuel and < 400 ppm CO at full load. [28]
Source: Fuel Tech experience list, [1]ICAC White Paper; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); [28] CP&L and Fuel Tech 2001 Technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Commercial SNCR + FLGR urea-based Fuel Tech installation claimed 40% NOx reduction from baseline of 0.65 lb/mmBtu (down to 0.39 lb/mmBtu) w/ 10 ppm ammonia slip[1]. This is 20 % lower than 0.49 lb/mmBtu baseline for SNCR alone. Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating[5].
Source: Fuel Tech experience list, [1]ICAC White Paper;[5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).
(Also see SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR) continued

Pulverized coal-fired boilers

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Mercer Station	(2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired	
Unit 1 and Unit 2	front wall PC, wet-bottom (slagging ash) eastern bituminous coal	
Furnace #11 & #12	1960 vintage	May 1999 startup
Furnace #21 & 22	1961 vintage	May 1999 startup

Commercial urea-based Fuel Tech SNCR + FLGR installation claimed 60% NOx reduction from baseline of 1.4 lb/mmBtu (down to 0.56 lb/mmBtu) w/ 5 ppm ammonia slip [(1)]. This is 72 % lower than 2.0 lb/mmBtu baseline without control. Initial demonstration of AEFLGR coinjected amine-enhanced natural gas into Furnace 22 in 1998. Subsequently installed AEFLGR on both units to reduce NOx starting in May 1999 using (2) levels of AEFLGR retractable gas injectors and (2) levels of SNCR injectors[(29)].
Urea-to-NOx NSR not stated, goal was NSR < 1.25.
{Note both units have since been retrofitted with low-dust tail-end SCRs in 2004; SNCR systems are still capable and operated as needed, mostly for flyash conditioning to aid ESP performance}
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 1999, but not currently operating[(5)].
Source: Fuel Tech experience list, [(1)]ICAC White Paper; [(29)] PSE&G, FT and ESA 2000 Technical paper;[(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Wisconsin Electric Power Company (WEPCO)

Pleasant Prairie Unit 1	DB Riley, turbo-fired PC, Powder River Basin coal	
620 MWg	1980 vintage	1999 startup

Fuel Tech urea-based SNCR +FLGR demonstration installation claimed 56% NOx reduction from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu w/ 5 ppm ammonia slip[(1)]. This is 44 % lower than 0.36 lb/mmBtu baseline for FLGR alone.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating[(5)].
Source: Fuel Tech experience list, [(1)]ICAC White Paper and F.T. experience list 0207;
[(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR

Pulverized coal-fired boilers

AEP Cardinal Unit 1	Pulverized Coal	cell-burner, opposed wall-fired B&W boiler
600 MW (nominal)	1967 vintage; Low NO_x burners installed in October 1998	

Produced 0.75 lb/mmBtu NOx post-LNB install baseline at full load.
LNBs reduced NO_X 57% from 1.20 down to 0.52*, produce NO_X at approx. 0.57 lb/mmBtu at min. load w/o SNCR (range 0.51 to 0.65) and produce 0.75 lb/mmBtu NO_X at approx. 585 MW (top of load range tested, NO_X range 0.73 to 0.86 lb/mmBtu) [(17)].
(50) original B&W circular burners were recently replaced on Cardinal Units 2 & 3 by Buckeye Power with DB Riley (now Babcock Power) CCV type low NOx burners.
Source: *Riley Power (Babcock Power Inc.) 8/16/04 experience list; [(17)] 2000 Fuel Tech technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)

Asheville Unit 1	Pulverized Coal, front wall fired
200 MWe DB Riley boiler	1964 vintage, eastern bituminous coal, June 2000 startup

Low NO_X burners were previously retrofitted in 1997 without separated overfire air[(22)]. NOx reduction was 46% from pre-LNB installation baseline of 1.08 lb/mmBtu [(12)] down to 0.58 lb./mmBtu [(28)].

(Also see SNCR, and FLGR with SNCR installation summaries for pulverized coal boilers).
Source: [12] 2005 US EPA Docket OAR-2002-0076-0446 Technical Support Document spreadsheet; [28] CP&L and Fuel Tech 2001 Technical paper.

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler ROFA startup in 2000
Mobotec USA's Rotating Opposed Fire Air (ROFA) is a high velocity boosted separated overfire air system claimed to lower NO_X without retrofitting low-NOx burners. This was the first U.S. installation of Mobotec USA's "Rotating Opposed Fire Air" (ROFA) on a utility boiler, which utilizes a booster fan.
CP&L technical paper claimed to lower NO_X 53% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.28 lb/mmBtu with ROFA alone following the installation of ROFA in 2000[18].
Source: [18] CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler ROFA startup in 2001
This unit's "ROFA" system was installed as part of a "Rotamix" SNCR + ROFA system.
CP&L technical paper shows ROFA alone reduced NOx 57% from full-load pre-ROFA baseline 0.54 lb/mmBtu to a NO_X emission rate of 0.23 lb/mmBtu. [18]
Source: [18] CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Conectiv (formerly Delmarva Power & Light)
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers eastern bituminous coal
REI performed CFD modeling on both units for potential SNCR application.
Unit 3 has Riley Low NOx burners (16), (8) front wall and (8) rear wall OFA ports, (8) wall boundary air ports, (66) side wall OFA slots, claimed baseline NOx around 0.37 lb/mmBtu w/o SNCR [20].
Unit 4 has (24) front and rear wall down-fired burners, (28) front and rear wall SOFA ports, claimed NOx around 0.44 lb/mmBtu w/o SNCR [20] {furnace has "Mae West" belt}.
Riley provided 16 CCV low-NOx burners for Unit 3 in 1994, and claimed to reduce NOx emissions by 67% from pre-LNB baseline of 1.05 lb/mmBtu down to 0.34 lb/mmBtu.
Source: [20]REI 1999 Technical Paper; Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see SNCR installation summaries for pulverized coal boilers).

Dayton Power & Light Pulverized Coal, Tangentially-fired
Killen Station, Unit 2 1955 vintage
632 MW CE boiler, bituminous Illinois coal
GE-EER provided low-NOx burners in 1999. Vendor claimed full load NO_X was reduced by 23% from a 0.57 lb/mmBtu baseline down to 0.44 lb/mmBtu.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, wall-fired
Havana Station, Unit 6 1978 vintage
460 MW B&W boiler, bituminous Illinois coal
GE-EER provided modifications to the original B&W dual-register burners, and an OFA system in 2000.
Vendor claimed full load NO_X was unchanged from 0.38 lb/mmBtu baseline.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
This rotating opposed fire air (Mobotec USA ROFA) system was installed in July 2002, as part of a "Rotamix" SNCR + ROFA system, without low-NOx burners.
Mobotec 2004 technical paper claimed to lower full load NO_X by 62% from 0.58 lb/mmBtu baseline to 0.22 lb/mmBtu in July 2002 (without LNB or SNCR). [21]
Source: [21] Mobotec 2004 technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Georgia Power Pulverized coal, opposed wall-fired,
Harlee Branch Unit 1 250 MW B&W boiler, 1965 vintage 2003 startup
Harlee Branch Unit 2 359 MW Riley boiler, 1967 vintage 1998 startup
B&W provided 24 DRB-4Z low NOx burners for Unit 1 B&W boiler, 24 DRB-XCL low NOx burners for Unit 2 Riley boiler (believe southeast coast lignite is primary fuel).
Source: B&W's experience list. No NOx reduction claims.

Kansas City Power & Light Pulverized coal, opposed wall-fired, 600 MW B&W boiler
Hawthorn Unit 5 30 burners, 2001 vintage, (Powder River Basin coal)
B&W provided 30 DRB-4Z low NOx burners and 11 OFA ports with the new boiler.
Source: B&W's experience list. No NOx reduction claims.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers LNBs startup in 1995, 1995, and 1993
Riley claimed Unit 1 LNBs reduced NOx emissions by 57% from baseline of 1.10 lb/mmBtu down to 0.42 lb/mmBtu; Unit 2's LNBs achieved 42% NOx reduction from a baseline of 0.95 lb/mmBtu down to 0.55 lb/mmBtu; Unit 3's LNBs achieved 60% NOx reduction from a baseline of 1.05 lb/mmBtu down to 0.42 lb/mmBtu.
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list.
(Also see SNCR installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Shiller Station Pulverized Coal/#6 Fuel oil, front-wall-fired
Units 4, 5, & 6 1952, 1955, 1957 vintage
50 MWe x 3 Foster Wheeler boilers
RJM provided (6) Low NO_x burner modifications per boiler in 1994, 1992, & 1994 respectively;
LNBs reduced NOx 43% from 0.85 to 0.48, 50% from 1.0 to 0.50, and 51% from 0.82 to 0.40 lb/mmBtu.
Source: RJM experience list

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	B&W boilers	

DB Riley (now Babcock Power) CCV type low NOx burners retrofitted in 1993 and 1994, respectively. Vendor claimed to lower NOx up to 52% and 50% from 1.35 and 1.40 lb/mmBtu baselines (to 0.65 and 0.70 lb/mmBtu, assumed at full load).
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, B&W boiler, 16 burners, 1962 vintage
175 MW	October 1992 baseline testing started (western bituminous coal)

Installed (16) Foster Wheeler Controlled Flow/Split Flame low NO_x replacement burners as part of a DOE Clean Coal Technology gas reburn demonstration performed with Gas Research Institute 1992-1995.
Uncontrolled NOx w/ original B&W flare-type burners was 0.73 lb/mmBtu. Replacement LNBs (assuming OFA included) reduced NO_X 37% to 0.46 lb/mmBtu[25].
Source: [25] DOE NETL 2001 Technical paper.

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* * * * *

APPENDIX B

EERC REPORT

Ash Impacts on SCR Catalyst Performance

ASH IMPACTS ON SCR CATALYST PERFORMANCE

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ASH IMPACTS ON SCR CATALYST PERFORMANCE

EXECUTIVE SUMMARY

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems. The Center lignite fired at the Milton R. Young (MRY) Power Station is highly variable in abundance of various types of ash/slag-forming components. Ash-forming components consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements combine with minerals during combustion, resulting in low-melting-point phases that cause a wide range of fireside deposition problems. In addition, the alkali and alkaline-earth elements also form very small particles that are carried into the backpasses of the combustion system and react with flue gas to form sulfates that can cause deposition, blinding, and plugging problems in selective catalytic reduction (SCR) systems. This report analyzes these problems, and concludes that SCR is not a feasible option to control NOx emissions at MRY Power Station because of the high sodium levels present in the coal.

Following is a list of the key problems that are associated with Center lignite which have not been overcome and, in our opinion, make the installation of SCR at the MRY plant technically infeasible for NO_x control.

- Blinding of Catalyst Pores by High Sodium Compounds

  X High levels of alkali and alkaline-earth elements present in the coal fired at the MRY plant produce small particles that react to form sulfates that blind the catalyst pores. The high levels of sodium in the coals combined with calcium will produce low-melting-point eutectic sulfate compounds that will form and melt inside the pores of the catalyst.

  - Alkali and alkaline earth sulfates are enhanced by cyclone fired system. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the ash as a a result of cyclone firing.

  - Sulfate formation is enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.

  - The sulfate reactions are more severe at MRY because of the high temperature where an SCR would be installed. The higher temperature increases the rate of formation of sulfates and rate of pore plugging.

  - The testing conducted by the Germans found catalyst deactivation and blinding occurs when firing coals with lignite or brown coals that have ashes that are rich in alkali and alkaline-earth elements. .

- The findings by the Germans were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or "popcorn ash," plugging the top of the SCR catalyst is a significant problem because of the extremely high deposition rates of the Center coal. When firing Center coal, deposits form on various parts of the boiler requiring continuous sootblowing. The sootblowing of upstream heat-exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, resulting in plugging. In addition, during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

- Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

➢ Cold Side SCR Installation

- High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces significant levels of homogeneously condensed sodium sulfate that pass through the ESP and wet scrubber.

- These small particles have been shown to pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials require sootblowing to remove the particulate and will result in increased opacity.

- Liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems are known to catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates.

ASH IMPACTS ON SCR CATALYST PERFORMANCE

INTRODUCTION

Ash produced during combustion of coal in conventional power systems is a major problem that results in decreased efficiency, unscheduled outages, equipment failures, and increased cleaning. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include fireside ash deposition on heat-transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Decades of research have been conducted to develop a better understanding of the chemical and physical processes of ash formation and deposition in combustion systems. Overviews of ash-related issues and compilations of work by many investigators can be found by referring to the work of Mehta and Benson (1), Schobert (2), Baxter and DeSollar (3), Couch (4), Williamson and Wigley (5), Benson and others (6), Benson (7), Bryers and Vorres (8), Raask (9, 10), and Benson (11). This work has led to a detailed understanding of ash formation and behavior in combustion systems as well as the development of predictive methods (12, 13).

The chemical composition and physical characteristics of ash-forming or inorganic components (mineral and organically associated elements) of the fuel(s) fired have an influence on the following processes in the combustion systems:

- Firing conditions such as cyclone, pulverized coal, and low-NO_x burners
- Transformations of coal inorganic components to ash particulate and vapor-phase species
- Boiler design characteristics, including number of burners, radiant section area, tube bank spacing, access for cleaning, and number of sootblowers
- Ash transport to heat-transfer surfaces in utility boilers
- Erosion wear and sticking
- Ash deposit growth and impact on heat transfer
- Ash blinding and plugging of selective catalytic reduction (SCR) catalysts
- Ash deposit removability

The ash deposition in North Dakota lignite-fired power plants is a major problem that impacts all fireside surfaces of the power plant. The ash problems are due to the variable and complex nature of inorganic components associated with lignite coals (2). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, thermophoresis,

and inertial impaction. The particle sticking and accumulation rates are dependent upon the quantity of ash and the abundance and viscosity of the liquid-phase components. In high-temperature regions of the boiler, high-temperature sodium–calcium–aluminosilicate liquid phases act as the sticky material, causing deposit initiation, growth, and development of deposit strength. As the temperature of the flue gases decreases, the condensation and reaction of flame-volatilized species play a more significant role in the formation of deposits from lignite coals. The formation of sodium and/or calcium magnesium sulfates dominates the deposit accumulation mechanisms at lower temperatures. The aluminosilicate phases are dominant above about 1800°F. Below about 1800°F, the sulfate phases become stable, with an optimum temperature of formation of about 1400°F, and can form at temperatures as low as 300°F.

The most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16).

INORGANIC COMPOSITION OF LOW-RANK COALS

Inorganic elements in coal occur as discrete minerals, organically associated cations, and cations dissolved in pore water. The fraction of inorganic components that are organically associated varies with coal rank. Lower-ranked subbituminous and lignitic coals have high levels of oxygen, which act as bonding sites for cations such as sodium, magnesium, calcium, potassium, strontium, and barium (other minor and trace elements may also be present in this form). In higher-ranked coals, bituminous and anthracite, inorganic components consist mainly of minerals. Mineral grains are usually the most abundant inorganic component in coal. The major mineral groups found in coals include silicates, aluminosilicates, carbonates, sulfides, sulfates, phosphates, and some oxides.

The behavior of ash produced during coal combustion is related to the abundance, size, and association of mineral grains in the coal. In addition, the association of the mineral grain with the coal matrix influences the temperature and gaseous environment the mineral is exposed to during combustion. A mineral associated with the organic part of a coal particle is said to be included. A mineral that is not associated with organic material is referred to as excluded. The behavior of the organically associated elements, those elements that are atomically dispersed in the coal matrix, must also be measured as to their abundance in the coal. The organically associated elements will react and interact with the other ash-forming constituents during combustion.

The Center lignite is highly variable in abundance of various types of ash/slag-forming constituents. Ash-forming components in the Center lignite are of two types. The first form may constitute up to 50% of the ash and is derived from inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix of the coal. The second type consists of mineral grains (sand, clay, limestone, and pyrite). The minerals are discrete particles of ash-forming species and the sources of silicon, aluminum, iron, titanium, and minor amounts of the calcium and potassium. The Center lignite fired at the Milton R. Young (MRY) plant has been examined extensively because of its problem with ash behavior. Analyses

of as-fired and drill core samples have been conducted. The mean and the range of selected components are shown in Figure 1. The results indicate that both the abundance of ash and the abundance of major oxides in the ash vary significantly. In addition, the abundance of alkali and alkaline-earth elements (Na and Ca) varied dramatically. Variations in Si were found to be the most significant. High levels of Ca and/or Na were found for lower-ash coals as compared to high levels of Al and Si associated with higher-ash coals (17, 18).

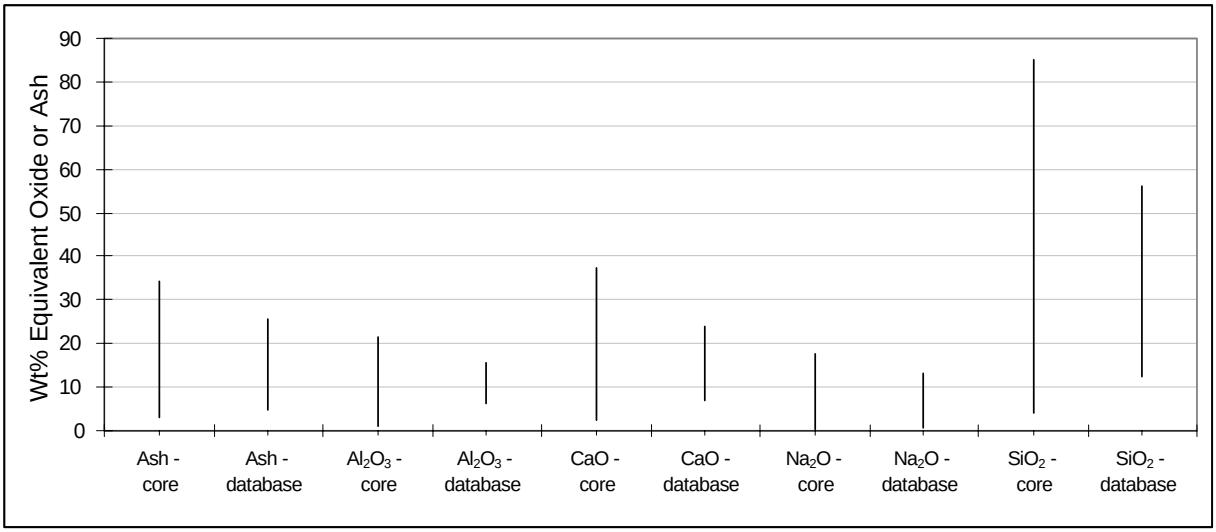

Figure 1. Variability of ash and selected constituents in core analysis database provided by BNI Coal, Ltd. and Minnkota as fired coal analysis database.

The variability of the ash-forming components has been examined for the approximately 5000 samples characterized to date. Wide variations in ash contents and the major ash-forming constituents are observed. During the mining processes, the inorganic components are mixed, and some of the extreme characteristics are diluted (17).

INORGANIC TRANSFORMATIONS AND ASH FORMATION

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species. The inorganic species consist of vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions.

The physical transformation of inorganic constituents depends on the inorganic composition of the coal and combustion conditions. The inorganic components can consist of organically associated cations, mineral grains that are included in coal particles, and excluded mineral grains. There is a wide range of combinations of mineral–mineral, mineral–coal,

mineral–cation–coal, and mineral–mineral–cation–coal associations in coal. These associations are unique to each coal sample.

The physical transformations involved in fly ash formation include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the ash has a bimodal size distribution. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The mass mean diameter of the larger particles is approximately 12 to 15 µm, depending upon the coal and combustion conditions. The larger-size particles have been called the residual ash by some investigators (19) because these ash particles resemble, to a limited degree, the original minerals in the coal. Processes such as ash mineral coalescence, partial coalescence, ash shedding, and char fragmentation during char combustion and mineral fragmentation, all play an important role in the size and composition of the final fly ash. Loehden and others (20) and Zygarlicke and others (21) indicate that three potential modes for fly ash generation can be used to describe fly ash particle-size and composition evolution. The first, "fine limit," assumes that each mineral grain forms a fly ash particle and that the organically associated elements form fly ash particles of less than 2 µm. The second, "total coalescence," assumes one fly ash particle forms per coal particle. The third, "partial coalescence," suggests that the fly ash composition and particle size evolve because of partial coalescence.

The transformations of excluded minerals are dependent upon the physical characteristics of the mineral. Excluded minerals such as quartz (SiO_2) can be carried through the combustion system with its angular structure still intact. Excluded clay minerals can fragment during dehydration, melt, and form cenospheres. The behavior of excluded pyrite depends upon its morphology. Some of the pyrite may be present as framboids. Framboidal pyrite may fragment more easily than massive pyrite particles. In addition, the decomposition of pyrite is very exothermic, and it transforms to pyrrhotite and oxidizes to FeO, Fe_3O_4, and Fe_2O_3 during combustion.

ASH DEPOSITION ON HEAT-TRANSFER AND OTHER SURFACES EXPOSED TO ASH AND FLUE GAS

The characteristics of a deposit depend upon the chemical and physical characteristics of the intermediate ash species, geometry of the system (gas flow patterns), gas temperature, gas composition, and gas velocity. Figure 2 illustrates the ash deposition phenomena in utility boilers. Ash particle accumulations occur via transport of particles to the fireside surfaces (heat transfer, ceramic materials, support materials, SCR catalysts, baghouse materials, and ESP wires and plates) and sticking of the particles. The transport mechanisms important for ash deposition include small-particle mechanisms for particles less than 10 µm that involve thermophoresis, electrophoresis, and vapor-phase and small-particle diffusion; and large-particle mechanisms for particles greater than 10 µm that involve inertial impaction. The ability of larger particles to stick depends upon the quantity and viscosity of the liquid phase on the particle surface.

Thermophoresis is a phenomenon that involves the transport of very small particles as a result of a thermal gradient from hot gases to cooler surfaces. Electrophoresis is the transport of particles because of a difference in charge. Vapor-phase and small-particle diffusion occurs in the boundary layer next to the surface and results in transport of ash to the surface. Inertial impaction is a larger-particle phenomenon where the particles are of a sufficient size and density to leave airflow patterns around the tube and impinge upon the surface of a tube or deposit. Deposits that form in high-temperature regions of the boiler, such as the radiant section, are called slag deposits. Deposits that form in lower-temperature regions of the boiler, such as in the convective pass on steam tubes and lower-temperature surfaces such as SCR catalysts, are called fouling deposits. Slag deposits are usually associated with a high level of liquid-phase components and are exposed to radiation from the flame. This is a description that many researchers use to aid in classification of deposits since some engineers call any type of deposit "slag". Slag deposits are typically dominated by silicate liquid phases, but may also contain moderate to high levels of reduced iron phases such as FeO and FeS. The liquid characteristics of the silicates are highly dependent upon the quantities of Na, Mg, Ca, K, and Fe ash on the silicates. In addition, the initiating layers of slag deposits may consist of very fine particulate and can produce a reflective ash layer. This phenomenon is especially evident when high organically associated calcium subbituminous coal is fired. These coals produce small CaO particles that usually form the initiating layers.

Fouling deposits form in the lower-temperature regions of the boilers and, in most cases, do not contain the high levels of liquid phases that are usually associated with slagging-type deposits. Fouling deposits contain lower levels of liquid phases as compared to slag deposits. The fouling deposit liquid phases usually consist mainly of sulfates that bind the particles together. Fouling deposits typically form as a result of the reaction of gas-phase sulfur oxide species with particles rich in alkali and alkaline-earth elements.

ASH-RELATED EXPERIENCES AT MRY FACILITY

The MRY is a minemouth electrical generating plant located near Center, North Dakota. The station consists of two units: Unit 1, rated at 276 MWg, began production in 1970; Unit 2, rated at 506 MWg, began production in 1977. Both Units 1 and 2 are equipped with B&W cyclone-fired boilers; the Unit 1 boiler has seven cyclones, and the Unit 2 boiler has twelve cyclones. Annual station gross generation is approximately 5.5 million MWh.

BNI Coal Ltd. is the sole coal supplier for the MRY Station. Coal is mined from the nearby Center mine, which consists of three distinct seams varying from 2½–9 feet thick. Coal is strip-mined using two draglines and is loaded with front-end loaders and delivered to the plant with bottom-dump haul trucks. Annual coal production is 4.3 million tons per year.

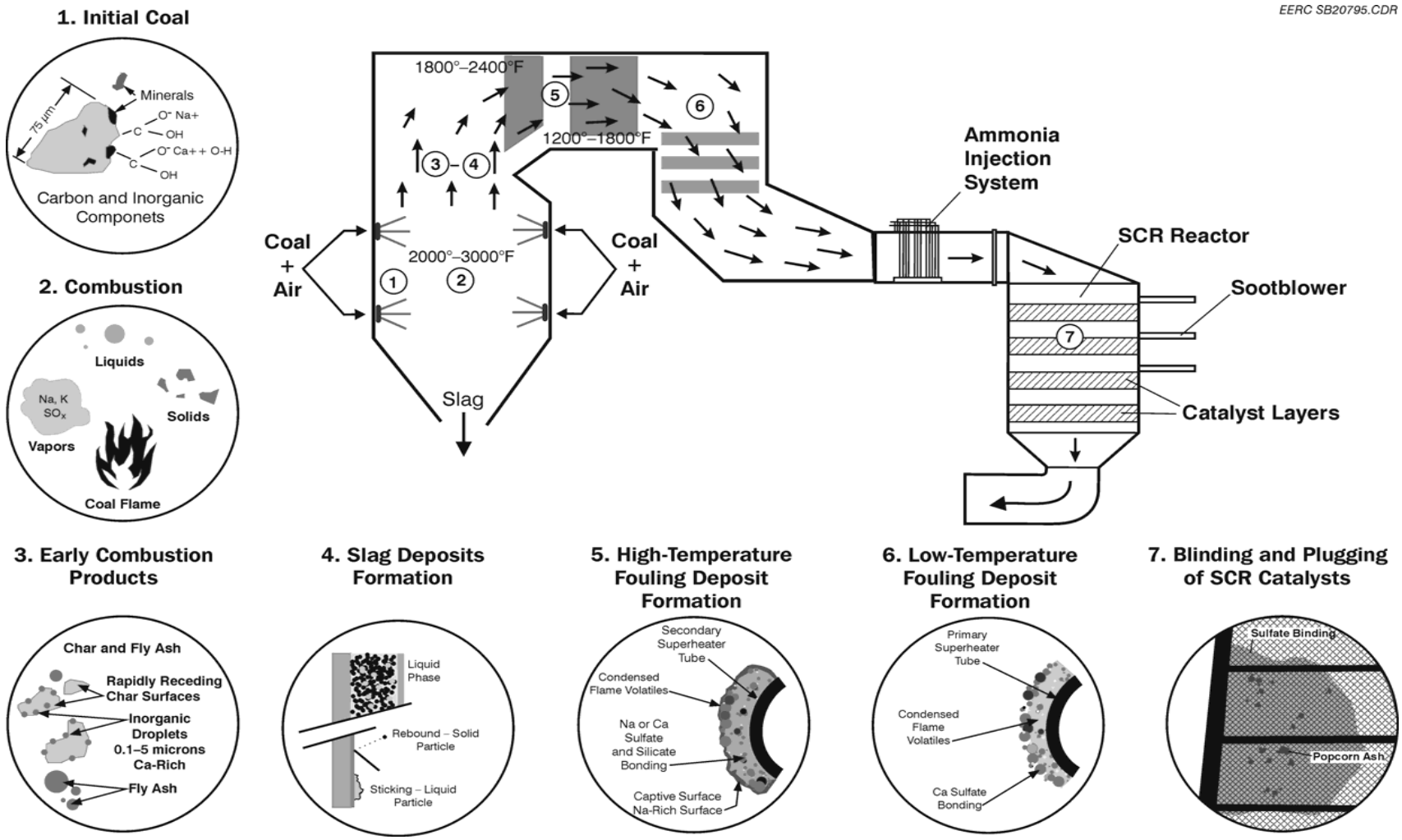

Figure 2. Overall processes of ash deposition typical of a lignite- or subbituminous-fired boiler.

History of Furnace Slagging/Fouling

Prior to 1991, besides annual maintenance outages, load reductions and forced outages due to furnace slagging/fouling were the largest cause of production loss. In 1985, operating guidelines were established that reduced furnace slagging/fouling, including deslagging outages scheduled every six months.

In 1991, a 3-month boiler cleaning cycle was proposed and initiated. The goal of this program was to increase annual generation by running the units at higher sustained loads and scheduling boiler-cleaning outages at 3-month intervals. However, furnace slagging/fouling continued to have a significant impact on plant operations. Success was measured in the number of production days between boiler-cleaning outages.

During the mid-1990s, a major outage every third year was scheduled for each unit. In addition, Unit 1 cleaning outages were scheduled for 80–90-day runs (four cleaning outages per year), and Unit 2 cleaning outages were scheduled for 65–75-day runs (five cleaning outages per year). The problem was that furnace and convection-pass surfaces gradually become coated with ash deposits, which, over time, sootblowers cannot remove. Some of the contributors to the ash deposits were as follows:

- Organically associated sodium is a primary contributor to deposition problems. Sodium is vaporized in the cyclones and condenses on other ash particles, causing them to become sticky and deposit at the furnace exit. The problem is associated with sulfate formation and occurs in the convective pass, including the economizer. Samples show that sodium in the ash varies from 0.6%–13.0%.

- Organically associated calcium is another component that causes deposition problems. Unlike sodium, calcium does not produce a vapor-phase component. Calcium does react with silicate (derived from clays) to cause low-melting-point phases that produce wall deposits and deposits in the high-temperature regions of the convective pass. Calcium also produces very small particles that will be transported to heat-transfer surfaces, resulting in the formation of thin, light-colored layers called reflective ash. These small particles of ash are carried through to the back passes where they are sulfated and can combine with sodium to cause the formation of strongly bonded sulfate-based deposits. Samples show that calcium in the ash varies from 6.8%–24.0%.

- Clay minerals and quartz – Center lignite can contain high levels of illite, which has a 1:3 Al:Si ratio and high levels of potassium, both of which cause wall slagging and high-temperature fouling. Quartz and other clays can significantly contribute to the mass of the deposits. Samples show that ash content varies from 5.0%–25.5%.

Advanced Boiler Performance Indices

Advanced indices are used to relate the coal characteristics as determined by computer-controlled scanning electron microscopy (CCSEM) and chemical fractionation to ash behavior in a coal-fired utility boiler (12). Fuel performance is estimated in terms of slag flow behavior,

abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling. The following indices are used to assess the effects of ash behavior on utility boiler performance:

- Convective-Pass Fouling Indices

Sulfation Index: Indicates the propensity of deposit to form in the convective pass of the utility boiler in the temperature range from 1000°–1750°F. This index is based on the availability of alkali (Na and K) and alkaline-earth (Ca and Mg) elements to react with SO_2 and SO_3 to form sulfates. The sulfates are the primary materials that cause particle-to-particle bonding in high-calcium coals. The sulfates are thermodynamically stable at temperatures below about 1650°F. Index values range from 1 (low) to 10 (severe).

Silicate Index: Indicates the propensity of deposits to form from 1600°–2400°F. This index is related to the formation of deposits in which the silicate material is the primary component that bonds the deposits together. The information used to derive the index includes the size of the minerals such as quartz and clay minerals, availability of alkali and alkaline-earth elements, and viscosity of the silicate liquid phase. Index values range from 1 (low) to 200 (severe).

- Waterwall Slagging

Slagging Index: Indicates the propensity of a deposit to form on the radiant walls from 2000°–3000°F. The basis of the slagging index is the size of the minerals (especially the illite, quartz, and pyrite), association of the calcium (calcite can contribute to slagging), and viscosity of the silicate-based liquid phase. Index values range from 1 (low) to 20 (severe).

- Wear Indices

Abrasion Index: This index indicates the potential for wear of fuel preparation and handling equipment. The wear is related to the hardness of minerals in the coal. The primary minerals of concern include quartz and pyrite. The index values range from 0.1 (low) to 10 (severe).

Erosion Index: This index indicates the potential for wear of boiler parts due to the impaction of fly ash particles. The erosion index is dependent upon the size of the ash/mineral particle, size of the particle, and velocity of the particle. The index values range from 0.1 (low) to 1.0 (severe).

- Cyclone Slagging Index: This index provides information on the slag flow behavior in cyclones. The factors that are included in this index include the partitioning of the ash in the cyclone based on size and association of the ash-forming components in the coal. The partitioning of the ash between the slag and entrained ash can significantly influence the flow behavior of the slag. Standard partitioning criteria have been developed to provide the composition of the slag. The composition is used to estimate the viscosity of the slag as a function of temperature. The index values have several ranges as follows: 1 (low viscosity), 1.5–2.5 (optimum viscosity), >3.0 (slag freezing).

- Strength Development Index: The strength index is based on the ability of the deposited material to develop strength. Strength development is primarily dependent upon the abundance and viscosity of the liquid-phase components in the deposits. Index values less than 0.25 indicate that the material will produce weak deposits; index values of 0.25–0.34 indicate weak-to-moderate-strength deposits; index values of 0.34–0.41 indicate high-strength deposits; and index values >0.41 indicate flowing slag.

Indices were calculated for a range of coals from the Center mine, and the propensity for ash deposition in various portions of the boiler indicates wide variations, as shown in Table 1. The BNI numbers indicate the location in the seams where the coal originated: Kinneman Creek seam (KC), Hagel A (HA), and Hagel (HB). Each seam has a different distribution of minerals and organically associated elements that can have a significant impact on the formation of deposits in the system. Comparison of Center lignite to subbituminous and bituminous coals from other regions of the United States, shown in Table 2, indicates significant differences in the potential to form deposits in the boilers. In all cases, the lignite (not the worst coal from Center mine) from the Center mine has a high propensity to produce deposits as compared to the other coals.

Another indication of the variability of lignites can be illustrated based on the calculation of the temperature where the slag flow would occur. This is defined as the T250 temperature, where the slag viscosity is 250 poise. Frequency distributions of the T250 values for all the data for coals analyzed are illustrated in Figure 3. Calculations of T250 values for 1212 samples obtained from the Center mine database (17) were made using empirical relations derived from CCSEM and chemical fractionation data and knowledge of how ash partitions in the cyclone. Figure 3 shows a bimodal distribution in the T250 based on the Urbain equation calculations. The primary mode was at a value of 2000°F. The secondary mode was at about 2700°F. The results indicate that many of the coals have a sufficiently low T250 for good slag flow. However, coals with T250 at 2700°F are not suitable for maintaining good slag flow.

Figures 4 through 6 illustrate the variations in T250 for the various seams of coals characterized. The HA and HB seam coals appear to have large numbers of samples, with T250 values at or near 2000°F. The KC seam coal, as illustrated in Figure 6, has extremely high T250 values. Based on these data, the KC coals are not favored relative to the slag flow behavior of the ash.

Frequency distributions of cyclone slagging index values indicated significant variations in slagging potentials of coals mined from the three seams, KC, HA, and HB. This information proved particularly useful in planning the mining and firing of coal from the KC seam.

During a July 1999 test burn, the composition of the cores was used to examine and illustrate the variability of the delivered coal quality based on base-to-acid ratio calculated from the ash composition. Figure 7 shows the variation in the base-to-acid-ratio and the seam where the coal was loaded. The base-to-acid ratios were calculated from core data that corresponded to the location in the seam where the coal was mined. There is a significant variation in the base-to-acid ratio for the coals. The coals that have the highest base-to-acid ratio are typically from the HA seam. HB seam coals generally have an intermediate base-to-acid ratio. KC or top-seam coal has the lowest base-to-acid ratio. Lower base-to-acid-ratio coals typically produce slag with high viscosities.

Table 1. Characteristics and Indices Calculated for Selected Center Lignite Samples

BNI No.	41-132HB	41-44KC	41-144HA	41-144HB	41-168KC	41-168HA	41-168HB	41-180KC	41-180HA	41-180HB	41-192KC	41-192HA
Mineral wt%, mineral basis												
Total Quartz Content			18.8	9.8	30.3	8.7	8.8	11.4	20.0	3.9	15.0	17.4
Quartz <10 microns		10.8		6.4	24.6	4.4	4.0	6.8	3.3	2.6	9.7	12.7
Total Kaolinite Content		10.6		10.8	7.7	6.4	1.7	9.5	4.4	2.4	14.3	28.0
Kaolinite Content <10 microns		5.1		6.3	4.5	2.6	0.9	4.8	1.1	0.9	10.2	20.8
Total Montmorillonite		10.7		2.7	6.5	1.7	6.1	7.0	2.3	2.4	7.6	5.1
Total Illite		14.1		9.3	6.6	0.2	28.0	19.1	10.2	1.6	6.8	1.9
Total Pyrite		8.0		26.7	18.9	67.1	19.7	9.1	10.9	57.2	22.6	32.3
Pyrite Content <10 microns		4.5		10.5	2.8	9.8	4.7	2.5	2.5	17.0	6.6	7.0
Gypsum Content		6.5		0.0	1.6	2.7	0.8	5.4	0.0	16.1	2.2	0.0
Proximate (wt% as received)												
Moisture		30.95		41.66	36.24	38.23	37.50	37.90	37.99	38.21	37.85	39.52
Volatile Matter		27.26		25.74	26.32	25.90	24.55	25.11	24.42	25.88	26.13	24.27
Fixed Carbon		26.56		27.97	28.18	29.65	30.37	27.94	29.53	31.54	29.15	30.30
Ash		10.30		4.63	9.26	6.22	7.58	9.05	8.1	4.37	6.88	5.91
Total Sulfur (% as received)		0.94		0.55	1.49	1.08	0.75	0.99	0.64	0.86	0.90	0.85
Btu/lb		6597		6593	6791	6957	6806	6584	6653	7194	6881	6835
% Ash (dry basis)	11.64	10.30		7.94	14.52	10.07	12.13	14.57	13.00	7.07	11.07	9.77
Ash Comp. (wt% equiv. Oxide)												
Na_2O		0.50		10.65	0.82	9.25	8.02	0.46	8.15	11.99	1.48	9.69
MgO		3.30		5.74	3.72	4.90	4.45	3.90	5.00	4.59	6.13	5.10
Al_2O_3		11.90		10.37	9.34	5.64	11.81	12.12	10.19	5.23	10.59	7.46
SiO_2		30.60		14.70	33.71	8.47	30.74	35.57	36.25	5.31	25.80	13.06
P_2O_5		0.20		0.06	0.15	0.42	0.25	0.07	0.26	0.23	0.25	0.24
SO_3		23.00		25.50	21.28	35.25	21.05	18.32	15.93	35.75	24.15	32.75
K_2O		1.20		0.96	0.47	0.62	1.52	1.03	1.22	0.47	0.55	0.60
CaO		16.80		21.00	15.31	18.94	12.10	17.15	14.87	15.43	20.01	18.98
TiO_2		1.30		0.39	0.72	0.29	0.40	0.51	0.29	0.16	0.48	0.28

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MnO		0.20		0.03	0.07	0.05	0.04	0.10	0.07	0.04	0.07	0.12
Fe_2O_3		10.30		8.43	14.87	15.95	10.44	7.80	6.84	18.88	10.12	13.29
Cyclone Slagging Index		2.77		1.28	2.5	1.1	2.6	3.3	2.9	0.4	2.2	1.3
Silicate		10.71		102.43	29.47	108.33	109.93	16.29	176.22	137.49	14.19	149.54
Sulfate		9.43		3.57	2.2	5.01	3.46	1.75	3.98	4.4	2.21	3.24
Wall Slagging Index		1.18		11	2.67	10.68	9.27	1.79	8.83	12.63	2.2	10.53
Erosion Index		0.19		0.15	0.17	0.19	0.22	0.21	0.27	0.17	0.17	0.17
Abrasion Index		2.14		0.71	6.46	1.55	1.41	2.25	1.93	0.83	1.75	1.68
Strength Index		0.32		0.66	0.35	1.11	0.35	0.3	0.33	1.32	0.43	0.63

Table 2. Advanced Index Values for Other Coals (12)

Advanced Indices	Lignite North Dakota	Powder River Basin	Bituminous Illinois	Bituminous Appalachian
Cyclone Slagging Index	1.6	2.1	3.5	3.2
Convective Pass Fouling				
Silicate	61.8	23.99	10.36	14.21
Sulfate	4.09	2.88	0	0
Wall Slagging Index	9.28	1.85	1.53	1.66
Erosion Index	0.15	0.17	0.14	0.17
Abrasion Index	0.71	1.96	3.94	1.96

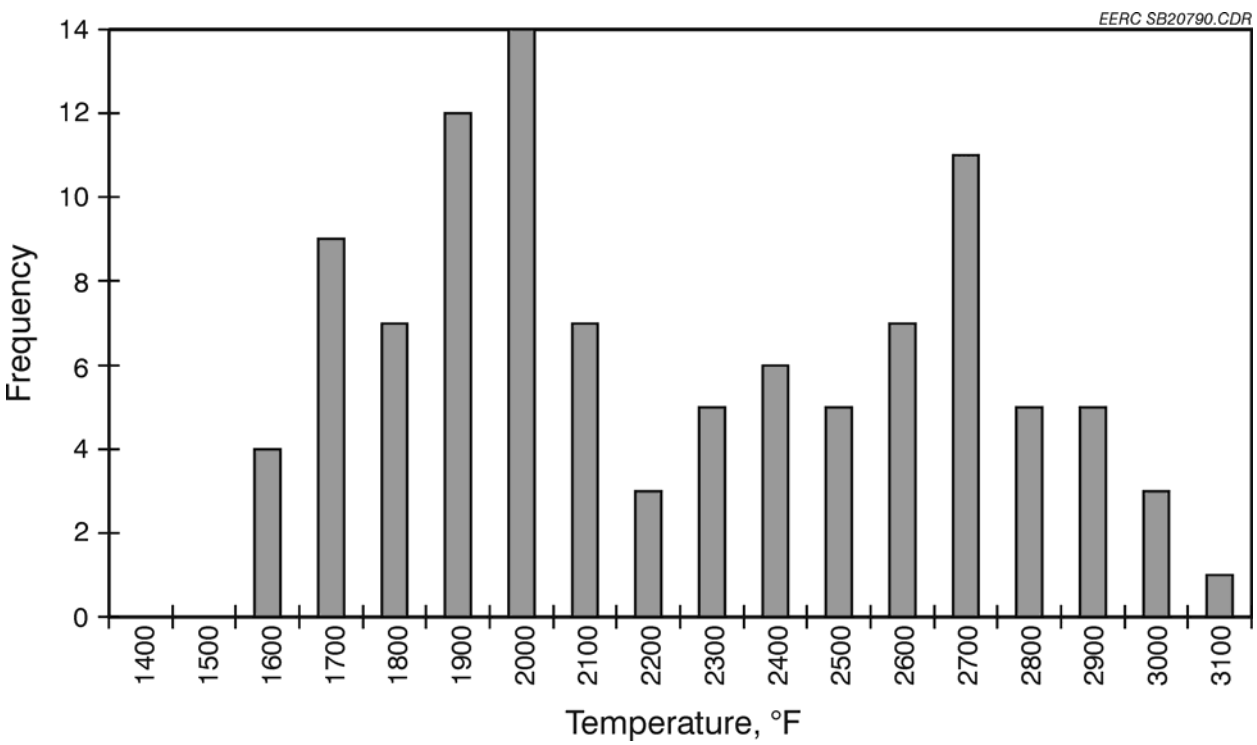

Figure 3. T_{250} frequency distribution for all Coal Quality Management System (CQMS) data, °F.

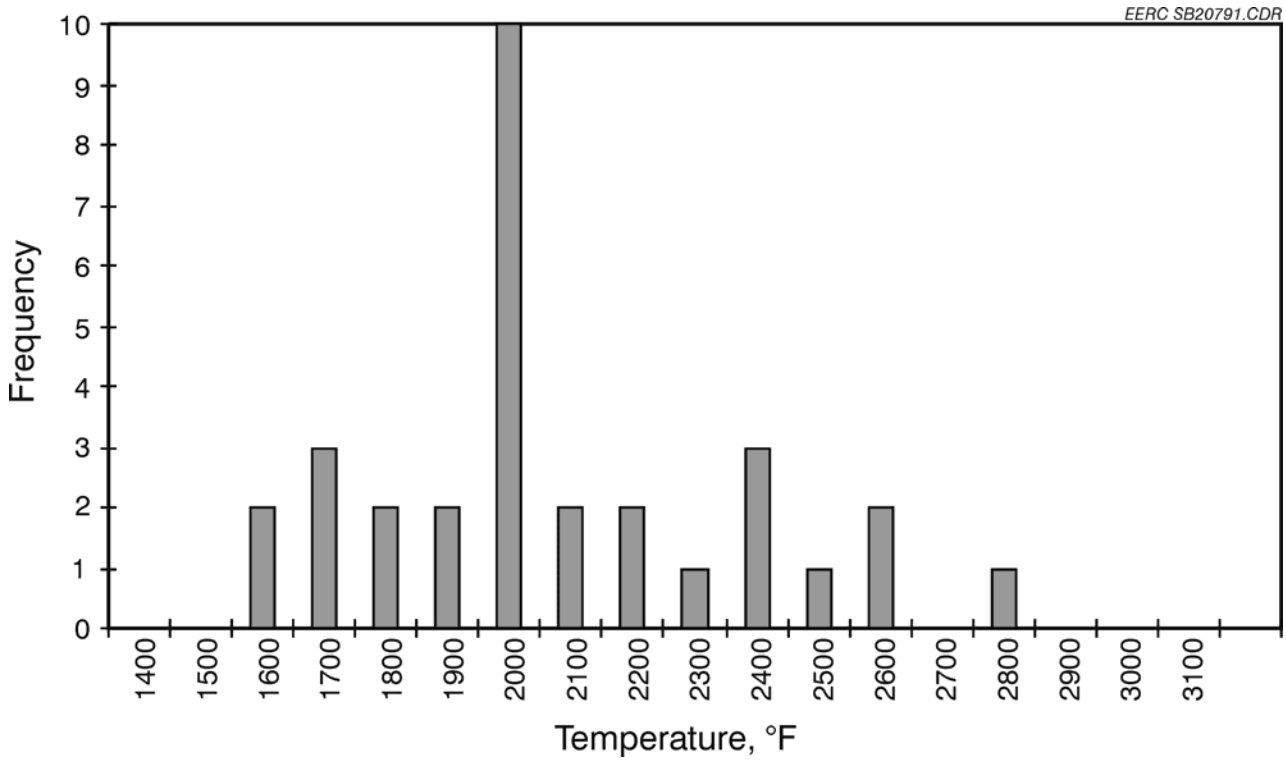

Figure 4. T_{250} distribution for HA seam coal.

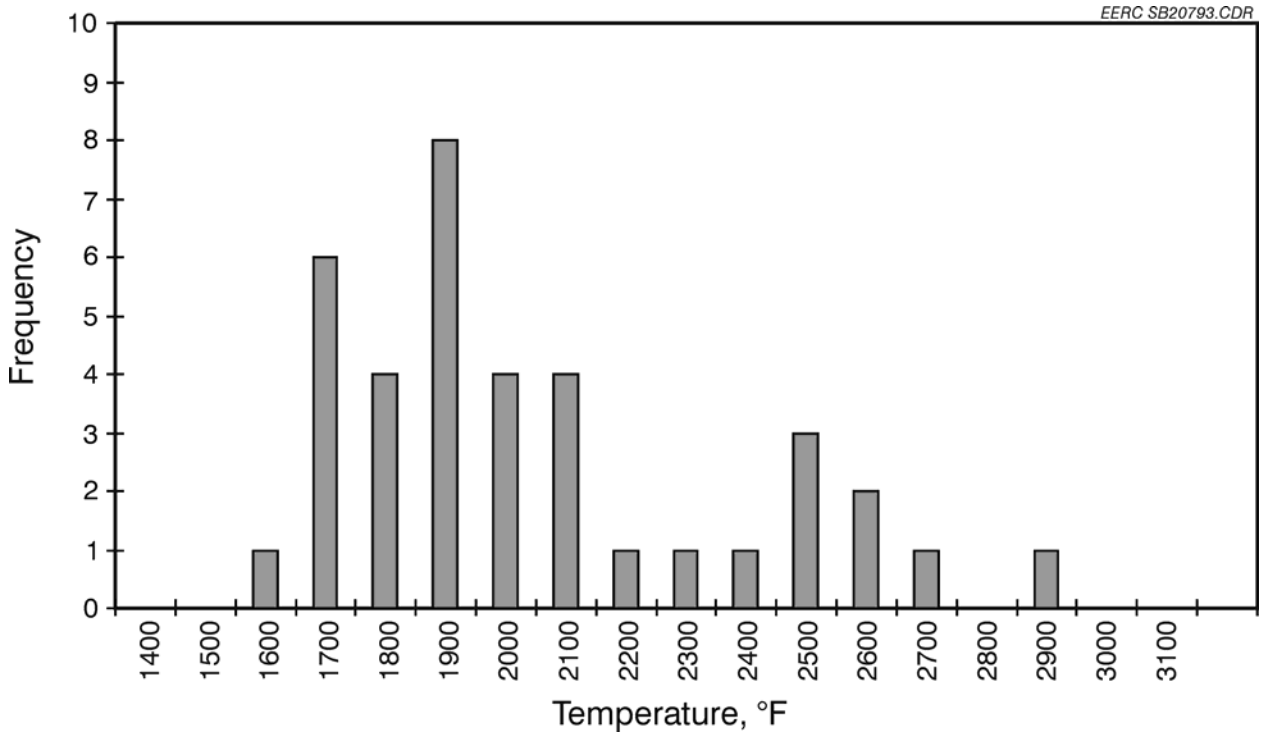

Figure 5. T_{250} distribution for HB seam coal.

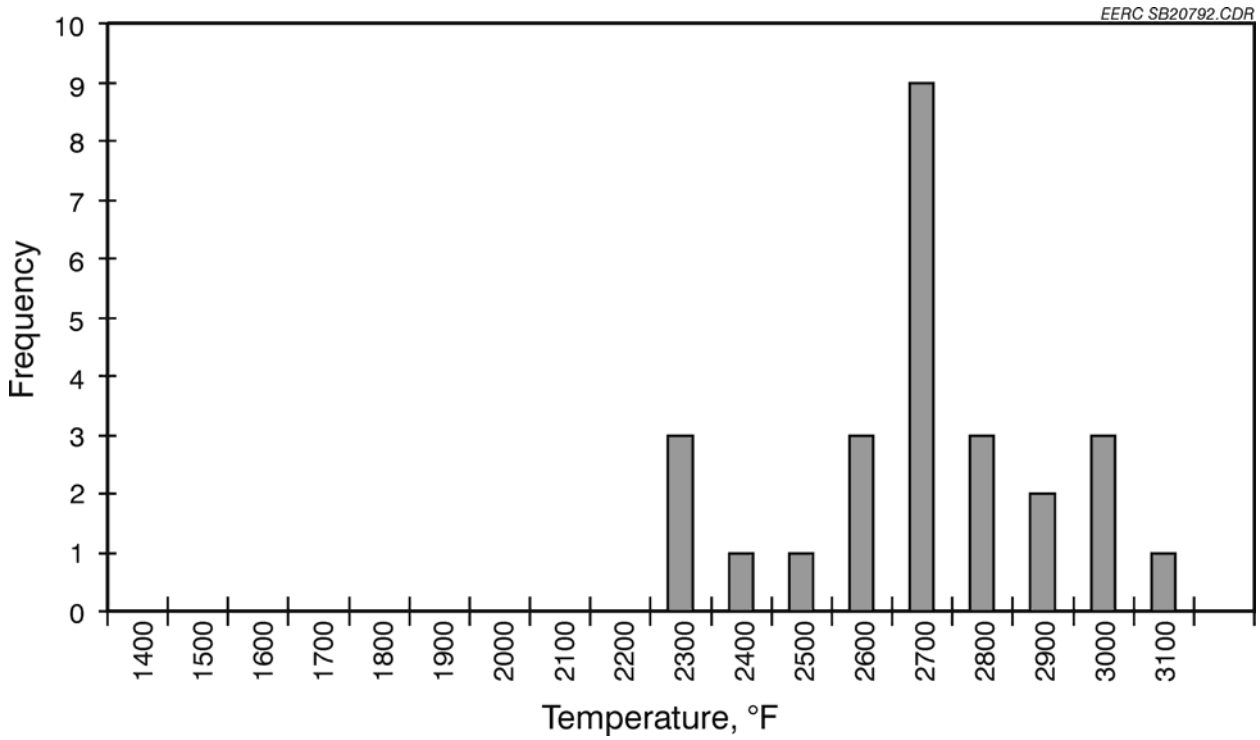

Figure 6. T_{250} distribution for KC seam coal.

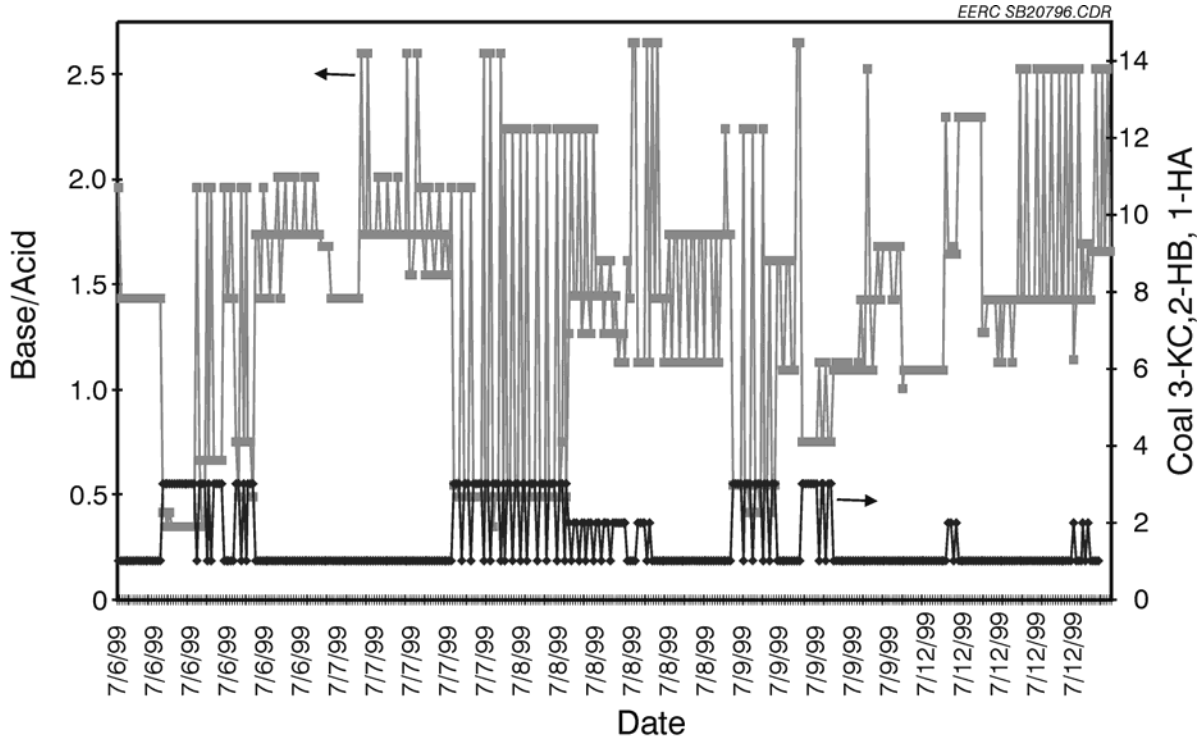

Figure 7. Variations in the delivered coal quality during a test burn period.

Figure 7 shows the sequence of deliveries beginning on July 6 and ending on July 12, 2004. During this period, the majority of the coal delivered was from the HA seam, followed by KC, and HB. Most of the deliveries alternated between KC and HA. Figure 6 shows several instances where significant quantities of KC coal were delivered, on July 6 through July 9. The quantity of KC coal delivered will have the potential to increase the viscosity of the slag and result in poor slag flow from the cyclones.

ASH-RELATED IMPACTS ON SCR CATALYST PERFORMANCE

Ash-related impacts on SCR catalyst performance will depend upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (14–16, 22). The problems currently being experienced on SCR catalysts include the following:

- Formation of sulfate- and phosphate-based blinding materials on the surface of catalysts.

- Carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing on top of the SCR catalysts.

Licata and others (14) conducted tests on a South African and German Ruhr coal and found that the German Ruhr coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9 % S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (15). Cichanosicz and Muzio (16) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8%–15% of the ash in European power plants. They also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3%–5% of the ash.

The mechanisms for this type of low-temperature deposition have been examined and modeled in detail at the Energy & Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s; however, the focus of those projects was specific to primary superheater and economizer regions of boilers and not SCR systems (22, 23). Deposit buildup of this type can effectively blind or mask the catalyst, diminishing its reactivity for converting NO_2 to N_2 and water and potentially creating increased ammonia slip (14). Arsenic and phosphates, which are not uncommon in low-rank coals, may also play a role in catalyst degeneration. Arsenic is a known catalyst poison (14) in applications such as catalytic oxidation for pollution control. Phosphates can occur in low-temperature ash deposits to create blinding effects, and they also occur with arsenic and can cause catalyst poisoning (23).

Lignite and subbituminous coals produce ash that plugs and blinds catalysts (25–28). The problems currently experienced with SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (14). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16, 27–28). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (15–16, 24, 27–28).

In studies (7) the impacts of temperature and the presence of catalyst on the ability of ash to sulfate were examined. The tests were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

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Full-Scale Slipstream Testing

More recently (8), the behavior of ash and mercury in flue gas produced from the combustion of lignite and subbituminous coals from the United States of America in selective catalytic reduction (SCR) systems for nitrogen oxide removal has been examined. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, these coals produce ash that has an abundance of alkali and alkaline-earth-rich oxide particles (<5 µm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and possibly carbonates. The forms of mercury in the flue gas produced from the lignite and subbituminous coals are dominated by the elemental form. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation.

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer is programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that allows for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The gas velocity is similar to that found in full-scale applications. The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- X Gas temperature: ~700°–800°F
- X Gas flow rate: 400–500 acfm
- X Approach velocity range: 5.0–5.5 m/sec
- X Ammonia injection rate: 0.5:1 with NO_x level
- X Tempering air for fan: ~ 50–200 scfm
- X Catalyst dP: 0.5–1.0 inches water column
- X Fan sized for up to 30 inches water column

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. The pitch of the catalyst was approximately 10 mm.

The coals produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The results of this testing found that the <5-µm ash rich in alkali and alkaline-earth elements is captured on the surface and within the catalyst pores. These materials react with SO_2/SO_3 in the flue gas, resulting in the formation of a continuous phase that blinds the catalyst. The ability of elemental mercury to be oxidized across the SCR catalyst was investigated at a North Dakota lignite-fired plant. These results showed no oxidation of mercury across the SCR catalyst.

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Figure 10 show the pressure drop across the catalyst test periods from 0 to 2 months. During the first two months of operation, the pressure was about 0.5 inches of water; at the end of two months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first two months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

The reactor was installed at the Columbia Station and operated for a 6-month period of time with the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Figure 11 shows the test periods from 0 to 2 months. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. The pressure drop for Months 2 to 4 increased from about 0.5 to 0.7 inches of water because of accumulation of ash. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over

0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst type was used in the reactor. The reactor was operated for a 6-month period of time. Figure 12 shows the test periods from 0 to 2 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 13 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

SCR Ash Deposit Characterization

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. Detailed information on all the samples can be found elsewhere (add FPT reference). Examples of two deposit and catalyst analysis are presented here.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 15a and 15b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure

15c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in Table 3. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

The 4-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst. Figure 16 shows the 4-month sample from the Coyote Station. The catalyst showed particles adhering to the surface and completely filling and masking the pores in the catalyst. The external morphology of the catalyst surface shows the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 4. The 4-month sample shows more sulfation than the two months of exposure samples. Figures 16b and 16c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. Significant sodium was found in the deposits, as shown in Table 4. The sample shows significant evidence of sulfation after 4 months of exposure and was much more pronounced than the samples for the Baldwin and Columbia Stations that are fired on PRB coals. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix (22).

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SCR Deposit Formation Mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (6).

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships to impacts on power plant performance (1–6, 9–13, 19–21, 29). During combustion, the inorganic components associated with western subbituminous and lignite coal typically are distributed into various size fractions of ash. The smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size

fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 17. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Figure 18 (30). The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-µm-sized particles. The particles are transported into the pores of the catalyst and subsequently react with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation (24, 25). The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates is possible (31). Pyrosulfate materials can melt at temperatures as low as 535°F in coal-fired power systems.

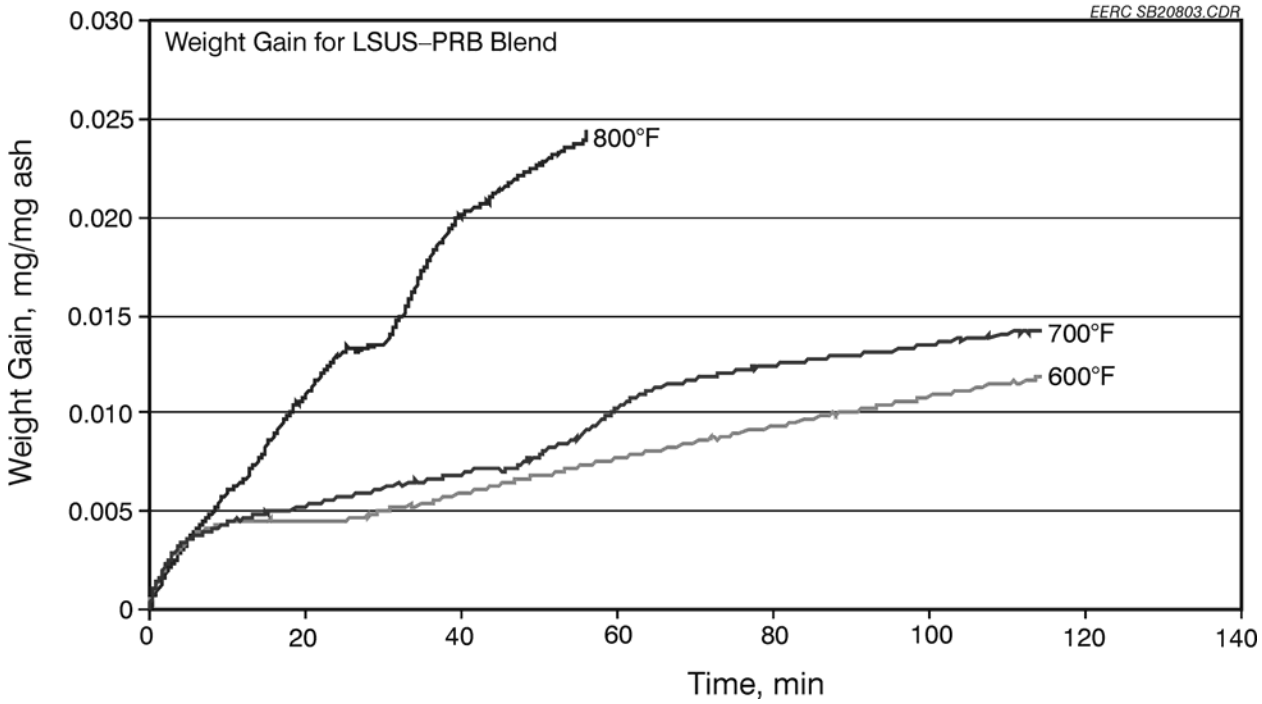

Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

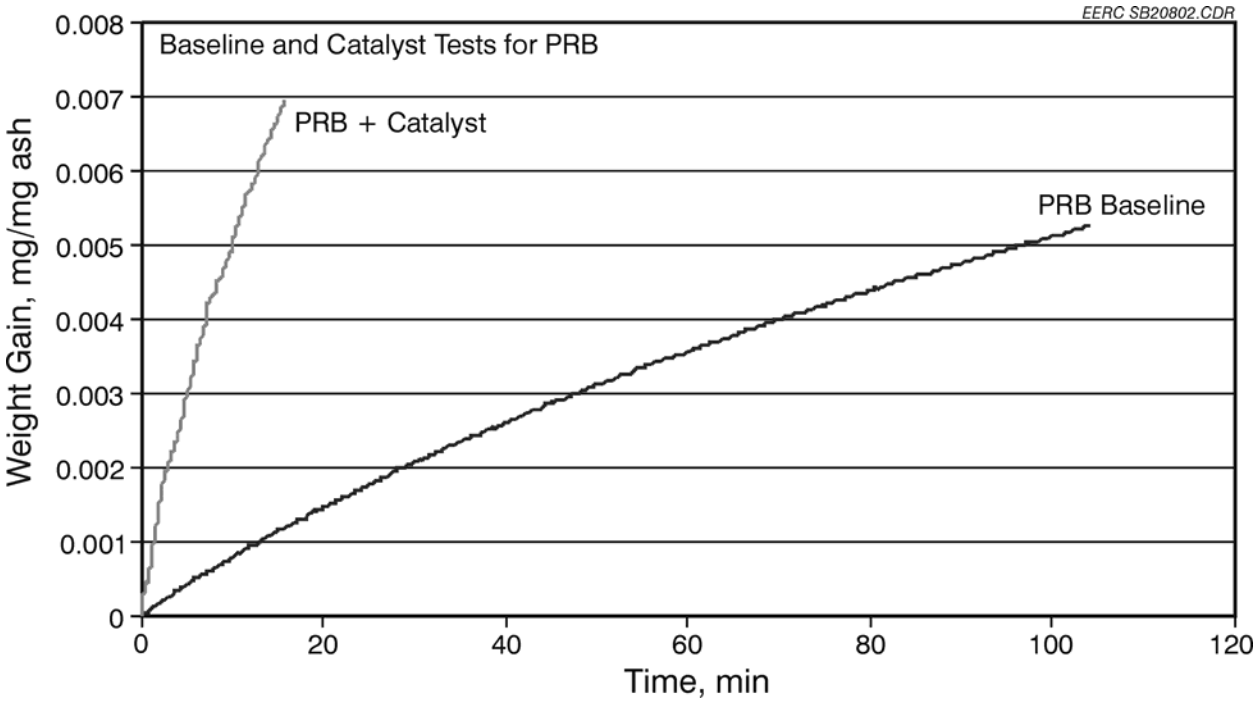

Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

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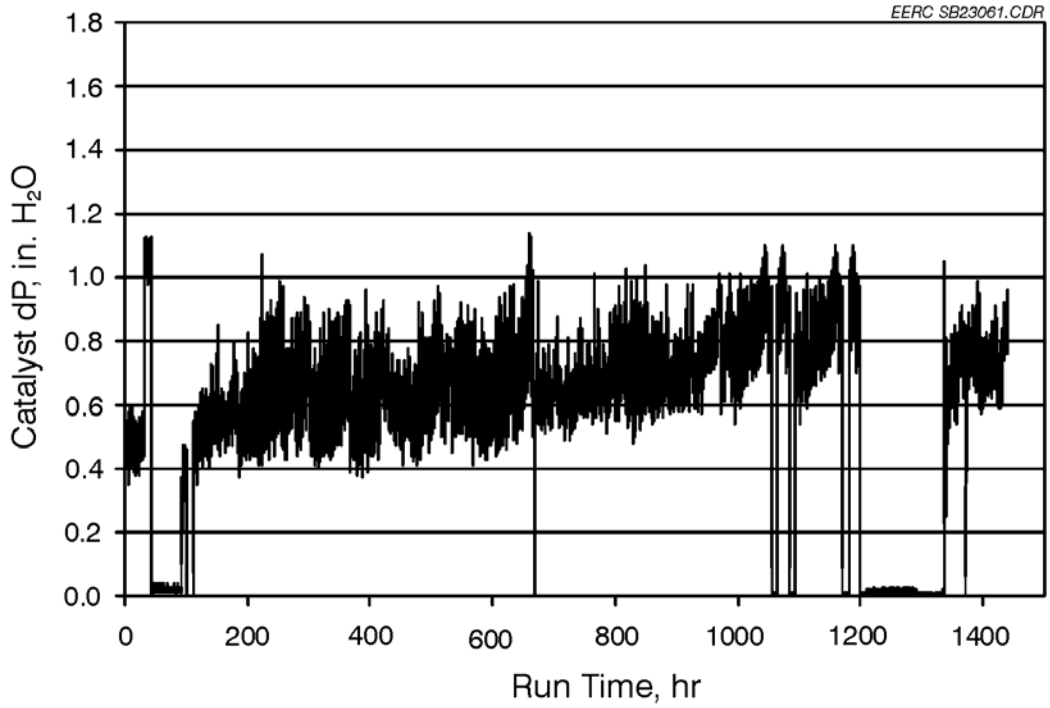


Figure 10. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

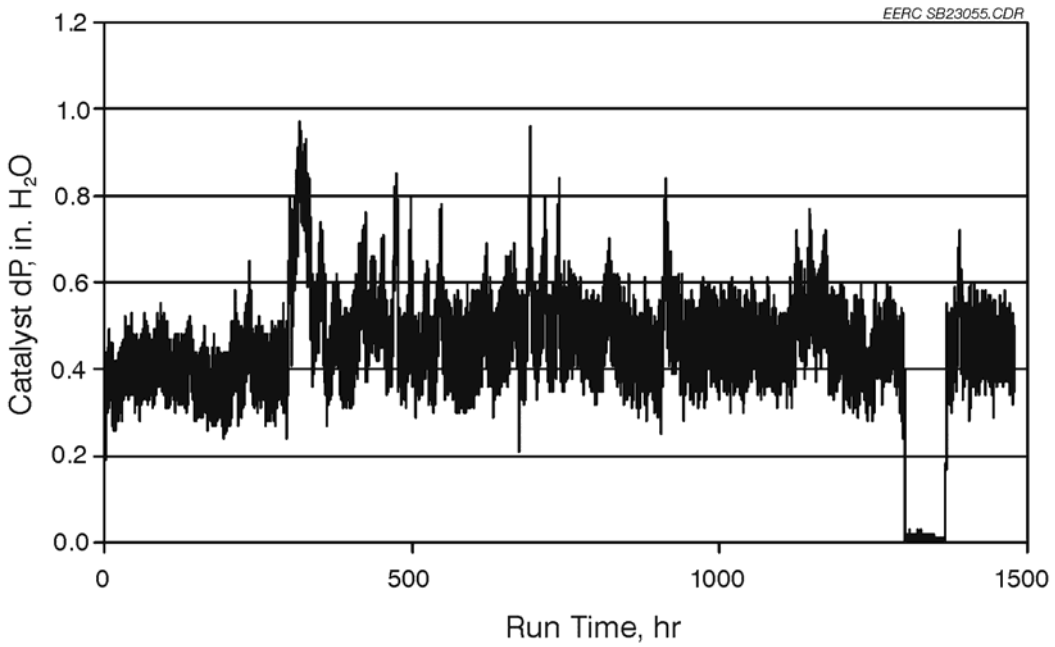


Figure 11. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

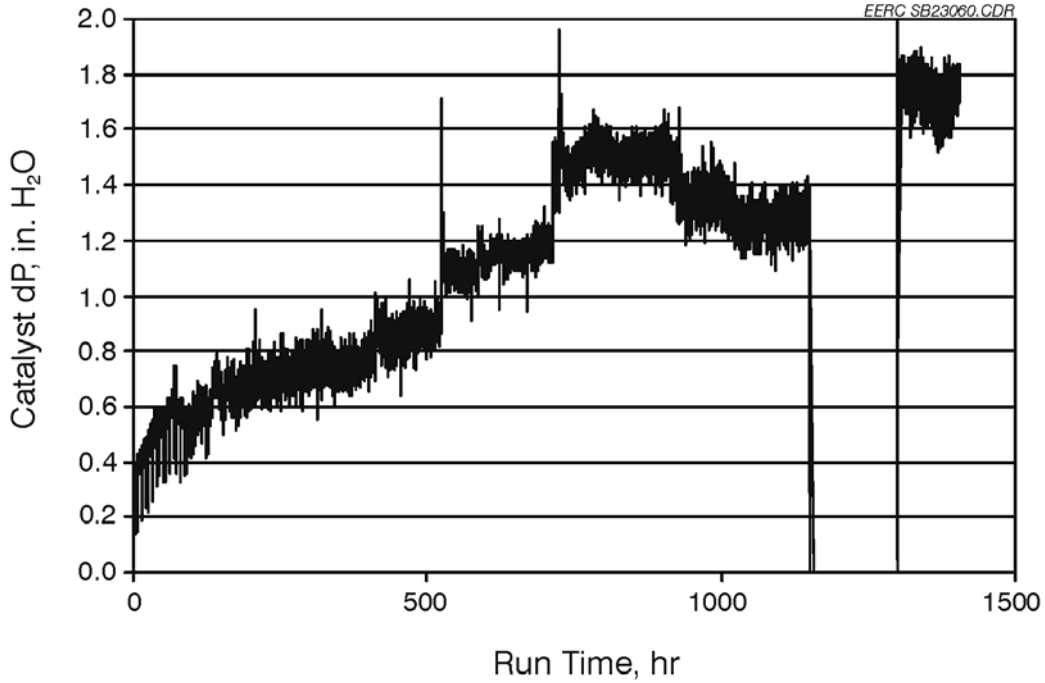
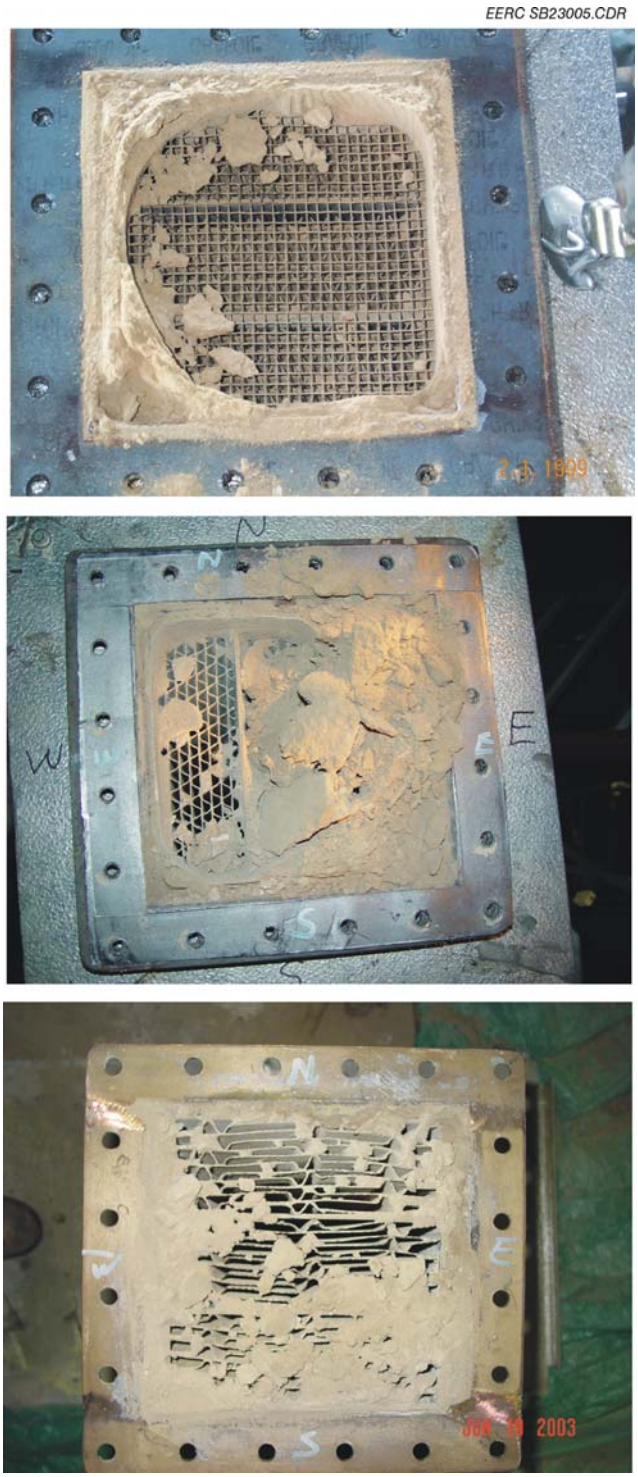


Figure 12. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.



Baldwin Station after 2 months

Coyote Station after 2 months

Columbia Station after 2 months

Figure 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

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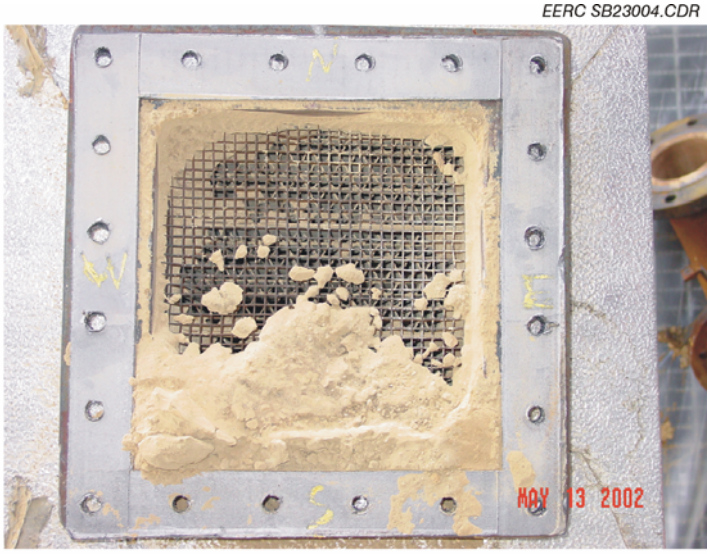
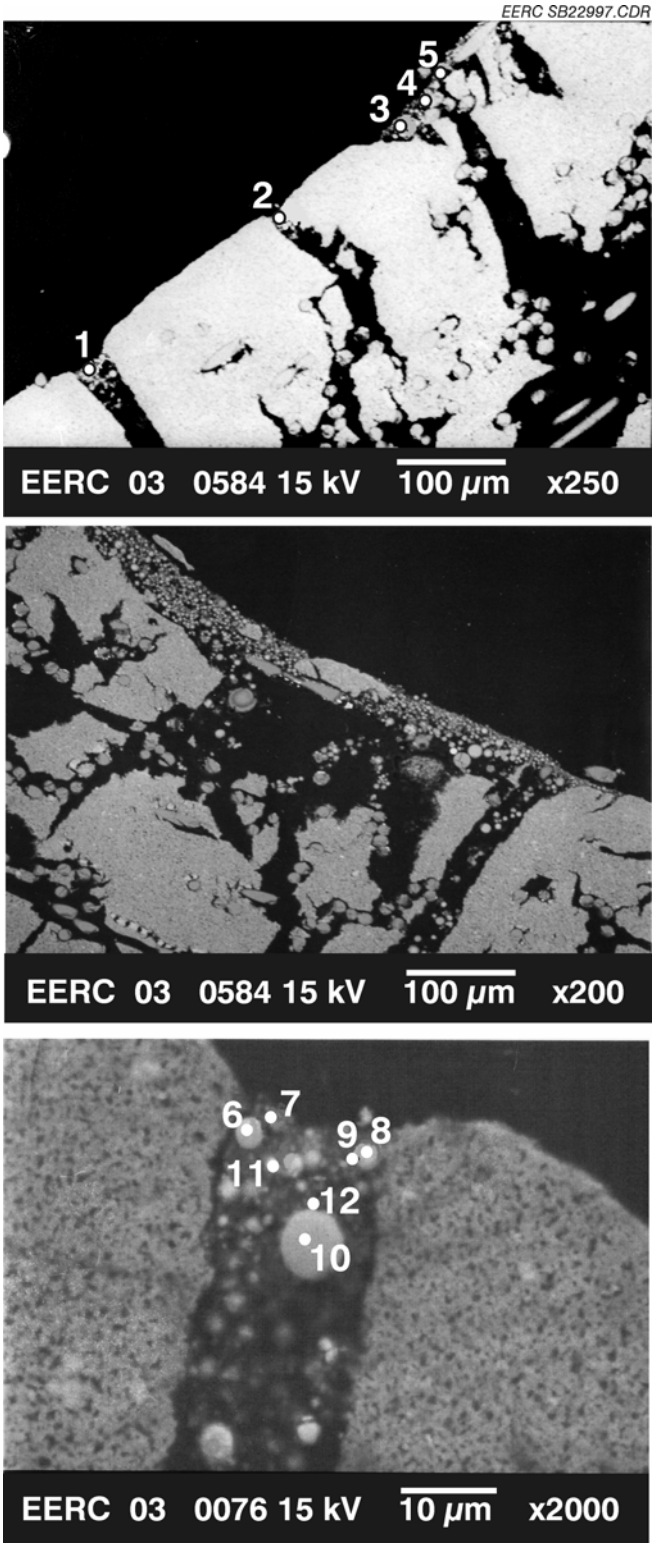


Baldwin Station after 4 months

Coyote Station after 4 months

Figure 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.



A

B

C

Figure 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. A) and B) low-magnification images of ash deposit on catalyst surface

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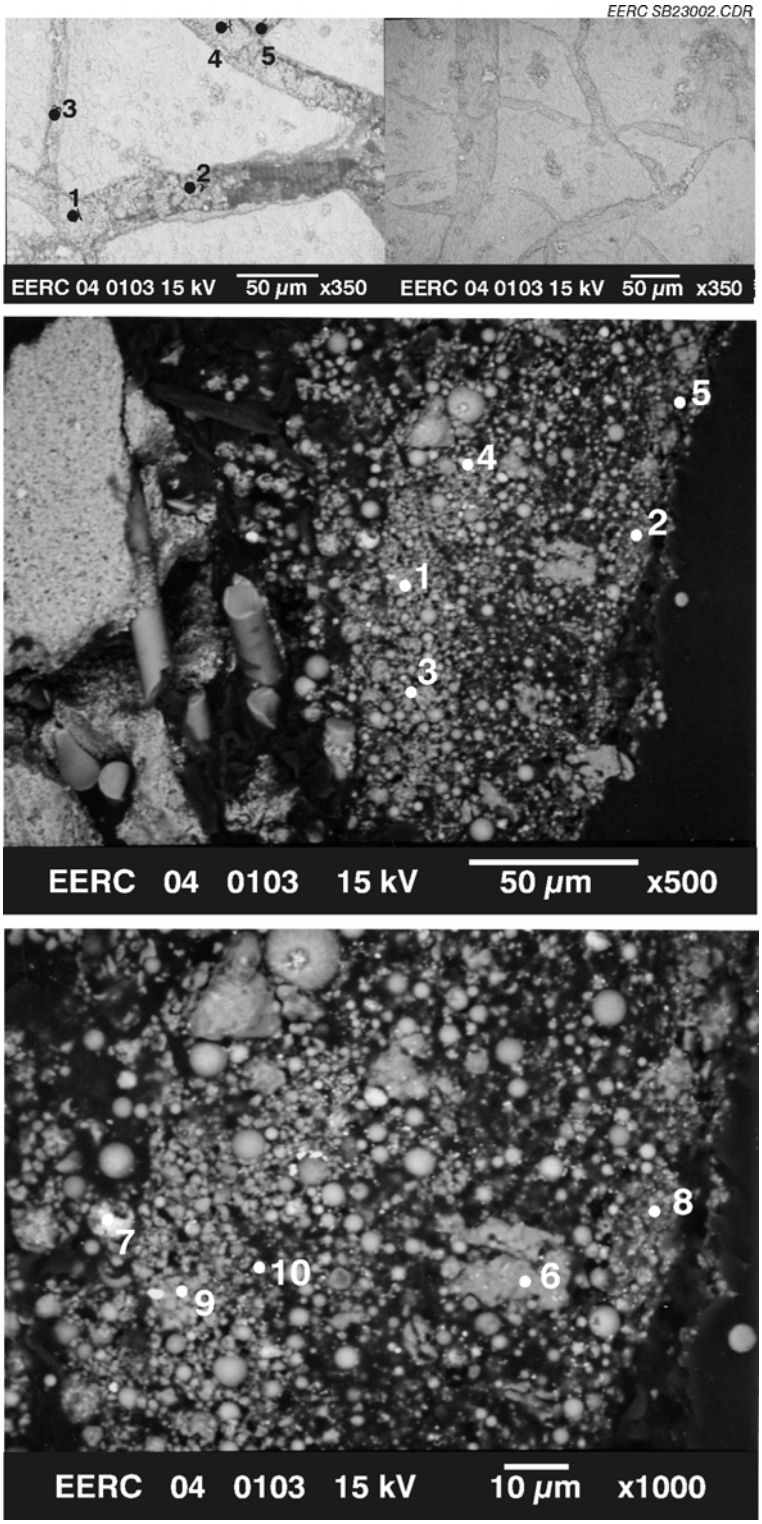
and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 3. Chemical Composition of Selected Points and Areas in Figure 15

	Chemical composition (normalized wt% equivalent oxide)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
1.1.1						
	0.6	1.0	2.1	0.3	0.5	2.7
Na_2O	4.3	2.5	6.3	0.7	1.6	7.6
MgO	14.8	16.0	15.6	15.5	14.7	0.9
Al_2O_3	3.3	7.8	18.8	57.7	7.7	47.3
SiO_2	2.3	2.1	0.5	0.6	1.8	0.0
P_2O_5	30.7	20.4	17.7	0.0	29.0	0.8
SO_3	0.7	0.0	1.0	0.4	0.9	0.9
K_2O	28.8	28.7	28.1	22.5	34.9	28.4
CaO	2.0	7.2	2.2	0.3	1.3	1.1
TiO_2	11.4	12.9	6.2	0.0	7.6	7.9
Fe_2O_3	1.1	1.4	1.4	2.0	0.0	2.5
BaO						
Total	100	100	100	100	100	100
Oxide	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
1.1.2						
	1.7	0.4	0.5	2.2	1.3	1.7
Na_2O	4.5	6.4	5.9	5.0	3.4	6.4
MgO	5.0	2.4	3.0	19.2	10.8	3.8
Al_2O_3	8.4	18.4	18.5	31.0	17.9	16.7
SiO_2	1.8	0.9	1.0	0.0	1.7	1.2
P_2O_5	37.9	1.7	5.3	0.0	22.5	13.9
SO_3	0.4	0.0	0.0	0.9	0.8	0.0
K_2O	31.4	52.6	49.0	28.9	30.6	45.4
CaO	1.9	6.9	7.4	2.4	2.0	1.1
TiO_2	7.1	5.7	6.0	6.3	6.1	6.5
Fe_2O_3	0.0	4.6	3.5	4.2	2.9	3.3
BaO						
Total	100	100	100	100	100	100



A

B

C

Figure 16. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. A) low-magnification image of ash deposit on catalyst surface, B) low-

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magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

1.1.2.1 Table 4. Chemical Composition of Selected Points and Areas in Figure 16

	Chemical composition (normalized wt% equivalent oxide)				
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
1.1.3					
Na_2O	6.7	1.9	7.1	6.2	3.1
MgO	1.1	1.7	1.1	2.6	3.2
Al_2O_3	2.6	8.8	4.0	4.8	10.5
SiO_2	7.0	21.1	11.3	5.6	32.2
P_2O_5	0.2	2.4	0.0	0.2	0.9
SO_3	54.7	38.5	56.4	57.5	30.4
K_2O	2.0	2.8	0.7	2.8	2.4
CaO	18.0	3.4	15.8	9.3	2.3
TiO_2	0.6	0.8	1.1	1.3	1.5
Fe_2O_3	5.8	5.1	2.1	6.5	9.8
BaO	1.4	13.5	0.5	3.4	3.6
Total	100	100	100	100	100
Oxide	Point 6	Point 7	Point 8	Point 9	Point 10
1.1.4					
Na_2O	9.5	2.6	10.4	8.9	4.4
MgO	1.2	1.9	1.3	3.0	3.7
Al_2O_3	2.6	8.6	4.2	4.9	10.6
SiO_2	6.3	18.2	10.5	5.0	28.9
P_2O_5	0.1	1.9	0.0	0.1	0.7
SO_3	41.8	28.4	44.9	44.5	23.4
K_2O	3.2	4.3	1.2	4.4	3.8
CaO	24.5	4.4	22.5	12.8	3.1
TiO_2	0.6	0.8	1.3	1.5	1.8
Fe_2O_3	7.7	6.6	2.9	8.9	13.2
BaO	2.4	22.3	0.9	5.9	6.3
Total	100	100	100	100	100

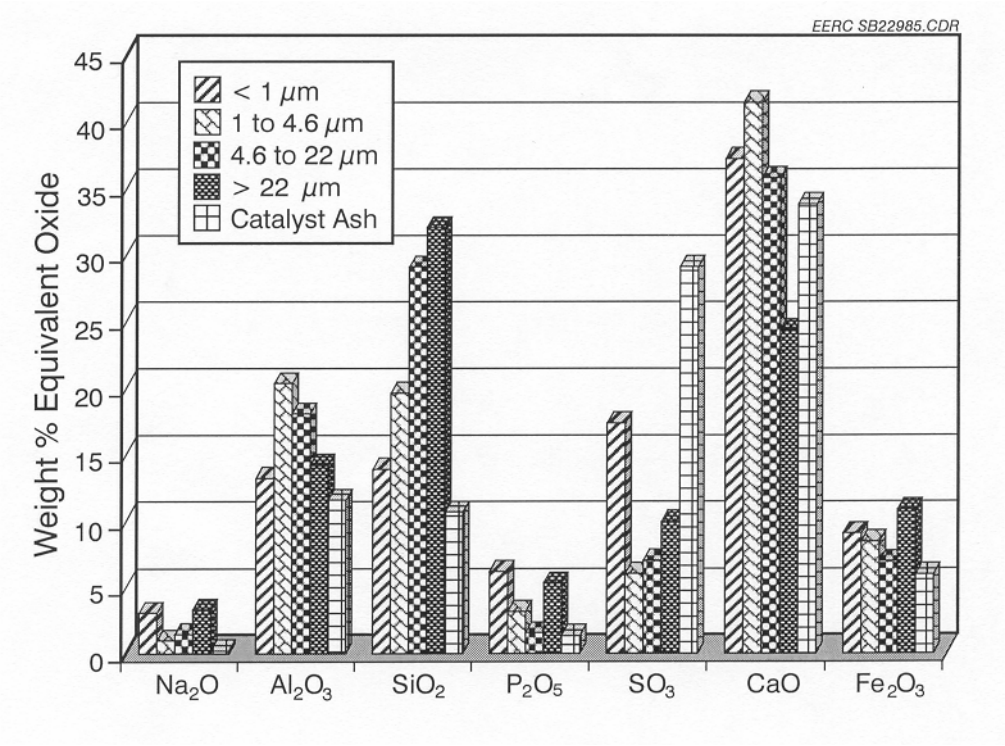

Figure 17. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

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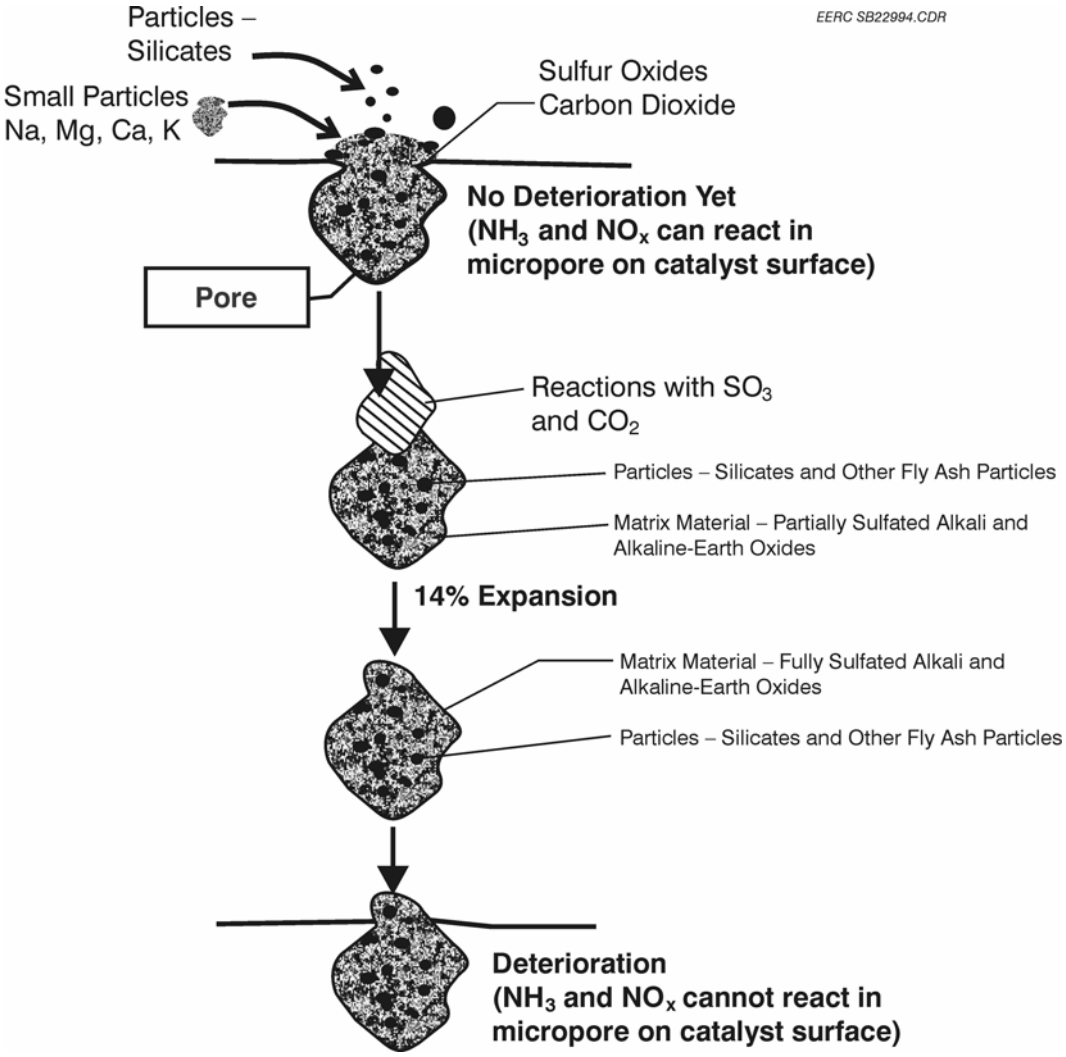

Figure 18. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [30]).

Low-Temperature Pyrosulfates

The presence of sodium sulfate in the flue gas exiting a scrubber will cause problems to low-dust and tail-end devices such as selective catalytic reduction (SCR) systems for NO_x reduction. There are two problems associated with the fine particulate rich in sodium sulfate on downstream devices. These include accumulation of fine particles on the SCR that, when sootblown, will cause opacity problems, and that the fine particles on the SCR will form pyrosulfates such as $(K_{1.5}Na_{0.5})S_2O_7$ that have melting points as low as 535°F (31) that will blind the catalyst. The presence of these compounds in low-temperature corrosion deposits is well known (32). In addition, the presence of SO_3 enhances the formation of the low-melting-point pyrosulfates (31). The sodium sulfate materials will cause opacity and SCR catalyst

blinding problems that limit the feasibility of the low-dust or tail-end SCR technology for use with high-sodium lignite coals.

The sodium sulfate materials will be transported to the catalyst surfaces by diffusion, electrophoresis, and, possibly, inertial impaction. The particles are held in place by weak electrostatic and van der Waals forces. Once accumulation takes place, the sodium sulfate particles will react with flue gas components, resulting in the formation of pyrosulfates. The formation of pyrosulfates involves the following processes (31):

1. Formation of sulfates such as Na_2SO_4 and K_2SO_4

2. Conversion of SO_2 to SO_3 in the bulk gas phase – catalytically active surface such as an SCR catalyst – $SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$

3. Pyrosulfate formation – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

The melting points of selected pyrosulfate phases are shown in Table 5.

Table 5. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

Melting points for pyrosulfates between 535° and 770°F have been reported in the literature. Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium.

There is significant evidence for the formation of sodium-rich fine particulate in full-scale power plants when firing high-sodium-containing coals. For example, Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash subbituminous coal, it experienced increases in opacity. Hurley and Katrinak (33) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with an electrostatic precipitator and a wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using an impactor and

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multicyclone. The sized fractions were analyzed to determine the composition of the submicron-sized fraction.

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of one of the coals. Vapor-phase sodium condenses in the convective pass to form fine sodium sulfate particles or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by scrubbing.

CONCLUSION: SCR IS NOT FEASIBLE FOR NO_X REDUCTION AT MILTON R. YOUNG

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be impossible because of the formation of sodium calcium sulfates in the pores of the catalyst. Following is a list of the key roadblocks associated with lignites which have not been overcome and, in our opinion, make the installation of SCR catalyst at the MRY plant technically infeasible for NO_x control.

- High alkali and alkaline-earth elements present in the coal fired at the MRY plant form sulfates that blind the catalyst.
    - Cyclone-firing partitions the ash during combustion. As a result the level of sodium and calcium in the fly ash is enhanced and will increase the SCR catalyst blinding.
    - Sulfate reactions increase with increasing temperature, and the suggested temperature of installation at the MRY facility is higher than typical installations; therefore, sulfation problems are enhanced.
    - Sulfate formation is also enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
    - The high levels of sodium in the coals combined with calcium produces low-melting-point eutectic compounds that will melt on the surface.
    - Sulfates form on the surfaces of catalysts firing PRB coals. Lignites will be several orders of magnitude worse because of the higher levels of sodium.

- The ash components to impact SCR performance in Japan and Europe (14–16) include alkali and alkaline-earth elements that result in sulfate formation. The total calcium content and the sum of the calcium, magnesium, potassium, and sodium provide an indication of the problems that occur. For the coals fired at the MRY power plant, the CaO content ranges from 6.8%–19.99%, and the sum of the alkali and alkaline-earth elements range from 9.33%–29.87% of the ash. The levels of calcium in Center lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.

- The finding or work conducted in Germany and Japan were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-

rich sulfate formation that fill and plug the catalyst at both lignite (North Dakota)- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments, is a significant problem because of the extremely high deposition potential of the coal. The formation of deposits in various parts of the boiler requires continuous sootblowing. The deposit fragments are likely going to be carried with the bulk gas flow to the SCR catalyst, resulting in plugging.

- The variability of the lignite is a problem of unique concern at MRY. The deposition potential of the coal is always changing rapidly, resulting in rapid growth and formation of deposits in various sections of the boiler. Aggressive sootblowing of all fireside surfaces is already required to maintain full-load operation. The sootblowing of upstream heat exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, and during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

The ash-related impacts of the lignites from North Dakota are the most complex and severe of any coals in the world, and installation of tail-end SCR systems for NO_x reduction will not be possible. The key problems associated with lignites that have not been overcome and, in our opinion, make the installation of tail-end SCR systems at the MRY plant technically infeasible for NO_x control at MRY's Units 1 and 2 are listed below:

X High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces extreme levels of homogeneously condensed sodium sulfate that pass through the wet scrubber. In addition, the cyclone-firing system captures much of the ash as slag, resulting in a decrease in ash that is available for providing condensation sites for vapor-phase sodium compounds upon gas cooling. This results in an increased homogeneous condensation of sodium sulfate.

X These small particles pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials cannot feasibly be resolved through conventional sootblowing and cleaning technologies to remove the particulate.

X Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

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The formation of liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates at MRY to an extreme level that cannot be dealt with effectively using cleaning technologies that exist today.

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APPENDIX C

COST METHODOLOGY

CAPITAL COST ESTIMATE DETAILS FOR NO_X CONTROLS

O&M COST ESTIMATE DETAILS FOR NO_X CONTROLS

C.1 METHODOLOGY FOR ESTIMATED COSTS

The summary economic evaluations of each alternative are presented in the cost impact sections of the main report. Capital and O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) for all the alternatives for control of a single pollutant (i.e. NO_X) from a single unit is then presented together with Unit Control Costs. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, again in current (2006) dollars. As a minimum, the design life for any alternative was taken to be that recommended by "The EPA Air Pollution Control Cost Manual", Sixth Edition, January 2002, EPA/452/B-02-001[i].

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

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

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

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

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table C.1-1 the Capital Recovery Factor was calculated to be 0.08718.

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

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

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

Therefore:

$$LAOMC = OMLF \times A_1$$

For the economic conditions described in Table C.1-1 the Operating and Maintenance Levelization Factor was calculated to be 1.24873.

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

$$LTAC = LACC + LAOMC = (CRF \times P) + (OMLF \times A_1) = 0.08718 \times P + 1.24873 \times A_1$$

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

In order to compare various pollutant control alternatives, the Unit Control Cost and the incremental Unit Control Cost of each alternative were also calculated and tabulated for comparison purposes. The Unit

Control Cost compares control technologies on a basis of dollars expended per ton of pollutant reduced ($/ton). This relationship is graphically depicted in the DCC chart.

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

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

Where,

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

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

Table C.1-1 – Economic Factors(1),(2)

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Conversion Tax (in lieu of property tax)	NA
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate (used to calculate NPV)	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2.5%
Fuel (coal and natural gas) Escalation	2.5%
Auxiliary Electric Power Cost, $/MW-hr	$35.00
Urea Cost, ($/ton delivered, 50% aqueous solution)	$380.00
Natural Gas ($/mmBtu)	$7.98

(1) - All financial percentages and unit auxiliary electric power cost were provided by MPC.
(2) - All costs are in 2006 dollars unless noted otherwise.

C.2 NOx CONTROLS - CAPITAL COST ESTIMATES

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

The limitations of these capital cost estimates developed from unit capital cost factors multiplied by unit output are:

- Scope basis uncertainty – inability to precisely determine what scope of supply, including such things as balance-of-plant (BOP) systems and equipment improvements were required, assumed, or accounted for when developing the unit cost factors. Some alternatives may have higher indirect or BOP capital costs than others. Similarly, the inclusion of general facilities, preproduction and inventory costs, and other indirect costs is not known. It is likely that the utility owner's final total expenditure for the implementation of the alternatives, especially options that are most capital cost-intensive, will be greater than the calculated cost estimates.
- Location-specific influences – most NO_X control techniques have been applied primarily to eastern bituminous coal-fired plants located near large metropolitan areas, not in largely rural, upper midwestern United States locales. The amount of space available is dependent on the existing powerplant equipment and building layout and property plot area, versus what is expected to be required for implementing various control technologies. Transportation and local/regional labor costs are also variables.
- Size influences – some technologies' capital costs are more sensitive to "economies of scale" than others.
- Capacity margins – some technologies' may require higher capacity margins to allow sustained operation at high throughput rates over extended periods of time.
- Reliability concerns – some technologies' have been refined to a higher degree, and others may require more component redundancy than others in order to avoid performance reductions and potential outages for failures and repairs or replacements.
- Inflationary influences – the significant increases in 2004-2005 for raw material costs, especially steel and alloys for fabrication of structural and mechanical components, has occurred after many of these technologies were installed in projects upon which the referenced unit capital cost factors were based.

- Market conditions – as demand increases for emission controls, some alternatives become more cost-competitive, while others do not. This can be influenced by the relative supply and demand for the technology and number of suppliers who can furnish it. The demand for some alternatives can also be strongly influenced by the stringency of the local, state, and national regulatory requirements. Schedule for implementation and availability of local/regional labor for installation contractors are also market-driven factors.

The estimated NO_X control costs are in addition to capital costs to provide normal replacements of the existing Milton R. Young Station's major power generating equipment.

C.2.1 Separated Overfire Air Capital Cost Estimates

Installation of separated overfire air systems typically includes windbox and/or secondary combustion air supply duct modifications, boiler waterwall tube openings, airflow distribution devices (dampers/registers), airflow controls and measurement instrumentation, and related structural and electrical tie-ins to the existing plant facilities. A basic separated overfire air retrofit system installed on a lignite-fired cyclone boiler includes ports across the front and rear walls of the upper furnace. The unit capital cost factor is expected to be above the high end of the typical published cost range of $5-10/kW[ii] ($12.0/kW or $3,080,000[iii] for MRYS Unit 1), due to the large ducts, relatively tall furnace (compared to typical bituminous coal-fired cyclone boilers), and the need to avoid existing obstructions within the boiler house.

An advanced form of SOFA unique to North Dakota lignite-fired boilers will include relocation of the existing lignite drying system vent port openings from the lower primary furnace to the upper furnace, to be placed at the same elevation as the new SOFA ports. This requires extension of the existing cyclones' lignite drying systems' vent piping to supply the new boiler furnace ports. This is expected to cost in the area of +$4.7/kW or approximately $1,200,000 for Unit 1's additional capital cost over and above the basic SOFA system. Overall, the advanced version of separated overfire air technology is estimated to have an installed capital cost of approximately $16.6/kW ($4.3Million) for MRYS Unit 1.

C.2.2 Reburn Capital Cost Estimates

C.2.2.1 Coal Reburn Capital Cost Estimates

There is one alternative that includes a new coal reburn system. Capital cost estimates for coal reburn systems are highly dependent on the requirements for reburn fuel preparation and feeding to the boiler. For the purposes of this analysis, the application of a pulverized coal reburn system assumed the need to make extensive additions to the existing fuel preparation equipment in the existing plant facilities and feeding to new furnace injectors. At least two new fine-grind pulverizers, or MPS-89 standard pulverizers followed by dynamic classifiers are expected to supply the amount of finely ground reburn coal for this method.

Addition of new electrical loads for the pulverized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/micro-mills and related new coal reburn equipment, but this has not been confirmed.

The existing crusher bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal crushers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing lignite drying system vent ports, along with new overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. This coal reburn system design was not expected to change the existing cyclone silo/feeder arrangement, such that all cyclones would remain operational. To achieve maximum NO_X emission control, only the advanced form of SOFA for pulverized coal reburn was included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

The installed capital cost of pulverized coal reburn for the cyclone boilers at Milton R. Young Station used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclones. The installed capital cost estimate of $21,900,000 for MRY Station Unit 1's pulverized coal reburn alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit

capital cost factor for cyclones of $82.33/kW (x 1.035 = $85.2/kW) included in a WRAP (Western Regional Air Partnership) draft report[iv] published on their website, dated April 26, 2005. The cost to relocate the lignite drying system vent ports (+$4.7/kW) was added to the inflation-adjusted CAMD number ($85.2 + $4.7/kW = $89.9/kW), since coal reburn is expected to include separated overfire air but not the extra costs for the special improvements identified for air-staged lignite-firing in cyclone boilers. This increased the installed capital cost by $1,200,000 for MRY Station Unit 1's coal reburn system to a total of $23,561,000. This does not include the additional particulate matter collection capacity considered necessary to limit the expected negative impact on opacity from this option.

To control particulate matter (PM) emissions that would be expected to increase from installation and operation of pulverized or micronized coal reburn, additional PM collection capacity will be required. A hybrid form of PM collection that supplements the existing electrostatic precipitator's performance, referred to as COHPAC (COmpact Hybrid PArticulate Collector). This was estimated in 2002 dollars at $20,191,000 for MRY Station Unit 1's COHPAC[3]. Adjusted by an escalation factor of 1.2623, the installed capital cost of the COHPAC addition was estimated to be $23,561,000 for MRY Station Unit 1 in 2006 dollars. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $46,656,000 for MRYS Unit 1 ($89.9 + $91.7 = $181.5 /kW).

C.2.2.1 Gas Reburn Capital Cost Estimates

Conventional gas reburn options assume that seventeen percent of the total fuel heat input to the boiler is through the new gas reburn injectors to be located in the lower secondary furnace above the top rows of cyclones. Eight to twelve gas reburn injectors would be expected to be required in this case. Seven percent of the total fuel heat input to the boiler through the gas reburn injectors is assumed to be supplied for the fuel lean gas reburn alternatives. Four to eight gas reburn injectors could be assumed in FLGR™ cases. Gas reburn options assume that a new high-pressure gas pipeline would be brought from near Bismarck, ND approximately twenty six miles. The pipeline diameter is proportional to the amount of fuel required for the specific alternative, ranging from 24 inches for conventional gas reburn to 12 inches for fuel lean gas reburn cases. A station gas main, with new gas trains, consisting of valves, metering, and safety shutoff valves for the front and rear boiler for the gas injectors' supply, would be furnished and installed.

The capital costs for conventional gas reburn alternatives were estimated considering unit capital costs published in published technical literature. One vendor that has supplied numerous domestic utility boiler gas reburn systems (GE Energy, formerly GE-EER) published $10/kW for gas reburn in a 2001 technical paper[v]. Another source published a 2005 technical paper[vi] that provided a unit capital cost range for gas reburn of $15/kW to $30/kW. Neither source included a detailed scope description nor cost breakdown for engineering, equipment, materials, and labor to install a gas reburn system.

Site-specific needs and challenges identified for applying conventional gas reburn to Milton R. Young Station, and lack of detailed gas reburn project scope and equipment descriptions available in published technical literature leads to a much greater degree of uncertainty with regards to an accurate capital cost estimate for this alternative. For the purposes of this study, the estimated installed capital cost for a conventional gas reburn system with advanced SOFA on MRYS Unit 1 is expected to be approximately $9.9M ($38.6/kW), which is above the top end of the previously stated range, before adding the new underground gas pipeline capital costs. This study assumed an average unit capacity capital cost factor of $22/kW for conventional gas reburn, plus the additional costs for the advanced from of SOFA over basic SOFA (+$1.2M or +$4.6/kW) and the new high-pressure gas pipeline. This results in a an estimated installed capital cost for conventional gas reburn system with advanced SOFA on MRYS Unit 1 of $11.1M ($25.7/kW) plus the new high-pressure gas pipeline costs. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

Fuel lean gas reburn (without SOFA) capital cost estimates were based upon a late 2004 budgetary proposal[vii] by a vendor (Fuel Tech) with experience in supplying FLGR™ equipment, typically combined with an SNCR system. Estimated capital costs of $3M include budgetary numbers for the equipment installation, including installation management, material and labor, with a –43% price adjustment assumed for 257 vs 450 MW for a fuel lean gas reburn system without SOFA on MRY Unit 1, not including the capital cost for the gas supply pipeline. Costs for work outside the vendor's scope, such as balance-of-plant additions plus other indirect costs were estimated to add approximately $0.5M (25% plus 10% contingency) to the adjusted vendor's estimated installed cost of $1.7M for their scope of supply. These adjustments result in a total installed capital cost for FLGR (without SOFA) estimated to be $2.2M plus the capital cost for the gas supply pipeline. Adding the incremental costs for the advanced from of SOFA over no SOFA (+$4.3M (+$16.6/kW) results in an estimated installed capital cost for a fuel gas reburn system with advanced SOFA on MRYS Unit 1 of $6.6M ($25.7/kW) plus the new high-pressure gas pipeline costs.

The capital cost estimates for the new high-pressure underground gas supply pipeline assumed $7 per inch of diameter per foot of length. This was calculated to be approximately $23M for conventional gas reburning and $11.5M for FLGR™. The cost analysis for each NO_X control alternative involving a particular form of gas reburn assumed that both boilers at Milton R. Young Station select the same alternative that burns natural gas. Therefore, the estimated capital costs for gas reburn alternatives reflect a capacity-based proportional share of the gas pipeline capital costs, avoiding double-counting. This results in an estimated installed capital cost for MRYS Unit 1's share of the gas pipeline to be $8.1M / for the conventional gas reburn alternative and $4M for fuel-lean gas reburn alternatives.

The total installed capital costs for conventional gas reburn (with ASOFA) with MRYS Unit 1's share of the total capital cost for the gas supply pipeline estimated to be $18M ($70.6/kW). The total installed capital costs for FLGR™ (with ASOFA) with MRYS Unit 1's share of the total capital cost for the gas supply pipeline were estimated to be $10.6M ($41.4/kW). Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

C.2.3 SNCR Capital Cost Estimate

The alternatives that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a 450 MW lignite-fired cyclone boiler in a late 2004 budgetary proposal[7] by a vendor (Fuel Tech) with experience in supplying SNCR equipment. Circulation, metering, dilution, control, and injection equipment is included. A 180,000 gallon field-erected stainless steel storage tank will hold the 50% urea solution (as delivered by truck). Individual and multiple nozzle lances with multiple levels of urea reagent injection will be designed and located to optimize distribution and accommodate various boiler load conditions. Estimated capital costs of $4.9 Million include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to a 450 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately $1.9 Million (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. This results in an estimated total capital cost for SNCR (without SOFA) of $6.8M for a 450 MW lignite-fired cyclone boiler.

Applying these adjustments to a 257 MW boiler, estimated direct capital costs of $2.800,000, plus $1,000,000 for indirect costs yields a total installed capital cost for applying SNCR to MRY Station Unit 1 of approximately $3,836,000 ($14.9/kW).

C2.5 Layered Technology Capital Cost Estimates

Capital costs were generally estimated based upon simple arithmetic addition of individual unit output capital cost factors for combinations of available NO_X reduction technologies, such as SNCR with ASOFA. An advanced form of separated overfire air system included the lignite-fired cyclone boiler equipment changes within the estimated unit capital cost factors.

Adding the advanced SOFA capital cost of $4.3 Million to the previous estimated installed capital cost of $3.8 Million yields a total estimated installed capital cost of $8.113 Million ($31.6/kW) for the SNCR with ASOFA alternative for MRYS Unit 1.

As previously discussed, Lignite (coal) reburn (CR) was assumed to be combined with advanced SOFA and a COHPAC addition considered necessary to limit the expected negative impact on opacity from this option. The installed capital cost of the COHPAC addition was estimated to be $23,561,000 for MRY Station Unit 1. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $46,656,000 for MRYS Unit 1 ($89.9 + $91.7 = $181.5 /kW).

C.3 Operating and Maintenance Cost Estimates for MRY Station NO_X Control

An evaluation was performed to determine the estimated operating and maintenance cost impacts of installing and continuously operating various feasible NO_X control technologies on Milton R. Young Station Unit 1. These were estimated to be in addition to existing O&M costs to operate and maintain the MRY Station equipment.

The expected loss of electrical power sales from the operation of the specific NO_X control alternative was included as an annualized cost, assuming $35 per megawatt-hour. This was determined to include estimates for:

- Reduction in annual unit output due to an expected negative reliability (i.e. uptime availability) impact for each alternative. This generation reduction was calculated by multiplying the estimated additional numbers of outage hours per year by the average running plant capacity factor for that specific alternative, multiplied by the historic 12-month average unit gross electrical power output (MW_g) determined during the same period as the highest 12-month rolling summation NO_X pounds.
- Net additional auxiliary electric power demand for the added control equipment for each specific alternative based on assumptions for gross horsepower, plus additional power demand for existing fans caused by flue gas pressure drop (COHPAC for additional PM collection capacity), with adjustment for expected reductions in power demand (such as a decrease in existing coal crusher and feeder electric demand for the pulverized coal reburn case).
- The average running plant capacity factor for each alternative, which may also include an expected negative impact on the unit capacity from operation of the technology. This assumes that the control technique limits the gross electrical power output of the Unit (such as causing an increase in flue gas flow) such that the firing rate of the boiler cannot be maintained or raised to compensate for the load impact. Examples are lower boiler thermal efficiency (higher unit heat rate) when firing natural gas (due to higher moisture content of the flue gas).

For the SNCR alternative that involves a chemical reagent injected for NOx control, such as urea, the annual reagent consumption based on an assumed actual stoichiometric ratio (ASR) of moles of equivalent NH_3 injected per mole of uncontrolled NO_X emission estimated at the point of injection, converted to a mass rate (lbs/hr) by multiplying by the estimated annual number of hours of operation and the estimated NOx reduction fraction, and then multiplied by unit reagent cost (for a specific inlet NO_X concentration, emission reduction percentage and ammonia slip level).

General annual maintenance costs were assumed to be 1.5 percent of the estimated installed capital cost for each alternative, except for the coal conveying and grinding equipment portion of the coal reburn alternative, which was assumed to be 3 percent. The periodic bag replacement costs and other COHPAC system maintenance costs were estimated to be approximately 5.3% of the installed capital cost of the additional particulate matter collection equipment.

Additional operating labor costs directly attributable to each alternative were assumed to be zero for all alternatives.

Other operating costs include:

- Reagent dilution water for those alternatives that involve a chemical reagent injected for NOx control, typically four times the amount of urea consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this follows EPA OAQPS convention[1].
- Heat required for urea reagent storage, for those alternatives that involve a chemical reagent injected for NOx control; the source of heat is assumed to be auxiliary electrical power, but could be auxiliary steam (depending on heat source availability and plant preference).
- Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water;
  This follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. For the purposes of this study, this additional coal consumption has been included in the annual O&M costs.

The sum of the estimated annual O&M costs was multiplied by the O&M levelization factor (1.24873) for each alternative to yield levelized total annual O&M costs.

C.3.1 Separated Overfire Air O&M Cost Estimate

Operation of SOFA is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and airflow measuring system transmitter on each port. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Maintenance of the new overfire air ports and relocated lignite drying system vent ports is included,

assumed to be 1.5 percent of the installed capital cost. This is included in every control alternative's estimated O&M cost.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 2.2% (188 hours per year), for M.R. Young Station Unit 1 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic cyclone slag tapping operational conditions encountered during substoichiometric cyclone operation with SOFA. The expected loss of electrical power sales from the reduction in annual electrical power output due to a decrease in expected Unit availability from ASOFA operation is included in every control alternative's estimated O&M cost.

Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric cyclone operation with SOFA. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The additional costs associated with potential change in the frequency of furnace wall tube failures and changeouts are difficult to estimate, and have not been quantified.

C.3.2 Reburn O&M Cost Estimates

The alternatives that include a new coal reburn system assume the use of new equipment for preparing the reburn fuel to replace 25% of the MRY Station Unit 1 boiler's total fuel heat input. Two additional lignite silos, with coal feeders and fine-grind pulverizers followed by dynamic classifier(s), are assumed to be located in a new separate building or powerhouse enclosure. Booster fan(s) addition was included because the existing forced draft fans were assumed to be incapable supplying the additional amount of primary air to the fine-grind pulverizers and dynamic classifier(s) for processing and conveying the reburn fuel. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected

to significantly change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. The expected loss of electrical power sales from the additional auxiliary electric power demand for the reburn milling equipment from an estimated 0.6% (1.5 MW) reduction in net output was included as a cost, assuming $35 per megawatt-hour for MRY Station Unit 1. Electrical power consumed by the increased load on boiler fans to overcome the higher flue gas system pressure drop, plus the COHPAC particulate collection system support equipment was estimated to be a 1.2% (3.2 MW) reduction in net output for Unit 1.

Maintenance of the separate reburn coal injectors, fuel and primary air piping, and reburn fuel milling equipment is expected to be similar to the expenses associated with typical pulverized coal burners. The estimated additional annual maintenance costs for a new micronized coal reburn system was assumed to be 3.0 percent of the installed capital cost, or roughly $693,000 per year, for MRY Station Unit 1. The estimated additional annual maintenance costs (inflation adjusted from 2002 to 2006 $) for the COHPAC system was approximately $1,223,000 for MRYS Unit 1. Boiler furnace waterwall tube and superheater/reheater tube maintenance may increase slightly as a result of more erosion due to increased particulate emissions or fouling by flyash deposits resulting from coal reburn operation with ASOFA. The additional costs associated with potential change in the frequency of boiler tube failures and changeouts are difficult to estimate, and have not been quantified.

The estimated impacts on operation and maintenance costs for the coal reburn alternative that include a new pulverized or micronized coal reburn system are approximate. The seven (Unit 1) existing coal crushers for preparing the main (cyclone) fuel fraction will have slightly lower electrical demand. This was estimated as -0.26 MW (-0.1%) for MRYS Unit 1. Addition of new electrical loads for the micronized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/classifiers and related new coal reburn equipment, but this has not been confirmed.

Coal Reburn with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 3.7% (316 hrs/yr), for M.R. Young Station Unit 1 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during coal reburn operation with ASOFA. This reduction in annual electrical power output

due to a decrease in expected Unit availability is included in the coal reburn control alternative's estimated O&M cost.

A Running Plant Capacity Factor reduction of 0.5% of annual gross electrical output was assumed for the coal reburn alternative. This would result in an estimated 1.2 MW average load decrease for M.R. Young Station Unit 1. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

Conventional and fuel-lean gas reburn options will involve higher operating costs compared with the existing operation of M.R. Young Station. Natural gas supply was assumed to be available near Bismarck, ND, but this has not been confirmed. The estimated unit cost of this natural gas was assumed to average $7.98/million Btu on a levelized annual cost basis, with a "credit" of $0.71 per mmBtu for avoided cost of consumption of lignite coal reduced by the natural gas heat input. The estimated annual cost of natural gas for the conventional gas reburning alternative applied to MRYS Unit 1 is approximately $29.7M per year. The estimated annual cost of natural gas for the FLGR™ alternative applied to MRYS Unit 1 is approximately $12.3M per year.

The new gas reburn injectors, station gas main and injector gas trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost. Maintenance of separated overfire air nozzles is expected to be similar to the expenses associated with Unit 2's existing flue gas recirculation ports.

C.3.3 SNCR O&M Cost Estimate

The alternatives that include selective non-catalytic reduction systems will involve higher operating costs compared with the existing operation of MRY Station Unit 1. Urea reagent supply was confirmed to be available regionally. The estimated unit cost of this 50% aqueous urea solution was assumed to average approximately $379/ton delivered (2006$). Consumption of urea reagent for SNCR with ASOFA was based upon preliminary numbers allowing for a boiler flue gas exit ammonia slip of 5 ppmvd. These were estimated as approximately 200 gph for SNCR when applied to MRY Station Unit 1 with ASOFA.

New electrical loads are required for high flow urea circulation, in-line and storage tank heating, water dilution, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in EPA Office of Air Quality Planning and

Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1]. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available, but this has not been confirmed. The new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost.

SNCR with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming urea injection does not impact the ability to maintain consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers. A Unit availability reduction of 3.2% (273 hrs/yr), for M.R. Young Station Unit 1 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during SNCR-related operation with ASOFA. This reduction in annual electrical power output due to a decrease in expected Unit availability is included in the these control alternatives' estimated O&M costs.

A Running Plant Capacity Factor reduction of 0.15% of annual gross electrical output was assumed for the SNCR with ASOFA alternative. This would result in an estimated 0.37 MW average load decrease for M.R. Young Station Unit 1. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

C.3.4 Layered Technology O&M Cost Estimates

Operating and maintenance costs for combinations of available NO_X reduction technologies were estimated based upon simple arithmetic addition of individual cost estimates. SNCR was combined with advanced SOFA, as previously shown. Pulverized coal reburn was assumed to be combined with advanced SOFA (and a COHPAC addition for PM control). The auxiliary electrical demands and reagent dilution water usage for SNCR with ASOFA were calculated based upon equations published in EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1].

C.3.5 Summary of O&M Costs Estimates for MRY Station NOx Control

The results of this evaluation for estimated variable operating and maintenance costs for the individual NOx control alternatives are summarized in this section. The expected reductions in Unit availability (uptime) and capacity are included in Tables C.3-1 through C.3-4 for MRYS Unit 1. Tables C.3-5 and C.3-6 for MRYS Unit 1 include the estimated urea reagent and dilution water usage rates and costs for the alternatives that involve SNCR with ASOFA NO_X control technologies.

TABLE C.3-1 – Expected Availability Reductions for MRY Unit 1 NO_X Controls

Alt.[1]	NOx Control Technique	Estimated Annual Average Unit Operating Time			
		Unit Availability[2]	Unit Operating Time[3], hrs/yr	Unit Outage Time[4], hrs/yr	Unit Operating Time Reduction[5], hrs/yr
E	SNCR w/ ASOFA	0.942	8255	505	273
D	Gas Reburn w/ ASOFA	0.952	8340	420	188
C	Coal Reburn w/ ASOFA	0.937	8212	548	316
B	FLGR w/ ASOFA	0.952	8340	420	188
A	Advanced SOFA (ASOFA)	0.952	8340	420	188
	Baseline	0.973	8528	232	0

1 – Alternative number has been previously assigned from least removal to highest removal percentage.
2 – 12-month baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
3 – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
4 – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
5 – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

TABLE C.3-2 – Expected Capacity Reductions for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction		
		Unit Running Plant Capacity Factor(2)	Unit Generation Reduction(3) kW-hrs/yr	Unit Generation Reduction Cost(4), 1000$/yr
E	SNCR w/ ASOFA	0.965	67,660,606	2,368
D	Gas Reburn w/ ASOFA	0.957	46,120,681	1,614
C	Coal Reburn w/ ASOFA	0.961	77,958,350	2,729
B	FLGR w/ ASOFA	0.962	46,400,200	1,624
A	Advanced SOFA (ASOFA)	0.966	46,586,546	1,631
	Baseline	0.966	0	0

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline running plant capacity factor is assumed at 96.6 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 244.4 MW.
(4) – Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-3 – Expected Auxiliary Electrical Power Demand Changes for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand (2) kW	Credit(3) kW	Total Net Demand(4) kW	Power Usage(5) kW-hrs/yr	Power Usage Cost(6), 1000$/yr
E	SNCR w/ ASOFA	73.1	0	73.1	582,411	20
D	Gas Reburn w/ ASOFA	1	133	(132)	(1,054,343)	(37)
C	Coal Reburn w/ ASOFA	4,666	261	4,405	11,905,082	1,217
B	FLGR w/ ASOFA	1	73	(72)	(578,744)	(20)
A	Advanced SOFA (ASOFA)	1	0	1	8,058	0.3

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 1,507 kW for feed preparation and conveying equipment demand plus 3,158 kW for the COHPAC system addition for PM control.
(3) – The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.
(4) – The total net auxiliary electrical power demand is the sum of the gross demand and credit.
(5) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.
(6) – The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
		APC Electrical Power Usage(2) kW-hrs/yr	Unit Generation Reduction(3) kW-hrs/yr	Total Unit Electrical Power Generation Change(4) kW-hrs/yr	Total Unit Electrical Power Generation Change Cost(5) 1000$/yr
E	SNCR w/ ASOFA	582,411	67,660,606	68,243,017	2,389
D	Gas Reburn w/ ASOFA	(1,054,343)	46,120,681	45,066,338	1,577
C	Coal Reburn w/ ASOFA	11,905,082	77,958,350	89,863,432	3,946
B	FLGR w/ ASOFA	(578,744)	46,400,200	45,821,456	1,604
A	Advanced SOFA (ASOFA)	8,058	46,586,546	46,594,605	1,631

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.
(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 244.4 MW.
(4) – The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control technique.
(5) – The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-5 – Expected NOx Reagent Usage and Cost Estimates for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	NOx Reduction Reagent Urea Usage(2)			NOx Reduction Reagent Dilution Water Usage(3)	
		lbs/hr	tons/yr	1000$/yr	1000 gal/yr	1000$/yr
E	SNCR w/ ASOFA	1,894	7,544	2,861	7,232	7

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – All cost figures in 2006 dollars.
(3) – Reagent dilution water usage assumes potable water is added to create a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) prior to injection. Dilution water unit cost assumed to be $1.00 per thousand gallons.

TABLE C.3-6 – Expected Heat Input and Equivalent Coal Cost to Evaporate Aqueous Urea for MRY Unit 1 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Equivalent Coal Consumption Cost for Aqueous Urea Evaporation		
		Heat Required to Evaporate Aqueous Urea(2), mmBtu/yr	Equivalent Coal Consumption for Heat Input(2), Tons/yr	Coal Consumption Cost(2), 1000$/yr
E	SNCR w/ ASOFA	54,315	4,077	38

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – Heat required to evaporate urea reagent dilution water assumes 900 Btu/lb required based on a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) injected for the estimated amount of urea usage. Coal heat content of 6,662 Btu/lb, unit cost of $0.71/mmBtu.

Appendix C References:

[i] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf.

[ii] "Stationary Source NOx and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts", October 1, 2003 Western Regional Air Partnership Final Report of the WRAP Market Trading Forum, Section VI: Summary of Emission Controls Available for Large Stationary Sources of NOx and PM (by Reaction Engineering International), available at http://www.wrapair.org/forums/mtf/nox-pm.html

[iii] Burns & McDonnell internal database.

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NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY

for

Milton R. Young Station Unit 2

Minnkota Power Cooperative, Inc.

Operating Agent for

Square Butte Electric Cooperative

Owner

Final Report

October 2006

31777

Minnkota Power

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NOx Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2

prepared for

Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative

October 2006

Project No. 31777

Final Report

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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INDEX AND CERTIFICATION

Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative
Milton R. Young Station Unit 2
NO_X Best Available Control Technology Analysis Study

Project 31777

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Certification

I hereby certify, as a Professional Engineer in the state of North Dakota, that the information in this document was assembled under my direct personal charge. This report is not intended or represented to be suitable for reuse by Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative or others without specific verification or adaptation by the Engineer. This certification is made in accordance with the provisions of the laws and rules of the North Dakota State Board of Registration under Title 28 Administrative Code.

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* * * * *

EXECUTIVE SUMMARY

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired steam-electric generating units (SEGUs). The units both fire North Dakota lignite supplied from the adjacent mine, near Center, North Dakota. Unit 1 has a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 250 MW_g (gross), and has a gross design output capacity rating of 257 MW_g. Unit 1 is owned and operated entirely by Minnkota. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 460 MW_g (gross), and has a gross design output capacity rating of 477 MW_g. Unit 2 is owned by Square Butte Electric Cooperative (Square Butte), and operated by Minnkota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota Power Cooperative on June 21, 2002. The NOV alleged that modifications had been made at the Milton R. Young Station that would have required a construction permit under New Source Review (Code of Federal Regulations 40 CFR 52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree (CD) has been approved that represents a final negotiated settlement of the United States' and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average NO_X Emission Rate [Consent Decree paragraph 24, page 7, and paragraph 5, page 4].

Burns & McDonnell was retained to conduct a Top-Down BACT Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. The results of the BACT analysis are presented in this study report.

The procedures mandated by the Consent Decree for performing a Top-Down BACT Analysis are outlined in Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990 ("EPA's NSR Manual"). The MRY Station BACT analysis was performed in accordance with this procedure. The

EPA's NSR Manual outlines five basic steps that are to be followed in this BACT analysis. These basic steps for such a BACT analysis are summarized as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

A Best Available Control Technology (BACT) analysis was performed for Milton R. Young Unit 2 for NO_X using the EPA's "top-down" approach. Best Available Control Technology is defined as "an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant" (40 CFR 52.21, NSR Manual B.1).

Unit 2 at Milton R. Young Station is a cyclone-fired boiler that burns North Dakota lignite. The method of firing is very significant in analyzing control options for NO_X emissions. A cyclone boiler produces inherently higher uncontrolled NO_X levels than pulverized-coal and circulating fluidized bed boilers. There have been no new coal-burning cyclone-fired boilers built and installed in the United States since the early 1980's. Consequently, there are no examples of BACT control options listed in the RACT/BACT/LAER Clearinghouse database for consideration and direct application of published NO_X emission permit limits on the Milton R. Young cyclone-fired boilers.

Step 1 – Identify All Control Technologies

The Consent Decree requires that the NO_X Top-Down BACT Analysis for the Milton R. Young Station "include an evaluation of Selective Catalytic Reduction (SCR), Selective Non-Catalytic Reduction (SNCR), Overfire Air (OFA), Rich Reagent Injection (RRI), as well as other NO_X control technologies" potentially applicable for lignite-fired cyclone boilers [Consent Decree paragraph 65, page 19]. Other identified control techniques, such as fuel switching and fuel cleaning, and combustion-related emission control technologies, such as fuel reburn and oxygen-enhanced combustion, were also considered.

Step 2 – Eliminate Technically Infeasible Options

The BACT evaluation determined that not all the technologies identified were considered available and applicable. The technically infeasible alternatives were eliminated from further evaluation, along with feasible technologies with economic impacts that were unreasonable compared to other cost-efficient alternatives to control NO_X emissions for MRY Station Unit 2.

The technical feasibility of applying NO_X emission reduction techniques and technologies at Milton R. Young Station is dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

Both boilers include a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Ash deposition in each boiler and air preheater is a significant operational challenge for the facility. Significant equipment and manpower resources are devoted to on-going removal of fireside ash accumulations. Unit outages must be conducted at regular intervals to clean each boiler (approximately every 80-120 days). There are a number of issues that make selective catalytic reduction (SCR) technically infeasible for NO_X emission control for Milton R. Young Unit 2. The consistent long-term operation of SCR technology on lignite-fired cyclone boilers will be drastically inhibited by the susceptibility of the SCR catalyst to severe fouling, deactivation, and erosion resulting from the actions of the emitted flue gases and flyash, and ash deposit removal operations. SCR technology is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station.

Rich Reagent Injection has been demonstrated on boilers burning bituminous and subbituminous coal. However, it has not been commercially installed and placed in continuous operation on a cyclone-fired boiler burning lignite coal with high fouling and slag temperature sensitivities associated and a highly

variable heat content. RRI adds urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea, and thus creating NO_X. While RRI is specifically intended for NO_X emissions control on cyclone boilers, RRI is considered technically infeasible for application on the lignite fired cyclone boilers at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

The application of separated overfire air (SOFA) for NOx emissions control on Milton R. Young Unit 2's boiler was evaluated as part of the BACT analysis. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. This highest-performing form of SOFA can be applied alone and in combination with other technologies. Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when "starved air" (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the individual cyclone furnaces can be operated with less-than-theoretical (substoichiometric) combustion air, which corresponds to operation of a SOFA system, directly contributes to less combustion-related NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. This places great emphasis on achieving tight control over the air/fuel ratios on each cyclone during air-staged combustion operation with SOFA in order for air-staged combustion to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

In the case of MRY Station Unit 2's boiler, air-staged combustion must be sufficient to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners. Due to the short-term variability of the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND, and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control while operating the highest-performing version of SOFA system is expected to be modest.

Selective Non-Catalytic Reduction (SNCR) technology has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation.

There are significant concerns associated with effective long-term SOFA operation for Milton R. Young Station Unit 2's boiler. The ability of basic combustion equipment and improvements to precisely measure the boiler's heat input rate in real-time on an individual cyclone by cyclone basis with compensation for the short-term variability of the combustible content of the Center lignite to consistently maintain substoichiometric operation of every cyclone during air-staged combustion is unproven.

Several other techniques and technologies were considered technically feasible for NOx emissions control at MRY Station: Fuel Blending/Switching; Basic Combustion Control Improvements; and various forms of Fuel Reburn. Fuel switching/blending was not evaluated further because of expected unreasonably high capital and operating costs and no additional emission reduction compared to continued lignite firing.

Other NOx emissions control techniques and technologies for MRY Station evaluated and determined to be technically infeasible were: Fuel Cleaning; Low NOx Burners (LNB); Flue Gas Recirculation; Oxygen-enhanced Combustion (OEC); Water/steam injection (combustion tempering); and Electro-Catalytic Oxidation (ECO®).

Step 3 – Rank Remaining Control Technologies by Control Effectiveness

The third step in the "top-down" BACT evaluation ranked the remaining control technologies by effectiveness. The purpose of ranking the control technologies was to establish a hierarchy that places at the "top" the control technology that achieves the lowest emission level. The technologies in order of their effectiveness, from highest to lowest, are: SNCR with ASOFA; Gas Reburn with ASOFA; Lignite Reburn with ASOFA; Fuel Lean Gas Reburn with ASOFA; and Advanced Separated Overfire Air (ASOFA). None of these control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application.

Step 4 – Evaluate Most Effective Controls and Document Results

Additional criteria besides technical feasibility were utilized for technology selection in this BACT analysis. These included estimates of control effectiveness (i.e. percent pollutant removed), capital plus operating and maintenance costs, annual emission reduction (tons per year), energy impacts, average and incremental cost effectiveness ($/ton), and environmental impacts (other media and emissions of toxic and hazardous air pollutants).

The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into a levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated.

Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 2were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

The two most cost-effective feasible control alternatives for reduction of NO_X emissions were reviewed to determine if the use of the technique or technology would result in any significant or unusual energy penalties or benefits. Potential increase in power plant energy consumption or net generation reductions, for ASOFA alone, or ASOFA with SNCR were relatively small.

The predicted environmental impacts from implementation of the two most cost-effective feasible NO_X emissions control alternatives from slightly higher unburned carbon in the emitted fly ash, carbon monoxide, and excess ammonia (“slip”) emissions was expected to be small in comparison with the

significant anticipated reduction in far-field ozone and improvement in atmospheric visibility as a result of the overall NO_X emission reduction.

Step 5 – Select BACT

Taking into account technical feasibility, energy, environmental, and economic impacts and other costs, the recommended Best Available Control Technologies and associated emission rates for nitrogen oxides emissions produced by Milton R. Young Station Unit 2 boiler are provided in the table below.

NO_X Emission Control Technology and Rate Recommended as BACT

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**Control Method**	**12-Month Rolling Average NOx Emission Rate (lb/ million Btu)**
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.330

This recommended BACT 12-month NO_X emission rate is based upon a historic pre-control 12-month baseline average annual NO_X emission rate used in the control and cost-effectiveness analysis of 0.786 lb/mmBtu for Unit 2. The baseline emission was determined from the 12 consecutive month period with the highest historic summation of NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005.

To complete the BACT determination process, the Consent Decree (CD) requires that "specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)" must be established for each subject emission Unit [CD Paragraph 66, pg 20]. Because there are expected to be minor short term variations in operating conditions where Minnkota has not, in fact, materially changed any of their normal daily operating practices, a margin between the 12-month average operating conditions and the 30-day permit limit is proposed. This recommended emission rate should be suitably higher such that operation consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices to the extent practicable for the recommended NOx BACT alternative would not result in an exceedance (violation) of an enforceable emission permit limit.

The Consent Decree also requires that the North Dakota Department of Health's (NDDH) NO_X BACT Determination address specific emission limitations during Unit startups at Milton R. Young Station [CD Paragraph 66, pg 20]. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The SEGU startup operating period is usually not defined in emission permits. However, for the purpose of this NO_X BACT analysis, Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 4800 million BTU/hr for Unit 2; or
- the amount of time reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

For MRYS Unit 2, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation excluding such startup periods:

- The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold startup up to and including maximum continuous rated output;
- The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
- The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
- The number of startups and their range of typical durations per 30-day period time frame.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 2. The approach taken in this analysis was to establish a historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) from the 30-consecutive day period with

the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1,2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. This was then compared to the 12-month historic pre-control baseline average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 2. This is summarized below.

Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.350

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.874 lb/mmBtu for Unit 2. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.35 lb/mmBtu for Unit 2 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
2	0.35	+0.102 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.959 lb/mmBtu for Unit 2 reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
2	1.064

These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

Compliance with these emission rate would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota (for Square Butte) to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trial period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

* * * * *

1.0 INTRODUCTION

The Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte) includes two cyclone-furnace, lignite-fired boilers producing steam for electric generation. Both units fire North Dakota lignite supplied from an adjacent mine, near Center, North Dakota.

A Notice of Violation (NOV) from the United States Environmental Protection Agency (US EPA or EPA) was issued to Minnkota on June 21, 2002. The NOV alleged that modifications have been made at the Milton R. Young Station that would require a construction permit under New Source Review (Code of Federal Regulations 40CFR52.21, and North Dakota Administrative Code NDAC 33-15). As a result of this allegation, a civil complaint was filed by the United States of America and the State of North Dakota against Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") in the United States District Court for the District of North Dakota. A Consent Decree[1] has been entered that represents a final negotiated settlement of the United States and North Dakota's claims against Minnkota and Square Butte. The Consent Decree requires Minnkota and Square Butte to perform a NO_X "Top-Down" Best Available Control Technology (BACT) Analysis to describe the emission limits for NO_X that will be required at Units 1 and 2, expressed as a 30-Day Rolling Average Emission Rate (lbs/million Btu)[2].

Burns & McDonnell was retained by Minnkota to conduct a "Top-Down" Best Available Control Technology (BACT) Analysis for nitrogen oxides (NO_X) at the Milton R. Young Station. Burns & McDonnell is a full service engineering, architectural, construction and environmental firm. The company plans, designs and constructs electric generating facilities and has been providing environmental services since the 1970s. As part of those services, Burns & McDonnell has extensive experience in permitting, Best Available Control Technology (BACT) studies and control technology analysis. The results of the BACT analysis are presented in this report.

[1] In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No. 1:06-CV-034

[2] Ibid – footnote number 1, CD paragraph 65, page 19.

The primary guidance utilized in preparation of this BACT analysis is the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990[3] ("NSR Manual").

In the next section of the report, the approach to the BACT Analysis is described. Following that, a quick summary of the plant conditions and report basis is given and then the BACT Analysis begins. The impact portion of the report is broken down into separate subsections. Within the last section, the results of all of the BACT Analysis steps are summarized for NO_X control options for Unit 2's boiler at the Milton R. Young Station.

* * * * *

[3] Chapter B of the U.S. EPA's New Source Review Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft, October 1990.

2.0 "TOP-DOWN" NO_X BACT ANALYSIS APPROACH

Best Available Control Technology (BACT) is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[4]. A BACT review does not result in an emissions removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station Unit 2's boiler NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps are as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The predefined steps of a BACT analysis are described in this section, and results presented. Available NO_X control techniques and technologies are defined, identified, and a technical description of the emission reduction process and capabilities are reviewed in the following section. Subsequently, those techniques and technologies deemed feasible for retrofit application are ranked according to nominal NO_X control capability. An engineering analysis reviews the estimated capital and operations and maintenance (O&M) costs for each feasible alternative, including taking a look at Balance of Plant (BOP) requirements. Following the cost impact determination, the energy and environmental impacts are reviewed for each feasible technology. Finally, the results of the engineering analyses are tabulated and a NO_X BACT selection is recommended for each unit.

2.1 STEP 1 – IDENTIFY ALL CONTROL TECHNOLOGIES

The first step in a "top-down" NO_X BACT analysis is to identify, for the emissions unit in question, a comprehensive list of all "available" control options. In the EPA's draft NSR Manual,

> "available control options are those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation. Air pollution control technologies and techniques include the application of

[4] Ibid footnote number 2, NSR Manual B.1

production process or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of the affected pollutant"[5].

According to the EPA's draft NSR Manual, "a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term"[6]. Also, "a control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development"[7].

In order to identify available NO_X emission control technologies and techniques appropriate for potential application to MRY Station units, the following information sources were reviewed for coal-fired electric generating unit powerplants:

- EPA's RACT/BACT/LAER Clearinghouse (RBLC) database and Control Technology Center (website).
- Federal (EPA) and State, including North Dakota Department of Health internet websites for air emission permits and recently-submitted applications, including BACT Evaluations following New Source Review procedures.
- Federal (EPA and Department of Justice) and State, including North Dakota Department of Health internet websites for Consent Decrees issued as a result of legal actions taken by the United States government for alleged violations of the Prevention of Significant Deterioration (PSD) provisions and New Source Review provisions of the Clean Air Act, and/or federally-approved and enforceable State Implementation Plans.
- Control technology vendor information.
- Published and available information from technical, engineering, and environmental consultants.
- Technical literature found in journals, reports, internet websites, newsletters, proceedings of technical seminars and conferences pertaining to studies, engineering, designs, and testing of air pollution controls.

[5] Ibid, NSR Manual B.5
[6] Ibid, NSR Manual B.17
[7] Ibid, NSR Manual B.18

2.2 STEP 2 – ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

The second step of the "top-down" BACT process is to evaluate the available NO_X control technologies and techniques identified in Step 1 in terms of the specific factors that apply to the emissions unit in question. In accordance with EPA's draft NSR Manual, "an available technology is "applicable" if it can be reasonably installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible[8]".

The EPA's NSR Manual states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique"[9]. Also, a "showing of unresolvable technical difficulty with applying the control would constitute a showing of technical infeasibility (e.g., size of the unit, location of the proposed site, and operating problems related to specific circumstances of the source)"[10]. After a determination is made that any of the processes are technically infeasible, options are eliminated if technical challenges would preclude or prevent the successful long-term use of the control option or technique on the emission unit under consideration. This is performed prior to any economic analysis.

However, the EPA's NSR Manual also states "…control options incapable of meeting an applicable New Source Performance Standard (NSPS) or State Implementation Plan (SIP) limit would not meet the definition of BACT under any circumstances. The applicant does not need to consider them in the BACT analysis"[11]. Also, it states "An NSPS simply defines the minimum level of control to be considered in the BACT analysis"[12]. The NSR Manual further states "When developing a list of possible BACT alternatives, the only reason for comparing control options to an NSPS is to determine whether the control option would result in an emission level less stringent than the NSPS. If so, the option is unacceptable"[13]. New Source Performance Standards (NSPS) for NO_X emissions from EGUs firing North Dakota lignite are 0.8 lb/mmBtu. The EPA Acid Rain Program's Title IV NO_X emission limit for Group 2, cyclone-fired coal boilers with outputs greater than 155 MWe is 0.86 lb/mmBtu.

[8] Ibid, NSR Manual B.17
[9] Ibid, NSR Manual B.20
[10] Ibid, NSR Manual B.19
[11] Ibid, NSR Manual B.12
[12] Ibid, NSR Manual B.12
[13] Ibid, NSR Manual B.12

EPA's draft NSR Manual also states "A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review"[14].

Also in the EPA's draft NSR Manual is a qualification for technical feasibility, as described by the statement "Commercial availability by itself, however, is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or "applicable" to the source type under consideration"[15].

2.3 STEP 3 – RANK REMAINING CONTROL TECHNOLOGIES BY CONTROL EFFECTIVENESS

The third step in the "top-down" BACT evaluation is to rank the control technologies remaining after the feasibility analysis by control effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that "places at the "top", the control technology that achieves the lowest emission level"[16].

Selecting common units in order to compare emissions performance levels amongst options is one of the two key issues that must be addressed in a BACT analysis. EPA's draft NSR Manual states "it is generally most effective to express emissions performance as an average steady state emissions level per unit of product produced or processed"[17]. For fossil fuel-fired boilers, pounds of nitrogen oxides per unit of fuel heat input (i.e. lb/mmBtu), is a common means of comparing and calculating NO_X emissions.

Many control techniques, including both add-on controls and inherently lower polluting processes can perform at a wide range of levels. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would

[14] Ibid, NSR Manual B.18
[15] Ibid, NSR Manual B.18
[16] Ibid, NSR Manual B.25
[17] Ibid, NSR Manual B.22

result in a large number of options"[18]. Also, "manufacturer's data, engineering estimates, and the experience of other sources provide the basis for determining achievable limits"[19].

2.4 STEP 4 – EVALUATE THE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

The fourth step of a "top-down" BACT review is to evaluate the technically-feasible emission controls, beginning with the most effective. Economic, energy, and environmental impacts are to be assessed and quantified, where possible, in the control technology analysis. The purpose of the evaluation is to determine if there are any identified impacts that would eliminate the top control technology from consideration. In the case where the most effective control alternative is determined to incur or produce adverse energy, economic or environmental impacts, the basis of the determination is documented, and the next most stringent control alternative is evaluated. This analysis process continues until the control technology under consideration cannot be eliminated by identification of any source-specific adverse energy, economic or environmental impacts.

The economic impacts are based on estimates of capital equipment pricing, procurement, installation and estimated operating and maintenance costs. The total installed capital costs along with the operating costs for each control technology are summarized in the economics of each respective section. The Levelized Total Annual Cost (LTAC) represents the levelized cost of procurement, construction, operation and maintenance over an assumed service life. Cost effectiveness ($/ton) of a control technique or technology is calculated by dividing the LTAC ($/yr) by the annual amount of NO_X removed (tons/yr). Baseline pre-control emissions are calculated using realistic upper boundary operating assumptions, considering inherent physical or operational constraints on the source. Plotting of the annual amount of NO_X removed (tons/yr) versus the levelized total annual control cost ($/yr) for the various control options on an x-y graph allows visualization of the cost-effectiveness. A "least-cost envelope" can be readily identified to indicate the inferior control options which should not be considered in the subsequent analyses. The incremental cost-effectiveness (difference in $/ton) between control techniques or technologies can also be calculated and compared. This allows evaluation of the dominant controls included on the least-cost envelope (curve).

[18] Ibid, NSR Manual B.23
[19] Ibid, NSR Manual B.24

2.5 STEP 5 – SELECT BACT

The final step in the "top-down" evaluation process is to select BACT for the applicable pollutant and emission unit. Per the EPA guidance document, BACT is "the most effective control technology not eliminated in Step 4"[20]. The methodology described above was applied to the Milton R. Young Station Unit 2's boiler for emissions of nitrogen oxides.

* * * * *

[20] Ibid, NSR Manual B.53

3.0 BACT ANALYSIS for MRY STATION UNIT 2 NO_X EMISSIONS

The approach taken in this BACT analysis for Milton R. Young Station included a technical analysis of demonstrated control alternatives for NO_X emissions. This approach followed the predefined steps of a BACT analysis process as generally described in Section 2. Potential NO_X control techniques and technologies were identified, and a technical description of the emission reduction process and capabilities were provided. Subsequently, those techniques and technologies deemed available and feasible for retrofit application were ranked according to nominal NO_X control capability. The engineering analysis then developed the estimated capital and O&M costs for each alternative, including taking a look at Balance of Plant (BOP) requirements. Finally, the cost effectiveness points for each feasible technology were plotted, and those that comprise the dominant controls curve were identified.

For the feasible techniques and technologies considered for determining NO_X control cost-effectiveness for the two steam electric generating units at the MRY Station, estimates were produced for predicted NOx reductions that represent achievable long-term expectations of the alternative reduction techniques and technologies being presented in the technical analysis. Each were tabulated and graphed.

3.0.1 EMISSION UNIT DESCRIPTION

Milton R. Young Unit 2 is a Babcock and Wilcox steam generator installed in 1977. The steam generator is a lignite-fired boiler with multiple cyclone-furnaces installed in parallel using balanced-draft and natural circulation assisted with circulation pumps. Original unit design steam generating capacity is 3.20 million lbs/hr at 2,620 psi with a fuel heat input of 4,696 mmBtu/hr. The boiler is fired by twelve ten-foot diameter cyclone burners, arranged “three over three” across the front and rear walls of the lower furnace. The unit has a tubular air heater installed between the boiler and the flue gas ductwork leading to the ESP. Exhaust gases leave the air heater and pass through an ESP for particulate collection and removal followed by the two induced draft fans (installed in parallel) prior to a wet flue gas desulfurization (FGD) system which discharges to the stack. The current air pollution control system’s configuration allows a portion of the low dust flue gas to reheat the stack gas, thus bypassing the FGD system. Unit 2 has a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 462 MW gross, and has an ultimate short-term maximum gross output (URGE) of 512 MW.

The EPA's Technical Support Document[22] lists nameplate steam turbine-generator capacity of MRY Station Unit 2 as 477 MW (gross), which was assumed for calculating capital cost estimates for control alternatives.

The Unit 2 boiler at M.R. Young Station includes a unique coal conditioning system (drying, crushing, and feeding) for each cyclone furnace specifically designed to aid in proper combustion of the lignite fuel. This method of firing solid fuel significantly influences the resulting nitrogen oxide concentration of the flue gases emitted from the boilers.

Milton R. Young Station Unit 2's boiler design, combustion performance, and NO_X emissions are dominated by the composition and combustion characteristics of the North Dakota lignite supplied solely from a surface mine adjacent to the plant. This mine is the only supplier of solid fuel for this station, as there are no railroad facilities provided to service the Milton R. Young plant. North Dakota lignite has high moisture and high sodium content, moderate higher heating values, and can have a widely variable and high ash content compared to other coals. These characteristics create difficulties in promoting consistent, steady combustion and slag formation in the cyclone burners. It also results in producing a flyash that has severe deposition characteristics.

The design unit operating conditions for this study are presented in Table 3-1. The historical average lignite coal analysis is shown in Table 3-2.

Table 3-1 – Unit Design Parameters

Design Unit Operating Characteristics	Unit 2 Design
Boiler Type	Subcritical(1)
Combustion System	Cyclone
Number of Cyclones; arrangement, location	12; 3 over 3, opposed
Unit Design Capacity Electrical Output(2), MW (net/gross)	439 / 477

(1) – Balanced draft, single drum, superheated steam with single stage of steam reheat.
(2) – These values were established by the original equipment manufacturers, prior to construction.

[22] Ibid

Table 3-2 – Historical Average Lignite Coal Analysis

Lignite - Center Mine Ultimate Coal Analysis: (as received)	**Average % by mass**
Moisture	37.29
Carbon	38.69
Hydrogen	2.50
Nitrogen	0.57
Sulfur	0.81
Ash	8.74
Oxygen	11.40
Total	100.00
Higher Heating Value, Btu/lb	6,662

3.0.2 NITROGEN OXIDES EMISSION FORMATION

Nitrogen oxides (NO_X) are produced when nitrogen in the fuel and combustion air are exposed to high temperatures. There are two primary sources of NO_X emissions, referred to as "thermal" NO_X and "fuel" NO_X. Thermal NO_X emissions are produced when elemental nitrogen in the combustion air is admitted to a high temperature zone and oxidized. Fuel NO_X emissions are created during the rapid oxidation of the fuel containing nitrogen compounds. For most coal-fired units, thermal NO_X emission typically represents approximately 20% and fuel NO_X about 80% of the total NO_X formed. Nitrogen oxide (NO) is typically the most predominant form of NO_X emissions from fossil fuel combustion, along with nitrogen dioxide (NO_2). The formation of these compounds in utility powerplant boilers is sensitive to the method of firing and combustion controls utilized. The techniques employed for mixing the combustion air and fuel, which creates flames and high temperature combustion products, results from the rapid oxidization of carbon, hydrogen, and other exothermic reactions. Cyclone-fired boilers, by design, create intense heat release rates to melt and fluidize the coal ash introduced into the barrel-shaped furnaces. This produces high temperature flue gases and results in very high uncontrolled NO_X emissions. The amount of thermal NO_X emissions produced by cyclone boilers can be considerably higher than fuel NO_X emissions.

3.1 IDENTIFICATION OF NO_X CONTROL OPTIONS FOR MILTON R. YOUNG STATION

The first step in the BACT evaluation is to identify all "demonstrated and potentially applicable control technology alternatives"[23] according to the EPA's draft NSR Manual. In identifying control technologies, "the applicant needs to survey the range of potentially available control options"[24].

[23] Ibid, footnote number 2, NSR Manual page B.11

3.1.1 REVIEW OF RETROFIT INSTALLATIONS

The BACT determinations listed in the EPA's RACT/BACT/LAER Clearinghouse (RBLC) database are for new facilities. The Milton R. Young Station is an existing powerplant facility with two coal-fired EGUs. A BACT evaluation for retrofitting control equipment to coal-fired EGUs in an existing facility will be substantially different than an analysis for installing control equipment on coal-fired EGUs in a new facility. Consequently, in performing the BACT analysis for existing boilers at Milton R. Young Station, it is important to review powerplant facilities, especially cyclone-fired coal boilers, which have retrofitted NO_X control equipment in recent years.

In 1998, EPA issued a NO_X SIP (State Implementation Plan) call. Under the SIP call, utility boilers in the eastern United States were required to substantially reduce NO_X emissions during the "ozone season". The compliance date for the NO_X SIP call is May 31, 2004. A high percentage of the fired electric generation facilities in the eastern United States have or are in the process of retrofitting NO_X controls to comply with the NO_X SIP call. The EPA's NO_X SIP call was not applicable to North Dakota utility boilers.

There are a number of fossil fuel-fired EGU powerplants around the United States that have implemented or are planning to implement modifications to reduce NO_X emissions. The NO_X emission control system installations are in response to Acid Rain requirements, EPA's NO_X SIP call, the Clean Air Interstate Rule (CAIR), the Regional Haze Rule (RHR), and local regulations.

In addition to the facilities that have had to retrofit emissions controls as a result of the Title IV Part 76 Acid Rain requirements and/or EPA's NO_X SIP call, a few installations have had to retrofit controls in recent years as the result of court decisions resulting from litigation and regulatory action. None of the boilers associated with identified consent decrees are cyclone-fired. They are also located in a region requiring compliance with an EPA-approved State Implementation Plan for nitrogen oxides emissions controls (i.e. NO_X SIP call). As mentioned above, North Dakota utility boilers were not subject to the EPA's NO_X SIP call.

[24] Ibid, NSR Manual page B.11

3.1.2 POTENTIALLY FEASIBLE NOx CONTROL OPTIONS FOR MILTON R. YOUNG STATION

A review of available information on retrofit installations performed at utility and industrial coal-fired powerplants during the past fifteen years was undertaken. NO_X emission control technologies and techniques with potential application to Milton R. Young Station boilers were identified, and are listed in Table 3-3.

TABLE 3-3 – Potentially Available NO_X Control Technologies Identified for BACT Analysis

NOx Control Technology
Pre-Combustion Controls
Fuel Cleaning/Blending/Switching
Combustion Controls
Basic Combustion Control Improvements
Low NOx Burners (LNB)
Separated Overfire Air (SOFA)(1)
Flue Gas Recirculation
Fuel Reburn
Oxygen-enhanced combustion (OEC)
Water/steam injection (combustion tempering)
Post-Combustion Controls
Selective Non-Catalytic Reduction (SNCR)(2)
Selective Catalytic Reduction (SCR)
Electro-Catalytic Oxidation (ECO®)(3)

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

A comprehensive literature search, with sources including technical papers and presentations made at conferences by nationally-recognized technical organizations, utilities and other parties involved with design, construction, and testing of NO_X control techniques, plus hardware supplier experience lists, was performed. The results of this search are presented in Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2 FEASIBILITY ANALYSIS

The second step of the "top-down" BACT process is to evaluate the control processes that have been identified and determine if any of the processes are technically infeasible.

An available technology is "applicable" if it can be reasonably be installed and operated on the source type under consideration. Also, a control technique is considered available if it has reached the stage of licensing and commercial availability. For the purposes of this analysis, the term "commercial" is further defined to mean "capable of establishing a full contractual agreement with commercial and performance guarantees supported by appropriate financial backing" for the implementation of full-scale, full-time systems of the technique or technology application. A technology that is available and applicable is technically feasible.

There are three basic categories of NO_X emission control techniques and technologies:

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

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

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

Most of the identified control options have been commercially-available, installed, and operating in many full-scale, permanent coal-fired utility boiler installations in the United States for five years or more.

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

Combustion controls, such as low-NO_X burners (LNBs) and overfire air systems, are very commonly applied to reduce NO_X emissions from fossil fuel-fired powerplants. Low-NO_X Burners are typically applied to pulverized coal, gaseous and liquid fuel-fired boilers. They are not applicable to cyclone-fired boilers. Flue gas recirculation (FGR) has been practiced and performed at numerous natural gas and fuel oil-fired utility and industrial powerplants for NO_X emissions control reasons. On large coal-fired utility boilers, FGR has primarily been applied for steam temperature control purposes, not for emissions control. Conventional Gas Reburn (CGR) with overfire air has been installed and placed in commercial operation on several cyclone-fired boilers, primarily in the eastern region of the United States. Coal Reburn (CR) with overfire air has been successfully demonstrated on two cyclone-fired boilers and commercially installed on three pulverized coal-fired boilers in the United States. Combustion tempering (water/steam injection) has been tested but has not been continuously practiced on cyclone-fired coal boilers. Oxygen-enhanced combustion has only been demonstrated and/or installed on a limited number of pulverized coal-fired powerplants, not on any coal-fired cyclone boilers.

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

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

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

- a full-scale basis, but only with temporary equipment; or
- a full-scale basis, with permanent equipment but in a limited number of installations; or

- with less than full-scale and full-time application.

3.2.1 SUMMARY OF RETROFIT INSTALLATIONS OF NO_X CONTROL TECHNOLOGIES

There are a number of facilities around the country that have implemented or are planning to implement modifications to reduce NO_X emissions. Table 3-4 summarizes the various NO_X emission control system installations currently installed, or that have been demonstrated on a full-scale, short-term basis, in response to Acid Rain requirements, EPA's NO_X SIP call and local regulations, or a utility investigating the technology.

TABLE 3-4 – Identified NO_X Control System Retrofits on Cyclone Coal-fired Boilers

No. of Units(1)	Cyclone NO_X Control Technology Description
1	Fuel Switching/Blending
39(2)	Separated Overfire Air (SOFA)
2	Selective Non-Catalytic Reduction, with or without SOFA
2(3)	Rich Reagent Injection, with SOFA
7(4)	Conventional fuel reburn (pulverized or micronized coal, gas), w/ SOFA
1(5)	Fuel lean gas reburn, with or without SOFA
22(6)	High-dust or low-dust SCR, with or without other technologies
1(6)	Tail-gas SCR, with or without other technologies

(1) – This list of known NOx control retrofit installations is primarily focused on units in the United States. There may be other installations that are similar but were not identified.
(2) – Installed for NOx control (without fuel reburn). A list of known cyclone boiler SOFA installations is included in Appendix A2.
(3) – RRI has only been demonstrated with temporary equipment for testing. See technical literature references in Appendix A1 and A2 for details.
(4) – Several conventional coal and gas reburn retrofits have discontinued reburn demonstration or routine operation. See Technical Literature Reference list and Appendix A3 for further details.
(5) – Only one example of fuel lean gas reburn retrofit (without OFA) on a cyclone-fired boiler has been demonstrated. This system was installed for short-term reburn testing and has been removed.
(6) – High-dust SCR technology has been retrofitted on sixteen U.S. cyclone-fired boilers, all believed to have SOFA. Low-dust SCRs in U.S. have only been installed only on pulverized coal-fired boilers, none on cyclones. One tail-gas SCR installation on a coal-fired cyclone boiler found in Germany; none in the U.S. See technical literature references in Appendix A1 and A2 for details.

A more detailed description of the various control technology retrofits and their claimed effectiveness is included in the technical descriptions and reference literature in the technical feasibility assessment of

Appendix A1, and Appendix A2, which includes a summary of various selected U.S. NO_X emission reduction retrofit projects.

3.2.2 SUMMARY OF FEASIBLE NO_X CONTROL TECHNOLOGIES FOR MRY STATION

One example of fuel switching applied to a cyclone-fired boiler was identified. Ottertail's Big Stone Unit 1 was originally designed to burn North Dakota lignite and was switched to western subbituminous (PRB) coal for reasons unrelated to NO_X emissions reduction. Big Stone Unit 1 and M.R. Young Station Unit 2 have similar boiler designs. Thus, conversion of Milton R. Young Station Unit 2's boiler to fire PRB coal or a lignite/PRB blend is technically possible. There are no railroad facilities provided to service the Milton R. Young plant. Additional operational and capital costs to bring in large quantities of PRB coal will be significant. Based on a comparison of available emission data between Ottertail's Big Stone Unit 1 and M.R. Station Young Unit 2, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station. Although fuel switching at Milton R. Young Station is technically feasible, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. For these reasons, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 2 boiler.

Separated Overfire Air (SOFA) is the most commonly-applied, combustion-related NO_X emission reduction technology that has been proven effective on cyclone-fired boilers. A version of separated overfire air specifically designed for increased NO_X emission reduction performance for lignite-fired cyclone boilers, referred to as "Advanced SOFA" in this analysis, can be installed on both units at M.R. Young Station. The potential operational limitations mentioned in the detailed feasibility discussions included in Appendix A1 for deeply air-staged cyclones associated with separated overfire air are expected to limit the control effectiveness of this technique, alone and in combination with other feasible NO_X control options.

Selective Non-Catalytic Reduction (SNCR) technology is a form of post-combustion NO_X emission control that has been successfully applied on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal to reduce NO_X emissions. SNCR has also been used on fuel oil and natural gas-fired units. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in

the boilers where it has been installed, with or without air-staged combustion with overfire air in full operation. This control technology adds urea (or ammonia) reagent to the hot furnace gases in the upper furnace to chemically reduce nitrogen oxides. SNCR was considered technically feasible for application on both units at M.R. Young Station. SNCR can be operated with and without SOFA. Variations of SNCR technologies such as Hydrocarbon-enhanced SNCR (HE-SNCR) and "Rotamix" have been installed on pulverized coal-fired boilers but are not proven on cyclone boilers. This is described in detail in Appendix A1.

Rich Reagent Injection (RRI) is a form of SNCR under development specifically intended for NOx emissions control on cyclone boilers. As of October 2006, RRI has been demonstrated but has not been commercially installed and placed in continuous operation on a cyclone-fired boiler, especially one burning coal with high fouling and slag temperature sensitivities associated with lignite supplied from the Center mine. RRI adds aqueous urea reagent to the hot furnace gases near the cyclones, which must be devoid of free oxygen in order to avoid oxidation of the urea which will increase NOx emissions. RRI is considered technically infeasible for application on the cyclone boilers at the Milton R. Young Station at the present time. This is described in detail in Appendix A1.

Various forms of fuel reburn with and without overfire air are types of combustion-related technologies that have been demonstrated and commercially installed on pulverized coal, fuel oil-fired, and cyclone utility and industrial boilers. Natural gas-consuming variations such as Conventional Gas Reburn (CGR) and Fuel-Lean Gas Reburn (FLGR™) have been applied to cyclone boilers burning bituminous and subbituminous coals. High capital costs expected for installing a natural gas pipeline and high operating costs from consumption of large volumes of such fuel make these alternatives economically unfavorable for both units at M.R. Young Station. Pulverized or micronized coal reburn, in combination with SOFA, are technically feasible but will require extensive capital, operating and maintenance costs for fuel grinding equipment and facilities when installed and operated for both units at M.R. Young Station. This is described in detail in Appendix A1.

Fuel cleaning is a technique normally applied to reduce the sulfur or ash content of a fossil fuel prior to combustion. No examples of fuel cleaning of North Dakota lignite or western subbituminous coal strictly for NO_X emissions reduction were found in available technical literature. This technique is considered infeasible for NO_X emissions control of M.R. Young Station boilers at the present time.

High-dust, low-dust, and tail-gas variations of selective catalytic reduction (SCR) technology have been applied on pulverized coal and cyclone boilers as a post-combustion type of NO_X emission control throughout the world and in the United States, except on units firing North Dakota lignite. The severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technology on the EGUs at the Milton R. Young Station. This is described in detail in Appendix A1 with supporting documentation in Appendix B.

The results of Step 2 of the NO_X BACT Analysis for determining the technical feasibility of potential control technologies, including various "layered" combinations, are listed in Tables 3-5 and 3-6.

TABLE 3-5 – Technically-Feasible Potential NO_X Control Technologies for M.R. Young Station Unit 2 Cyclone Boiler

Control Technology(1)	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on M.R. Young Station Unit 2 boiler?
Selective Non-Catalytic Reduction (SNCR)	Yes(2)	Yes
Conventional Gas Reburn	Yes(3)	Yes(3); Requires SOFA or ASOFA
Coal Reburn	Yes(4)	Yes(4); Requires SOFA or ASOFA
Fuel Lean Gas Reburn	No(5)	Yes(5) (w/ or w/out SOFA or ASOFA)
Advanced SOFA	No(6)	Yes(6). Includes relocated lignite drying vent ports
Separated OFA (basic SOFA)	Yes(6)	Yes(6)
Combustion Improvements	Yes	Yes(7); typically included with separated OFA
Flue Gas Recirculation	Not for NOx control	Yes(8) (not expected to reduce NOx further)
Fuel Switching / Blending	Yes	Yes(9) (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.
(1) – All potential combinations of technologies not listed. See discussion of "layered" technologies.
(2) – Assumes use of urea for reagent. Limited number of active installations on cyclone-fired boilers burning western subbituminous (i.e. Powder River Basin or PRB) coal.
(3) – Limited number of active conventional gas reburn (CGR) installations on cyclone-fired boilers burning PRB coal.
(4) – Limited number of demonstrations or active installations of pulverized or micronized coal reburn on cyclone-fired boilers. One demonstration of pulverized coal reburning with PRB coal has been performed on a cyclone-fired boiler, no longer active. Only one active permanent coal reburn installation on cyclone-fired boiler burning eastern bituminous coal, none burning PRB coal or lignite.
(5) – Only one short-term test demonstration of FLGR™ on a cyclone-fired boiler burning coal with separated overfire air.
(6) – No cyclone boilers firing North Dakota lignite have installed basic or advanced SOFA. See Appendix A.
(7) – Considered part of SOFA installation for coal boilers without combustion controls for NOx reduction.
(8) – No examples of using recirculated flue gas on coal-fired boilers for NOx emissions control were found in available technical literature. Zero additional NO_X reduction potential expected from this technique alone for MRY Station Unit 2. Potential NO_X reduction improvement on MRY Unit 2 considered part of "advanced" SOFA.
(9) – Zero additional NO_X reduction potential expected from this technique (switching from lignite to lignite/PRB blends or 100% PRB) alone for MRY Station Unit 2.

TABLE 3-6 – Technically Infeasible Potential NO_X Control Technologies for M.R. Young Station Unit 2 Cyclone Boiler

Control Technology[1]	In Permanent, Full-Scale Service on Existing Coal-Fired Cyclone Utility Boilers?	Technically Feasible on M.R. Young Station Unit 2 boiler?
Selective Catalytic Reduction (SCR): conventional (high dust); Low-dust; Tail-gas	Yes[2] / No / Yes[3]	No[4] - Unresolvable fouling and catalyst deactivation problems expected. See discussion of SCR feasibility for ND lignite.
Electro-Catalytic Oxidation (ECO®)	No	No, has not been demonstrated full-scale nor reached commercial availability
HE-SNCR (using ammonia)	No[5]	No[5]. Has not been demonstrated on cyclone.
Rotamix (ROFA + SNCR)	No[6]	No[6]. Has not been demonstrated on cyclone.
Rich Reagent Injection (RRI) with ASOFA	No[7]	No[7]. Requires oxygen-free furnace environment, varying air/fuel would increase NOx emissions.
RRI + SNCR with ASOFA	No[7]	No[7]. See footnote and feasibility discussion.
Advanced Conventional Gas Reburn (ACGR) + SNCR	No[8]	No. Has not been demonstrated on cyclone.
Coal Reburn + SNCR	No[8]	No. Has not been demonstrated on cyclone.
Fuel Lean Gas Reburn + SNCR	No[8]	No. Has not been demonstrated on cyclone.
Rotating Opposed-Fired Air	No[6]	No. Has not been demonstrated on cyclone.
Oxygen Enhanced Combustion	No[9]	No. Has not been demonstrated on cyclone.
Water Injection	No[10]	No[10]
Fuel Cleaning	Not for NOx control	No[11] (not expected to reduce NOx further)

See technical feasibility details and literature References in Appendix A for details.

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

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

(3) – No identified installations on coal-fired boilers in the United States. One tail-end SCR on cyclone boiler in Germany.

(4) – See discussion of SCR feasibility for ND lignite in Appendix A1 and Appendix B.

(5) – Hydrocarbon-enhanced SNCR has not been demonstrated on a cyclone-fired boiler, nor any boiler firing western subbituminous coal or lignite.

(6) – Rotating Opposed-Fired Air with or without SNCR has not been demonstrated on a cyclone-fired boiler. No apparent significant advantages over SOFA on cyclone-fired boilers.

(7) – Rich Reagent Injection has been successfully demonstrated for brief periods with SOFA with and without SNCR at two cyclone powerplants. There are no permanent RRI installations completed and operational as of May 2006. Difficulties in maintaining an oxygen-free furnace environment in MRY Station boilers where the urea reagent would be injected due to cyclone air/fuel imbalances during air-starved combustion would increase NOx emissions.

(8) – No known demonstrations or permanent installations of Advanced conventional gas reburn (CGR) or FLGR™ or pulverized/micronized coal reburn (PCR/mCR) in combination with SNCR on cyclone-fired boilers. CGR and PCR/mCR require separated overfire air. FLGR™ has been applied to pulverized coal firing with and without SOFA, with and without SNCR; FLGR™ with SNCR is also called amine-enhanced fuel lean gas reburn (AEFLGR™).

(9) – No known demonstrations or permanent installations of oxygen-enhanced combustion (OEC) on cyclone-fired boilers.

(10) – No permanently installed examples of using this technique continuously on coal-fired boilers were found in available technical literature. Not suitable for high-moisture lignite fuels.

(11) – No known demonstrations or permanent installations of using this technique continuously on coal-fired boilers for NOx emissions control were found in available technical literature.

Additional criteria besides technical feasibility are utilized for technology selection in a BACT analysis have been included in the following sections summarizing control effectiveness estimates, capital plus operating and maintenance cost estimates, energy impacts, and environmental impacts:

- Control effectiveness (i.e. percent pollutant removed)
- Expected emission rate (see Tables 3-7, 3-8) and emission reduction (tons per year)
- Economic impacts (total cost and incremental cost effectiveness)
- Energy impacts
- Environmental impacts (other media and emissions of toxic and hazardous air pollutants)

3.3 RANK OF TECHNICALLY FEASIBLE NO_X CONTROL OPTIONS BY EFFECTIVENESS

The third step in the "top-down" BACT evaluation is to rank the remaining control technologies by effectiveness. The purpose of ranking the control technologies is to establish a hierarchy that "places at the "top" the control technology that achieves the lowest emission level."

The emission reduction (control effectiveness) percentages developed for ranking the available NO_X emission control options considered feasible for Milton R. Young Station Unit 2 are shown in Table 3-7. These are estimates based upon engineering judgments with considerations of:

- Boiler heat input rates associated with realistic upper boundary operating assumptions;
- baseline emission rates corresponding to the realistic upper boundary operating assumptions;
- the general combustion properties of North Dakota lignite;
- published and available emission reduction performance achieved at other similar utility powerplants (cyclone-fired boilers);
- computer-derived predictions; and
- inclusion of performance margins to allow for variations in fuel, weather, equipment condition, and other factors that prevent the ultimate peak short-term performance from being reliably sustained over the course of long-term operation.

These NO_X emission level and reduction percentage estimates include adjustments of previously demonstrated or predicted performance that reflect differences between North Dakota lignite and eastern or midwestern bituminous and western subbituminous coals.

The numbers assume the estimated capability of the employed technique is achievable and sustainable (long-term) and that potential operational limitations mentioned in the feasibility discussions allow the successful practice of the technique or technology. None of the remaining control options has been installed on a cyclone-fired boiler burning North Dakota lignite. As such, the expressed control percentages reflect the use of engineering judgment, based on the listed technique or technology application. This is particularly pertinent to all control options that involve air-staged combustion associated with various forms of separated overfire air. SOFA-based controls for cyclone-fired coal-burning boilers have typically reduced NO_X emission levels significantly from the precontrol baseline, and which allow or enhance further reductions when combined with other control techniques and technologies.

3.3.1 ESTABLISHING BASELINE NO_X EMISSIONS FOR RANKING CONTROL OPTIONS

Before the various feasible NO_X emission control alternatives can be estimated and ranked in order of effectiveness, the precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual provides general guidance for establishing estimated baseline emissions to be used for the purpose of calculating and comparing the control and cost-effectiveness of a control option:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions. When calculating the cost effectiveness of added post-process emissions controls to certain inherently lower polluting processes, baseline emissions may be assumed to be the emissions from the lower polluting process itself. In other words, emission reduction credit can be taken for the use of inherently lower polluting processes"[25].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true

[25] Ibid, NSR Manual B.37

upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[26].

Establishing estimated baseline NO_X emissions for a new or existing source involves determining the design or operational basis of the emission rate. A useful means of comparing such emission rates is to establish the unit emission rate, expressed in pounds of pollutant per unit of process output. For processes such as steam-electric generating powerplants utilizing combustion in boilers, the desired process output (kilowatts or megawatts) can be related to the pollutant-bearing flue gas created by the combustion of fuel. Units of fuel heat input (millions of BTUs) required to create a unit of desired electrical output (kW) and thus the efficiency of converting the fuel heat to such electrical output (unit heat rate, Btu/kW-hr) are important.

A review of reported hourly NO_X emissions for MRY Station Unit 2 boiler, including unit mass rates (lb/mmBtu and lb/hr), boiler heat input (mmBtu/hr), and gross electrical output in megawatts (MW_g), was performed for the operating periods in years 2001-2005 inclusive. A realistic upper bound emission case scenario for each boiler's baseline emissions at Milton R. Young Station determined the highest summation of any rolling 12-month period NO_X mass emissions (pounds), along with the summation of the gross heat input (mmBtus) and the boiler operating hours for the same rolling 12-month period corresponding to the highest NO_X pounds. Dividing the summation of the rolling 12-month NO_X pounds by heat input results in a average unit emission rates (lb/mmBtu). Likewise, the summation of the rolling 12-month gross heat input (mmBtus) divided by the boiler operating hours yields an average gross heat input rate (mmBtu/hr). This emission evaluation revealed that:

- Unit 2 at Milton R. Young Station is typically operated in a base-loaded manner;
- MRYS Unit 2's highest 12-consecutive month NO_X mass emissions summation divided by the summation of the same 12-month period's heat input averaged 0.786 lb/mmBtu at a corresponding average unit heat input rate of 4,885 mmBtu/hr and unit gross electrical output of 440 MW_g.

3.3.2 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The degree of success in operation of separated overfire air alone and in combination with the other selected feasible alternatives is important to the amount of NO_X emission reduction achieved. The

[26] Ibid, NSR Manual B.37

emission control performance from the advanced version of separated overfire air (ASOFA) is highly dependent on the degree of success in admitting combustion air insufficient for complete combustion in the cyclones without causing related negative impacts. The control percentages estimated for firing North Dakota lignite in the MRY Station boilers reflect the belief that operating the existing cyclones much below an average cyclone stoichiometric ratio of approximately 0.95 (95% of the theoretical amount of combustion air required for complete combustion) will not be successful. This is due primarily to the expected "starved air" combustion causing a reduction in cyclone furnace gas temperatures, thus creating a strong potential for molten slag solidifying in the cyclone barrels, slag taps, and lower furnace floor openings. This would impose a great interruption to steam production since forced outages would be required to remove this physical obstruction before full load boiler operation could be reestablished. The EPA's draft NSR Manual states "It is not the EPA's intention to require analysis of each possible level of efficiency for a control technique, as such an analysis would result in a large number of options"[27].

The potential operational limitations for deeply air-staged cyclones associated with separated overfire air and coal reburn alternatives are expected to limit the amount of NO_X control potential possible from successful practice of the particular technique or technology. This is described in the detailed feasibility discussions included in Appendix A1.

The advanced form of separated overfire air is expected to be effective in NO_X emission reduction and can be combined with other feasible combustion-related and post-combustion control alternatives for these lignite-fired cyclone boilers. The basic form of SOFA in combination with coal reburn, gas reburn options, and SNCR, was not included in the detailed control effectiveness analysis in order to limit the number of options that were evaluated.

Using an advanced form of SOFA system, M.R. Young Station's Unit 2's boiler operating at MCR is expected to achieve a NO_X emission level of 0.49 lb/mmBtu when operating modestly air-staged cyclone furnaces with suitable combustion controls. This level of NO_X reduction from ASOFA operation, approximately thirty eight percent, is based on the expected ability to reduce emissions without incurring potential significant negative impacts of this technique. This reduction estimate includes the additional amounts of control potential available from operating with relocated lignite drying system vent ports (and FGR ports for Unit 2) associated with ASOFA operation with modestly air-staged cyclone furnaces.

[27] Ibid, NSR Manual B.37

Coal reburn with ASOFA is estimated to reduce NO_X emissions for M.R. Young Station's Unit 2's boiler operating at MCR slightly more than 54 percent from the pre-control baseline NO_X emission rate, considering similar control levels demonstrated by previous coal-reburn retrofits on cyclone-fired boilers and limitations previously discussed with ASOFA.

Conventional Gas Reburn and Fuel Lean Gas Reburn options were both assumed to be installed with ASOFA. NO_X reduction from CGR with ASOFA operation is expected to be approximately 55.4 percent. FLGR with ASOFA is expected to reduce NO_X emissions approximately forty five percent. Estimates for NO_X emissions for M.R. Young Station's Unit 2's boiler considered similar control levels demonstrated by previous gas-reburn retrofits on cyclone-fired boilers with modestly air-staged cyclone furnaces and limitations previously discussed with ASOFA.

The NO_X emission rate for Selective Non-Catalytic Reduction (SNCR) (using urea) with ASOFA is expected to be approximately 0.355 / 0.33, resulting from a reduction in NO_X emissions of approximately 58 percent from the 12-month average pre-control baseline NO_X emission rate.

Included in the feasible control option ranking of Table 3-7 are layered alternatives that were shown in Table 3-5. The highest-performing NO_X control alternatives remaining in consideration are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" SOFA, which is expected to have significantly lower NO_X emissions than a typical SOFA system as applied to the Milton R. Young cyclone boilers.

TABLE 3-7 – Ranked NO_X Control Options Feasible for MRY Station Unit 2 Boiler with Expected Control Performance

Alt. Label(1)	NO_X Control Technique	Emission Rate (lb/mmBtu)	Control Percentage(2)
E	SNCR (using urea) w/ ASOFA	0.330	58.0
D	Gas Reburn with ASOFA	0.350	55.4
C	Lignite Reburn w/ ASOFA	0.360	54.2
B	Fuel Lean Gas Reburn with ASOFA	0.432	45.0
A	Advanced Separated Overfire Air (ASOFA)	0.489	37.7
-	Baseline	0.786	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.
(2) - Control percentages are relative to an average pre-control emission baseline of 0.786 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.

The annual emission levels developed for Table 3-7's ranking the feasible alternatives assume that the highest 12-month average pre-retrofit level of unit NO_X emissions for M.R. Young Station's Unit 2's boiler is a baseline of 0.786 lb/mmBtu. This was determined from the highest reported rolling 12 consecutive month period's summation of hourly NO_X emissions (lbs).

The hourly gross fuel heat input (mmBtu) was summed over that same 12-month time period, and divided by the number of boiler operating hours to yield an annual average gross fuel heat input rate (mmBtu/hr). Multiplying the 12-month average heat input rate (mmBtu/hr) by the baseline or control alternative's 12-month average unit emission rate (lb/mmBtu) equals a 12-month average hourly NO_X emissions rate (lb/hr). Annual NO_X emissions (tons) for the baseline pre-control condition were calculated by multiplying the 12-month summation for boiler operating hours during the same period as the highest NO_X emissions by the 12-month average emission rate (lb/hr). The annual tons for the control options were calculated by multiplying the alternative's average annual emission rate (lb/yr) by a reduction factor (if applicable) for heat input or running plant capacity and adjusting boiler operating hours by an annual uptime (availability) factor. Details for these adjustments are included in Appendix C3. Based on these calculations, the annual emissions for M.R. Young Station's Unit 2's boiler are shown in Table 3-8.

TABLE 3-8 – Expected Annual NO_X Control Performance for MRY Station Unit 2 Alternatives

		EMISSIONS				NOx Removal Efficiency(5) %
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission(2) lbs/hr	Annual Emission(3) tons/yr	Emission Reduction(4) tons/yr	
E	SNCR (using urea) w/ ASOFA	0.330	1,663	6,298	9,216	58.0
D	Gas Reburn w/ ASOFA	0.350	1,764	6,693	8,820	55.4
C	Lignite Reburn w/ ASOFA	0.360	1,815	6,806	8,707	54.2
B	Fuel Lean Gas Reburn w/ ASOFA	0.432	2,176	8,306	7,207	45.0
A	Advanced Separated Overfire Air (ASOFA)	0.489	2,466	9,451	6,063	37.7
-	Baseline	0.786	3,959	15,513	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 4,885 mmBtu/hr MCR heat input.
(3) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 89.5% was assumed for the baseline case.
(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).
(5) - Estimated NO_X control level percentage reductions relative to 0.786 lb/mmBtu emission baseline at 4,885 mmBtu/hr MCR heat input.

3.4 NO_X CONTROLS ANALYSIS AND IMPACTS EVALUATION

The fourth step of a "top-down" BACT review is to evaluate the most effective emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

3.4.1 NO_X CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 2

An evaluation was performed to determine the various cost impacts of installing feasible NO_X control alternatives on Milton R. Young Unit 2. This evaluation includes estimated:

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

to engineer, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 3-9 through 3-13.

3.4.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

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

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the NO_X control technologies capital cost estimate basis was 477 MW_g for MRY Station Unit 2[28].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 2 NO_X control technologies are presented in Table 3-9. The estimated installed and levelized capital costs for the highest-performing form of the various feasible NO_X emission reduction technologies evaluated for cost-effectiveness are shown in Table 3.10. These are listed in order of control effectiveness, with the highest ranked option at the top.

[28] Ibid footnote number 23.

TABLE 3-9 – Unit Capital Cost Factors of Feasible NO_X Control Options for MRY Station Unit 2

Alt. Label[1]	NO_X Control Technique	Range[2] ($/kW)	Single Point Unit Capital Cost Factor[3], ($/kW) MRYS Unit 2
E	SNCR (using urea) w/ ASOFA	20-35[6]	35.9[4],[5]
D	Gas Reburn w/ ASOFA	15-30[6]	74.4[5],[6],[7]
C	Lignite Reburn w/ ASOFA	30-60[6]	170.2[5],[8]
B	Fuel Lean Gas Reburn w/ ASOFA	--[9]	45.7[4],[5],[9]
A	Advanced Separated Overfire Air (ASOFA)	5-10[6]	21[5]

(1) – Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) – Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) – Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on existing nameplate rating. Single point cost figures in 2006 dollars.
(4) – Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. See Appendix C2 for details.
(5) – The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(6) – NESCAUM 2005 Technical Paper, posted at their website. See technical references in Appendix A1 for details.
(7) – The single point unit capital cost factor shown for a conventional gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.
(8) – The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report, posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 75.5 $/kW. See technical references in Appendix A1 for details.
(9) – The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. The single point unit capital cost factor shown for a fuel lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (15.7 $/kW), and that both boilers share the capital cost in proportion to their respective rated MW gross output capacities.

TABLE 3-10 – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
E	SNCR w/ ASOFA	17,128	1,493
D	Gas Reburn w/ ASOFA[4]	35,490	3,094
C	Lignite Reburn w/ ASOFA[5]	81,167	7,077
B	Fuel Lean Gas Reburn w/ ASOFA[4]	21,817	1,902
A	Advanced SOFA (ASOFA)	10,008	873
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars.
(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.
(4) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR; and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. See footnotes #8 and 10 under Table 3-9.
(5) - Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost, and $3,140,000/yr annualized capital cost.

3.4.1.2 Operating and Maintenance Cost Estimates for MRY Station NO_X Controls

The operational and maintenance costs to implement the various NO_X control technologies were largely estimated from cost factors (percentages of installed capital costs) established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[29], and from published in technical papers discussing those control technologies. In the cases including various forms of SNCR, preliminary vendor quotes were obtained and used in place of, or to adjust the OAQPS cost factors. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

Fixed and variable operating and maintenance costs considered and included in each NO_X control technology's annual O&M costs are estimates of:

- Auxiliary electrical power consumption for operating the additional control equipment;
- Reagent consumption, and reagent unit cost for SNCR alternatives; and
- Reagent dilution water consumption and unit cost for SNCR alternatives.

[29] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

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

For economic evaluation purposes, an annual average running plant capacity factor of 95.2 percent compared to a nominal unit output capacity of 462 MWg combined with an average annual availability (uptime) of 8,229 operating hours (94.7 percent of 8760 hours per year) resulting in an annual unit capacity factor of 89.5% were assumed for Unit 2's pre-control baseline annual operation. A heat input rate of 4,885 mmBtu/hr and a NO_X emission rate of 0.786 lb/mmBtu were assumed for calculating control and cost-effectiveness from pre-control maximum rolling 12 month summation of nitrogen oxides' mass emissions for MRY Station Unit 2.

Table 3-11 show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the highest-performing form of the various feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 provides more details for the levelized annual O&M cost calculations and cost factors.

TABLE 3-11 – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(3) $1,000
E	SNCR w/ ASOFA	7,937	9,911
D	Gas Reburn w/ ASOFA	48,680	60,789
C	Lignite Reburn w/ ASOFA	9,929	12,398
B	FLGR w/ ASOFA	21,951	27,411
A	Advanced SOFA (ASOFA)	2,805	3,503
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at nominal unit capacity (462 MWg) and assumes a 94.7% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(4) - Costs for increased PM collection capacity included in lignite reburn option are $3,358,000/yr for annual O&M cost, and $4,194,000/yr annualized O&M cost.

3.4.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

In order to compare a particular NO_X emission reduction alternative during the initial engineering analysis portion of the BACT selection process, the sum of estimated annualized installed capital plus levelized annual operating and maintenance costs, which is referred to as "Levelized Total Annual Cost" (LTAC) of expected pollutant removal by implementing that alternative was calculated. The LTAC for all NO_X control alternatives was calculated based on the same economic conditions and a 20 year project life (see Appendix C1 for methodology). The unit control cost was then determined as the LTAC divided by annual tons of pollutant emissions that would be avoided by implementation of the respective alternative. The control alternatives were also compared by calculating the change in unit cost (incremental cost) per incremental ton removed for the next most stringent alternative. This identified which alternatives produced the highest increment of expected pollutant reduction for the estimated lowest average annual cost increment compared with the baseline emission rate. The expected annual number of tons of pollutant removed versus estimated LTAC for each remaining control alternative was then plotted.

The comparison of the cost-effectiveness of the remaining NO_X emission reduction technologies was made and is shown in Table 3-12 and Figures 3-1 and 3-2 for MRY Station Unit 2. These figures plot estimated annual amount of NO_X removal (emission reduction) in tons per year on the ordinate (horizontal axis) and the estimated levelized total annual cost in thousands of U.S. dollars per year on the abscissa (vertical axis), for each of the remaining NO_X control technologies. Points on the graph that are farthest to the right and closest to the horizontal axis are deemed more cost-effective, since they represent controls that achieve more NO_X removal per dollar required for total annual costs of operation, maintenance, and capital recovery (depreciation).

Although the NSR Manual repeatedly prescribes following a "top down" analysis approach for BACT determination, the development of a least cost envelope with dominant controls (as seen in NSR Manual Figure B-1, page B.42) clearly labels points with lower emissions reductions and total annual costs first, i.e. "A", "B", etc. then proceeding with labeling and connecting points plotted further away from the zero emission reduction point. This "bottom-up" approach is for plotting the least-cost (dominant) control curve. The labeling of each unit's NOx control technique alternative has followed this approach.

TABLE 3-12 – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 2

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
E	SNCR w/ ASOFA	6,298	9,216	11,405	1,238
D	Gas Reburn w/ ASOFA	6,693	8,820	63,883(6)	7,243
C	Lignite Reburn w/ ASOFA	6,806	8,707	19,475(7)	2,237
B	FLGR w/ ASOFA	8,306	7,207	29,313(6)	4,067
A	Advanced SOFA (ASOFA)	9,451	6,063	4,376	722
	Baseline	15,513	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated annual emission tons assume an annual capacity factor specific to each alternative; 89.5% was assumed for the baseline case.

(3) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).

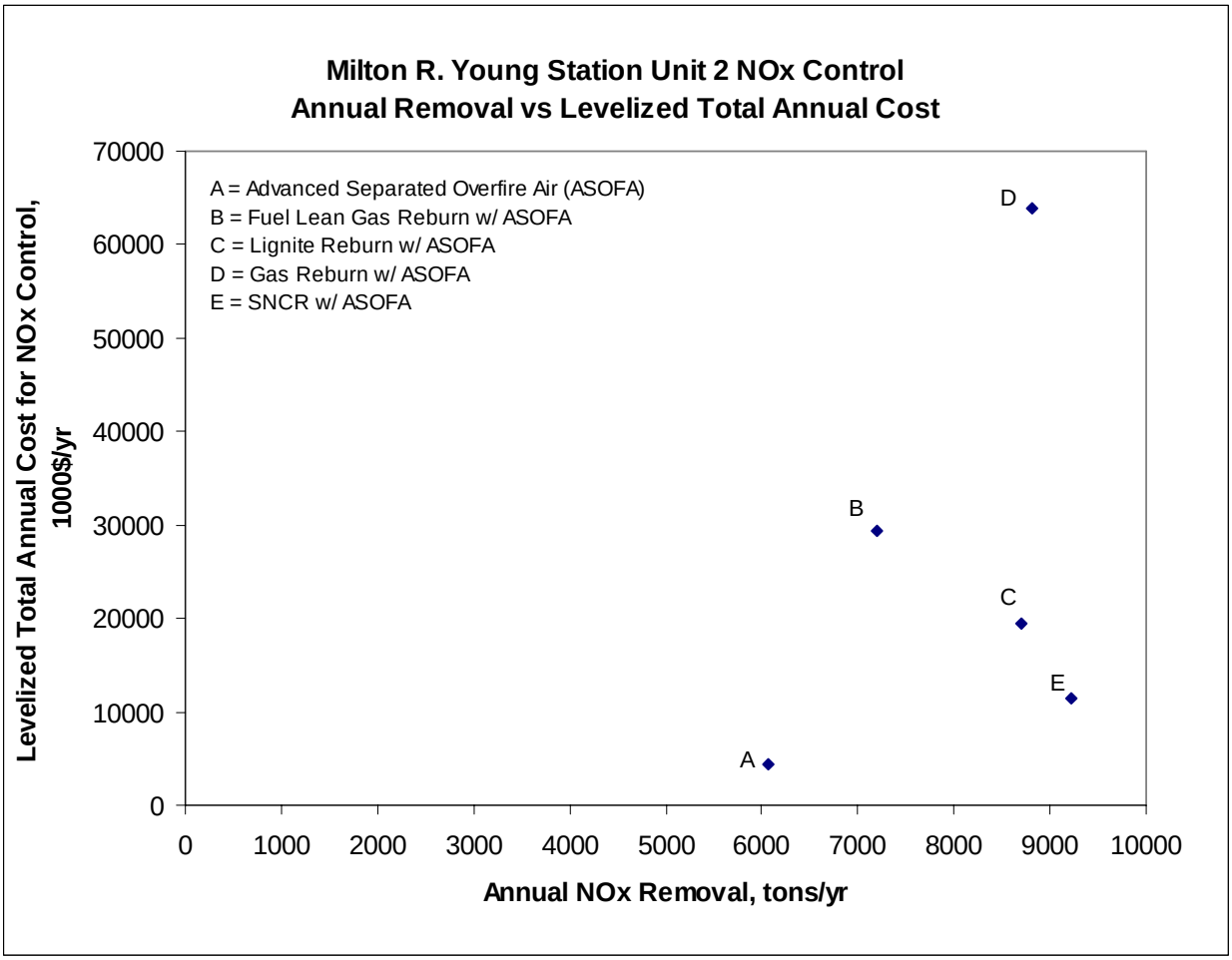
(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note #3 for Tables 3-10 and 3-11 for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at highest allowable pre-control NOx emission rate.

(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 plus for FLGR. See footnotes #8 and 10 under Table 3-9

(7) - LTAC for increased PM collection capacity included in lignite reburn option are approximately $3,140,000 for annualized capital cost plus $4,194,000/yr for annualized O&M cost, for a LTAC subtotal of $7,333,000/yr.

Figure 3-1 – NO_X Control Cost Effectiveness - MRY Station Unit 2(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-12.

The purpose of Figure 3-1 is to show the range of control and cost for all feasible NO_X reduction alternatives evaluated. A dominant set of control alternatives were determined by generating what is called the "envelope of least-cost alternatives". The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Following a "bottom-up" graphical comparison approach, each of the NO_X control technologies represented by a data point to the left of and above the least cost envelope are inferior control alternatives per the NSR Manual and should be excluded from further analysis on a cost efficiency basis.

Of the technically feasible NO_X control alternatives considered for MRY Station Unit 2, data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), lay distinctly left and above the other points of the control cost points' scatter plot of Figure 3-1. These control options are inferior and therefore were eliminated from further control cost-effectiveness analysis.

Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Table 3-13. The annual NO_X control tons per year, divided by the total levelized annual cost, yields an average unit cost ($/ton). Incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. The additional tons per year of NO_X control relative to the previous apparent least-cost curve point, divided by the increase in levelized annual cost, yields an incremental unit cost ($/ton). Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the envelope of least-cost control alternatives, also called the dominant controls cost curve or DCCC) between successively more effective alternatives which are considered technically feasible for Milton R. Young Station boilers.

TABLE 3-13 – Dominant Controls Cost Curve Points for Feasible BACT NO_X Alternatives - MRY Station Unit 2

Alt. Label(1)	NOx Control Technique	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
E	SNCR w/ ASOFA	11,405	9,216	7,029	3,153	2,229
A	Advanced SOFA (ASOFA)	4,376	6,063	4,376	6,063	722

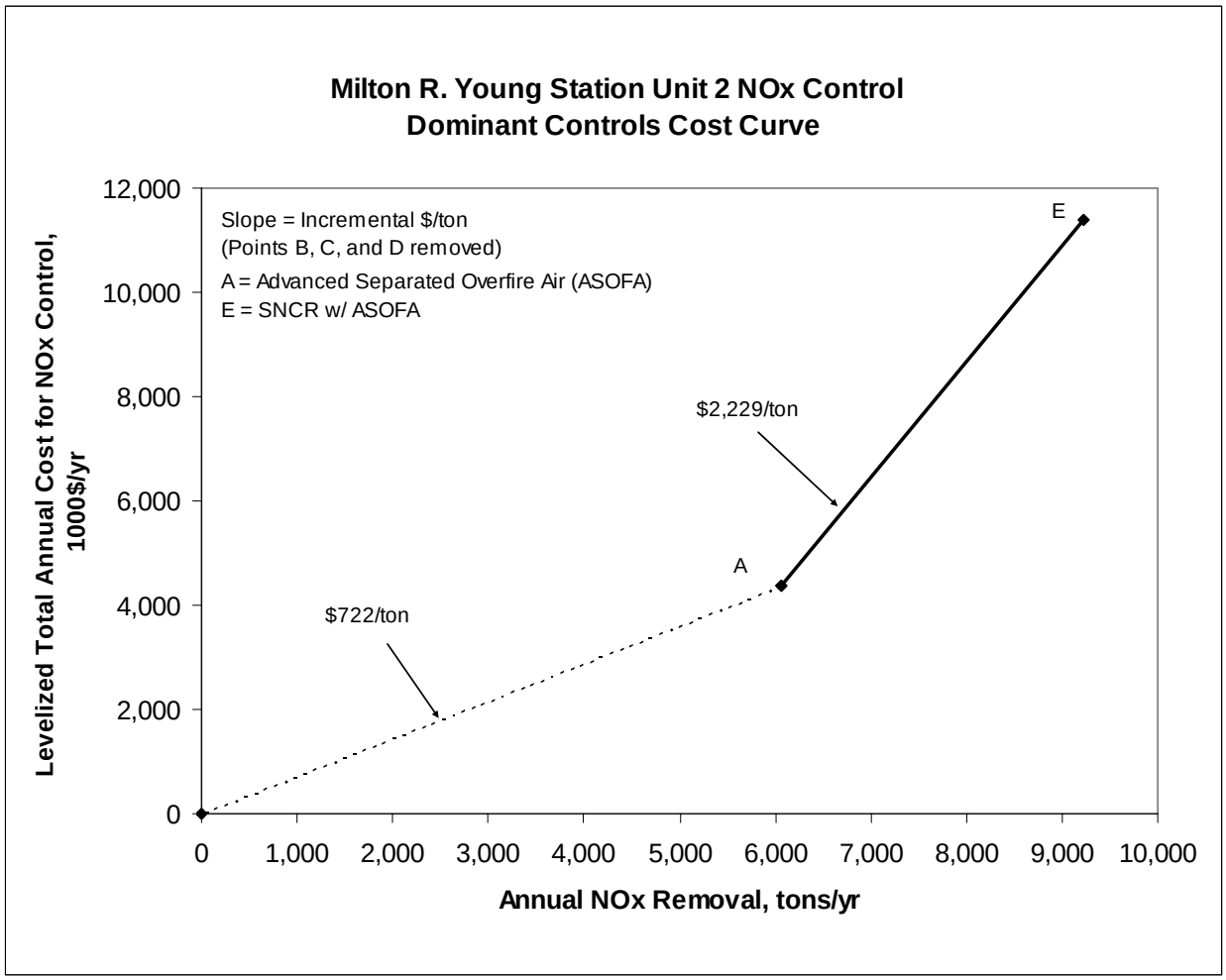
(1) – Dominant controls cost curve points from lowest (ASOFA) to highest (SNCR w/ ASOFA) are labeled the same as in Table 3-12, and on the graphs that accompany this table (Points B, C, and D were eliminated).
(2) – All cost figures in 2006 dollars.
(3) – Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.
(4) – Increment based upon comparison between consecutive alternatives (points) from lowest to highest, except as noted.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control

technique (slope from zero baseline to ASOFA, Point A was $722/ton for MRYS Unit 2; the incremental cost (slope) from ASOFA, Point A to SNCR with ASOFA, Point E was $2,229/ton for MRYS Unit 2.

Figure 3-2 contains a repetition of the levelized total annual cost and NO_X control information from Figure 3-1 for MRY Station Unit 2, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 2 NO_X emissions alternatives.

Figure 3-2 – MRY Station Unit 2 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1)



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 3-13

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. As can be seen from a review of Table 3-14, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from

approximately $722/ton to $7,243/ton of MRYS Unit 2's NO_X emissions removed. It should be noted, however, that the highest estimated average control costs involve gas reburn technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost effectiveness is a measure of the increase in marginal cost effectiveness between two specific alternatives. Alternatively, the incremental cost effectiveness analysis identifies the rate of change of cost effectiveness with respect to removal benefits (i.e., the slope of the least-cost envelope of dominant control alternatives or dominant controls cost curve) between successively more effective alternatives. The economic impact analysis indicates that from a cost effectiveness viewpoint, the highest performing alternative is SNCR with ASOFA (Point E). This control option is considered technically feasible for Milton R. Young Station Unit 2 boiler but incurs a significant annual (levelized) incremental cost relative to the next highest feasible NO_X control technique, ASOFA (Point A) when ASOFA is compared against the pre-control baseline. The Advanced Separated Overfire Air alternative has an average unit control cost ($722/ton) approximately 58% of the highest performing feasible alternative on the dominant controls cost curve (SNCR with ASOFA, $1,238/ton). ASOFA also has a much lower incremental cost per ton relative to the pre-control baseline (slope from zero to Point A, $722/ton) compared to SNCR with ASOFA (Point E) versus ASOFA (Point A); the slope from Point A to Point E was $2,229/ton.

The other elements of the fourth step of a BACT analysis following economic impacts are to evaluate the following impacts of feasible emission controls:

- The energy impacts.
- The environmental impacts.

TABLE 3-14 – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 2

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 2

Alt. Label(1)	NOx Control Alternative	EMISSIONS(2) Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency(2) %	ECONOMIC IMPACTS Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton
E	SNCR w/ ASOFA	0.330	1,663	6,298	9,216	58.0	17,128	7,937	11,405	1,238
D	Gas Reburn w/ ASOFA	0.350	1,764	6,693	8,820	55.4	35,490	48,680	63,883(7)	7,243
C	Lignite Reburn w/ ASOFA	0.360	1,815	6,806	8,707	54.2	81,167	9,929	19,475(7)	2,237
B	FLGR w/ ASOFA	0.432	2,176	8,306	7,207	45.0	21,817	21,951	29,313(7)	4,067
A	Advanced SOFA (ASOFA)	0.489	2,466	9,451	6,063	37.7	10,008	2,805	4,376	722
	Baseline	0.786	3,959	15,513	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.

(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.

(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $14,988,000 for CGR and $7,494,000 for FLGR; and annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost.

(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 440 MWg and assumes a 95.2% average running plant capacity factor compared to nominal unit gross electrical output capacity of 462 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $3,155,000/yr for annual O&M cost.

(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.

(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.

(7) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $1,307,000/yr for CGR and $653,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $3,140,000 for annualized capital cost plus $3,940,000/yr for annualized O&M cost, for a total of $7,080,000/yr.

3.4.2 ENERGY IMPACTS OF MRY STATION NO_X CONTROLS

Operation of the most cost-effective NO_X control technologies considered feasible for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electrical power at the facility. The details of estimated energy usage and costs for the various NO_X control alternatives are summarized in Appendix C3.

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

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

3.4.2.1 ENERGY IMPACTS OF SOFA TECHNOLOGY

There should not be a major impact on energy consumption resulting from the operation of the advanced variation of a separated overfire air system. SOFA does not significantly change the total amount of air introduced into the boiler, only the location where it is introduced. Damper resistance and supply pressure impacts of the SOFA system on fan power consumption should be insignificant. The amount of flyash emitted from the boiler is expected to be reduced (less than five percent) from the baseline level

when the SOFA system is in full operation. Slightly higher levels of unburned carbon in the flyash may occur with the operation of a SOFA system. This could have a small negative impact on the plant heat rate (higher Btu/kw-hr). These changes are expected to be within the typical range of current operation.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a separated overfire air system. Typical SOFA operation on bituminous or western subbituminous coal-fired cyclone boilers does not carry a significant additional risk of causing insufficient or excessive accumulation of slag within the cyclone barrels or furnace bottom compared with non air-staged combustion. Reliable boiler operation depends on avoiding such adverse conditions in the cyclones and lower furnace, which could require a forced outage to remove the solidified slag prior to returning the boiler to generation production service.

The challenges of maintaining adequate slag layer development and flow while firing lignite in MRY Unit 2's cyclones under excess air conditions have been significant during the operating history of the powerplant. Minimizing forced outages resulting from cyclone slag issues have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of combustion characteristics of lignite supplied from the Center mine, and the dependency of the slag flow on the temperature within the cyclone barrels or furnace bottom, conditions may occur during ASOFA operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the solidified slag.

The potential impact on annual unit operating time due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation was estimated to be approximately 2% reduction from the assumed pre-control baseline availability, i.e. 0.94-0.02=0.92. The estimated electrical generation production lost due to the reduction in MRY Unit 2's annual availability is shown in Table 3-16.

3.4.2.2 ENERGY IMPACTS OF SNCR TECHNOLOGY

For SNCR, the injection of a diluted urea solution will require some additional auxiliary power for heating and pumping the liquid and using compressed air for atomization and cooling the reagent injection nozzles/lances, on the order of 100 to 300 kW. The injection of water (used for urea dilution) into the boiler flue gas also will have a small negative impact on the plant heat rate (higher Btu/kw-hr), although the vendor of SNCR systems advises that the heat released from the oxidation of a portion of the

injected urea compensates for this impact. The impact of additional flue gas created by operation of an SNCR-related system on fan power consumption should be small.

There is a potential reduction in reliability and availability of a lignite-fired cyclone boiler to generate steam for production of electrical power as a result of installing and operating a SNCR-related system. Typical SNCR operation with low ammonia slip when firing low-sulfur western subbituminous coal in cyclone-fired boilers does not carry a significant additional risk of causing excessive fouling of the tubular air preheater compared with non-SNCR operation. Reliable boiler operation depends on avoiding adverse fouling conditions in the air preheater, which could require a forced outage to remove the ash deposits prior to returning the boiler to generation production service.

The challenges of maintaining open passages through the air preheater tubes while firing lignite in MRY Unit 2's cyclones under typical conditions have been minor during the operating history of the powerplant. Minimizing forced outages resulting from ash deposits within the air preheater have largely been successful through operational practices that do not affect day-to-day boiler reliability and availability. Due to the variability of fouling characteristics of lignite supplied from the Center mine, and the dependency of the fouling within the air preheater on sodium, sulfur, and ammonia slip emission levels, conditions may occur during SNCR operation that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the air preheater deposits.

The potential impact on annual unit operating time due to air preheater fouling and other potential issues associated with SNCR system operation was estimated to be an incremental 1% reduction from the assumed pre-control baseline or ASOFA availability. The estimated electrical generation production lost due to the reduction in MRY Unit 2's annual availability is shown in Table 3-16.

TABLE 3-15 – Expected Auxiliary Electrical Power Impacts for NO_X Controls - MRY Station Unit 2

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Auxiliary Electrical Power Demand and Consumption of NOx Control Equipment	
		Gross Demand(2) kW	Power Usage(3) kW-hrs/yr
E	SNCR w/ ASOFA	133	1,008,704
A	Advanced SOFA (ASOFA)	1	7,664

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects.
(3) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.

TABLE 3-16 – Expected Electrical Power Generation Availability and Capacity Impacts for NO_X Controls - MRY Station Unit 2

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Availability(2)	Estimated Annual Average Operating Time Reduction, hrs/yr(3)	Estimated Annual Average Running Plant Capacity Factor(4)	Estimated Annual Average Electricity Generation Reduction kW-hrs/yr(5)
E	SNCR w/ ASOFA	0.909	263	0.951	110,176,095
A	Advanced SOFA (ASOFA)	0.919	181	0.952	75,859.855

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – Baseline availability is assumed at 93.9 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(3) – Annual lost operating time resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.
(4) – Baseline running plant capacity factor is assumed at 95.2 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(5) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 462 MW (MCR gross unit electrical output capacity).

TABLE 3-17 – Expected Total Electrical Power Generation Impacts for NO_X Controls - MRY Station Unit 2

Alt. Label(1)	NOx Control Technique	Power Usage(2) kW-hrs/yr	Estimated Annual Average Electricity Generation Reduction(3) kW-hrs/yr	Est. Annual Change in Net Electrical Power Generation Available for Sale(4) kW-hrs/yr
E	SNCR w/ ASOFA	1,008,704	110,176,095	111,184,799
A	Advanced SOFA (ASOFA)	7,664	75,859.855	75,867,520

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique. A negative reduction in generation is an increase in annual new electrical power available for sale.
(3) – Annual electricity generation reduction is annual reduction of operating time multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the MCR capacity rating of 462 MW (MCR gross unit electrical output capacity).
(4) – Annual change in net electrical power generation available for sale is arithmetic sum of annual power generation reduction due to a change in the auxiliary electrical power consumed plus the annual generation reduction from a decrease in annual operating time and average annual running plant capacity factor resulting from the implementation of the individual NOx control technique, compared with baseline.

3.4.3 ENVIRONMENTAL IMPACTS OF NOx CONTROLS - MRY STATION

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

3.4.3.1 ENVIRONMENTAL IMPACTS OF SOFA TECHNOLOGY

The operation of a separated overfire air system is expected to slightly increase carbon monoxide concentrations in the stack flue gas. The advanced form of SOFA alternative is expected to slightly lower the amount of particulate matter emitted from the boiler and may raise the amount of unburned carbon in the flyash collected for land disposal and emitted to the atmosphere by small increments. Alternatives involving forms of gas reburn should experience lower particulate emissions, and a reduction in the amount of boiler bottom and flyash requiring disposal.

The environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons removed will increase, by approximately two percent.

3.4.3.2 ENVIRONMENTAL IMPACTS OF SNCR TECHNOLOGY

Operation of a conventional SNCR system is not expected to significantly impact emissions of CO or volatile organic compounds (VOCs).

Operation of an SNCR system will normally create a small amount of unreacted urea or ammonia to be emitted. The amount of ammonia slip produced by SNCR depends on the amount of reagent utilization and location of the injection points. Higher SNCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 10 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the flue gas ductwork to form the sulfates.

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

Delivery of the urea reagent to the powerplant facility and storage of aqueous urea reagent on-site creates the potential for accidents, leaks, and subsequent releases to air, ground, and surface water immediately surrounding the facility. Urea is much less volatile than anhydrous or aqueous ammonia, and these risks are expected to be manageable. Emergency planning and community communications are part of the management plan requirements for such reagent usage.

The environmental impact from potential reduction of annual unit operating time by approximately one percent due to air preheater fouling issues associated with SNCR system operation will be to reduce the annual amount (tons) of nitrogen oxides emitted, and therefore the annual number of NO_X tons eliminated relative to the constant pre-control emission baseline will increase by approximately one percent.

3.4.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF MRY STATION NO_X CONTROLS

The economic, energy, and environmental impacts of each feasible BACT alternative evaluated for this study is summarized in this Section. Table 3-18 summarizes the various impacts discussed in Sections 3.4.1 through 3.4.3. The economic analysis examined the capital cost of each feasible BACT alternative evaluated and any other powerplant upgrade costs necessary to implement the alternative. In addition, the economic analysis examined the operating and maintenance cost associated with the highest-performing forms of each feasible BACT alternative evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each alternative was evaluated. Two alternatives were on the dominant controls cost curve and thus were identified as the more cost effective alternatives. The two BACT NO_X control alternatives evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 2 were:

- Selective Non-Catalytic Reduction (SNCR) combined with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA); and
- ASOFA alone.

TABLE 3-18 – Summary of Top-Down BACT Impact Analysis Results for Dominant NO_X Control Alternatives - MRY Station Unit 2

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
E	SNCR w/ ASOFA	0.330	1,663	6,298	9,216	17,128	7,937	11,405	1,238	2,229	133	111,184,799	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.489	2,466	9,451	6,063	10,008	2,805	4,376	722	722	1	75,867,520	Flyash UBC	CO
	Baseline	0.786	3,959	15,513	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.786 lb/mmBtu at 4,885 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at gross unit electrical output of 440 MWg and assumes a 93.9% average annual availability.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 477 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $36,013,000 for installed capital cost
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at gross unit electrical output of 440 MWg and assumes a 95.2% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost (1000$/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.
(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.
(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr).
(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations likely will increase with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology.

3.5 BACT RECOMMENDATIONS AND CONTROL LEVELS – MRY STATION UNIT 2

This report presents the analysis of control technologies for nitrogen oxides (NO_X) for Minnkota Power Cooperative's (MPC's) Milton R. Young Station Unit 2 using the EPA's "top-down" BACT approach. BACT is an emissions limitation for each pollutant from a source determined to be achievable using control technologies(s) that provide the "maximum degree of emission reduction…taking into account energy, environmental, and economic impacts"[30]. A BACT review does not result in a percent removal efficiency requirement. The generally accepted procedures for performing a BACT analysis are outlined in the EPA's draft NSR Manual. The BACT analysis for Milton R. Young Station NO_X emissions was performed in accordance with this procedure. The EPA's draft NSR Manual outlines five basic steps that are to be followed in the "top-down" BACT evaluation. These steps were as follows:

Step 1 – Identify All Control Technologies
Step 2 – Eliminate Technically Infeasible Options
Step 3 – Rank Remaining Control Technologies by Control Effectiveness
Step 4 – Evaluate Most Effective Controls and Document Results
Step 5 – Select BACT

The final result of this analysis is a recommendation of the BACT alternative and the associated NO_X emission rate for Square Butte Electric Cooperative's Milton R. Young Station Unit 2. The emission limitations for a generation facility are expressed in a pounds per million British Thermal Units (lb/mmBtu) basis.

3.5.1 UNIT 2 NO_X BACT

In step one of the technology evaluation, three basic categories of NO_X controls for EGUs were-identified: pre-combustion, combustion, and post-combustion. Eleven basic types of NO_X control processes were identified within these three categories. Twenty four variations of these eleven processes were reviewed for availability and applicability to cyclone-fired EGUs burning North Dakota lignite. An "advanced" form of Separated Overfire Air, alone and in various combinations with Lignite Reburn, Selective Non-Catalytic Reduction (SNCR), Conventional Gas Reburn and

[30] Ibid, NSR Manual B.1

Fuel Lean Gas Reburn™, was evaluated for cost-effectiveness. The cost-effectiveness analysis indicated that ASOFA alone, and ASOFA with SNCR were cost effective alternatives for MRY Station Unit 2 NO_X control. The energy and environmental impacts analysis for MRY Station Unit 2's cost-effective NO_X control alternatives were generally insignificant.

Based upon the definition of BACT and the results of the BACT analysis, Selective Non-Catalytic Reduction (SNCR) in combination with a special form of separated overfire air (SOFA) specifically for lignite-fired cyclone boilers (referred to as Advanced SOFA or ASOFA) is recommended as the Best Available Control Technology for nitrogen oxides emissions from Square Butte Electric Cooperative's Milton R. Young Station Unit 2. The unit BACT NO_X emissions rate for MRYS Unit 2 is 0.330 lb/mmBtu , determined as a rolling 12-month average. This is shown in Table 3-19.

TABLE 3-19 – NO_X Emission Control Technology and Rate Recommended as BACT for Milton R. Young Station Unit 2

Control Technology and Emission Rate Recommended as BACT			
Unit	**Pollutant**	**BACT Control Method**	**12-Month Rolling Average BACT NOx Emission Rate (lb/mmBtu)**
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.330

3.5.2 EMISSION RATE LIMITATION RECOMMENDATION

To complete the BACT determination process, the Consent Decree (CD) requires that "specific control technologies to be installed and a specific Phase II 30-day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu)"[31] (pounds per million Btu) must be established for each subject emission Unit. The CD also states that "a "30-day Rolling Average Emission Rate" shall be determined by calculating an arithmetic average of all hourly emission rates in lbs/MMBtu for the current Operating Day and the previous 29 Operating Days. A new 30-day Rolling Average Emission Rate shall be calculated for each new Operating Day. Each 30-day Rolling Average Emission Rate shall include startup, shutdown, and Malfunction periods within each Operating Day"[32].

[31] Ibid footnote number 1, Paragraph 66, page 20.
[32] Ibid footnote number 1, Paragraph 5, page 4.

The Consent Decree also states that the North Dakota Department of Health's (NDDH) NO_X "BACT Determination shall address specific emission limitations during Unit startups"[33] at Milton R. Young Station. The type and duration of firing during startups, and the limited ability of available and feasible technologies to control startup NO_X emissions, both significantly influence the 30-day rolling average BACT NO_X emission rate limit recommended for Milton R. Young Station boilers. A 24-hour rolling average NO_X emission rate limit applied to startup periods is also recommended for Milton R. Young Station boilers.

The Consent Decree and the EPA's NSR Manual do not describe the method for determining a 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT applied to Milton R. Young Station Unit 2.

In keeping with the establishment of a specific CD Phase II 30-day Rolling Average NO_X Emission Rate limitation, a relevant precontrol baseline level of emissions and its basis must be determined. The EPA's NSR Manual states:

> "The baseline emissions rate represents a realistic scenario of upper boundary uncontrolled emissions from the source. The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with State or local air pollution regulations, are not considered in calculating the baseline emissions. In other words, baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions"[34].

Also stated in the EPA's NSR Manual:

> "Estimating realistic upper bound case scenario does not mean that the source operates in an absolute worst-case manner all the time. For example, in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[35].

[33] Ibid footnote number 1, Paragraph 66, page 20.
[34] Ibid footnote number 2, NSR Manual page B.37
[35] Ibid footnote number 2, NSR Manual page B.37.

The BACT Analysis was conducted based upon the highest historical 12-month rolling NO_X emission summation operating conditions for Milton R. Young Station boilers during years 2001-2005. However, a baseline reflecting a realistic upper bound case scenario based upon the highest historical 30-day rolling NO_X emission operating conditions during years 2001-2005 was established prior to recommending enforceable permit conditions for BACT to be applied to each Milton R. Young Station boiler.

The approach taken in this analysis was to identify pre-control 30-day baseline operating conditions from the 30-consecutive day period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation between January 1, 2001 and December 31, 2005. This reflects unit NO_X emissions that were generated during periods of high unit operations, not affected by unit shutdowns, startups, or malfunctions. MRYS Unit 2's highest reported 30-day rolling average NO_X unit emission rate during years 2001-2005 was 0.874 lb/mmBtu for the period ending April 5, 2002. The corresponding MRYS Unit 2 30-day average hourly NO_X mass emission rate was 3,726 lb/hr. The average unit heat input rate for MRYS Unit 2 was 4,264 mmBtu/hr, and the average gross unit electrical power output was 450.2 MW_g for the same 30-day period.

The operating conditions during the highest historical 30-day rolling NO_X emission for years 2001-2005 were then compared to the highest 12-month historic pre-control baseline conditions. The average unit NO_X emission rate (lb/mmBtu) from the highest historic pre-control 30-day baseline period was compared with the average NO_X emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NO_X mass emissions (pounds) reported for actual operation during the same 5-year look-back period. An estimate of NO_X emission reduction for the proposed BACT NO_X alternative operating at the historic pre-control 30-day baseline average NO_X emission rate (lb/mmBtu) was made. This rate considered recognized operational factors and equipment designs applied to "steady state" conditions with sustained output close to maximum continuous capacity ratings. The potential impact of startups, recognizing operational and technical limitations on NO_X emission control performance, was then applied to the steady-state rate, to establish a recommended 30-day Rolling Average NO_X Emission Rate permit limitation (CD Phase II) that reflects BACT for Milton R. Young Station Unit 2. This is explained below.

NO_X emissions for cyclone-fired boilers are typically higher in pounds per million BTUs during start up events than during steady-state operation at maximum continuous rating (MCR) conditions. This is because hourly heat and combustion air input rates required to establish adequate molten

slag formation within the cyclone barrels and promote slag tapping are typically produced from firing conditions that create high flame temperatures. NO_X emissions are sensitive to peak furnace gas temperatures, thus uncontrolled NO_X emissions can be high during cyclone boiler startups. Furnace exit flue gas temperatures (FEGTs) during cyclone boiler startups are less than those occurring during conditions of steady state MCR firing rates due to the high heat absorption of the boiler metal and water being raised from ambient or near-ambient temperatures. Until sufficient FEGT exists for a feasible and available post-combustion technology, such as SNCR, to be effective, NO_X emissions will be basically uncontrolled. There is a practical lower limit of boiler heat input for conventional combustion-based NO_X emission control techniques, such as the advanced version of separated overfire air, to be operated beyond the amount required for cooling the SOFA injection nozzles when it can be diverted from the cyclone burners and significantly control NO_X emissions. These limitations of the effectiveness of BACT controls on Milton R. Young Station boilers during startups and other reduced-load operating periods influence the recommended 24-hour and 30-day rolling average NO_X emission rate limits.

Startup procedures for steam electric generating units (SEGUs) comprising a fossil fuel-fired boiler and steam turbine-generator are specified by the original equipment manufacturers to follow guidelines for heat and pressure increases to provide protection of boiler and turbine equipment. Initial start up duration after an outage may be dictated by the need to gradually warm up burner port/cyclone refractory materials, steam drum shell, steam headers, and other boiler metal surfaces exposed directly or indirectly to furnace gases, and the steam turbine's multiple casings and rotor shafts. This is normally accomplished with easy-to-ignite fossil fuel firing (such as natural gas, distillate fuel oil, or propane) of the boiler combined with coal to gradually increase firing until recommended boiler steam outlet temperature and pressure are reached. This is followed by supplying the steam turbine with sufficient inlet steam flow to reach conditions that allow the coupled generator to be synchronized and electricity to be generated above zero megawatts. From this point, boiler fuel firing is increased within prescribed rates until the desired operating load is achieved.

The SEGU startup operating period is usually not defined in emission permits. Startup is the period beginning with initiation of fuel ignition, and continuing until the powerplant equipment has reached operating conditions that include continuous fuel firing and sustained operating steam pressure and temperature levels within the guidelines of the designs for the boiler and turbine and their auxiliary systems for minimum sustainable levels without causing damage to the equipment.

A recent SEGU proposed PSD permit has included a definition of startup as "the period beginning with ignition and lasting until the equipment has reached a continuous operating level and operating permit limits"[36]. Similarly, a shutdown is defined as "the period beginning with the lowering of equipment from base load and lasting until fuel is no longer added to the boiler and combustion has ceased"[37]. Based on the referenced definitions of a startup period and a shutdown period, the amount of time required for a SEGU's load (boiler steam output or generator electrical output) to increase beyond such minimum sustainable operating levels can be considered part of startup events if the SEGU is typically base-loaded at full load or MCR output. This is the case with both MRY Station SEGUs.

Startups of SEGUs may be labeled as cold, warm, and hot to account for the amount of residual heat remaining in the boiler and steam turbine equipment. The various types of starts are dependent upon the amount of time the SEGU has been out-of-service (i.e. without boiler fuel firing or generator megawatt output). Cold starts have been defined as starts after the boiler has been without fuel firing for more than 72 hours, warm starts are more than 8 hours and less than 72 hours, and hot starts are less than 8 hours[38].

Although the definition of a startup event and the corresponding startup period is not required by the Consent Decree, defining start-ups is recommended. This helps to address the specific emission limitations during Unit startups at Milton R. Young Station and determine the impact of such operations on 30-day rolling average NO_X emissions. For the purpose of this NO_X BACT analysis, a Unit startup was defined as the period from initial fuel combustion to the point in time when:

- the measured Heat Input to the boiler on a 6-hour rolling average basis is greater than or equal to 4800 million BTU/hr for Unit 2; or
- the amount of time reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005 elapses, whichever occurs first; or
- fuel firing is discontinued prior to satisfying either previous criteria.

This startup definition for MRY Station Unit 2 accounts for conditions where cyclone refractory materials replaced during boiler overhauls must be cured by extended low-firing heating cycles,

[36] Desert Rock Energy Center (AZP04-01) Proposed PSD Permit Conditions, page 7. (http://www.epa.gov/region09/air/permit/desertrock/#permit)
[37] Ibid, page 7.
[38] Application for Prevention of Significant Deterioration Permit for the Desert Rock Energy Facility, Document Number 09417-360-250R1, May 2004, page 5-1.

unit controls are upgraded and must be adjusted during low-load operation, or for boiler feedwater quality to improve after boiler maintenance has been performed that affects the insides of the waterwall and superheated steam tubes. It also allows for a failed or interrupted start sequence which can require considerably less or more time to elapse than an average startup duration.

Analysis of MRY Station Unit 2 operations data from 2001 through 2005 revealed:

- There were 62 total startups in the five year period;
- Minimum startup was 14 hours for a "hot" start following a boiler master fuel interruption (Unit "trip");
- Maximum startup with an extended ramp-up period until full load was reached was 115 hours.

Unit 2 had a start-up that began on October 25, 2001 that lasted for 115 hours. This startup included initial firing in the 20th hour of 10/25 (2000 hours being the beginning of the startup period), and which ended at the end of the 14th hour (i.e. at 1500 hours) on October 30, 2001, upon reaching 451 MW (gross) output. The criteria of a 6-hour average heat input rate of more than 4800 million Btu per hour was not reached during this startup.

There are certain boiler operating conditions that need to exist before the BACT NOx control techniques and technologies can be effectively operated:

1. The furnace gas temperature in the region where a urea reagent solution is injected for SNCR-based NO_X control must be between 1700°F and 2100°F. This region is expected to be in the vicinity of the furnace exit, which is commonly defined as either the horizontal plane extending from the furnace rear wall arch ("nose") to the front wall of the boiler, or the vertical plane from the nose up to the furnace roof, upstream of the gas inlet to the superheater tube banks. The gas temperature (FEGT) range in this furnace region is dependent on boiler heat input rate and cleanliness of the firesides of the furnace walls, which affects the amount of radiant energy absorbed by the wall tubes and transferred to the water within.
2. The numbers of active cyclones and continuous coal firing rates must be enough to establish sufficient:
    a. coverage of molten slag on the actively-fired cyclone barrel surfaces and drainage of the slag from the bottom of the boiler; and

b. combustion airflow through the actively-fired cyclones to allow a portion to be diverted to the separated overfire air system above the amount required for idle cyclone cooling and SOFA nozzle cooling.

As previously discussed, furnace exit flue gas temperatures (FEGTs) will need to be measured or determined empirically during operation of the MRY Station boilers in order to be able to effectively control NO_X emissions using SNCR technology. The design and operation of the SNCR systems at MRYS for CD Phase II emissions control should include features that accommodate cyclone boiler startups and low-load operation with "clean" or "dirty" boiler heat transfer surfaces as soon as conditions occur that are technically practicable, i.e. within the SNCR system vendor's recommended operating guidelines, as well as full-load conditions in order to minimize NO_X emissions.

The amount and duration of sustained boiler heat input required to establish the operating conditions described in item 2 above is more difficult to precisely determine. Lignite heat content variability and inability to accurately determine the actual air/fuel ratio on a cyclone-by-cyclone basis in real-time, and the slagging and fouling characteristics of the lignite ash, cause (and are expected to continue to cause) difficulties with stable combustion performance. The minimum firing rates of the MRY Station boilers required to successfully initiate the effective operation of the SOFA system are specific to each individual boiler, and are not currently known. Due to such operating problems and emission control limitations, the ability to effectively limit NO_X emissions during startup periods and low-load operation following implementation of advanced SOFA (CD Phase I control) and/or an SNCR system (CD Phase II control) is uncertain.

Because there are expected to be minor short term variations in operating conditions during startups where Minnkota has not, in fact, materially changed any of their normal startup operating practices and criteria, a margin between the 30-day rolling average steady-state NO_X emission rate (which does not include the impacts of startups) and the proposed 30-day rolling average NO_X emission permit limit that includes startup emissions is recommended. This rate considered recognized operational factors and equipment designs applied to steady state conditions with sustained output close to maximum continuous capacity ratings. The recommended 30-day Rolling Average NO_X Emission Rate permit limitation excluding the impact of startups that reflects BACT for Milton R. Young Station Unit 2 is shown in the table below.

TABLE 3-20 – Recommended NO_X BACT Control Method and 30-Day Rolling Average NO_X Emission Rate Limit Without Startups

Unit	Pollutant	Control Method	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)
2	NO_X	Selective Non-Catalytic Reduction with Advanced Separated Overfire Air (ASOFA)	0.350

This recommended BACT 30-day NO_X emission rate limit is based upon a historic pre-control 30-day baseline average NO_X emission rate of 0.874 lb/mmBtu for Unit 2. The baseline emission was determined from the 30-consecutive day period with the highest historic unit NO_X emissions rate reported for actual operation between January 1,2001 and December 31, 2005.

A recommended BACT 30-day NO_X emission rate limit that includes the impact of startup emissions should be suitably higher such that operation consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices to the extent practicable for the MRY Station boilers would not result in an exceedance (violation) of an enforceable 30-day rolling average NO_X emission permit limit.

For MRYS Unit 2, the recommended 30-day rolling average NO_X emission permit limit rate that includes the impact of startups is based upon recognized operational factors and equipment designs that influence whether the startup emissions result in higher 30-day emissions compared to normal continuous operation without or excluding such startup periods:

1. The uncontrolled emission rate (i.e. without separated OFA or SNCR in operation) and its variability during operation from a cold, warm, or hot startup up to and including maximum continuous rated output;
2. The operating conditions that are required to exist for the selected NO_X BACT control techniques to be initiated and be effective; and
3. The effectiveness of these two particular control techniques if invoked at less-than-MCR steady-state operating conditions.
4. The number of startups and their range of typical durations per 30-day period time frame.

The October 25-30, 2001 startup was chosen for additional evaluation as the start-up for MRY Station Unit 2.

An incremental adjustment to the proposed 30-day rolling average steady-state unit NO_X BACT emission rate without startups of 0.35 lb/mmBtu for Unit 2 is recommended for the 30-day rolling average NO_X emission permit limit periods as defined and applied to Milton R. Young Station. This is summarized in the table below.

TABLE 3-21 – Recommended BACT 30-Day Rolling Average NO_X Emission Rate Limit and Startup Impact

Unit	30-day Rolling Average NOx Emission Rate Limit Excluding Startups (lb/million Btu)	Impact on 30-day Rolling Average NOx Emission Rate Limit Due to Startups (lb/million Btu)
2	0.35	+0.102 per startup

This recommended adjustment to the proposed 30-day rolling average steady-state NO_X BACT emission rate limit without startups is based upon average historic pre-control NO_X emission rates of 0.959 lb/mmBtu for Unit 2 reported for the longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005. These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

A 24-hour rolling average BACT NO_X emission rate limit applied to startup periods is also recommended for each of the Milton R. Young Station boilers.

This is summarized in the table below.

TABLE 3-22 – Recommended 24-Hour Rolling Average NO_X Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
2	1.064

These emissions occurred during the 115-hour October 25-30, 2001 startup for Unit 2.

Compliance with these emission rates would be measured at the stack of the Unit, verified with Continuous Emission Monitoring (CEM) systems in accordance with the reference methods specified in 40 C.F.R. Part 75, and would be determined on a 30 consecutive Operating Day and 24-consecutive hour rolling average basis, respectively.

A trial demonstration operating period of 18 months after the completion of Consent Decree Phase II NO_X emission reduction system installation commissioning at Milton R. Young Station is recommended. It is proposed to allow Minnkota (for Square Butte) to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system. Operating experience during the trial period will:

- confirm steady-state control performance of the combined NO_X BACT emissions reduction system;
- allow determination of the ability to further control Unit start-up emissions;
- allow the determination of the permitted 30-day rolling average NO_X emission limit including startups, shutdowns, and malfunctions; and
- address the specific emission limitations during Unit startups at Milton R. Young Station and their impact on the proposed 30-day rolling average emission rate limit (without startups).

Based upon the information obtained during the trail period, final emission limits can then be determined.

The means that will be employed to minimize emissions during startup will primarily be based on operating procedures, both before and after the level of upper furnace gas temperatures and/or heat input rate are considered sufficient to start the NO_X controls and operating conditions are conducive for effective emissions reduction. These could be similar to Minnkota's current MRYS practices, or could be different, depending upon the capabilities of the NO_X controls and their impacts on Unit operations.

References:

1. In the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034.

2. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").

3. EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: from EDOCKET at http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b; this is associated with EPA Acid Rain Program Clean Air Markets Division, Technical Support Document – Methodology For Developing BART NO_x Presumptive Limits, June 15, 2005, OAR-2002-0076-0445.

4. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NO_X Controls – NO_X Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf

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APPENDIX A

Technical Feasibility Assessment Details for NO_X Control Technologies (A1)

U.S. Coal Cyclone NO_X Reduction Projects Summary

With Retrofit NO_X Control Projects' Technical Literature Summary (A2)

A.1 Technical Feasibility Assessment of NO_X Control Alternatives

A.1.1 Pre-Combustion Fuel Treatment/Switching

Fuel switching can be a viable method of NO_X emission reduction in certain situations. Often, coal combustion facilities are constructed to take maximum advantage of the particular combustion characteristics of a specific fuel. In the case of MRY Station, the Unit 1 and 2 boilers were designed and constructed specifically for firing North Dakota lignite, which has a fuel higher heating value (Btu/lb) approximately 20% lower than typical Powder River Basin (PRB) coal. A cyclone–fired boiler (Ottertail's Big Stone Unit 1) that is similar in geometry and steam generation design to MRY Station Unit 2 fires PRB coal. Based on a comparison of available emission data between Big Stone Unit 1 and MR Young Unit 2, there is no expected reduction in baseline (i.e. uncontrolled) NO_X emissions from switching to PRB from lignite at Milton R. Young Station.

Conversion of Milton R. Young Station Unit 2 boiler to fire PRB coal is technically possible. It is expected that major plant modifications will be required. Rail service is not presently installed at this site, so the additional operational and capital costs to bring in large quantities of PRB coal will be significant. Investigation of the specific source, distance, and costs for supplying necessary quantities of PRB coal via rail or trucks to M.R. Young station has not been performed. With zero baseline NO_X emissions reduction expected from application of fuel switching, this alternative will not be economically competitive with other NO_X control technologies that offer better results for a much lower combination of capital and operational costs. Although fuel switching is technically feasible, it has not been considered further as an effective NO_X emissions control option for MRY Station Unit 2 boiler.

A.1.2 Combustion Controls

Combustion controls comprise the most numerous category of NO_X emission reduction technologies. These techniques employ methods that reduce the amount of NO_X emissions created in the combustion zone of the boiler prior to exhausting the flue gases from the furnace (upstream of the convective heat transfer zones). These controls result in fewer emissions to atmosphere or that may require subsequent reduction from additional applicable combustion and/or post-combustion techniques.

As the boilers in question were designed for firing North Dakota lignite fuel, they were furnished with suitably-sized furnaces and limited back-end economizer heat transfer surfaces upstream of the air preheaters. This provides high temperature air to aid the evaporation of excess moisture from the crushed coal particles in the pre-combustion drying systems, and long residence times for solid and gaseous fuel

particles to burn essentially to completion prior to leaving the furnaces. The latter feature is especially advantageous for applying various forms of combustion modifications which are conducive in reducing NO_X emissions.

A.1.2.1 Basic Combustion Improvements

Combustion improvements are commonly-applied techniques which may produce modest incremental NO_X emissions reductions. In their most basic form, these typically provide improvements to combustion air flow distribution, measurement, and pressure, together with fuel flow measurement and metering, to promote consistent combustion performance by burning fuel with more accuracy in maintaining a desired fuel/air ratio.

These improvements may allow, or be combined with, the practice of several other NO_X control techniques. Separated overfire air (discussed below), with or without "low excess air" (LEA), burners out-of-service (BOOS) and biased firing (BF) operation of the cyclones, cause a decrease in the ratio of combustion air to fuel supplied to the cyclones (burners), thus reducing the amount of thermal NO_X emissions produced during combustion. The amount of potential NO_X emission reduction achievable from these basic techniques is highly-dependent on the specific type of firing, fuel, and conditions which apply to the boiler(s) being reviewed.

Making lignite drying system air adjustments and adding improvements to the boiler combustion controls and reducing combustion air inputs have already reduced uncontrolled NO_X emissions at Milton R. Young Station Unit 2 boiler approximately 27%. Further incremental improvements from additional combustion controls that allow operation with modest amounts of cyclone air staging, similar to the effect of a separated overfire air system, are possible. Incremental NO_X emissions reductions are expected from such improvements being incorporated into another feasible alternative, such as separated overfire air. This alternative was not considered as a stand-alone option for additional NO_X reduction at Milton R. Young Station for the Unit 2 boiler.

A.1.2.2 Low NO_X Burners (LNB)

Low NO_X burners (LNBs) of various designs have been commonly applied to pulverized coal-fired utility and industrial boilers for more than ten years. However, they are not installed on cyclone-fired boilers. This technology is infeasible on cyclone boilers[1], and was eliminated from consideration for additional NO_X reduction at Milton R. Young Station Unit 2's boiler.

A.1.2.3 Separated Overfire Air (SOFA)

Separated overfire air (SOFA) is a combustion-related NO_X emission reduction technology frequently-applied with and without low NO_X burners to utility and industrial boilers for more than twenty five years. Separated Overfire Air (SOFA) is an air-staging NO_X emission reduction combustion technique that is typically based on withholding 15 to 20 percent of the total combustion air conventionally supplied to the firing zone. The diverted combustion air is then injected in the upper furnace, where combustion is completed. For typical cyclone coal-fired boilers, this involves diverting approximately 20 percent of the secondary combustion air, forcing the cyclones to operate fuel-rich. Starved-air combustion causes fewer NO_X emissions to be produced.

At least thirty nine existing cyclone-fired boilers, firing eastern bituminous, midwestern bituminous, and western subbituminous ("Powder River Basin") coals in units ranging in size from 50 to 1150 MW, have been retrofitted with commercial SOFA since 1998. A summary of several of the first SOFA (and reburn) retrofits to cyclone-fired boilers is described in published technical papers[1,2]. Cyclone boiler retrofit SOFA installations are included in the EPA's BART technical support document[3] and listed later in Appendix A2.

A basic form of separated overfire air (SOFA) can be applied and installed on MRY Station Units 2. There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application.

Key aspects of successfully applying and operating a separated overfire air system on a cyclone-fired boiler are the ability to:

- Accurately measure the fuel heat input rate (BTUs) and combustion air inputs on a real-time, individual cyclone by cyclone basis, to allow the ability to determine and control the desired air/fuel ratio, especially when "starved air" (i.e. substoichiometric) combustion conditions are required.
- Maintain adequate molten coal ash (slag) formation and flow within the barrels and slag taps.

The degree to which the cyclone furnaces can be operated with less than theoretical (substoichiometric) combustion air directly contributes to less NO_X formation and further in-furnace emission reduction but also risks solidification of the molten coal ash. In the case of MRY Station Unit 2 boiler, cyclone combustion must be sufficiently air-staged to reduce NO_X emissions while releasing enough heat to continue to melt the fuel ash so that it flows effectively within and from the cyclone burners.

In the case of MRY Station boilers, there is a significant amount of variability in the combustible and ash components of North Dakota lignite supplied from the current mine near Center, ND. Analysis of several hundred coal feed samples taken simultaneously from multiple cyclones of MRY Station Unit 2's boiler revealed that the maximum differential of the lignite heating values from cyclone-to-cyclone was just over 12% of the average heating value of all the samples. Assuming an operating case occurred where the maximum cyclone-to-cyclone differential heating value was for two cyclones at the opposite ends of the fuel heat content range, there would be a plus or minus 6% variation in fuel heat content for either of the individual cyclones from the overall average. If the desired average cyclone air/fuel (stoichiometric) ratio was 0.95 when operating with air-staged cyclones associated with separated overfire air, and the amount of secondary combustion air to each cyclone was equal, there would be a stoichiometric ratio of approximately 1.01 in one cyclone and a stoichiometric ratio around 0.89 in another cyclone at the same time. The modestly air-staged cyclone would produce higher than average NOx emissions. The deeply staged cyclone would produce less than average NOx emissions and potentially insufficient amounts of heat release, and raise the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil in the deeply-staged cyclone or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in lower emissions removal performance and higher operating costs. Thus, due to the variability of the fuel heat content and the complex behavior of lignite ash when exposed to high temperatures, the extent of air-staging and thus the level of NO_X control in MRY Station boilers is expected to be modest while firing lignite coals.

In order to potentially achieve lower NO_X emission rates with modestly air-staged combustion for MRY Station boilers, additional combustion improvements can be installed. One potential improvement is to implement a unique form of SOFA for North Dakota-lignite–fired cyclone boilers. This includes relocated lignite drying system vent ports, and in Unit 2's case, also involves blocked or relocated lower furnace flue gas recirculation ports. This will be referred to as "Advanced SOFA" (ASOFA). There are several design challenges anticipated for implementing the advanced version (with the described port relocations) of separated OFA. These are believed to be solvable.

Both forms of separated overfire air as a combustion-related NO_X control technique are considered feasible for application to Milton R. Young Station cyclone boilers. Since the advanced SOFA is the highest-performing form of this technology, only this ASOFA version of the alternative was considered for additional NO_X reduction at Milton R. Young Station boilers.

Another form of separated overfire air being marketed commercially is "Rotating Opposed Fire Air" (ROFA). For utility applications in the United States, this has only been applied to pulverized coal-fired boilers, primarily tangentially-fired units[4]. It is different than basic SOFA in that it includes a hot air booster fan, and injects the overfire air in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. The vendor (Mobotec USA) claims ROFA maximizes air-staged in-furnace combustion NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon.

While this variation of separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Because cyclone boilers do not require the addition of hot air booster fans for SOFA, this technique is not distinct enough from basic SOFA from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration. ROFA technology lacks demonstrated cyclone-fired boiler experience, and thus was considered infeasible and not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.2.4 Oxygen-Enhanced Combustion

A supplier of liquid oxygen (Praxair) has developed a method of replacing some of the combustion air supplied to the burners with pure oxygen. Combustion air, which is normally input through the secondary air system ductwork downstream of the forced draft (FD) fan and air heater, is supplemented with pure oxygen directly injected into the burners. Oxygen-enhanced combustion (OEC) can reduce boiler NO_X emissions resulting from " thermal NO_X", a reaction of the nitrogen in the combustion air admitted to the burners with the available oxygen in the air in the flame or peak temperature regions of the fuel combustion process. The use of pure oxygen instead of air reduces the availability of nitrogen from the air to be oxidized in the high temperature regions, thus reducing formation of thermal NO_X. This technique has only been demonstrated in a boiler with pulverized fuel burners firing bituminous coal[5].

The lack of adequate experience on any cyclone-fired coal-burning boiler, on a temporary demonstration or permanent full-scale basis, and for a coal-fired facility of this size, precludes consideration of oxygen-enhanced combustion at MRY Station Unit 2's boiler. This is deemed to be infeasible technology at this location at the present time.

A.1.2.5 Flue Gas Recirculation

Flue gas recirculation (FGR) has been commonly applied to coal-fired boilers, primarily to inject into the lower furnace, just above the burners, supplied from the boiler's economizer flue gas outlet via a hot gas booster fan. This modifies the amount and temperature of hot furnace gas either in the lower-middle or upper furnace and convection heat transfer zones. As this flue gas typically has an oxygen content around 2-5%, it limits the availability of oxygen in a high temperature, possibly fuel-rich lower furnace zone. Flue gas recirculation for NO_X control is most commonly applied with gaseous or liquid fossil fuels to reduce the high temperatures which convert nitrogen in the combustion air to nitrogen oxides. No examples of using or installing FGR on cyclone-fired boilers strictly for NO_X emissions control were found in available technical literature.

FGR is already practiced at MRY Station in the Unit 2 boiler, primarily for furnace gas temperature and lower wall slagging reduction reasons. For this boiler, FGR could aid in potentially providing some small additional NO_X emissions control if it were modified from its current configuration, as part of an advanced form of separated overfire air. Complete elimination of the use of FGR could also slightly reduce NO_X emissions from Unit 2's boiler during air-staged cyclone combustion with separated overfire air system operation. There is uncertainty whether elimination of the use of FGR in the lower furnace of MRY Station's Unit 2 boiler could be successful in controlling lower furnace wall fireside ash deposition.

A.1.2.6 Water/Steam Injection (Combustion Tempering)

When applied to older gas-fired and oil-fired utility and industrial boilers, water and/or steam injection adds moisture into the lower furnace, concurrent with or near (to the side or slightly above) the burners, supplied from the boiler's treated feedwater or auxiliary steam systems via a metering pump or valve. There has been some limited testing of water injection for NO_X emissions control on natural gas-fired and coal-fired cyclone boilers[6,1]. For coal-fired cyclones, this technique is most effective on boilers burning bituminous coal; however, it has not been permanently installed and continuously operated in such applications. Successful long-term operation of water injection would be difficult for lignite-fired cyclone boilers, due to the high moisture levels in the coal and the need to readily ignite and sustain stable combustion and molten slag formation in the cyclone furnaces. For these reasons, water/steam injection is considered technically infeasible for NO_X control application at Milton R. Young Station.

A.1.2.7 Fuel Reburn

Another combustion technology that may be applicable to control NO_X emissions from the Milton R. Young Station units is fuel reburn. In a similar manner that overfire air diverts a portion of the combustion air input to the main firing zone, the reburning process involves supplying a portion of the fuel heat input to the boiler at a higher elevation in the furnace. This creates an upper furnace atmosphere where the reburn fuel's combustion products causes some of the NO_X formed in the main burner combustion zone and reburn zone to be converted into molecular nitrogen. Depending on the amount of reburn fuel added and the amount of oxygen available in the furnace gases to combine with the reburn fuel introduced, additional combustion air may be supplied as supplemental or overfire air. Downstream of the air injection elevation, the intention is to complete the reaction of any remaining carbon monoxide (CO) to carbon dioxide (CO_2), plus reduce the amount of combustible matter remaining in the entrained flyash.

The most common forms of reburn technology applied to utility powerplant boilers are:

- Pulverized or micronized coal reburn (PCR or MiCR); and
- Gas reburn (GR).

Pulverized coal reburning and micronized coal reburning have been applied to pulverized coal and cyclone-fired boilers. NO_X reduction efficiencies of 50 to 60 percent have been demonstrated on eastern bituminous coal and midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone[7,8].

For utility powerplant boiler applications, natural gas has been utilized as reburn fuel most often, demonstrated in two basic approaches:

- Conventional gas reburn (CGR); and
- Fuel-lean gas reburn (FLGR™).

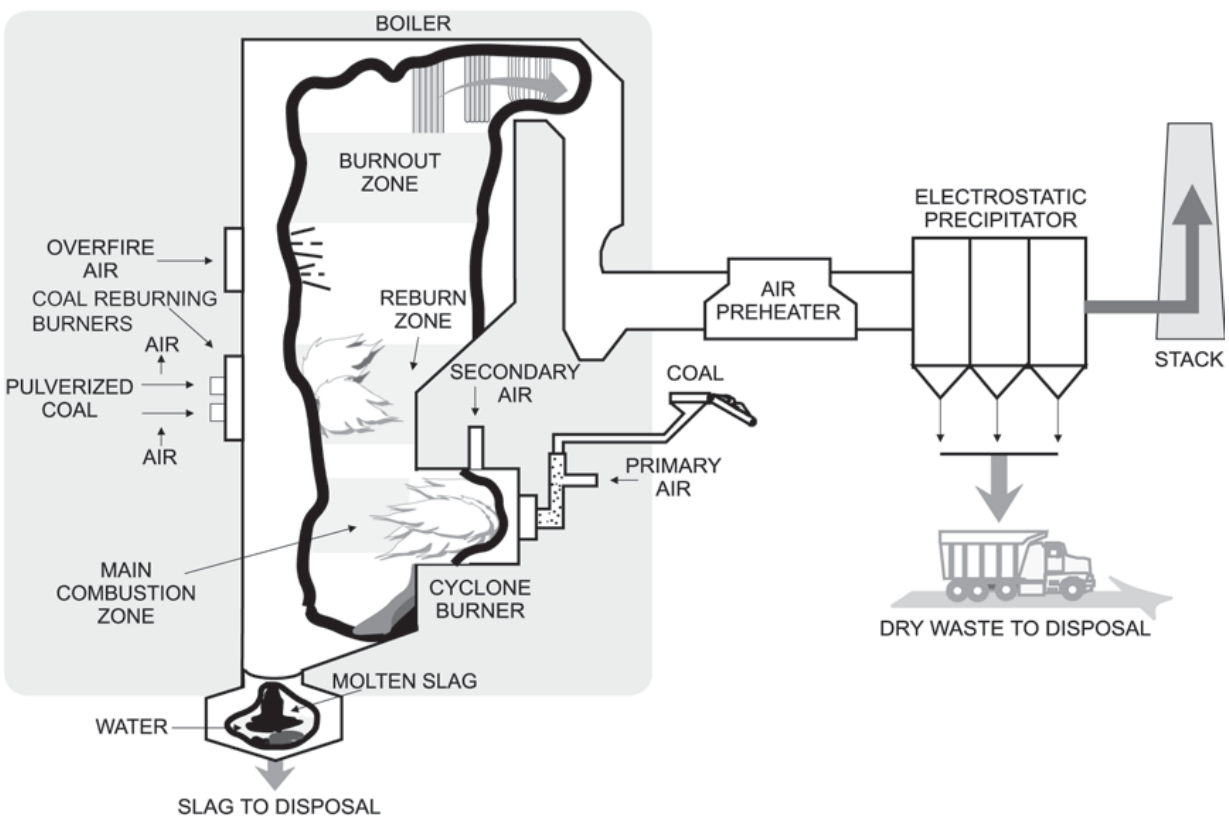
Either natural gas or pulverized coal (lignite) can be used as the reburn fuel. A sufficient quantity of natural gas is not currently available at the Milton R. Young Station plant site. Supplying enough natural gas to provide 6 to 25% of the total heat input to either or both boilers at MRY Station is expected to be technically feasible, although transport pipeline installation capital costs, and current and predicted unit natural gas costs and operating economics, are likely to be unfavorable.

Various forms of fuel reburning have been demonstrated and operated routinely on cyclone boilers for NO_X emission controls. This has been applied to units firing eastern bituminous coal, and western subbituminous or PRB/bituminous coal blends, using pulverized or micronized coal or natural gas as the most common reburn fuel. Reburning for NO_X emissions reduction has not been demonstrated on a unit firing high moisture, low heat content North Dakota lignite. Pulverized/micronized coal, along with conventional and fuel lean gas reburn technologies, are discussed below.

A.1.2.7.1 Coal Reburn

In the case of applying conventional coal reburn to cyclone boilers, the existing cyclones are supplied with the majority of the fuel, with either natural gas or pulverized coal (lignite) used as the reburn fuel such that the total heat input to the boiler is essentially the same as without fuel reburn. Separated OFA ports are located above the reburn fuel injection section of the furnace. These SOFA ports provide sufficient oxygen in a conventional fuel reburn installation to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones. This is shown schematically for a pulverized coal reburn application on a cyclone-fired boiler with SOFA in Figure A.1-1.

Figure A.1-1 Pulverized Coal Reburn Application on Cyclone Boiler With Overfire Air[8]



In the United States, pulverized coal reburning and micronized coal reburning techniques for utility powerplant NO_X emissions reduction have been applied on a very limited full-scale, full-time basis to cyclone-fired boilers in field demonstration tests and longer-term demonstration operation, respectively. There have been only two known pulverized or micronized coal reburn installations in the United States on cyclone boilers, one on a utility boiler in Wisconsin, and one on a small industrial-size cyclone boiler in New York state[7,8,9,10,11,12,13,14]. NO_X emissions reduction efficiencies of 57 percent have been demonstrated on cyclone boilers firing eastern bituminous coal, or midwestern bituminous and Powder River Basin (PRB) western subbituminous coals while supplying up to approximately 20-30% of the boiler's total fuel heat input to the reburn zone. With the exception of the U.S. Department of Energy's (DOE) Clean Coal Technology Program demonstration projects[7,8,9], no known commercially-available coal reburn systems have been installed and are routinely operated on cyclone boilers in the United States to date. The DOE-CCTP projects for coal reburn applied to cyclone boilers are described below.

Pulverized coal reburning for NO_X emissions reduction in a cyclone-fired boiler was demonstrated on the 110 MW Nelson Dewey Unit 2 for Wisconsin Power & Light in 1991-1992. Reburn fuel preparation and handling, reburn burners with flue gas recirculation, and a separated overfire air system were added. Coal reburn tests were conducted on this unit while firing bituminous and PRB coals. NO_X emission control efficiencies of 50 to 60 percent, with reductions from 0.75-0.83 lb/mmBtu baselines to around 0.38 lb/mmBtu, but as low as 0.29 to 0.32 lb/mmBtu, with PRB coal at full load with approximately 25-30% of the total fuel heat input from reburn fuel were demonstrated[9,11,12]. The reburn system is no longer operated on Nelson Dewey Unit 2.

Micronized coal reburning has been demonstrated in 1997-1998, and continues to operate year-round on a small industrial cyclone boiler (400,000 lb/hr steam output, 50 MW gross equivalent) for Eastman Kodak Company at their Kodak Park facility in Rochester, NY. This unit (Boiler #15) achieves a NO_X reduction efficiency of approximately 57 percent on eastern bituminous coal, involving limited cyclone air-staging (cyclones believed to be slightly above 0% excess air) and a modest amount of overfire air injection downstream of the micronized reburn fuel input nozzles. Approximately 17% of the boiler's total fuel heat input is typically supplied to the reburn zone. This coal reburn system continues to operate routinely at this facility. This installation is reported to use a Fuller MicroMill to produce micronized coal with 80% passing through a 325 mesh screen[7,9,13].

If a coal reburn system was applied to MRY Station boilers, the existing cyclones would be supplied with the majority of the fuel in the form of crushed coal, and the balance of fuel would be supplied to a pair of dedicated pulverizers to feed the reburn injection ports, such that the total heat input to the boiler is essentially the same as without fuel reburn. In a conventional fuel reburn installation, OFA ports located above the reburn section of the furnace provide sufficient oxygen to complete the combustion process that begins in the main combustion zone and is supplemented in the reburn and burnout zones.

Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. As a reburn fuel, lignite is expected to behave appropriately upon introduction in the lower middle furnace to help reduce NO_X emissions. The concerns are that the diversion of a significant amount of heat input from the cyclone barrels to use as a source of reburn fuel in the form of pulverized or micronized lignite may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with reburn and separated overfire air is the typical approach to avoid slag tapping problems.

Potential NO_X emissions reduction performance is expected to be limited on lignite-fired cyclone boilers with a basic form of separated overfire air system, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to any conventional reburn process in that it would require much higher reburn fuel injection rates to create a substoichiometric atmosphere in the lower secondary furnace that is conducive to promoting in-furnace NO_X reduction.

Significant additions to the fuel preparation equipment in the existing plant facilities will be required. The coal reburn system expected to be applied to MRY Station boilers may use two new fine-grind pulverizers and dynamic classifiers to achieve the level of coal particle size distribution required.

Higher unburned carbon levels in the flyash exhausted from the boiler may occur, especially when the reburn fuel is coal, and the regular burners are fired with less than theoretical amounts or combustion air commonly practiced with the use of overfire air. Lowering the reburn fuel injection elevation, decreasing

the amount of reburn fuel, and grinding the reburn coal to a greater degree of fineness can help to offset some of the increase in flyash unburned carbon content. Flue gas opacity from the stack may increase if the particulate removal equipment is an electrostatic precipitator, due primarily to reduced resistivity and smaller particle sizes of the flyash.

An issue that affects the feasibility of lignite reburning is the uptime required for the lignite reburn fuel pulverizing system, and impact of the reburn system on effectiveness in reducing NO_X emissions during load changes and lower loads. Typically, one new pulverizer is dedicated to prepare reburn fuel in existing pulverized fuel-fired boiler applications. Cyclones may be fired with less fuel or deactivated during boiler operation in order to accommodate changes in fuel combustion characteristics, boiler load, and for scheduled or unscheduled individual crusher maintenance. Milton R. Young Station Unit 2 has twelve crushers for cyclone coal grinding, each dedicated to one of the twelve cyclone furnaces. Diverting as much as 30% of the total heat input as reburn fuel could require four existing cyclones to be deactivated, and two new MPS-89 pulverizers to be dedicated to reburn fuel preparation. As each of these mills requires periodic maintenance, boiler emissions and/or load could be negatively impacted during individual reburn mill outage periods while the boiler remained in service. A high level of fineness of coal particles from the reburn mills is important to achieve and maintain in order to limit increases in flyash combustibles. A minimum of 60 percent passing through 200 mesh fineness is recommended by one of the reburn technology vendors (B&W) for pulverized lignite reburn. Micronized coal reburn requires even greater fineness: 70-80 percent passing through a 325 mesh screen.

Pulverized or micronized coal reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on MRY Station Unit 2's boiler. These combined techniques are expected to reduce NO_X emissions approximately 54% from current pre-control baseline levels (down to 0.36 lb/mmBtu) for the MRY Station Unit 2 boiler. These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers, which may not be successful given the concerns expressed about the potential impacts of this technique. Using finely pulverized lignite for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 2's boiler.

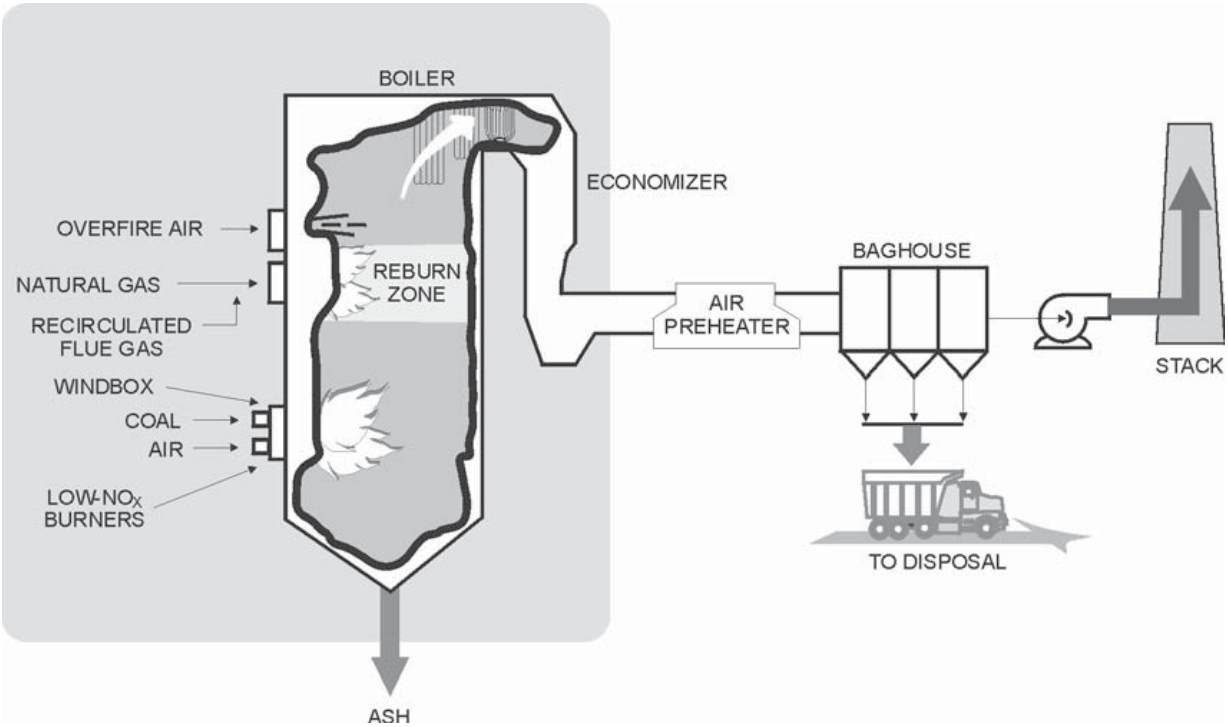
A.1.2.7.2 Conventional Gas Reburn

Natural gas has been preferred as the reburn fuel of choice. Natural gas has been utilized for reburn fuel in two basic approaches: conventional reburn and fuel-lean gas reburn. In the conventional approach, up to 30% of the boiler's total fuel heat input is supplied to the reburn zone, followed by a significant amount of overfire air for completion of combustion prior to flue gases exiting the boiler.

Conventional gas reburning in a cyclone-fired boiler has been available at Tennessee Valley Authority's Allen Station Boiler #1 (300 MW) since 1998. The reburn technology provider (vendor) claims NO_X emissions were reduced 67% from a full-load baseline of 1.29 (down to 0.42) lb/mmBtu when firing a blend of western bituminous and PRB coals[14]. Conventional gas reburn fuel input rates were not available from the technology vendor's literature. Another reference source of information stated NO_X emissions were reduced 65% from a full-load baseline of 0.86 (down to 0.30) lb/mmBtu with 7 percent of the total fuel heat input supplied as reburn fuel[9].

A schematic graphic of conventional gas reburn on a pulverized coal-fired boiler is shown in Figure A.1-2.

Figure A.1-2 Natural Gas Reburn Application on Wall-Fired Pulverized Coal Boiler with Overfire Air[8]



Similar to the application of separated overfire air, there are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. For the most effective NO_X reduction by applying the various available forms of fuel reburn, the injection of fuel is usually performed using recirculated flue gas as a diluent and carrier media to aid dispersion and avoid completely oxidizing the carbon and nitrogen components in the fuel and furnace gases from staged burners/cyclones. Improved gas reburn designs have reduced or eliminated FGR with higher gas injection pressures. For lignite-fired cyclone boilers, reburn fuel firing with a basic form of separated overfire air is expected to be much less effective in reducing NO_X emissions than previously demonstrated elsewhere. This is related to the likelihood that the injection of reburn fuel will be near the elevation of the existing lignite drying system vent ports, and that the oxygen introduced with the lignite drying system's vented moisture will disrupt the desired in-furnace nitrogen oxides reduction process.

It should be recognized that application of air-staged cyclones with basic or advanced forms of SOFA with reburn techniques will require the overfire air injection ports to be located at a somewhat lower elevation of the furnace compared with air-staged cyclones without reburning. This means that less air-staging of the cyclones may be practiced, or that less residence time will be available for the in-furnace NO_X reduction process to occur.

Similar to coal reburning, there are concerns that withholding a significant amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones for use of separated overfire air to further complement combustion NO_X reduction as part of this reburn technique will further risk slag "freezing" in the barrels and lower furnace. Reducing the number of active cyclones which are air- and fuel-staged to accommodate reduced firing rates while operating a coal-fired boiler with conventional reburn and separated overfire air systems is the typical approach to avoid slag tapping problems. Natural gas reburn with the advanced form of separated overfire air (ASOFA) can be applied and installed on Milton R. Young Station's Unit 2 boiler.

Although the unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages, using high-pressure natural gas for reburn fuel is considered technically feasible for NO_X emissions control under evaluation for application to MRY Station Unit 2's boiler.

A.1.2.7.3 Fuel Lean Gas Reburn

Another approach to gas reburning is "fuel-lean gas reburn" (FLGR™) technology, which injects limited amounts of natural gas (approximately 3-10 percent of the total fuel heat input) above the burners (or cyclones) with or without significant air-staging of the burners (cyclones) or the addition of overfire air upstream of the fuel injection elevation. FLGR's first field-test on a cyclone-fired boiler was at Commonwealth Edison's Joliet Unit 6 (327 MW), a 9-cyclone-furnace boiler[15]. NO_X emissions reduction with FLGR (without SOFA) was believed to be approximately 35-40% with 7% of the boiler's total fuel heat input supplied in the reburn zone. This test yielded 0.59 lb/mmBtu NO_X emissions from a baseline of 0.98[16]. One other cyclone boiler has been modeled using computational fluid dynamics (CFD) as part of a study looking at applying FLGR at Owensboro Municipal Utilities' Elmer Smith Station Unit 1 (150 MW single-wall, eastern bituminous coal-fired boiler). This model predicted that NO_X emissions could be reduced by 25-30% over that achievable from overfire air and SNCR[17].

More commonly, FLGR™ has been applied on medium to large pulverized coal wall-fired boilers burning eastern bituminous or western subbituminous coals. On Wisconsin Electric Power Company's (WEPCO's) Pleasant Prairie Unit 1, a 620 MWg Riley turbo-fired wet-bottom (slagging) boiler, FLGR™ alone was predicted to reduce NO_X emissions by 35-39 percent at a gas reburn rate of 7-8 percent but only achieved 20% from a baseline of 0.45 lb/mmBtu[16,18]. This is presumably without burner air-staging or SOFA. It has also been applied in combination with SNCR at this WEPCO site.

A potential advantage of FLGR™ over conventional gas reburn is that the former is generally compatible with, but does not require, the installation and operation of SOFA. The staged reburn fuel is introduced into an oxygen-rich atmosphere downstream of the burners and any OFA injection points. The amount of reburn fuel injected is typically limited by acceptable carbon monoxide levels in the boiler exit flue gas.

There are potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application. This is significant, especially for alternatives with FLGR™ technology when combined with basic or advanced SOFA to allow the natural gas introduced above the SOFA ports to burn completely prior to the furnace exit plane. In either case, the amount of additional potential NOx reduction possible with FLGR™ is limited, since the reburn fuel injection location is expected to coincide with the existing lignite pre-drying system vent ports. The amount of oxygen introduced by the vent ports will be disruptive to the fuel-lean

reburn process in that it would require much higher reburn fuel injection rates in the lower secondary furnace to promote in-furnace NO_X reduction. There are reduced concerns that the withholding of a modest amount of heat input from the cyclone barrels to use natural gas as a source of reburn fuel may reduce cyclone temperatures enough to inhibit slag formation and flow, especially as boiler load is reduced. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this reburn technique which will further risk slag "freezing" in the barrels and lower furnace.

Fuel lean gas reburn can be applied and installed on MRY Station Unit 2's boiler with or without SOFA/ASOFA. This technique is considered technically feasible for application to MRY Station Unit 2's boiler. Expected NO_X reduction will be modest for FLGR™ without SOFA and FLGR™ with a basic form of SOFA. Unit operating and capital costs to supply large quantities of gaseous fuel not currently available at this site are economic disadvantages. Because of these factors, these variations of this technology will not be cost-effective compared to other alternatives with similar control effectiveness. FLGR™ without SOFA and FLGR™ with a basic form of SOFA were not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of fuel lean gas reburning in combination with post-combustion technologies, such as amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.2.7.4 Fuel Oil Reburn

Fuel oil has been substituted for natural gas in a conventional reburn application. This is much less common in the United States than using natural gas as a reburn fuel, due to the general lack of demand and difficulties in supplying the volume of fuel oil which would be required. It has been installed commercially on three 350 MW oil-fired boilers in New Brunswick (Canada) at the Coleson Cove plant. NO_X emissions reduction with reburn and SOFA was 78% with 25% of the boiler's total fuel heat input supplied in the reburn zone. This yielded 0.22 lb/mmBtu NO_X emissions from a baseline of 1.0 lb/mmBtu[9]. No examples of conventional fuel oil reburn applied to a coal-fired cyclone boiler were found in available literature.

Fuel oil reburn could potentially be considered for application to MRY Station Unit 1 and Unit 2 boilers. Investigation of the specific source, distance, and costs for supplying significantly increased quantities of fuel oil via transport trucks hauling tanker trailers or underground pipeline to M.R. Young station has not

been performed. The unit operating and capital costs to supply large quantities of high-volume liquid fossil fuel at this site are economic disadvantages. The concerns regarding potential impacts and limitations unique to the firing of North Dakota lignite in cyclone-fired boilers that should be recognized as part of this emission reduction technology application are similar to those expressed for conventional gas reburn. It is believed that potential NO_X control with oil reburn would be slightly less than comparable conventional gas reburn systems.

Although fuel oil reburn could potentially be considered for application to MRY Station Unit 2's boiler, the lack of any distinct potential NO_X reduction advantages and demonstration on cyclone-fired boilers does not appear to support its consideration. This alternative was not included in the NO_X control and cost-effectiveness analysis.

A.1.3 Post-Combustion Controls

Post-combustion controls deal with techniques that thermally or chemically-treat the flue gases to reduce NO_X emissions after they have exited the boiler's lower furnace. In the case of Milton R. Young Station Unit 2, this primarily involves forms of selective catalytic reduction (SCR) and selective non-catalytic reduction (SCR) technologies. Another emerging technology that has recently entered the commercial market is Powerspan's Electro Catalytic Oxidation®, which treats utility boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury. Another emerging technology that has recently entered the commercial utility air pollution control market is Powerspan's Electro Catalytic Oxidation®, which treats boiler flue gas for removal of nitrogen oxides, sulfur oxides, and mercury.

A.1.3.1 Selective Non-Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR), and variations such as hydrocarbon-enhanced SNCR (sold under the trade name of NOxStar™), and Rich Reagent Injection (RRI), are all post-combustion types of boiler NO_X emission controls. While these technologies are insensitive to the specific fuel types whose combustion products are being treated, the large majority of boiler applications to date have been on pulverized coal-fired units burning eastern bituminous fuels. SNCR has been used to reduce NO_X emissions on numerous utility boilers burning eastern bituminous coal, midwestern bituminous coal, and, to a lesser extent, western subbituminous coal. SNCR has also been used with fuel oil and natural gas-fired units. SNCR (and hydrocarbon-enhanced SNCR) technologies can each be applied to cyclone boilers with or without the use of a SOFA system. SNCR does not appear to be dependent directly on the type of burners (wall-fired, tangentially-fired, and cyclone-fired) employed in the boilers where it has

been installed, with or without overfire air in full operation. Operation at these plants has demonstrated that SNCR can decrease NO_X emissions as much as 15-40% at full load, most typically between 25-35 percent[19].

In the conventional SNCR process, urea or ammonia is injected into the boiler in a region where the combustion gas temperature is in the 1700 to 2100 degrees F range. Under these temperature conditions, the urea reagent [$CO(NH_2)_2$] or ammonia [NH_3] reacts with the NO_X, forming N_2 and water, reducing NO_X emissions.

Long-term examples where SNCR has been used to reduce NO_X emissions on two cyclone-fired boilers are on a 138 MW unit and 160 MW unit burning eastern bituminous coal at Conectiv's B.L England Station (Units 1 and 2) since 1995 and 1996, respectively. Tests at these plants demonstrated that SNCR can decrease NO_X emissions as much as 30-36% at full load, from around 1.3-1.4 lb/mmBtu respectively to as low as 0.85 lb/mmBtu (without overfire air)[18,19,20]. These boilers, located near Atlantic City, New Jersey, continue to operate SNCR (with OFA) for annual NOx emissions around 0.55 and 0.45 lb/mmBtu, respectively.

SNCR can be applied and installed on MRY Station boilers. Estimated NO_X emission rates for using SNCR with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor predictions. SNCR alone is expected to reduce NO_X emissions approximately 37% from MCR baseline levels (down to around 0.5 lb/mmBtu) for the MRY Station Unit 2 boiler with ammonia slip limited to approximately 5 ppmvd. Because of the operating costs of the consumed reagent, this technology will not be cost-effective compared to other alternatives with similar control effectiveness (i.e. SOFA), SNCR alone was not included in the control effectiveness and cost-effectiveness sections of the main report.

Other demonstrated forms of SNCR-related technologies, such as Rich Reagent Injection with SNCR, and amine-enhanced fuel lean gas reburn (FLGR™ with SNCR), are discussed under the layered technologies section.

A.1.3.2 Hydrocarbon-enhanced SNCR (NOxStar™)

Hydrocarbon-enhanced SNCR technology, commercially marketed as NO_XStar™, is offered by a single vendor (Mitsui Babcock) as a post-combustion type of enhanced SNCR technology, whereby an

ammonia-based reagent is continuously injected into the superheater/reheater pass of an operating boiler with small amounts of gaseous hydrocarbon (typically either natural gas or propane) and air or steam to provide lance cooling and aid reagent dispersion. The targeted combustion gas temperature range is between 1500°F and 2000°F. The amount of gaseous hydrocarbon introduced is small enough (0.1 to 0.2% of total fuel heat input) that this is not intended to act as a form of reburn or staged fuel combustion. An array of permanently-installed injection lances are located within the boiler convection pass, divided into numerous discrete zones across the full width and height of the duct. The hydrocarbon auto-ignites, forming hydroxyl (OH) radicals which react with the NO_X and ammonia to produce elemental nitrogen (N_2) and water vapor (H_2O).

NO_XStar™ was demonstrated at Tennessee Valley Authority's Kingston Power Station Unit 9 (tangentially-fired 200 MW twin-furnace boiler firing eastern bituminous coal) in 2002[21]. This technology was subsequently permanently-installed at TVA's Colbert Station Unit 4 in late 2003 on a 192 MW wall-fired boiler burning eastern bituminous coal[22]. NO_X reduction was stated as 68-80% for these applications, which included the impact of overfire air and air-staged combustion upstream of the ammonia and propane injection locations.

An example of a hydrocarbon-enhanced SNCR installation on a wall-fired pulverized fuel boiler is shown as a sectional side elevation view of the upper furnace in Figure A.1-3.

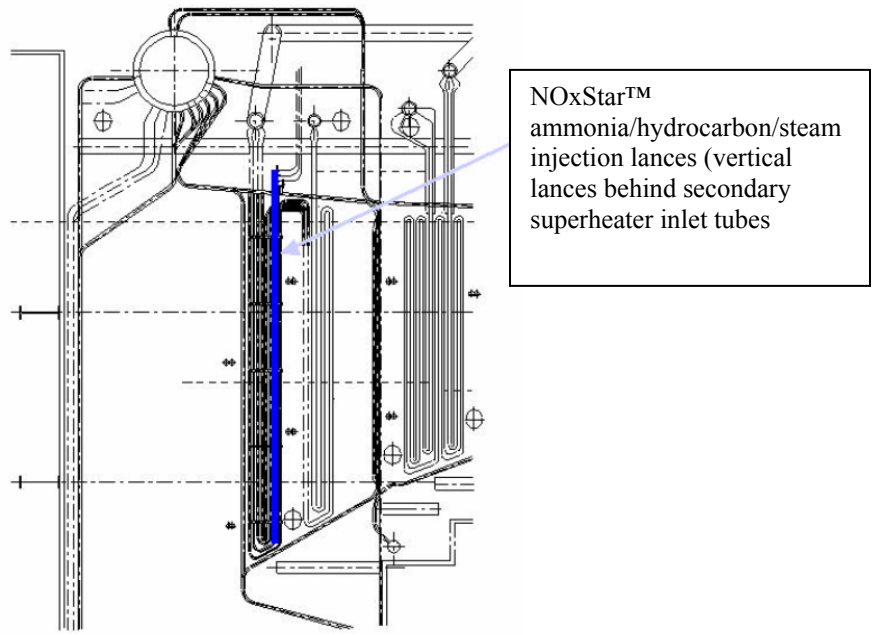


Figure A.1-3 Hydrocarbon-enhanced SNCR Application on PC-fired Boiler[22]

The supplier (Mitsui Babcock) of hydrocarbon-enhanced SNCR technology claims there is little sensitivity to the type fuel (coal) or burners this technique can be potentially applied to in order to reduce NO_X emissions. The chemical reagent injection for hydrocarbon-enhanced SNCR (NO_XStar™) NO_X control technology must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) model simulations are needed to determine the optimum injection points and spray patterns. Boiler operating conditions change with unit load and varying fuel characteristics. The NO_XStar™ process control system must be able to adjust for these changing conditions in order to be effective throughout the intended load range and firing conditions encountered. Non-retractable ammonia injection lances arranged in a parallel-series manner are permanently mounted inside the upper furnace zone, attached to convective tube elements. Different sections of the injection "grid" can be turned off or on, depending on load and firing conditions and amount of NO_X reduction required. Injection nozzles are continuously purged and cooled by extracted superheated steam from the boiler's main steam outlet, whether ammonia reagent is being introduced into the flue gas stream or not. Ammonia slip can be minimized by injecting less reagent, although NO_X control performance will be reduced.

There are a number of issues with firing North Dakota lignite that make the applicability of hydrocarbon-enhanced SNCR infeasible compared to previous experience in other coal-fired powerplants. These issues include:

- Hydrocarbon-enhanced SNCR (NOxStar™) technology has not been applied to cyclone boilers (with or without the use of a SOFA system). It has been only applied to date on pulverized coal-fired boilers burning eastern bituminous fuels.
- There is no successful demonstrated full-scale experience in continuous service of hydrocarbon-enhanced SNCR (NO_XStar™) technology on units firing high-slagging coals such as western subbituminous (PRB) and lignite. The heat transfer surfaces in the convective heat transfer zone where the reagent mixture is injected are prone to severe fouling from flyash constituents common in North Dakota lignite coals. Flyash deposit accumulation on the outside of the NO_XStar™ lances in Milton R. Young Station Unit 2 boiler's upper furnace is expected to be significant, potentially occurring within a matter of a few weeks from startup and nearly impossible to prevent or remove effectively during boiler operation. Such buildup is expected to cause maldistribution of the NO_X reduction chemical reagent from the injection nozzles. Effective on-line removal of these deposits from the injection nozzles is anticipated to be insufficient to maintain effective injection distribution and volume control. It is anticipated that this would significantly reduce the NO_X emission reduction performance consistently achieved on a sustainable basis.

The lack of experience with cyclone boilers, especially those firing coal with severe deposition characteristics such as North Dakota lignite, makes this technology technically infeasible for application on the Milton R. Young Station Unit 2 boiler.

A.1.3.3 Rich Reagent Injection (RRI)

Rich Reagent Injection (RRI) is a NO_X control process that has been developed and demonstrated specifically for use on cyclone boilers. Rich Reagent Injection is an SNCR process that involves the injection of aqueous urea into the lower furnace between the cyclones and the SOFA ports. RRI targets a high temperature, fuel-rich zone within the boiler-furnace environment immediately adjacent to the cyclone burners, and requires temperatures in the range of 2400 to 3100 degrees F.

The three zones of a Rich Reagent Injection SNCR application on a boiler with separated overfire air are shown as a sectional side elevation view of the furnace in Figure A.1-4.

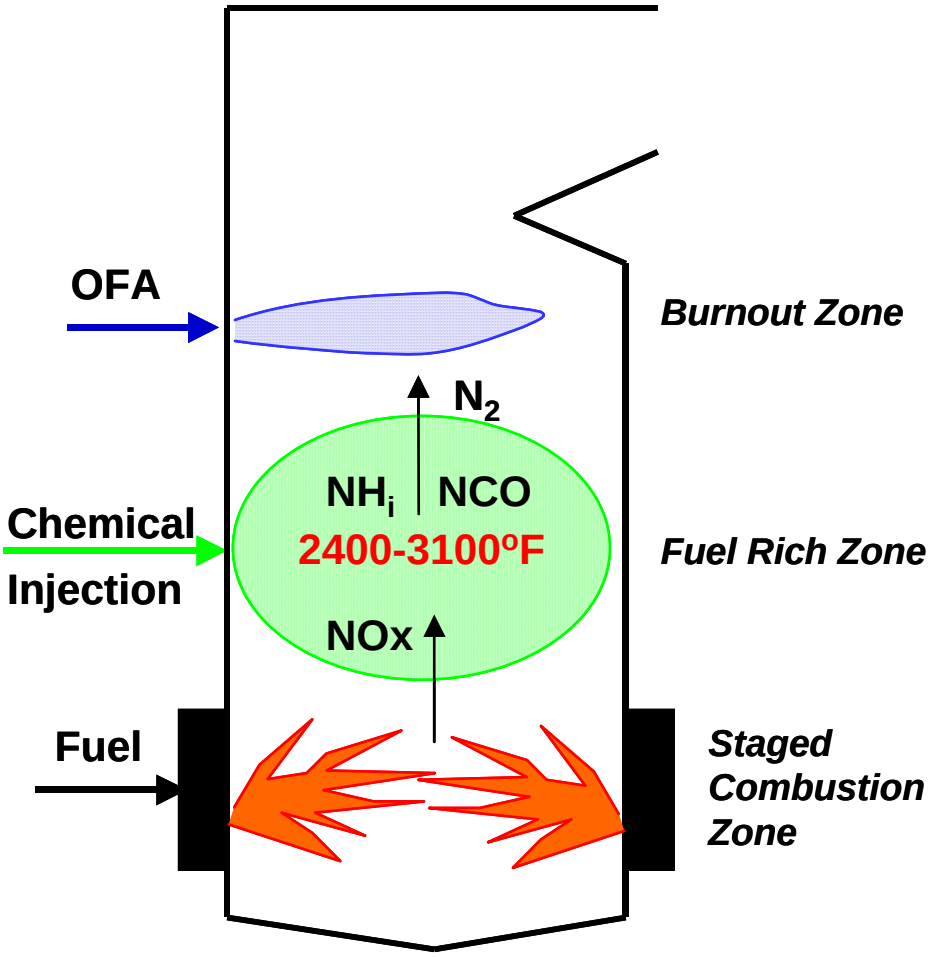


Figure A.1-4 Rich Reagent Injection Application on Boiler With Overfire Air[23]

The Rich Reagent Injection (RRI) process has been successfully demonstrated on at least two cyclone-fired boilers, with the most recent installation at Ameren's Sioux Unit 1, a 500 MW boiler firing a blend of PRB and midwestern bituminous coals. Generally, the heat content of these coals typically varies very little. Short-term testing of the RRI process has been performed alone and in combination with SNCR on B.L. England Unit 1 in 1999[24,25], and more recently at Ameren's Sioux Unit 1 in 2002[23,25], in 2004[26] (alone), and in the first half of 2005[27] (alone, and with SNCR).

The RRI process is intended to be used only with air-starved (substoichiometric staged-air) cyclone combustion, in conjunction with the installation and operation of an OFA system. The RRI process has not been demonstrated on any unit that fires North Dakota lignite. As of October 2006, no commercial installation of a permanent Rich Reagent Injection system has been made at any cyclone-fired boiler.

There is only one holder of a commercial license for modeling and conceptually designing RRI (Reaction Engineering International), with two vendors sub-licensed to design and sell RRI equipment (Fuel Tech and Combustion Components Associates). Since these license agreements are in place, and considering that successful demonstration testing has been performed at two cyclone-fired boiler powerplants, this technology is considered to be applicable and commercially available for potential application on cyclone boilers which burn coals with heat contents that are relatively constant. However, due to the variable heat content of lignite coal, RRI is considered to be technically-infeasible for application on North Dakota lignite-fired boilers. Technical feasibility and expected NO_X emissions from RRI for application on the Milton R. Young Station Unit 2 boiler are included in the "Layered NO_X Reduction Technologies" section.

A.1.3.4 Selective Catalytic Reduction (SCR)

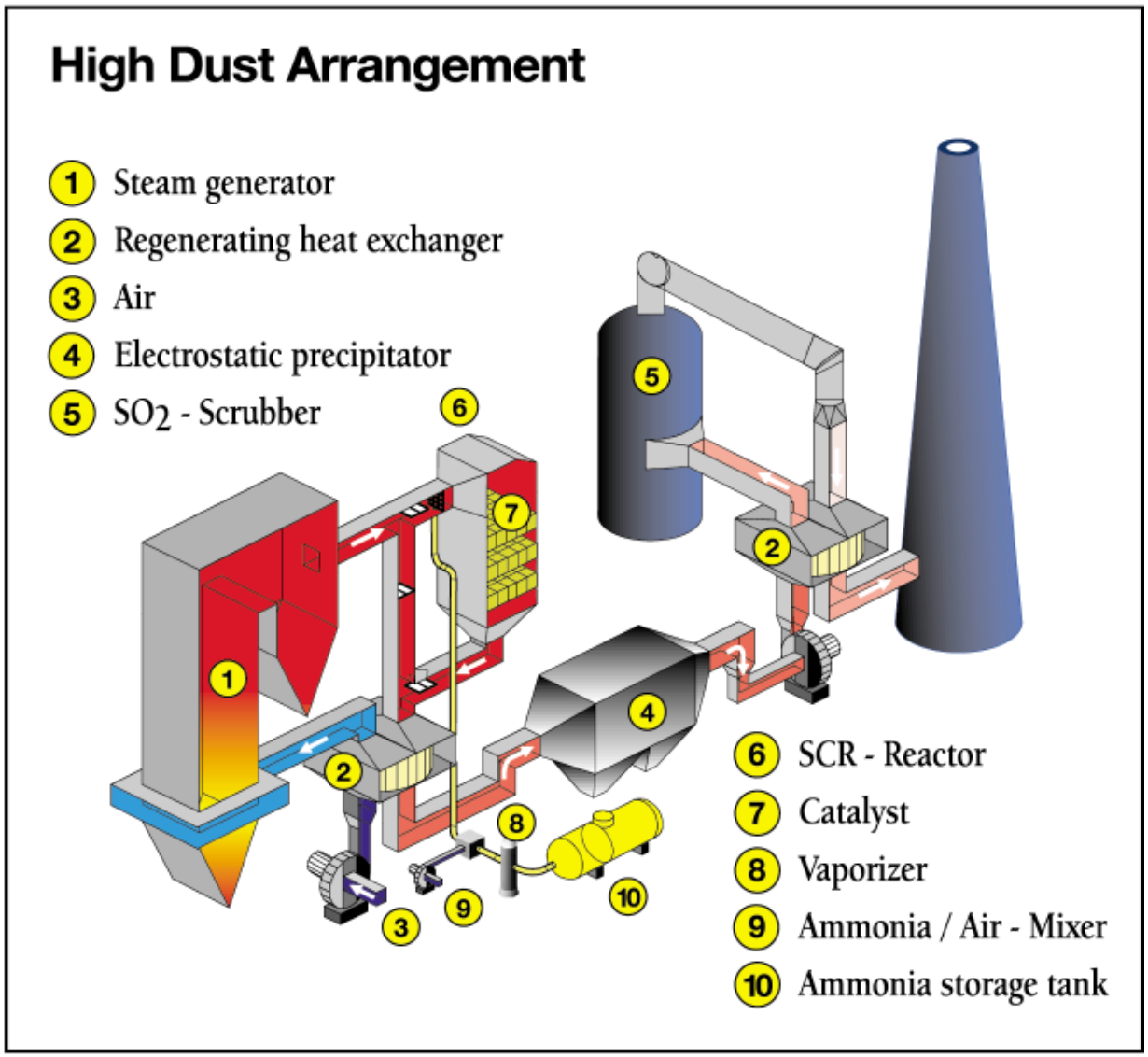
The lowest NOx emission levels from coal-fired utility boilers are typically achieved by installing and operating selective catalytic reduction (SCR) technology. In the SCR process, the gas stream is passed through a catalyst bed in the presence of ammonia to reduce NO_X to molecular nitrogen and water. The process is termed "selective" because the ammonia preferentially reacts with the NO_X rather than with the oxygen in the flue gas. A catalyst is used to enhance NO_X reduction and ammonia utilization at appropriate flue gas temperatures. SCR is usually applied to flue gas in the 600°F to 750°F temperature range. There are variations in the SCR process for coal-fired boilers that mostly involve locations in the flue gas path where the catalyst is placed in order to promote the desired NO_X emission reduction effect. These are described below.

A.1.3.4.1 High-Dust Selective Catalytic Reduction (HD-SCR)

For coal-fired boilers, a conventional SCR reactor utilizes readily-available catalyst materials and reagent in the form of ammonia. A conventional SCR reactor is commonly installed in a high-dust, hot-side arrangement, located between the economizer outlet and air heater inlet, where the flue gas temperature is within the desired operating range for the SCR catalyst. The conventional SCR reactor arrangement is preferred for most coal-fired applications in utility boilers because it avoids the added expense of reheating the flue gas if placed after the air heaters which cool the flue gas, and downstream of any flue gas treatment to remove acid gases. Conventional SCR technology uses an ammonia injection grid (AIG), which consists of multiple nozzles, for distributing the reagent into the flue gas at the boiler's economizer flue gas outlet.

A schematic graphic diagram for a conventional high-dust, hot-side SCR system on a boiler with a flue gas desulfurization system and stack gas reheat is provided in Figure A.1-5.

Figure A.1-5 Conventional High-Dust SCR Arrangement with FGD Scrubber Outlet Reheat



(figure copied from Wheelabrator Air Pollution Control literature)

Conventional high-dust, hot-side SCR technology has been installed on several pulverized coal and cyclone boilers firing bituminous and subbituminous coal in the United States. There are also a limited number of European SCR installations on steam electric generating units (SEGUs) firing lower grade (brown) coal. There are, however, no existing full-scale SCR installations on units that fire North Dakota

lignite. There are approximately 50 cyclone-fired units located in the states affected by EPA's NO_X SIP call. Over half of these units are planning to install conventional high-dust, hot-side SCR systems in response to the SIP call. The installation of conventional high-dust, hot-side SCR systems has been completed on approximately 22 of these units. Appendix A2 lists several conventional high-dust hot-side U.S. SCR installations on pulverized coal and cyclone-fired utility boilers, along with measured NO_X emissions. Initial data from these units indicate that conventional high-dust, hot-side SCR systems operated on suitable cyclone-fired units may be able to reduce NO_X emissions to as low as 0.07 lbs/mmBtu. Several SCR installations have been retrofit on existing cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). For cyclone coal-fired utility boilers retrofitted with SCR technology, all were originally designed to burn bituminous coal.

The EPA NO_X SIP call only applies to units in the eastern United States. There are no facilities firing North Dakota lignite in the EPA NO_X SIP call region. SCR system operation is currently only needed during the ozone season (June – September) for units installing control equipment solely to meet the EPA NO_X SIP call requirements. Limited annual operation is a significant factor with respect to SCR equipment reliability, maintenance, operational costs, and catalyst life. The demands on the SCR system are much more severe if the equipment is required to operate on a full-time, annual basis.

Two byproducts from the high-dust, hot-side SCR process are ammonia slip and SO_3:

- Ammonia Slip: Slip is ammonia that is unreacted in the NO_x emission reduction process. Maximum ammonia slip for a gas fired unit is usually 10 ppmvd whereas, on a coal fired unit, ammonia slip below 5 ppm is desired. For certain applications, this concentration can be problematic, therefore requiring more catalyst to reduce slip. Most new SCR applications have ammonia slip guaranteed at a 2 ppmvd maximum for an initial operating period.
- SO_3: Due to the composition of typical SCR catalysts, a small percentage of inherent SO_2 will be oxidized to SO_3. This oxidation can be controlled by catalyst selection and can be less than one percent. SO_2 to SO_3 oxidation must be carefully controlled to avoid creating SO_3 levels sufficiently high to raise the possibility of air heater fouling. A unit firing high-sulfur coal with SCR technology is especially vulnerable to SO_3 oxidation and ammonia slip-related fouling problems. The deposition and fouling is due to formation of solid ammonium sulfate ($(NH_4)_2SO_4$) and liquid ammonium bisulfate (NH_4HSO_4). The most important design variable is optimizing the catalyst selection and amount of catalyst that will reduce NO_X emissions, control ammonia slip, and minimize SO_2 oxidation.

Recent technology has allowed catalyst suppliers to make more rigorous and lengthy guarantees. A reasonable initial operating period for conventional catalysts in high-dust reactor arrangements on boilers firing eastern or midwestern bituminous coal is around 24,000 active operating hours (i.e. when ammonia reagent is being injected). Factors that need to be taken into account in design of a high-dust, hot-side SCR application that affect the need for catalyst replacement are:

- Pressure drop: The amount of restriction to flue gas flow through the SCR inlet, ammonia injection grid, SCR reactor, and downstream ductwork directly increases induced draft fan horsepower required to maintain adequate boiler draft. This is an important parameter to consider and minimize during the design stage. Pressure drop is a function of the average and maximum SCR reactor duct velocities, the amount of restriction caused by flow distribution correction devices (baffles or vanes), and the number and geometrical aspects of the catalyst layers. Many retrofit SCR installations require a booster fan or upgraded induced draft fan to overcome the added flow resistance. This increases operating cost for the increase in auxiliary power consumption and loss of saleable electric power. The type and pitch of the catalyst are factors most influential in determining the amount of pressure drop.
    - Catalyst type: The most common types or forms of catalyst material are honeycomb or plate. The former offers more surface area per volume, but can be more restrictive and prone to pluggage from ash deposits. The latter is usually less restrictive but requires more catalyst per layer or more layers to achieve the active surface needed to achieve the intended NO_X emission reduction.
    - Catalyst pitch: The pitch of the catalyst, a term used to describe the size of the gas path openings through the catalyst, varies depending on the manufacturer and design dust loading. Pitch is generally on the order of 5 to 7 millimeters. Potential pluggage of flow channels within the catalysts layers is therefore an issue that must be dealt with during design.
- Catalyst performance: The amount of NO_X emission reduction expected is a function of the specific activity level of the catalyst material and the amount of catalyst installed, over a given period of time. Catalyst formulation selection and features of construction have a significant impact on long-term NO_X emission reduction and subsequent costs for reagent and catalysts replacement. The frequency of catalyst replacement is influenced strongly by:
    - Catalyst erosion: Erosion of the catalyst material in coal fired units from entrained flyash or sootblowing action reduces the amount of active surface available for reacting with the reagent and flue gas, and can cause distortions in gas distribution ("channeling") through the

SCR reactor. Catalyst material is fragile and can be easily damaged. Some catalyst is provided with erosion-resistant top edges to mitigate this tendency.

- Moisture absorption: Many types of catalyst are damaged by absorption of moisture. The reactor must be kept above ambient dewpoint temperatures or protected from freezing during outages in order to protect the catalyst from moisture damage. Spare catalyst must be carefully packaged to keep it dry and must be handled delicately to prevent damage.
- Thermal degradation: The specific active elements of the catalyst surface, or the matrix structure itself upon which the catalyst material is applied, can degrade when exposed to flue gas temperatures greater than the intended design of the formulation. High flue gas temperatures within the reactor causes sintering, leading to a permanent loss of catalyst activity due to a change in the pore structure of the catalyst. Proper selection and manufacturing control of the catalyst structure and formulation can minimize thermal degradation.
- Catalyst poisoning: The loss of performance or activity of the catalyst over time can be due to chemical damage or poisoning. Two elements especially detrimental to the life of common titanium-supported vanadium pentoxide SCR catalyst are arsenic and zinc. Vanadia/tungsten-based catalysts are particularly susceptible to rapid deactivation due to gaseous arsenic poisoning. In some German SCR installations, a 50% loss of activity has been reported within 10,000-15,000 operating hours. Addition of molybdenum to a vanadia-titanium SCR catalyst on similar applications shows relative activity reductions of 20-25%. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to poisoning is not possible to restore without effective cleaning to remove the deposits, or eventual replacement.
- Catalyst fouling: The surface area potentially exposed to the reagent (ammonia) and nitrogen oxides in the flue gas can become fouled with flyash or sulfur-related compounds. The presence of excess calcium oxide in the presence of sulfur in the flue gas can form a calcium sulfate surface coating that can be extremely dense, masking the pores of the catalyst. Progressive loss of SCR NO_X reduction performance from catalyst deactivation due to fouling is difficult to restore without effective cleaning to remove the deposits, or eventual replacement.

SCR technology has been installed on numerous coal-fired utility boiler facilities around the world and there are a large number of manufacturers that market the catalysts. The question is whether SCR is a

feasible technology for a unit firing North Dakota lignite. There are serious concerns whether installation of SCR technology on a North Dakota lignite-fired unit can be successful, especially in a conventional "hot-side, high-dust" configuration. The effectiveness of the SCR process is highly dependent upon the ability of the nitrogen oxides in the flue gas being able to contact the active sites within microscopic pores of the catalyst in the presence of ammonia reagent with minimal interference from contaminants.

A recent technical paper "Ash and Mercury Behavior in SCR Catalysts When Firing Subbituminous and Lignite Coals" by the Energy & Environmental Research Center (EERC) of the University of North Dakota was published in the February 2005 issue of Fuel Processing Technology magazine[28]. This paper summarized the results of SCR slipstream testing at two PRB-fired plants and one North Dakota lignite-fired powerplant. The evaluation included determination of impacts of ash on SCR plugging and blinding. Flue gas was isokinetically extracted from the convective pass of the boiler upstream of the air heater. Pressure drop across the catalyst was measured during the initial two-month test period, and the two consecutive two-month test periods following the initial trial, while holding flue gas flow and temperatures constant. Ammonia was injected downstream of a screen, upstream of a flow straightener and air pulse section. Compressed air was injected ahead of the reactor, and was periodically pulsed to simulate sootblowing to minimize ash deposit accumulation.

This slipstream SCR testing examined the significance of ash accumulations on SCR catalyst on both the macroscopic and microscopic levels. Very small flyash particles were found bonded together by a matrix of sodium-, calcium-, and sulfur-rich materials, likely in the form of calcium sulfate. North Dakota lignite coal contains many alkali and alkaline-earth elements, and sulfur. The firing of lignite coal which produces fine (less than 5-µm diameter) flyash particles creates conditions that enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

As posted on Electric Power Research Institute Inc.'s (EPRI's) website regarding the impact of coal type on SCR catalyst life and performance, a recent EPRI study[29] produced field data analyzed from an "In-Situ Mini SCR Reactor" system installed in a typical "high-dust" location at seven different test sites, including four firing PRB coal, one firing Texas lignite, one firing high-sulfur eastern bituminous coal, and one firing a PRB/eastern bituminous coal blend. The PRB/bituminous coal blend test was performed at AmerenUE's Sioux Station, on one of the two 500 MW cyclone-fired boilers. This study found that the cyclone unit firing the PRB/bituminous coal blend exhibited the fastest rate of catalyst activity degradation. Also, the higher deactivation rates seen at this site were due to economizer exit flue gas

temperatures being significantly higher than at the other sites. A comparison of the Texas lignite and one of the PRB-fired sites with two different catalysts, deactivation was more a function of trace elements in the flue gas and flyash than the specific catalyst type or formulation.

North Dakota lignite produces an ash that is very sticky and creates severe ash deposition problems. There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite. A technical assessment was conducted for the installation of SCR technology on a North Dakota lignite unit. In order to further evaluate the feasibility of installing a conventional SCR system on a North Dakota lignite fired unit, the Energy & Environmental Research Center (EERC) at the University of North Dakota was consulted. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash.

Technical difficulties and anticipated operating problems that are unresolved with respect to installing conventional SCR technology at Milton R. Young Station include the impacts of erosion, severe ash deposition, and "popcorn ash" on the catalyst. According the EERC's study (see Appendix B), "the most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium-calcium-magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency". For these reasons, application of available conventional high-dust SCR technology is considered technically infeasible for Milton R. Young Station Unit 1 and Unit 2 boilers. These concerns can be divided into four categories. Each category is addressed below. An explanation of the factors that make conventional SCR technology infeasible for these boilers follows:

1. Ash Deposition: North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. This fuel produces ash with severe deposition characteristics that are not typical with other coals. When exposed to the heat of the combustion process inside the cyclone burners, the majority of the fuel ash becomes molten and flows into the bottom of the furnace. A significant portion of the fuel ash is entrained into the flue gas exiting the cyclone barrels at high velocity, where it comes into contact with the lower furnace waterwalls. The portion that is carried with the rising flue gas cools and some is deposited on heat transfer surfaces in the upper furnace and boiler convection pass. Ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite. The problem is so severe at Milton R. Young that the Unit 2 boiler must be shut down at 80 to 90-day intervals to

allow for cleaning of ash deposits from the boiler heat transfer surfaces in order to restore reasonable furnace exit gas velocities and temperatures.

Sodium is a significant contributor to the "stickiness" of the ash produced from firing North Dakota lignite. Sodium content of the lignite ash averages approximately 4.4%, and can nearly double this value for some of the lignite produced from the Center mine. PRB coal typically averages around 1.5% sodium content. Boilers firing North Dakota lignite typically have a 2.5% higher heat rate (million Btu per kilowatt of electric generation) than a typical boiler firing PRB coal, thus requiring more heat input and firing more fuel per megawatt of electricity output. A cyclone boiler firing North Dakota lignite also converts approximately 50% of the fuel ash to flyash, compared with a 35% conversion rate for PRB coal-fired cyclone boilers. Overall, this results in an amount of sodium emitted from a cyclone boiler firing North Dakota lignite of approximately 7.3 lbs/MW-hr compared with 0.9 lbs/MW-hr for a PRB-fired cyclone boiler.

The catalysts in coal-fired boiler SCR reactors are highly susceptible to ash deposition. In a typical conventional high-dust SCR reactor, the flue gas typically passes through two to four layers of catalyst modules. The catalyst modules have numerous narrow passages to provide intimate contact between the flue gas, ammonia and catalyst. The clearance (pitch) in these passages is typically 6-10 millimeters. A typical catalyst layer is approximately 1 to 1.5 meters deep. The catalysts in coal-fired boiler SCR reactors must be cleaned frequently using soot blowers and/or sonic horns. This is true even on units firing fuels that do not produce a sticky ash that contributes to ash deposition. Ash deposition on the catalyst in a high-dust SCR application would be severe for a unit firing North Dakota lignite.

Sulfur in the coal is oxidized during excess air combustion to form sulfur dioxide (SO_2), and a small amount of sulfur trioxide (SO_3). Some of the ammonia-based reagent injected upstream of the SCR reactor will combine with SO_3 to form ammonium bisulfate. The catalyst in the SCR reactor will also oxidize a portion of the SO_2 to SO_3. Excess unreacted ammonia reagent carryover ("ammonia slip") from the SCR reactor will also react with these sulfuric acid compounds in a similar fashion. The deposition characteristics for a unit burning North Dakota lignite will create difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst, and increase the probability that the air preheater downstream and flue gas ductwork will be prone to accumulations which could be severe. High-dust SCR performance and catalyst life

will be severely impacted. It is anticipated that a high-dust SCR's catalyst life will be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement.

Hot-side air preheaters are susceptible to fouling. Tubular air pre heaters originally supplied with all cyclone boilers also tolerate moderate dust loadings, since their height and size make them difficult to maintain cleanliness. Leak tightness of the air preheater is important on cyclone-fired boilers with relatively high forced draft fan discharge (combustion air supply) pressures. A high-dust SCR installation will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

2. "Popcorn Ash": A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. Boilers firing North Dakota lignite have severe problems with ash deposition on boiler surfaces. North Dakota lignite has a high propensity to form deposits on the boiler's furnace and convection pass fireside surfaces. For lignite-fired units, the boiler's heat transfer surfaces must be cleaned by sootblowing and other methods (e.g. water lances) frequently to maintain satisfactory boiler operation. Some of the removed deposits released by the cleaning action within the boiler and convection passes form "popcorn ash", which will be entrained in the flue gas. Carry over of boiler ash deposits will contribute to pluggage of the "popcorn ash" screen ahead of the top layer of SCR reactor catalyst. This can cause distortions in gas distribution ("channeling") through the SCR reactor, which will aggravate erosion in the high velocity areas and ineffective performance of the catalyst.

3. Temperature: A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units is catalyst operating temperature. The performance of any SCR catalyst is highly dependent on the temperature of the flue gas passing through the reactor. Typically, a temperature of 600 – 750 degrees F is required to obtain satisfactory operation of an SCR reactor. Operation of commonly supplied catalyst suitable for a high-dust SCR reactor at temperatures above 750 degrees results in severe and rapid deterioration of the catalyst and SCR reactor's NO_X emission reduction performance. For bituminous and sub-bituminous coal-fired units, boiler flue gas passing between the economizer outlet and air heater inlet is generally

within a temperature range acceptable for conventional SCR catalysts without additional heating or cooling of the flow stream.

North Dakota lignite-fired cyclone boilers, including those at Milton R. Young Station, have high temperatures at the economizer's flue gas outlet by design. The highest gas temperatures downstream of the convection pass economizer sections and upstream of the air heater inlets in Milton R. Young Unit 2's boiler are much higher than 750 degrees.

High gas temperatures at the air heater inlet are required to produce the high air temperatures (700°F) needed for the pre-combustion lignite drying system, along with primary and secondary combustion air supplied to the cyclones. Such air preheater arrangements and capabilities have been taken into account in the design of the North Dakota lignite-fired cyclone boilers. Reducing this high gas temperature to accommodate conventional catalysts for a conventional high-dust SCR reactor would result in pre-combustion air temperatures that are too low to provide satisfactory drying and rapid ignition of the high-moisture fuel. This will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, it is not feasible to modify the Milton R. Young Unit 2's boiler to operate with the lower economizer outlet flue gas temperature.

Catalysts for a conventional high-dust, hot-side SCR system have not been installed nor successfully demonstrated in a full-scale installation of an operating solid fuel-fired unit that are designed to continuously operate at the high temperatures (above 750 degrees F) that exist between the convection pass economizer and air heater on the Milton R. Young Unit 2's boiler.

4. Erosion: A final consideration on whether hot-side, high-dust SCR technology can be successful on a North Dakota lignite-fired unit is the potential for erosion of the SCR catalyst. North Dakota lignite supplied from the Center mine has an average fuel ash content of 10.5%, and can have an ash content up to 25.5 percent. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MW-hr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream can result in physical erosion of the catalyst. In addition, effective on-line cleaning of the

high-dust catalyst will likely require steam or compressed air sootblowing. Cleaning cycles of the catalyst will be required much more frequently than a typical conventional SCR installation due to the ash deposition characteristics of the North Dakota lignite and the expected buildup and pluggage resulting from the carry over of "popcorn ash". Frequent sootblowing of the catalyst to remove fouling deposits and ash accumulations will contribute to erosion and decreased catalyst life. There is some European experience with high ash brown coals that catalyst manufacturers will be able to draw upon. This experience, however, will not be directly applicable to these United States units because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

The EPA's NSR Manual states that for a technology to be feasible it must "available and applicable". SCR technology is an available technology which has been installed on numerous powerplant facilities around the world and there are a large number of manufacturers that market the technology. The question is whether SCR technology is "applicable" for a unit firing North Dakota lignite.

In accordance with EPA's NSR Manual, a technology is "applicable" if it has been installed on a "similar unit". Hot-side, high-dust SCR technology has been retrofit on coal-fired units featuring cyclone boilers. However, there are no SCR installations in operation or planned on units that include cyclone burners firing North Dakota lignite with severe slagging and fouling tendencies combined with such high boiler economizer outlet gas temperatures (over 750°F) required for high-moisture fuel pre-drying systems and tubular air preheaters.

The EPA's NSR Manual also states a technology may be determined to be not applicable if "a technical assessment considering physical, chemical and engineering principles and/or empirical data showing the technology would not work on the emissions unit under review or that unsolvable technical difficulties would preclude the successful deployment of the technique." In this SCR technology application, it appears that a facility utility powerplant firing North Dakota lignite would experience extended time delays or be required to devote significant internal resources and engage outside research, followed by extended field trials to learn how to apply a conventional high-dust, hot-side SCR technology on a such a fuel source.

Based upon this technical assessment that looked at the various design and operational issues associated with the installation of hot-side, high-dust SCR technology on a North Dakota lignite-fired steam-electric

generating unit, this control option is considered technically infeasible for Unit 2's boiler at Milton R. Young Station.

A.1.3.4.2 Low-Dust Selective Catalytic Reduction (LD-SCR)

Low-dust SCR (LD SCR) technology could potentially be applicable to North Dakota lignite-fired boilers for NOx emission control. Low-dust SCR refers to the location of the SCR system downstream of a particulate collection system, such as an electrostatic precipitator or a fabric filter. If the low-dust SCR is downstream of a hot-side electrostatic precipitator and prior to the air preheater, flue gas reheating is unnecessary. This has been the prevalent form of alternative retrofit SCRs in the United States for coal-fired utility boilers. There are ten known hot-side low-dust SCR installations (without flue gas reheat) operating in the United States as of July 2005. These are listed in Appendix A2. If applied to MRY Station Unit 2's boiler, the low-dust SCR equipment would be downstream of a cold-side electrostatic precipitator; flue gas reheat prior to the LD SCR reactor inlet would be required for proper NO_X emission reduction performance.

For a cold-side LD SCR, the ESP outlet flue gas passes through a low-dust gas-to-gas heat exchanger (LD GTG-HE), prior to passing to the low-dust SCR reactor. After the LD GTG-HE, the flue gas will travel through the new duct, receiving hot flue gases from a direct-fired gas burner or set of high-pressure steam coils, leading to an ammonia injection grid, turning vanes and then into the LD SCR reactor. The flue gas entering the inlet to the LD GTG HE is expected to be near the air heater outlet temperature (330-340°F) in a cold-side LD SCR application. The supplemental heat added downstream of the LD GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the LD SCR NO_X–ammonia reaction to be effective. The LD gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the FGD system (if applicable) and stack. The use of rotary regenerative-type heat exchangers has been applied in European LD SCRs. With this design, there will be leakage between the untreated and treated gas streams such that the exit flue gas has higher NO_X concentrations than the LD SCR outlet gas. The direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the LD SCR reactor. The LD SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

The factors that make low-dust SCR technology infeasible for the Milton R. Young Station Unit 2's boiler with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: An existing electrostatic precipitator upstream of a low dust SCR reactor will still expose the catalyst to the acid gas content and fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the LD-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the low-dust SCR catalyst life will still be unacceptably short. The small particle flyash passing into the reactor will be sufficient to cause pluggage of the catalyst pores, resulting in deactivation of the catalyst. The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of a low-dust SCR. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. One catalyst vendor's has stated it is their "experience that low-dust catalyst is more difficult to clean than that from high-dust"[30]. Low-dust SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.
- Site Space Constraints: The installation of a low-dust SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A low-dust SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the SCR reactor outlet to the flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the cold-side low-dust SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where low-dust SCR systems must be located. The situation is particularly severe for Unit No. 2. Equipment that impacts the feasibility of installing a low-dust SCR system on Units 1 and 2 includes the Unit 2 absorbers, Unit 2 flue gas desulfurization (FGD) dewatering equipment, fly ash handling equipment, fuel storage and transfer equipment, stacks, fans and ductwork. It would be extremely

disruptive to the continued economic operation of both boilers to relocate all the mentioned equipment to create space for the low-dust SCR systems at the M.R. Young Station. Stacks, fans and ductwork and the Unit 2 FGD system cannot be readily relocated due to adjacent structures and the need to continue operation while constructing the retrofit installations. The fuel handling equipment includes a coal storage barn and the main conveyors supplying lignite to the units. Relocating the coal handling equipment currently occupying space needed for the low dust SCR systems would be quite difficult given the site configuration. It is conceivable that the fly ash equipment located west of Unit 1 could be relocated to provide some of the space needed for the low-dust SCR. However, the availability of this space is doubtful, since avoiding the likelihood of severe SCR catalyst sulfate fouling will require a new Unit 1 FGD system to be installed. If a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a low-dust SCR system.

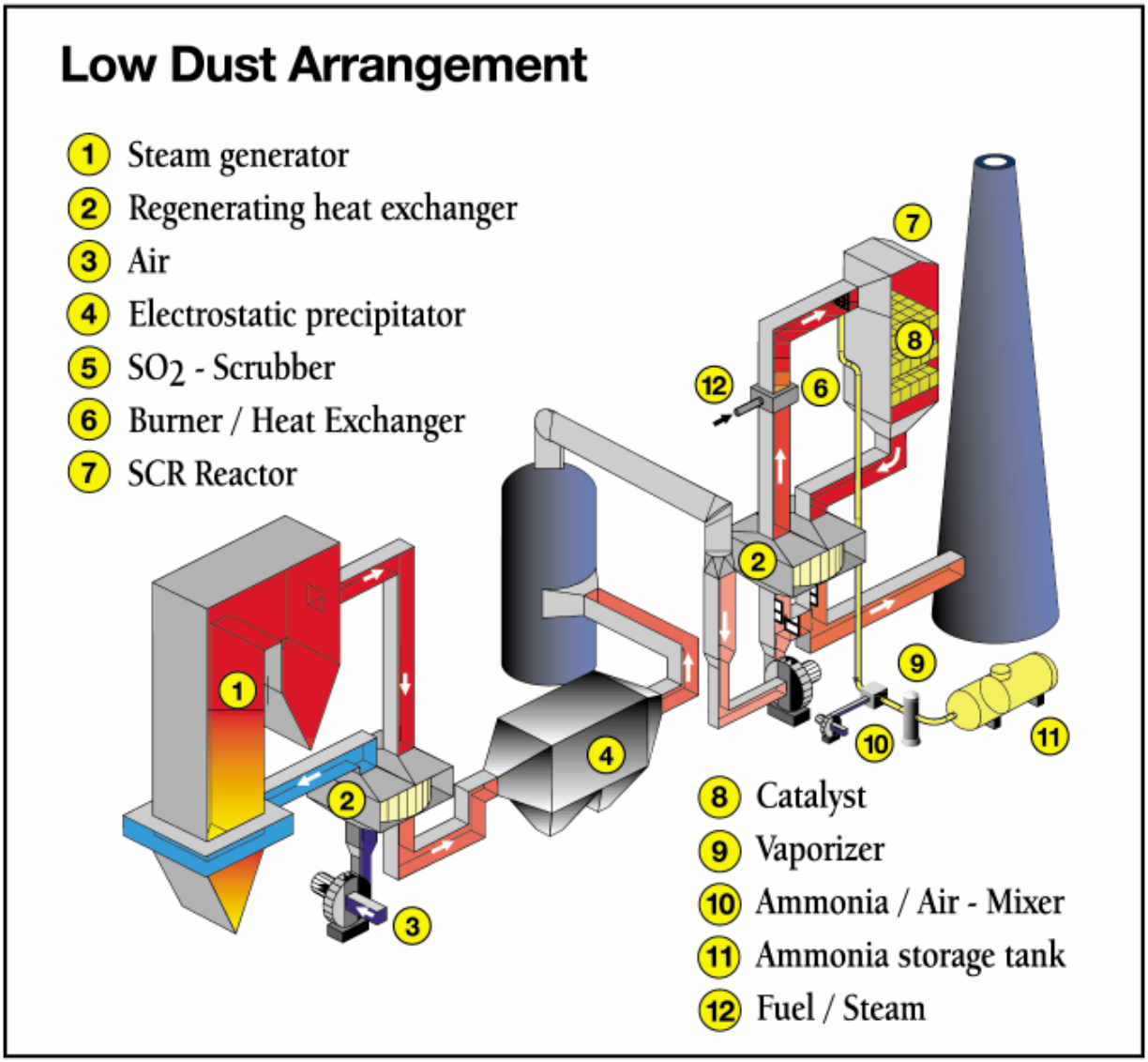
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of low-dust SCR technology on a North Dakota lignite-fired steam-electric generating unit, this control option is considered technically infeasible for the Milton R. Young Station Unit 2's boiler.

A.1.3.4.3 Tail-Gas Selective Catalytic Reduction (LD-SCR)

A tail-gas (TG) SCR is a low-dust SCR system where the LD SCR reactor is installed downstream of a FGD scrubber. The FGD outlet flue gas passes through a gas-to-gas heat exchanger (GTG-HE), prior to passing to the tail-gas SCR reactor. The flue gas will travel through new or modified ductwork leading to an ammonia injection grid, turning vanes and then into the TG SCR reactor. The TG SCR reactor, GTG HE, and connecting ductwork will increase the pressure drop through the flue gas system. This normally requires an induced draft fan upgrade or a booster fan addition.

A schematic graphic diagram for a low dust arrangement is shown in Figure A.1-6.

Figure A.1-6 Tail-Gas SCR Arrangement



(figure copied from Wheelabrator Air Pollution Control literature)

The flue gas from a wet FGD scrubber outlet entering the inlet to the gas-to-gas heat exchanger is expected to be near the saturation temperature (140°F) in a cold-side TG SCR application. The supplemental heat added downstream of the TG GTG-HE can be supplied from high temperature steam coils (indirect heat exchange) or directly from natural gas-fired duct burners. The flue gas must be heated to a minimum of approximately 600°F for the TG SCR NO_X– ammonia reaction to be effective. The TG gas-to-gas heat exchanger is used to recover part of that supplied heat, prior to exhausting to the stack. With a rotary regenerative-type gas-to-gas heat exchanger, there will be internal leakage between the untreated and treated gas streams such that the stack exit flue gas has higher NO_X concentrations than the

TG SCR reactor outlet gas. Using direct-fired flue gas reheat duct burners will also create NO_X emissions, which will add to the amount emitted from the boiler and input into the TG SCR reactor.

There is limited technical information published in English for coal-fired steam-electric generating units (SEGU) with low-dust/tail-gas SCR technology in applications requiring full flue gas reheat prior to the reactor inlet. There is no experience with TG SCR on eastern bituminous, western subbituminous coal or lignite-fired SEGUs in the United States. As of 1997, there was one low-dust/tail-gas SCR on a 220 MWe German cyclone-fired boiler with a 1988 retrofit installation. This boiler was reported to be operating without combustion controls or FGD, burning low sulfur, low ash, moderate moisture bituminous coal with an average pre-SCR NO_X emission rate of approximately 1.07 lb/mmBtu, and was meeting a 30-day rolling average emission limit of approximately 0.16 lb/mmBtu (85% reduction)[31].

Milton R. Young Station Unit 1 does not currently incorporate any flue gas desulfurization equipment, which would place the reactor catalyst in a low-dust SCR configuration, which is considered infeasible when burning North Dakota lignite. A new FGD system for Unit 1 would be required in order to avoid or significantly reduce expected sulfate formation within the catalyst and gas-to-gas heat exchanger when combined with ammonia required for the TG SCR. Unit 2 currently employs a wet scrubber which currently treats approximately 83% of the total flue gas flow from the boiler. Flue gas reheat is currently provided by the FGD bypass (i.e. warm, untreated flue gas is mixed with the cool scrubbed gas).

The factors that make tail-gas SCR technology infeasible for both Milton R. Young Station boilers with existing particulate collection via electrostatic precipitators are as follows:

- Catalyst Fouling and Deactivation: The TG SCR reactor downstream of a flue gas desulfurization (FGD) scrubber will still be susceptible to fouling, contamination, pluggage, and catalyst deactivation.
    - An existing electrostatic precipitator (ESP) upstream of a tail-gas SCR reactor will still expose the catalyst to fine particulate containing trace metals and the high alkali mineral content of the entrained lignite flyash not removed by the ESP upstream. Although the total amount of flyash carryover into the TG-SCR reactor is greatly reduced compared with a high-dust design, it is anticipated that the tail-gas SCR catalyst life will still be unacceptably short.
    - The firing of lignite coal produces fine (less than 5-µm diameter) flyash particles, which are also least likely to be removed by the existing particulate collection equipment (e.g. ESP) upstream of

a TG-SCR. Flue gas with entrained fine particulate matter, including some involving sodium and sulfur-containing compounds, will pass through and be carried-over from a wet FGD scrubber. This treated gas stream will carry sodium sulfate particles, formed by homogenous condensation after exiting the boiler and not removed by the FGD system, into the catalyst layers of the TG-SCR reactor. A dry FGD system followed by a fabric filter upstream of the TG-SCR will still allow sulfur-bearing flue gas and fine particles to enter the catalyst. There is serious concern that fine particles passing into the reactor will accumulate within the catalyst, and be resistant to removal by conventional sootblowers and other cleaning technologies. This creates conditions that allow these small flyash particles to enter the pores of the catalyst, react with SO_2 and/or SO_3 in the flue gas, and form sulfates which bind other ash particles into a matrix of sodium-, calcium-, and sulfur-rich materials (likely in a form of calcium sulfate). Once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. Catalyst that is exposed to such conditions will be ineffective at maintaining adequate activity upon which the performance of the TG-SCR's NO_X removal is based.

- These entrained particles will also deposit on the gas-to-gas heat exchanger ahead of the tail gas SCR reactor. This deposition will decrease heat transfer between the incoming (cool) flue gas and the outgoing (warm) flue gas. Sootblowers could be used to remove the accumulated deposits from the GTG HE, but the SCR reactor could still suffer catalyst fouling from the deposits dislodged from the GTG HE cleaning cycle becoming reentrained in the reheated flue gas. Tail-gas SCR performance and catalyst life could be severely negatively impacted. Shortened lifespans of the TG SCR catalyst will require premature, extended, frequent outages for replacement.

- Site Space Constraints: The installation of a tail-gas SCR system with flue gas reheat requires a substantial amount of space for installation and operation. A tail-gas SCR system will likely use a regenerative gas-to-gas heat exchanger (reheater) to raise the temperature of the flue gas at the SCR inlet. A GTG HE will transfer heat from the flue gas at the TG SCR reactor outlet to the scrubbed flue gas entering the SCR reactor in order to minimize the supplemental SCR energy usage. The gas-to-gas heat exchanger dictates the footprint of the TG SCR system. Space is required for the GTG HE and for ductwork in and out of the reheater. Sufficient free space around the reheater and SCR system is also required for maintenance.

  The area around Units 1 and 2 at the M.R. Young station is extremely congested in the areas where TG SCR systems must be located. A flue gas desulfurization system will be needed for Unit 1 in the

near future to comply with the Consent Decree. When a new FGD system is installed for Unit 1, the FGD system would need to occupy the space that can be made available by relocating ash handling equipment. This space subsequently would not be available for a tail-gas SCR system. Thus, the availability of adequate space for all the new FGD and TG-SCR system equipment and structures while accommodating existing coal storage and handling needs for both existing boilers at Milton R. Young Station is doubtful.

The challenges for installation of new ductwork, SCR reactors, and flue gas reheating equipment and the lack of pertinent experience with all aspects of design, construction, operation and maintenance of tail-gas SCRs on such high-fouling coals as North Dakota lignite are significant. The flue gas conditions that the TG-SCR catalyst will be exposed to will create unresolvable fouling and blinding that makes successful application of this technology difficult, expensive, and uncertain.

The risk of failure and uncertainty of successfully applying low-dust, tail-gas SCR technology to a cyclone-fired utility powerplant firing North Dakota lignite appear substantial.

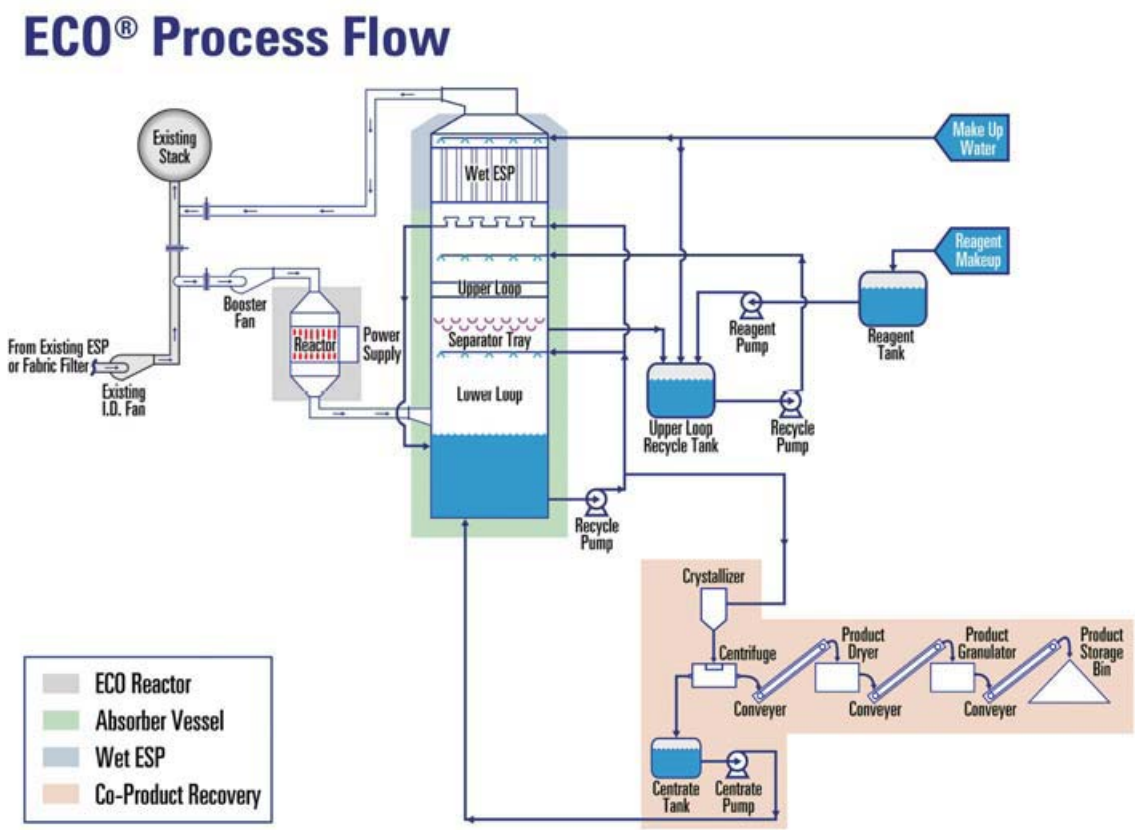
Based upon a technical assessment that looked at the various design and operational issues associated with the installation of tail-gas SCR technology on a North Dakota lignite-fired steam-electric generating unit including a cyclone boiler, this control option is considered technically infeasible for the Milton R. Young Station Unit 2's boiler.

A.1.3.5 Electro-Catalytic Oxidation (ECO®)

Powerspan's Electro-Catalytic Oxidation (ECO®) system is a multi-pollutant technology designed to control emissions of NO_X, SO_2, fine particulate, mercury and certain Hazardous Air Pollutants (HAPs). The ECO® process has two main process vessels, a barrier discharge reactor, and a multi-level wet scrubber. The barrier discharge reactor utilizes an electrical discharge to create oxygen and hydroxide radicals which then react with NO_X, and other constituents in the flue gas stream. The flue gas stream then enters the bottom of the ECO® scrubber where the lower loop cools the flue gas and removes a portion of the acid gasses [sulfur trioxide (SO_3), sulfuric acid (H_2SO_4), nitric acid (HNO_3)] produced in the barrier reactor and oxidized metals such as mercury, with a low pH aqueous ammonia reagent. A second scrubbing loop is then entered where additional SO_2, NO_2, acid gases and oxidized metals are removed with an aqueous ammonia reagent, though at a higher pH. Above the second scrubber loop is an absorber section for absorbing fugitive ammonia from the first and second scrubbing loops. The final

step in the ECO® process is a wet electrostatic precipitator (WESP) which collects fine particulate matter, aerosols generated in the scrubber and additional mercury. An updated schematic process flow diagram for the basic ECO® process is shown in Figure A.1-7.

Figure A.1-7 – Electro-Catalytic Oxidation (ECO®) Process Flow Diagram
(copied from http://www.epa.gov/appcdwww/aptb/EPA600R03110.pdf)



Powerspan has been involved in an extended ECO® process demonstration using a 28 MW Commercial Demonstration Unit (CDU) at R.E. Burger Station Units 4&5. The ECO® CDU project treated a slipstream and demonstrated performance, reliability and economics for approximately one year. The demonstration program started in January, 2004. NO_X removal is stated to be up to 90% with a claimed 0.05 lb NO_X/mmBtu outlet condition achievable for the front-end of the ECO® process. Further sustained operational tests of the ECO® CDU are underway during the second and third quarters of 2005.

As this is a post-combustion multi-pollutant control technology, it is claimed that there is little sensitivity to the type boiler or burners that Powerspan's Electro-Catalytic Oxidation (ECO®) process can be

potentially applied to in order to reduce NO_X emissions. The effectiveness of this ECO® process for NO_X control has been demonstrated on a slip-stream commercial demonstration unit (CDU) associated with pulverized fuel boilers firing midwestern or eastern bituminous coal.

Powerspan's published data from the commercial demonstration unit's performance of up to 90% when treating flue gas with an inlet NO_X concentration around 0.5 lb/mmBtu. This would result in a stack NO_X emission around 0.05 lb/mmBtu.

The ECO® process has not been demonstrated in a full-scale configuration on any unit, nor tested in a slipstream configuration on any boiler that fires western subbituminous coals or North Dakota lignite. It has also not been applied to emissions from a cyclone-fired boiler. According the EPA's Draft NSR Manual, "Technologies which have not been applied to (or permitted for) full scale operations need not be considered available: an applicant should be able to purchase or construct a process or control device that has already been demonstrated in practice".

There are a number of issues with firing North Dakota lignite that make the applicability of the ECO® process technically infeasible for MRY Station boilers. These issues include:

- Deposits and Pluggage: The flyash deposition characteristics of the North Dakota lignite are extremely severe. Anything that contributes to flyash deposition and pluggage within the barrier reactor is expected to have a detrimental impact on the multi-pollutant control performance of the ECO® process, and thus could have a serious impact on MRY Station operations. The lack of demonstrated operation on treating the emissions from a boiler firing coal with a high slagging index precludes the use of the ECO® process as technically feasible for BACT as applied to a boiler firing North Dakota lignite.
- Reliability and Availability: Milton R. Young Station's major planned outages for each unit are scheduled to occur once every three years. Any NO_X control technology selected as BACT will need to operate year-round, year in and year out, on a routine basis, while performing at high levels of pollutant reduction. The Powerspan ECO® system is a new technology and is not as highly developed as other more common NO_X and SO_2 control technologies such as SCR or SNCR plus wet or semi-dry flue gas desulfurization (FGD). It is expected to require a full-time, full-scale application with sustained continuous operation to confirm levels of currently demonstrated reliability and availability from the ECO® CDU are acceptable to meet the

expectation of infrequent major outages over long time periods while maintaining high levels of control.

There are additional factors that make the application of the ECO® process potentially more difficult than other established emission control technologies available for coal-fired powerplants:

- There is a lack of experience with the ECO® downstream ammonia scrubber's coproduct crystallization and granulization equipment design, operation, and maintenance, which was not included with the initial commercial demonstration unit. The coproduct stream that would normally feed into the crystallization and granulation processes was collected and transported offsite for this process step during CDU operation. Because crystallization and granulation of ammonium sulfate from an ammonia scrubber solution is not a new technological process, this was not considered a technical feasibility deficiency. For instance, the Dakota Gasification Company (DGC) in Beulah, ND currently operates an SO_2 scrubber utilizing ammonia as a reagent. Following the generation of ammonium sulfate, DGC crystallizes and granulates a fertilizer product on site. However, at MRY Station, considerable costs would be incurred for interim storage and shipment of the ECO® process scrubber's liquid bleedstream until sufficient experience has identified and eliminated potential failures and repairs for the crystallization and granulation equipment should it prove to be unreliable.

- Size of the barrier reactor: Powerspan recently indicated that they would scale the reactor for optimum cost and space arrangement based upon lessons learned from the CDU plant operation. The number of individual passages within a barrier reactor sized for either of MRY Station boilers' maximum flue gas flow and gas stream constituents is expected to require a cross-sectional area comparable to half of a large electrostatic precipitator. Although this has not been closely examined for all aspects of design, construction, operation and maintenance, the amount of physical space required to hold the barrier reactor and inlet and outlet ductwork is believed to not be available for potential retrofit to MRY Station units. Site space constraints are considered to be a barrier to technical feasibility for potential application of the ECO® process at Milton R. Young Station for Unit 1 and Unit 2's boilers.

- Additional station auxiliary power consumption: The barrier reactor, plus the ammonia scrubber and wet electrostatic precipitator additions by an ECO™ system, require an increase in station

auxiliary power consumption. For NO_X control, this includes more horsepower required by the booster fan needed to compensate for the flue gas pressure drop created across the barrier reactor. It also includes the power consumed by the electrodes of the barrier reactor itself.

Because of the technical feasibility issues and lack of commercial availability and full-scale experience, especially on such high fouling coals, the ECO® system was considered technically infeasible as a BACT alternative for Milton R. Young Station for Unit 2's boiler.

A.1.4 "Layered" NOx Reduction Technologies

Many of the NO_X emission reduction technologies which involve furnace or convection pass areas for their introduction into the flue gas stream have been, or can potentially be, applied in combinations so as to result in an overall higher level of removal. Separated overfire air, various types of fuel reburn, and various forms of SNCR could potentially be combined in series to reduce NO_X emissions prior to boiler's flue gas exit. However, all the possible NO_X control technology combinations have not been installed on coal-fired powerplants, so actual feasibility of some combinations have not been demonstrated as viable, particularly in consideration of the special challenges posed by cyclone boilers firing lignite coal.

A.1.4.1 SOFA Combined With Other NO_X Reduction Technologies

Separated Overfire Air can be favorably combined with every other method in order to reduce the amount of reagent or reburn fuel required to achieve the resulting level of NO_X emission reduction. Some control technologies, especially conventional fuel reburn systems, require overfire air to complete the combustion of the staged fuel admitted to the upper furnace. Fuel lean gas reburn can be applied with or without SOFA, as this limited amount of staged fuel is introduced into an oxygen-rich atmosphere downstream of the cyclone burners and any overfire air injection points.

A.1.4.1.1 SOFA with SNCR

Selective non catalytic reduction technologies are post-combustion, in-furnace NO_X control alternatives that have been installed in numerous boilers of various designs, fuel types, with and without overfire air. It is usually advantageous to apply overfire air so that the amount of chemical reagent consumption can be minimized in order to achieve the targeted NO_X emission rate from the boiler outlet.

Tests at Conectiv's B.L England Station (Units 1 and 2) demonstrated that SNCR can decrease NO_X emissions as much as 31% at full load, from 0.55 to 0.38 lb/mmBtu, over and above the reduction possible from overfire air alone (approximately 60% drop, from 1.3 to 1.4 down to 0.55) in full operation. This is an overall NO_X emission reduction of 72% from pre-retrofit baseline[24].

SNCR can be applied alone or combined with either the basic or the advanced forms of separated overfire air (ASOFA) on MRY Station boilers. Air-staging the cyclones with the use of separated overfire air to further complement combustion NO_X reduction is an optional part of this technique. However, as previously explained in the discussion of SOFA alternatives, this will risk slag "freezing" in the barrels and lower furnace. Estimated NO_X emission rates for using SNCR techniques with North Dakota lignite considered published levels achieved by cyclone-fired units firing western subbituminous coal, and vendor estimates. SNCR with ASOFA is expected to reduce NO_X emissions approximately 32.6% below NO_X levels predicted for ASOFA operation, and potentially 58% overall from current baseline level for the MRY Station Unit 2 boiler with ammonia slip limited to approximately 5 ppmvd. This highest performing basic SNCR system is potentially able to achieve a NO_X emission rate of 0.330 lb/mmBtu, when combined with the advanced form of SOFA on MRY Station Units 2 boiler during operation at the pre-control baseline (near MCR load). These levels of NO_X reduction depend on the advanced form of separated overfire air technique to achieve the expected NO_X reduction percentages when applied to lignite-fired cyclone boilers.

Another form of SNCR is combined with separated overfire air. This is currently being marketed commercially as "Rotating Mixing" (Rotamix). In the United States' utilities industry, this has only been applied to pulverized coal-fired boilers. It is different than basic SNCR in that it includes a hot air booster fan and a small ambient air fan, and injects the ammonia (or urea) reagent into the high-pressure overfire air flow stream ahead of the ROFA nozzles' outlets. This mixture is imparted into the boiler in an offset fashion from opposite sides of the furnace at high velocities, with multi-port nozzles located at high elevations relative to the top burner row. This vendor (Mobotec USA) claims that Rotamix (rotating opposed fire air or ROFA + SNCR) helps to distribute the reagent across the furnace cross section, which maximizes in-furnace NOx reduction while minimizing negative impacts on carbon monoxide and flyash unburned carbon. Three tangentially-fired utility boilers burning eastern bituminous coal or Illinois bituminous coal were retrofitted with Rotamix, each achieving a NO_X reduction of approximately zero to 55 percent beyond the levels produced by ROFA alone, from pre-SNCR baselines of 0.22 to 0.28 lb/mmBtu down to 0.10 to 0.23 lb/mmBtu without low-NO_X burners[4,32,33,34].

While this variation of SNCR combined with separated overfire air could potentially be applicable to cyclone boilers, it has not been marketed to serve such applications. Since cyclone boilers do not require the addition of hot air booster fans for SOFA, and optimum injection locations for both SOFA and SNCR reagent may not coincide, Rotamix may not perform as well as, or significantly better than, a well-designed combination of conventional SOFA and SNCR. This technique is not distinct enough from basic SNCR from functional and air-staged cyclone NO_X reduction performance standpoints to warrant individual consideration for Milton R. Young Station boilers. Because of a lack of cyclone-fired boiler experience with ROFA and Rotamix, the latter was considered infeasible and thus was not included in the control effectiveness and cost-effectiveness sections of the main report.

A.1.4.1.2 SOFA with RRI

Rich Reagent Injection must be used in an oxygen-deprived atmosphere in order to effectively reduce nitrogen oxide emissions. This requires air-staged cyclones and separated overfire air operation.
The NO_X emission reduction reagent injection for RRI processes must be precisely located and carefully controlled to be effective. Operation outside of the required operating ranges can even result in increased NO_X emissions. Extensive computational fluid dynamic (CFD) simulations are needed to determine the optimum injection points. Boiler operating conditions will change with unit load and varying fuel characteristics. The RRI process control systems must be able to adjust for these changing conditions.

RRI has the potential to provide a moderate degree of NO_X reduction on coal-fired boilers. Data from B.L. England and Sioux plants show this technology can reduce NO_X emissions between zero and 39 percent beyond the amount attributable to overfire air system operation[23,24,25,26,27]. During initial demonstration testing of RRI at Ameren's Sioux Unit 1 boiler, a 500 MW unit firing a blend of PRB and midwestern bituminous coals (without SNCR), with SOFA in August 2001 at a lower furnace SR of approximately 0.99, NO_X emissions were reduced approximately 55% to 0.55 lb/mmBtu w/ SOFA only, with zero to 15% additional NO_X reduction from RRI (down to 0.47 lb/mmBtu) with zero ammonia slip[25]. Results of this initial RRI testing at Sioux plant were poor at cyclone stoichiometric ratios close to 0.99 because inconsistent, sporadic, and non-repeatable NO_X emissions reductions between zero and 15% were measured. Subsequent RRI testing at Sioux Unit 1 in March 2002 with SOFA at an average cyclone stoichiometric ratio around 0.95 showed NO_X emissions reduction of 29 percent (down to 0.27 lb/mmBtu) beyond those achieved with a modest amount of cyclone air-staging with SOFA (68% drop down to 0.38 lb/mmBtu from SOFA alone), for an 80% overall decrease from uncontrolled baseline; RRI CFD model

predictions for these conditions were NO_X emissions reduction of 31% with FGR and 37% without FGR operation. Tested NO_X emissions with RRI+SOFA in 2002 were with a reagent normalized stoichiometric ratio (NSR) of 3 (lbs NH_3 per lb NO_X)[25].

Parametric testing at Sioux Unit 1 in May 2005 reduced NO_X emissions between 15-38% with RRI, down to 0.15 to 0.20 lb/mmBtu. Reagent NSR between 1.0 and 4.0 and low ammonia slip levels less than 2 ppm from an established baseline condition of 0.20 to 0.285 lb/mmBtu level achieved NO_X emissions as low as 0.12 lb/mmBtu with deep cyclone air-staging and SOFA operation firing an 80:20 PRB/Illinois coal blend at 480 MWg unit output[27].

The intent of the RRI process for NO_X reduction is that it must be used in conjunction with air-starved (substoichiometric staged-air) cyclone combustion resulting from the installation and operation of an OFA system, with or without SNCR. The cyclones' air/fuel stoichiometry must be carefully controlled to maintain fuel-rich conditions for the RRI process to be effective. The combustion gases in the vicinity of the RRI urea injection ports must be essentially devoid of free oxygen, in order to avoid oxidizing the nitrogen contained in the injected reagent, which will increase NO_X emissions. For lignite-fired cyclone boilers, the basic form of separated overfire air (without relocated lignite drying system vent ports) is incompatible with RRI. Reagent injection will be near the elevation of the existing lignite drying system vent ports in the lower front and rear walls of a lignite-fired cyclone boiler located immediately above the top rows of cyclones. These vent ports are located concurrently with the existing flue gas recirculation (FGR) ports on Unit 2's boiler. The oxygen introduced with the lignite drying system's vented moisture-laden airstreams will cause the urea to be oxidized, creating NO_X emissions.

The advanced form of SOFA relocates these lignite drying system vent ports from the lower to the middle furnace, enhancing the desired in-furnace nitrogen oxides reduction process. Therefore, in order for RRI to be even moderately effective in reducing NO_X emissions from a lignite-fired cyclone boiler, this technology must be combined with an advanced form of separated overfire air, whether installed with or without SNCR.

As mentioned in the feasibility discussion of applying separated overfire air to lignite-fired cyclone boilers, the degree to which each and every individual cyclone furnace can be successfully operated with less than theoretical (substoichiometric) combustion air directly impacts potential NO_X formation and further in-furnace emission reduction. Because the heat content of lignite from the Center mine is not

consistent from hour to hour, there can be substantial deviations in air/fuel ratios for individual cyclones from the overall average.

In the case of MRY Station boilers, Minnkota has simultaneously sampled the unprepared lignite feed to several cyclones' lignite drying systems in order to determine the variability in the combustible and ash components of North Dakota lignite. This investigation found that fuel quality variations can result in individual samples' heating values to have a maximum differential of over 12% of the lignite samples' average.

TABLE A1-1 – Lignite Heating Values and Variations for Milton R. Young Station Unit 2

M.R. Young Station Individual Cyclone Lignite Samples		Differences Between Individual Cyclone Lignite Samples	
Higher Heating Values, Btu/lb	Percentage of Average HHV	HHV Differential, Btu/lb	Percentage of Average HHV
Minimum HHV: 5,852	88.9%	Minimum : 4	0.06%
Maximum HHV: 7,101	1.08%	Maximum : 797	12.1%
Average HHV: 6,584	100%	Average: 165	2.51%

When operating with air-staged conditions associated with separated overfire air, any individual cyclone with lignite heat input lower than average can allow significant amounts of oxygen to oxidize the urea reagent at high temperatures, thus increasing NOx emissions in that zone at that time. Cyclones with lignite heat inputs higher than average would produce lower stoichiometric air/fuel ratios and less NOx emissions. Less complete combustion in the deeply staged cyclones may release insufficient amounts of heat, thus raising the risk of solidifying the fuel ash so that it accumulates within the cyclone barrel. This could result in firing auxiliary fuel oil or taking the boiler out-of-service to remove the pluggage. Neither of these conditions is desirable because they result in increased emissions, lower performance, and higher operating costs.

The MRY Station Unit 2 boiler's cyclone air/fuel ratios vary in real-time based on significant changes in combustible content on an individual cyclone by cyclone basis. Adjustment of individual cyclone combustion air inputs to compensate for the variability in individual cyclone lignite heat input rates for Unit 2's boiler would be necessary to maintain consistent substoichiometric operation of every cyclone during air-staged combustion. This places great emphasis on achieving tight control over the air/fuel

ratios on each cyclone during air-staged combustion operation in order for ASOFA to be successful in producing significant additional NOx emissions reduction on lignite-fired cyclone boilers.

There is no equipment available for coal-fired boilers that can measure the fuel heat input at the prepared feed injection point on such a variable fuel to allow the determination of reasonably accurate air/fuel ratios on individual cyclones in real time. Without being able to measure the cyclone air and heat inputs to allow for control of air/fuel proportions and emissions, the stoichiometric ratios of individual cyclones can not be established accurately to produce combustion products essentially devoid of free oxygen. This requirement is especially necessary when employing RRI to avoid increasing, rather than reducing, NO_X emissions on the Milton R. Young Station Unit 2 boiler.

Flue gas recirculation in MRY Station Unit 2 boiler's lower furnace could increase NO_X emissions by admitting oxygen-bearing flue gas in the vicinity of the injected urea if RRI were applied with basic or advanced forms of SOFA. To avoid this negative impact, FGR in the lower furnace would need to be discontinued. There is uncertainty whether modification or elimination of the use of FGR in the lower furnace of MRY Station's Unit 2 boiler could be successful in controlling lower furnace wall fireside ash deposition and gas temperatures.

Because of the significant insurmountable problems discussed above which would increase NO_X emission rates, RRI is considered technically infeasible for application on the Unit 2 cyclone boiler at the Milton R. Young Station.

A.1.4.1.3 SOFA with RRI and SNCR

When RRI is combined with separated overfire air and SNCR, it has demonstrated very high NO_X emissions reduction at Conectiv's B.L. England Unit 1 boiler during short-term testing firing eastern bituminous coal, on the order of 80% from an uncontrolled baseline around 1.2 lb/mmBtu[24]. In May 2005, testing RRI+SNCR+SOFA at Ameren's Sioux Unit 1 boiler firing a high PRB-blend coal demonstrated NO_X emissions as low as 0.12 lb/mmBtu. This was from an established baseline condition of 0.20 lb/mmBtu level achieved with deep cyclone air-staging and SOFA operation. These testing results when firing an 80%:20% PRB/Illinois coal blend at 480 MWg unit output with a reagent NSR of 4 and ammonia slip limited to less than 5 ppmvd, showed an overall 90% reduction with no apparent adverse short-term impacts of deeper air-staged combustion together with overfire air, RRI and SNCR applications[27].

Because of the significant insurmountable problems regarding RRI as mentioned above, RRI with SNCR and ASOFA is considered technically infeasible for application on the Unit 2 cyclone boiler at the Milton R. Young Station due to the variable heat content of the lignite fuel which allows the creation of oxygen-rich conditions in the boiler.

A.1.4.2 SNCR and Reburn

SNCR could potentially be installed downstream of separated overfire air and various types of fuel reburn, to reduce NO_X emissions prior to a boiler's flue gas exit. Several of these examples were already described[7,8,9,10,11,1213,14]. Conventional gas (CGR) or coal reburn systems, by and large, have not been combined with forms of SNCR, although at least one vendor (GE Energy) has promoted a combination of conventional gas reburn with SNCR and overfire air systems as "advanced" gas reburn. Only one example of permanent installation of SNCR with conventional gas reburn (and overfire air) on a tangentially-fired boiler was found in available technical literature[10] and vendor experience lists[14]. The vendor (GE Energy) that provided the advanced gas reburn system at 120 MW NRG Somerset Station claimed NO_X emissions were reduced by 44% from a baseline of 0.45 down to 0.25 lb/mmBtu with overfire air alone; an additional reduction of 20% resulting from conventional gas reburn with overfire air, down to 0.20 lb/mmBtu; and further decrease of 45% down to 0.11 lb/mmBtu using gas reburn with SNCR with an unstated amount of ammonia slip, for an overall reduction of 75% from uncontrolled baseline[14].

No examples of actual demonstration or permanent installation of SNCR with conventional gas or coal reburn (and overfire air) on cyclone-fired boilers were found in a search of published and proprietary technical literature. The lack of experience with these combinations on a cyclone-fired boiler, especially for lignite-firing, makes the application for MRY Station's boilers infeasible.

FLGR™ has been installed with SNCR for NO_X emission reduction on several pulverized coal boilers, as discussed in the following subsection. A potential advantage of FLGR™ over conventional coal or gas reburn techniques is that the former is generally compatible with, but does not require, the installation and operation of SOFA.

Rich Reagent Injection would appear to be less capable of being combined with fuel reburn, especially conventional fuel reburn alternatives with high amounts of reburn fuel injection. This is due to the

expected need to idle (e.g. not fire) up to four of the twelve cyclones when operating the reburn system at full boiler load. In this case, the cooling air introduced into the idle cyclones, and any conveying air injected with pulverized reburn coal (or if natural gas is injected with recirculated flue gas), are expected to counteract the fuel-rich conditions of the air-and fuel-staged cyclones operating substoichiometrically. This will cause a portion of the amine reagent to be oxidized in the lower furnace, creating NO_X emissions instead of converting them to nitrogen and water. No example of actual demonstration or permanent installation of RRI with reburn (and overfire air) on cyclone-fired boilers was found in available technical literature or vendor experience lists. This combination is considered infeasible due to the location of injection and variable heat content of the lignite reburn fuel which allows the creation of oxygen-rich conditions in vicinity of RRI injectors in the lower furnace of Unit 2's boiler.

Hydrocarbon-enhanced SNCR (e.g. NO_XStar™) may potentially be combined with all types and forms of reburn previously discussed, since the location of the enhanced ammonia injection nozzles will be above (beyond) the elevation in the middle furnace where any reburn fuel should be reacted. No example of actual demonstration or permanent installation of HE-SNCR with reburn (and overfire air) on any coal-fired utility boilers, especially cyclone-fired units, was found in available technical literature or vendor experience lists. The advantage that HE-SNCR presents is the potential for greater-than-SNCR-levels of NOx reduction without significant amounts of gaseous hydrocarbon being required. Because of a lack of experience with HE SNCR applied to cyclone boilers, and none with significant amounts of fuel reburn, this combination has not been investigated further, and was not included in the control and cost-effectiveness analysis for NO_X controls.

A.1.4.2.1 Amine-Enhanced FLGR™ (AEFLGR™) or FLGR™ + SNCR

Fuel-lean gas reburn has been combined with SNCR as a hybrid form of amine reagent technologies on at least five pulverized coal-fired utility powerplants retrofit installations within the United States. This combination of technologies allows the boiler to be operated with FLGR™ alone, FLGR™ and SNCR simultaneously, or SNCR only (without SOFA) for the specific level of control desired or required.

No examples of actual demonstration or permanent installation of FLGR™ + SNCR (with or without overfire air) applied to a cyclone-fired boiler were found in available technical literature or vendor experience lists. The vendor (Fuel Tech) that provided the AEFLGR™ system at Mercer Station claimed NO_X emissions were reduced by 60% (from a baseline of 1.4 down to 0.56 lb/mmBtu) with 5 ppm ammonia slip without overfire air. A technical paper provides more details[18]. Another technical paper

stated that FLGR™ alone only reduced NO_X emissions approximately 27% from the 1.4 lb/mmBtu baseline, down to 1.03 lb/mmBtu[35].

An AEFLGR™ system (with or without SOFA or ASOFA) may be potentially applied to a cyclone-fired boiler. The high capital and operating costs associated with applying fuel lean gas reburn is expected to make this economically unattractive, and the existing lignite pre-drying vent ports will likely limit the NO_X emission reduction potential of the FLGR™ component if installed without the advanced form of SOFA. The lack of experience with this combination on any cyclone-fired boiler, especially for lignite-firing, makes this combination infeasible for MRY Station Unit 2 boiler.

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A.2.1 - U.S. Cyclone NOx Reduction Projects Summary

SELECTIVE NON-CATALYTIC REDUCTION/ RICH REAGENT INJECTION
Cyclone-Fired Boilers

Conectiv (formerly Atlantic Electric)
BL England Unit 1 Crushed Coal, single-wall cyclone-fired 1962 vintage
138 MW B&W boiler aqueous urea SNCR, 1995 startup eastern bituminous coal
Boiler has only 3 cyclone burners, arranged "1 over 2" style.
RJM implemented commercial Fuel Tech urea-based SNCR system installation in 1995 after short-term (3-month demonstration test) in 1993-1994. 31 % NOx reduction claimed, from 1.31 lb/mmBtu NOx baseline[(1)] for SNCR only; RJM claimed 35% reduction from 1.31 lb/mmBtu down to 0.85 lb/mmBtu (without overfire air) with urea-to-NOx NSR = 0.85 (RJM experience list).

Added eight temporary RRI ports (three nozzles on each lower sidewall, and two nozzles on the upper rear wall, and performed one month demonstration parametric testing of overfire air only (without SNCR or RRI), at 120 MW nominal boiler load and cyclone S.R. = 0.90 in 1999. REI claimed 55% NOx reduction from a 1.2 lb/mmBtu uncontrolled NOx baseline to 0.55 lb/mmBtu with OFA only, with stack CO emissions below 50 ppm. For Rich Reagent Injection; REI claimed 25-30% NOx reduction for RRI down to 0.38 lb/mmBtu from controlled baseline w/ OFA alone of 0.55 lb/mmBtu NOx and a RRI urea-to-NOx NSR = 2; also showed RRI+SNCR w/ OFA reduced NOx 55% to 0.25 lb/mmBtu (34% beyond RRI w/ OFA), for an overall 79% NOx reduction with a SNCR urea-to-NOx NSR = 1. Measured less than 1 ppm ammonia slip during RRI testing, < 5 ppm slip for RRI + SNCR. No significant increase in CO emissions during RRI testing[(2)].
Source: [(1)] ICAC White Paper; RJM experience list; [(2)] REI 2001 Technical Paper.

Conectiv (formerly Atlantic Electric)
BL England Unit 2 Crushed Coal, cyclone-fired, single-wall-fired 1964 vintage
160 MW B&W boiler SNCR, 1996 startup eastern bituminous coal
RJM implemented commercial Fuel Tech urea-based SNCR system in 1996, claimed 36% reduction from 1.36 lb/mmBtu down to 0.85 lb/mmBtu, urea-to-NOx NSR = 0.85 (without overfire air) [(1)].
An OFA system was added in 1998, resulting in NOx emissions of 0.33 lb/mmBtu, for an overall NOx reduction of 76%.
Source: RJM experience list. (Also listed in [(1)] ICAC White Paper).

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler Rich Reagent Injection demonstration testing in 2001
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.

Installed twenty temporary RRI ports (six nozzles on each lower sidewall, and four nozzles on each front and rear wall), and performed one month demonstration parametric testing of overfire air only and initial testing with RRI in August 2001, followed by additional testing in March 2002, and the second quarter of 2004. Added 8 RRI ports (1 in each sidewall, 4 in each front and rear wall) and 14 SNCR ports (5 on upper front wall, 9 on upper rear wall) to the furnace in early 2005, followed by three weeks of parametric testing and 3 days of continuous testing of RRI with SNCR and deeper-staged OFA.
Tested in August 2001 at lower furnace SR approx.=1.0, 0.55 lb/mmBtu w/ OFA only, only 15% NOx reduction w/ RRI, zero ammonia slip.

Tested in March 2002 at lower furnace SR approx.=0.95, from 0.38 lb/mmBtu baseline w/ OFA only, achieved 29% NOx reduction w/ RRI down to 0.27 lb/mmBtu, NSR=3, zero ammonia slip[3].
(assume blend of PRB and Illinois bituminous coal w/ tire-derived fuel and petroleum coke)[3].
Operation in the second quarter 2004 showed actual stack NOx averaged around of 0.30 lb/mmBtu with OFA only and lower furnace at a cyclone SR around 0.88 burning a 85% PRB, 15% Illinois #6 bituminous coal blend, presumably at 440 MW. This is a 75% NOx reduction from a 1.19 lb/mmBtu pre-control baseline. REI using CFD modeling predicted NOx down to 0.18 lb/mmBtu with RRI+OFA, and below 0.15 with RRI+SNCR under similar deep cyclone air-staging (1.19 to 0.28 lb/mmBtu is 76% reduction, 0.18 vs 0.28 is an additional 36% reduction w/ RRI, and 0.14 vs 0.28 is a 50% reduction w/ RRI+SNCR, for an overall reduction of 88%)[4].
Tested in May 2005 at 480 MWg with lower furnace SR approx. = 0.85-0.88, 76-83% reduction from 1.2 lb/mmBtu baseline down to as low as 0.20 lb/mmBtu w/ SOFA only firing 80% PRB, 20% Illinois #6 bituminous coal blend; additional 15-39% NOx reduction w/ RRI, to as low as 0.15 lb/mmBtu from 0.20-0.28 lb/mmBtu baseline w/ SOFA only at urea NSR varied between 1 and 4, with one ppm ammonia slip; achieved additional NOx reduction w/ RRI +SNCR down to 0.12 lb/mmBtu, NSR=4, ammonia slip10 ppm or less. RRI+SNCR w/ SOFA NOx reduction percentage varied from 15% to 50% below SOFA-only levels, with NSRs between 1 and 4.5. SNCR alone had 13% (NSR=1) to 32% (NSR=1) NOx reduction with ammonia slip around 1-2 ppm*.
Source: [3] REI 2002 and 2003 Technical Papers; [4] REI 2004 Technical paper;* REI 2005 Technical paper.

REBURN – GAS, CONVENTIONAL
Cyclone-Fired Boilers
Constellation Energy (formerly Baltimore Gas & Electric)
C.P. Crane Station, Units 1 & 2 (MD) Crushed Coal, cyclone-fired, eastern bituminous coal
2 x 200 MW B&W boilers (four cyclones each) 1961, 1963 vintage
GE-EER Conventional Gas Reburn, 1999 startup
Added gas supply piping, metering, hangers, supports; reburn injectors and cooling air ductwork, OFA ductwork, injection nozzles and wall ports, field (assume eastern bituminous coal)
GE-EER claimed Gas Reburn with OFA lowered NOx between 60% and 65% from baselines of 1.50 lb/mmBtu to between 0.60 and 0.52 lb/mmBtu, at full load with reburn operation. No claims of percent reburn fuel or percent OFA included in GE-EER's experience list.
Another technical paper showed this installation of CGR operated with 25 percent reburn fuel[5].
Source: Sept. 2005 GE-EER experience list; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

City Water, Light & Power
Lakeside Unit 7 Crushed Coal, front-wall cyclone-fired, midwestern bituminous coal
300,000 lb/hr steam B&W boiler (approx. 33 MWe equivalent, two cyclones) 1961 vintage
Springfield, IL DOE Clean Coal demonstration project (included sorbent injection)
GE-EER conventional gas reburn w/ OFA 1992 startup (CGR not currently operating)
Vendor claimed to lower NOx by 66% from 0.95 lb/mmBtu baseline to 0.32 lb/mmBtu. A GE-EER 2004 technical paper showed 25% reburn fuel yielded minimum NOx emissions[6].
A DOE NETL technical paper showed this demonstration of CGR from 5/93-10/94 (assume with OFA) with 23 percent reburn fuel reduced NOx 60% from 0.97 to 0.39 lb/mmBtu [5].
Source: Sept. 2005 GE-EER experience list; [6] GE-EER 2004 Technical paper; [5] DOE-NETL 2004 Reburn Conference Technical paper.

Eastman Kodak Company
Kodak Park Boilers 41 & 42 Crushed Coal, front-wall cyclone-fired, 1964 & 1966 vintage

400,000 lb/hr steam B&W boilers (approx. 50 MWe equivalent, two 8-ft dia. cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn w/ OFA December 1998, July 1998 startups (still operating)
Commercial installation of CGR, with (1) gas burner added to each sidewall + (2) large and (2) small OFA ports added to front wall above cyclones, utilizing higher reburn gas pressure (vs. Boiler #43) requires no flue gas recirculation; {Very small furnace w/ cyclone SR not <1.0}.
B&W claimed reburn with OFA lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 10-12% percent reburn fuel to achieve 0.6 lb/mmBtu and 23-24% reburn gas input to reach 0.33 lb/mmBtu NOx (73% reduction) [(7)].
Another technical paper showed NOx lowered by 52% from 1.25 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel[(5)].
Source: [(7)] B&W Technical Paper; [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL
Cyclone-Fired Boilers, continued
Eastman Kodak Company
Kodak Park Boiler 43 Crushed Coal, front-wall cyclone-fired 1968 vintage
600,000 lb/hr steam B&W boiler (approx. 60 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
B&W conventional gas reburn 1995 startup (still operating)
Commercial installation of CGR, with flue gas recirculation (FGR) for injection mass momentum w/ (1) FGR fan; (1) gas burner added to each sidewall + (2) OFA ports added front wall above cyclones. {Very small furnace/low residence time w/ cyclone SR not <1.0}
B&W claimed reburn with OFA & FGR lowered NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. B&W graph shows 18% percent reburn fuel to achieve 0.6 lb/mmBtu and 29% reburn gas input to reach 0.36 lb/mmBtu NOx (70% reduction) [(7)].
Another technical paper showed NOx lowered by 56% from 1.35 lb/mmBtu baseline to 0.60 lb/mmBtu with 18 percent reburn fuel[(5)].
Source: [(7)] B&W Technical Paper; [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Tennessee Valley Authority (TVA)
Allen Station Unit 1 (TN) Crushed Coal, cyclone-fired (seven cyclones) 1959 vintage
300 MW B&W boiler PRB &western bituminous coal blend fired
GE-EER Conventional Gas Reburn, 1998 startup
Commercial installation added gas supply piping, metering, hangers, supports; reburn injectors and cooling air piping, OFA ductwork, injection nozzles and wall ports, field I&C devices.
Reburn with OFA claimed to lower NOx 65% from baseline 1.20 lb/mmBtu to 0.42 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included. (TVA also installed duplicate OFA systems on Allen Units 2 & 3 boilers).
Another technical paper showed NOx lowered by 65% from 0.86 lb/mmBtu baseline (to 0.30 lb/mmBtu) with 7 percent reburn fuel[(5)].
Source: Sept. 2005 GE-EER experience list; [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, CONVENTIONAL
Cyclone-Fired Boilers
Alliant Energy (formerly Wisconsin Power & Light)
Nelson Dewey Station Unit 2 Crushed Coal, cyclone-fired, PRB coal 1962 vintage

110 MW B&W boiler 3-cyclones across front wall, 4 reburn burners +
4 OFA ports across rear wall, aligned vertically in columns.
US DOE Clean Coal Demonstration project of B&W's Conventional Coal Reburn, 1991 startup (since discontinued) added coal supply piping, reburn burners with flue gas recirculation, OFA ductwork + dual zone ports; coal feeder, pulverizer & PA fan, tested with PRB and bituminous coals. (western subbituminous coal)
B&W claimed reburn operation lowered NOx by 57% from baseline of 0.83 mmBtu to 0.38 lb/mmBtu at full load[7]. Approx. 30% percent of total fuel input supplied as reburn fuel. Increased unit output by 10 MW, increased flyash unburned carbon by 4% (13-22% vs 9-18%), decreased furnace exit gas temperature (FEGT). OFA ports listed in B&W experience list.
B&W shows full load NOx w/o reburn was 0.75 lb/mmBtu, and 0.29-0.32 lb/mmBtu w/ PRB fuel during reburn operation (57% decrease). At 75% load, 0.64 vs 0.29-0.32 lb/mmBtu. At 55% load, 0.62 vs 0.29-0.31 lb/mmBtu without and with reburn activated[8].
Another technical paper showed NOx lowered by 52-55% from 0.82 lb/mmBtu baseline (to 0.39-0.34 lb/mmBtu) with 25-30 percent reburn fuel[5].
Source: [7] 2004 B&W Technical Paper; [5] DOE-NETL 2004 Reburn Conference Technical paper;
[8] B&W case history (from website, dated 1997).

REBURN – COAL, MICRONIZED, CONVENTIONAL
Cyclone-Fired Boilers
Eastman Kodak Company
Kodak Park #15 Boiler Crushed Coal, front-wall cyclone-fired, 1956 vintage
400,000 lb/hr steam B&W boiler (approx. 50 MWe equivalent, two cyclones)
Rochester, NY eastern bituminous coal
GE-EER micronized coal reburn 1996 initial startup (operating since 1997)
Demonstration project performed with Dept. of Energy's US Clean Coal Technology Program. Project added flue gas recirculation for injection mass momentum, FGR fan and two micronized coal pulverizers; (6) reburn coal injectors added to rear wall + (1) reburn coal injector on each of the sidewalls, with (4) OFA ports added across front wall above cyclones[9]. GE-EER designed and fabricated the coal injectors and OFA ports. {Extremely small furnace and low residence time}.
GE-EER claimed reburn + OFA w/ FGR reduced NOx by 50% from 1.20 lb/mmBtu baseline to 0.6 lb/mmBtu. No claims of percent reburn fuel included.
Another technical paper showed this demonstration of micronized coal reburn from 4/97-10/98 lowered NOx by 57% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 17 percent reburn fuel[5].
Source: [9] DOE Topical Report Number 14 (May 1999); GE-EER experience list;[5] DOE-NETL 2004 Reburn Conference Technical paper.

REBURN – FUEL LEAN GAS REBURN
Cyclone-Fired Boilers
Midwest Generation (formerly Commonwealth Edison)
Joliet Station 9, Unit 6 Crushed Coal, opposed-wall cyclone-fired (nine cyclones)
340 MW B&W boiler 1959 vintage, 1997 startup (FLGR has since been decommissioned)
Energy Systems Associates demonstrated 25-30% NOx reduction using 5-10% of total heat input as reburn natural gas injected (without OFA)[5].
Another technical paper showed this demonstration in collaboration with Gas Research Institute of FLGR lowered NOx by 28-43% from 1.36 lb/mmBtu baseline (to 0.59 lb/mmBtu) with 7 percent reburn fuel[10].
Source: [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
[10] NGB Technologies Technical Paper.

REBURN – FUEL LEAN GAS REBURN w/ SNCR continued

Cyclone-Fired Boilers

Owensboro Municipal Utilities (KY) Crushed Coal, front-wall cyclone-fired
Elmer Smith Unit 1 (three cyclones) 1965 vintage
150 MW B&W boiler
CFD model study only predicted NOx reductions from 1.59 to 0.39 lb/mmBtu with OFA only (75% reduction, 0.90 SR); 25-30% NOx reduction using 6% of total heat input as reburn natural gas injected above OFA; 40-45% NOx reduction from SNCR with <5 ppm ammonia slip[11].
Source: [11] REI Technical paper.

Separated OVERFIRE AIR

Cyclone-Fired Boilers

Tennessee Valley Authority (TVA) Crushed Coal, cyclone-fired, 1959 vintage
Allen Station Units 2 & 3 (TN) (seven cyclones)
300 MW B&W boilers PRB &western bituminous coal blend
GE-EER Overfire air (duplicate of Allen 1), 1999 startup
GE-EER claimed to lower NOx with OFA alone up to 29% from baseline 1.20 lb/mmBtu to 0.85 lb/mmBtu on Units #2 and 3 at full load.
Source: Sept. 2005 GE-EER experience list.

AmerenUE (formerly Union Electric Co.)
Sioux Unit 1 Crushed Coal, opposed-wall cyclone-fired 1969 vintage
500 MW B&W boiler PRB/Illinois Coal blend
Boiler has 10 cyclone burners, arranged "2 over 3" style, on opposite walls, and fires a blend of 85% to 50% western subbituminous (PRB) coal, with Illinois bituminous coal, petroleum coke, and tire-derived fuel.
A ten-port OFA system (five ports on each front and rear wall) began operation in mid-2001, which reduced NOx emissions approx. 40-50% reduction from 1.1-1.3 (assume average of 1.19) down to 0.7 lb/mmBtu with moderate cyclone air-staging (cyclone SR from 1.19 to 1.0).[3] Subsequent testing and full load operation at deeper cyclone air-staging (SRs ≤ 0.90) has dropped NO_X with SOFA alone to around 0.3 lb/mmBtu in 2004[4].
Source: [3] REI 2002 and 2003 Technical Papers; [4] REI 2004 Technical paper;* REI 2005 Technical paper

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with Separated Overfire Air CR technology are listed in Table A.2-1. A large majority of the cyclone-fired boilers listed burn western subbituminous coal (or PRB blended with midwestern bituminous coal).

TABLE A.2-1 – Cyclone-Fired Boiler Overfire Air Retrofit Installations[12]

Facility Name	Installation Date	Comments
Allen Station Units 1	Installed 1998*	OFA w/ CGR retrofit; has SCR
Allen Station Unit 2	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Allen Station Unit 3	Installed 1999*	(Similar to Unit 1, w/o CGR) have SCR
Asbury Unit 1	Installed 5/10/1999	Empire District, BART-eligible
Bailly Unit 7	Installed 2003[13]	SCR to be installed in 2006-7
Bailly Unit 8	Installed 5/31/2000	SCR retrofit 5/11/2004
Baldwin Unit 1	Installed 12/31/1999	SCR retrofit 4/28/2003
Baldwin Unit 2	Installed 5/8/2000	SCR retrofit 4/12/2002
Big Stone Unit 1	Installed 10/22/1997	part of conversion to PRB
BL England Unit 2	Installed 1998*	previous SNCR retrofit in 1996
CP Crane Unit 2	Installed 2/1/1999	OFA w/ CGR retrofit
Coffeen Unit 1	Installed 2/1/2001	SCR retrofit 4/21/2003
Coffeen Unit 2	Installed 2/9/2000	SCR retrofit 4/09/2002
Edgewater Unit 3	Installed 11/2001[13]	
Edgewater Unit 4	Installed 6/19/2001	
Joliet 9 Unit 6	Installed 2000[13]	
Kincaid Unit 1	Installed 4/28/2000	SCR retrofit 12/17/2002
Kincaid Unit 2	Installed 5/24/2000	SCR retrofit 6/07/2002
Allen S. King Unit 1	Installed 11/30/1999	
LaCygne Unit 1	Installed 2/28/2000	
Lake Road Unit 6	Installed 6/01/2002	
Michigan City Unit 12	Installed 4/1998[13]	SCR retrofit 5/01/2003
Nelson Dewey Unit 1	Installed 2002[13]	
Nelson Dewey Unit 2	Installed 2002[13]	
Paradise Unit 1	Installed 11/14/1998	SCR retrofit 5/01/2001
Paradise Unit 2	Installed 12/8/1999	SCR retrofit 5/01/2000
Paradise Unit 3	Installed 5/4/2000	SCR retrofit 3/10/2004
Powerton Unit 5-1	Installed 6/1/2003	
Powerton Unit 5-2	Installed 6/1/2003	
Powerton Unit 6-1	Installed 6/1/2002	
Powerton Unit 6-2	Installed 5/4/1999	
Schahfer Unit 14	Installed early 2000[13]	SCR retrofit 5/11/2004
Sibley Unit 2	Installed 5/24/2002	
Sibley Unit 3	Installed 5/4/1999	
Sioux Unit 1	Installed 4/30/2001	SNCR demo May 2005
Sioux Unit 2	Installed 4/30/1997	
State Line Unit 4	Installed 11/2001[13]	Similar to Joliet 9 Unit 6
Tanners Creek Unit 4	Installed 5/12/2002	
Thomas Hill Unit 1	Installed June 2004[13]	
Thomas Hill Unit 2	Installed November 2000[13]	

Note: This table does not include every installed U.S. coal-fired cyclone boiler OFA retrofit project.
Source: [12] US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005 (except as noted below)
* Vendor experience list (GE Energy for Allen Station Units 1-3; RJM for BL England Unit 2)
[13] Burns & McDonnell internal database.

Coal burning cyclone-fired utility boilers in the United States that have been retrofitted with SCR technology are listed in Table A.2-2. This list includes at least eighteen cyclone-fired boilers burning western subbituminous coal (or PRB blended with midwestern bituminous coal). The highest emission

reductions listed in Table A.2-2 for SCR systems are for clean reactor catalyst and ideal operating conditions.

TABLE A.2-2 – Cyclone-Fired Boiler High-Dust SCR Installations

Facility[1]	Unit Size[2],MW	Tested Control Efficiency[3]	Tested Outlet NO_X Emission Rate (lb/mmBtu)[3]	2003 Ozone Season Average NO_X Emission Rate[4] (lb/mmBtu)
Allen 1, 2, & 3[5,6]	330 ea.	91.1/NAD[7]/88.7	0.070/NAD[7]/0.088	0.088/0.077/0.086
Baldwin 1[5,6]	600[3]	82.9	0.072	0.238
Baldwin 2[5,6]	605[3]	83.5	0.067	0.286
Bailly 8[5,6]	422	NAD[7]	NAD[7]	0.84
Coffeen 1[5,6]	389	NAD[7]	NAD[7]	0.114
Coffeen 2[5,6]	617	NAD[7]	NAD[7]	0.120
Dallman 31 & 32	207	NAD[6]	NAD[6]	0.149/0.146
Kincaid 1 & 2[5,6]	660[3] ea.	89/89	0.079/0.079	0.181/1.198
Marion 4	173	94.3	0.067	0.252
Merrimack 1[5,8]	114	50.5[9]	0.148	0.158
Merrimack 2	346	51.3[9]	0.155	0.171
Michigan City 12[5,10]	540	84.2	0.109	0.418
New Madrid 1 & 2[8,10]	600 ea.	87.4/88.1	0.149/0.147	0.319/1.172
Paradise 1 & 2[5,6]	704 ea.	87.7/87.7	0.102/0.101	0.124/0.113
Paradise 3[5,6]	1150	89.1	0.088	0.658
Schahfer 14[5,10]	540	83.5	0.106	0.478

[1] – original design fuel for all listed cyclone boilers was bituminous coal
[2] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.
[3] – Burns & McDonnell internal database.
[4] – as reported to US EPA, available from their website at http://cfpub.epa.gov/gdm/index.cfm
[5] – includes application of separated overfire air for combustion NO_X control
[6] – current fuel believed to be a blend of subbituminous and bituminous coals
[7] – NAD = no published data from SCR emission testing found on these units.
[8] – original air preheaters were tubular-type; changed to rotary-type during SCR retrofit
[9] – Design NO_X removal efficiency is higher, approx. 90%.
[10] – current fuel believed to be subbituminous coal

For Merrimack Unit 1's SCR, inlet (i.e. uncontrolled) NO_X was 1.34 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. The catalyst was designed for 88.9% NO_X removal efficiency

and 5 ppm ammonia slip. SCR commercial service date July 20, 1999. [(14) Babcock Borsig Power 2000 technical paper on SCRs].

For Merrimack Unit 2's SCR, inlet (i.e. uncontrolled) NO_X was 2.66 lb/mmBtu, for a blend of high sulfur bituminous and medium or low sulfur bituminous coals, and requires year-round SCR operation for compliance. Initial testing demonstrated 70% removal(15), which exceeded the 65% requirement to achieve a 0.92 lb/mmBtu permit limit. The catalyst was designed for 85-95% NO_X removal efficiency and 5 ppm ammonia slip(16).

(15)NETL-DOE Clean Coal Technology 1997 technical paper on SCRs; (16) 1997 ICAC White Paper on SCRs.

Northern Indiana Public Service Company (NIPSCO)
Bailly Unit 8 Crushed Coal, cyclone-fired, opposed-wall-fired 1968 vintage
360 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires a blend of 85% western subbituminous (PRB) coal, with Illinois bituminous coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Michigan City Unit 12 Crushed Coal, cyclone-fired, opposed-wall-fired 1974 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2003 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2003 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 1998(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

Northern Indiana Public Service Company (NIPSCO)
Schahfer Unit 14 Crushed Coal, cyclone-fired, opposed-wall-fired 1975 vintage
520 MW B&W boiler Urea/ammonia conversion for high-dust SCR, 2004 startup
Boiler fires western subbituminous (PRB) coal.
Commercial Fuel Tech urea-based system installed in 2004 to convert urea to ammonia for injecting reagent ahead of boiler economizer outlet and high-dust SCR. An OFA system was retrofitted in 2000(13).
Source: Fuel Tech experience list dated 1/28/2005; (13)Burns & McDonnell internal database.

TABLE A-3 – Low-Dust Pulverized Coal-Fired Boiler SCR Installations

Operator/Facility[1,2]	SCR Startup Date[3]	Average NO_X Emission Rates[4] (lb/mmBtu)	Unit Size[5], MW
AEP/Cardinal Unit 3[6]	5/01/03	0.74 / 0.34 / 0.135	650
Carolina P&L/Mayo Unit 1[7]		- / (0.36) / N/A	368 x 2
Carolina P&L/Roxboro Unit 4[7,8]	5/07/01	0.57 / 0.26 / 0.081	372 x 2
Cinergy/East Bend Unit 1	4/01/02	- / (0.28) / 0.067	648
Constellation/Brandon Shores Unit 1[8]	(2001)	0.47 /0.33 / 0.126	685
Constellation/Brandon Shores Unit 2[8]	(2000)	0.45 / 0.31 / 0.094	685
Dayton P&L/Killen Station Unit 2	11/01/03	- / (0.48) / 0.06[9]	666
Dynegy Midwest Gen/Havana Unit 6[10]	(2000)	0.46 /0.20 / 0.102[9]	488
PSEG Power LLC / Mercer Unit 1[11]	(2005)	- / (0.63) / N/A	320
PSEG Power LLC / Mercer Unit 2[11]	(2004)	- / (0.76) / N/A	320

[1] – Burns & McDonnell internal database.
[2] – Current fuel is eastern or midwestern bituminous coal, except Havana
[3] – US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, except where noted. Dates in () are believed to be accurate but have not been confirmed.
[4] – The three values are "Pre-control average", "2004 annual average", and "2003 ozone season average" NO_X emission rates, as reported to US EPA. Pre-control and year 2004 annual average data as shown in US EPA Docket OAR-2002-0076-0446 Technical Support Document for BART NOx Limits for Electric Generating Units Excel Spreadsheet 6/15/2005, posted on their website: http://docket.epa.gov/edkpub/do/EDKStaffItemDetailView?objectId=090007d48084562b. Values shown in parentheses are year 2003 annual average where 2004 data is not available. Year 2003 and 2003 ozone season data is available from the EPA's website at http://cfpub.epa.gov/gdm/index.cfm, includes application of separated overfire air for combustion NO_X control where applicable.
[5] – Generator nameplate rating, March 2002 Energy Information Administration report DOE/EIA-0095(2000). Actual unit MW output rating may be higher or lower than nameplate.
[6] – This boiler has low-NOx burners for combustion controls.
[7] – Carolina Power & Light plants listed here have two boilers per unit, total nameplate for Mayo is 736 MW, Roxboro is 745 MW; emission numbers are the average of both boilers.
[8] – This boiler has low-NOx burners and overfire air for combustion controls.
[9] – This is preliminary data reported to the US EPA for 2004 ozone season average emission rate.
[10] – This boiler's current fuel is believed to be subbituminous coal.
[11] – Mercer boilers listed have low-dust SCR with flue gas reheat. Unit size is approximate, not nameplate.
N/A = complete 2004 ozone season data is not available, and 2003 ozone season data is not representative of the post-SCR installation emission rate.

SELECTIVE NON-CATALYTIC REDUCTION

Pulverized coal-fired boilers

American Electric Power (AEP) Pulverized Coal, cell-burner, opposed wall-fired B&W boiler
Cardinal Unit 1 1967 vintage; Low NO_x burners installed in October 1998
600 MW (nominal) Brilliant, Ohio
Fuel Tech urea-based SNCR installed in October 1998.
Fuel Tech, DOE, EPRI-member utilities SNCR demonstration project. Tested in March-April 1999, claimed 65% reduction with LNBs + SNCR w/ 5 ppm NH_3 slip, (from pre-LNB retrofit baseline of 1.20 lb/mmBtu*) down to 0.52 lb/mmBtu at 620 MW (100% MCR). SNCR reduced NO_X 31% below LNBs alone (0.75 lb/mmBtu baseline), at 620 MWg (100% MCR), 34% reduction at 75% MCR (450 MWg), and 42% reduction at minimum load (340 MWg, 55% MCR) ≤ 5% ammonia slip[17], burning eastern bituminous coal. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005; [1]ICAC White Paper, [17] 2000 Fuel Tech technical paper, *Riley Power (Babcock Power Inc.) experience list 8/16/04.

Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 SNCR startup
Fuel Tech commercial SNCR installation claimed 25% NOx reduction from low-NO_X burner w/o OFA baseline of 0.58 lb/mmBtu (down to 0.44 lb/mmBtu on SNCR alone). Urea-to-NOx NSR not stated.
(Also see FLGR + SNCR installation summaries for pulverized coal boilers).
Source: Fuel Tech experience list dated 1/28/2005.

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler SNCR startup in 2002
Mobotec USA "Rotamix" ammonia-based SNCR system injects aqueous ammonia liquid into a high velocity boosted separated overfire air (ROFA) system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.28 lb/mmBtu baseline by 43% to 0.16 lb/mmBtu in 2002 with 5 ppm NH_3 slip following the installation of ROFA in 2000.
Overall reduction 73% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.16 lb/mmBtu[18].
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.13 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 54% decrease from 0.28 lb/mmBtu with ROFA alone, or 78% overall decrease[19]. Ammonia-to-NOx NSR not stated.
Source: [18] CP&L 2002 Technical paper; [19] Mobotec 2003 technical paper.

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler SNCR startup in 2001
Mobotec USA "Rotamix" ammonia-based SNCR system, injects aqueous ammonia liquid into a high velocity boosted separated overfire air ("ROFA") system at the boiler.
CP&L technical paper claimed to lower NO_X from 0.23 lb/mmBtu baseline by 22% to 0.18 lb/mmBtu with 5 ppm NH_3 slip following the installation of ROFA+SNCR in 2001[18]. Presentation slide graph shows no reduction for Rotamix beyond ROFA alone at full load NO_X emission rate of 0.23 lb/mmBtu. Ammonia-to-NOx NSR not stated.
Overall reduction 67% from full-load pre-ROFA baseline 0.54 lb/mmBtu to 0.18 lb/mmBtu.
Mobotec claimed further NO_X reduction was possible by injecting urea in place of ammonia, achieving 0.10 lb/mmBtu instead of 0.18 lb/mmBtu, which would be 56% decrease from 0.23 lb/mmBtu with ROFA alone, or 81% overall decrease[19]. Urea-to-NOx NSR not stated.
Source: [18] CP&L 2002 Technical paper; [19] Mobotec 2003 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Cinergy (formerly Cincinnati G&E) Pulverized Coal, Tangentially-fired,
Miami Fort Unit 6 (Ohio) 1960 vintage; startup prior to 2000
163 MW CE boiler
Fuel Tech urea-based SNCR system, claimed to lower NOx by 35% from 0.55 lb/mmBtu baseline[(1)].(assume eastern bituminous coal). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [(1)] ICAC White Paper.

Conectiv (formerly Delmarva Power & Light)
Edgemoor Unit 3 Pulverized Coal, Tangentially-fired, 1954 vintage
84 MW CE boiler mid-March 1996 startup; (assume eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system. HRC claimed 35% NOx reduction with less than 10 ppm ammonia slip. Urea-to-NOx NSR not stated.
Another source shows a 30% reduction from 0.54 lb/mmBtu baseline[(1)].
Source: Hamon experience list (not listed by Fuel Tech); [(1)] ICAC White Paper.

Conectiv (formerly Delmarva Power & Light) Pulverized Coal
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers Spring 2000 startup (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR system (not listed by Fuel Tech) on both units.
HRC claimed 35% NO_X reduction with less than 5 ppm ammonia slip. Urea-to-NOx NSR not stated.
An REI 1999 technical paper shows a pre-SNCR baseline of 0.37 and 0.44 lb/mmBtu, respectively. [(20)]
Another source listed these units as having a pre-control NO_X baseline of 0.97 and 0.57 lb/mmBtu, and 2004 post-SNCR startup average of 0.32 and 0.33 lb/mmBtu, respectively. [(12)]
Source: Hamon experience list (not listed by Fuel Tech); [(20)] REI 1999 technical paper;
[(12)] US EPA Docket OAR-2002-0076-0446 Excel Spreadsheet 6/15/2005.

Dominion Generation (Virginia E&P Co.) Pulverized Coal, Tangentially-fired
Clover Station, Units 1 & 2 (VA) ABB/CE boilers, 1995, 1996 vintage
2 x 465 MW (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) 1995, 1996 startup (initial commercial)
Fuel Tech claimed NOx reduced by 25% from 0.32 lb/mmBtu baseline (to 0.24 lb/mmBtu).
Source: Fuel Tech experience list dated 1/28/2005. Urea-to-NOx NSR not stated.

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
Mobotec USA "Rotamix" urea-based SNCR system with rotating opposed fired air (ROFA).
Mobotec 2004 technical paper claimed to lower NO_X by 55% from 0.22 lb/mmBtu baseline to 0.10 lb/mmBtu in April 2004 with urea-based Rotamix SNCR and < 5 ppm CO. NH_3 slip not mentioned.
Overall reduction 83% from full-load pre-ROFA baseline 0.58 lb/mmBtu to 0.10 lb/mmBtu [(21)]. Urea-to-NOx NSR not stated.
Source: [(21)] Mobotec 2004 technical paper.

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Eastern Utilities Associates, Pulverized Coal, Tangentially-fired
Montaup Electric Company 1959 vintage
Somerset Unit 8 (Massachusetts) Summer 1995 startup
112 MW CE boiler (eastern bituminous coal)
Hamon Research-Cottrell supplied a urea-based SNCR (Fuel Tech system), claimed to lower NOx below 0.38 lb/mmBtu (Mass. RACT). Urea-to-NOx NSR not stated.
Another source listed 28-60% NOx reduction from a 0.49-0.89 lb/mmBtu baseline[(1)].
Source: Hamon experience list, Fuel Tech experience list dated 1/28/2005, [(1)]ICAC White Paper.

First Energy Pulverized Coal, Tangentially-fired,
Eastlake Unit 3 (Ohio) 1954 vintage
130 MW CE boiler (w/ division wall) (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Fuel Tech claimed to lower NOx from 20-32.5% from 0.34-0.40 lb/mmBtu baseline[(1)]. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [(1)] ICAC White Paper.

First Energy Pulverized Coal, wall-fired,
Sammis Unit 2 (Ohio) 1960 vintage
180 MW Foster Wheeler boiler SNCR startup Fall 1999
Urea-based SNCR (Fuel Tech system) (eastern bituminous coal)
Fuel Tech claimed to lower NOx from 25-30% from 0.45 lb/mmBtu baseline [(1)]. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [(1)] ICAC White Paper.

First Energy Pulverized Coal, wall-fired,
Sammis Units 6 & 7 (Ohio) 1969 & 1971 vintage
680 MW B&W Universal Pressure boilers (eastern bituminous coal)
Urea-based SNCR (Fuel Tech system) SNCR startup after 1999
Fuel Tech claimed to lower NOx from 25% from 0.38 lb/mmBtu baseline. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers SNCR startup prior to 2000
Urea-based SNCR (Fuel Tech system)
Fuel Tech claimed 66% (50-75%) NOx reduction from baseline of 1.0 ± 0.1 (range 0.85-1.12) lb/mmBtu, (which would lower NOx to around 0.34±0.07 lb/mmBtu). Urea-to-NOx NSR not stated. {These NOx reduction percentages may include impact of low-NOx burners}.
Source: Fuel Tech experience list dated 1/28/2005, [(1)]ICAC White Paper.
(Also see LNB installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Schiller Units 4, 5, & 6 Pulverized Coal/#6 Fuel oil, front-wall-fired
50 MWe x 3Foster Wheeler boilers 1952, 1955, 1957 vintage
Urea-based SNCR (Fuel Tech system) Colombian bituminous coal
August 1999 startup
RJM implemented Fuel Tech urea-based commercial SNCR installation on all three boilers.

RJM claimed 50% reduction from 0.50 lb/mmBtu pre-SNCR baseline to 0.25 lb/mmBtu for SNCR coal-firing operation; NO_X baseline 0.82 lb/mmBtu prior to RJM's LNB modifications installed in 1994, 1992, & 1994 (39% reduction); Urea-to-NOx NSR not stated.
Fuel Tech claimed 30% NO_X reduction for SNCR from baseline of 153 ppm firing #6 fuel oil on Units 4 & 6 only.
Source: RJM experience list, Fuel Tech experience list dated 1/28/2005.

SELECTIVE NON-CATALYTIC REDUCTION continued
Pulverized coal-fired boilers
Owensboro Municipal Utilities (KY) Pulverized Coal, Tangentially-fired,
Elmer Smith Unit 2 1974 vintage
300 MW CE boiler eastern bituminous coal
Hamon Research-Cottrell supplied an ammonia-based SNCR system but stated no claims for NOx reduction; (this project is not listed in ICAC White Paper[(1)]). Ammonia-to-NOx NSR not stated.
Source: Hamon experience list.

PECO Energy (formerly Philadelphia Electric Company)
Cromby Unit 1 Pulverized Coal, front wall-fired divided furnace
160 MWe B&W boiler 1954 vintage eastern bituminous coal
RJM installed Fuel Tech urea-based SNCR with low NO_X burner modifications & OFA in 1999, June 1999 startup.
RJM claimed 29% SNCR NO_X reduction from baseline of 0.35 lb/mmBtu, down to 0.25 lb/mmBtu with urea NSR = 0.8; RJM provided burner modifications of B&W XCL low-NOx burners installed in 1994 + OFA; this reduced NO_X from 0.50 to 0.35 lb/mmBtu (30% reduction) without SNCR. Urea-to-NOx NSR not stated.
Source: RJM experience list; [(1)]ICAC White Paper.

Exelon (formerly PECO Energy/ Pennsylvania Electric Company)
Eddystone Units 1 & 2 Pulverized Coal Tangentially-fired, 1954 vintage
318, 333 MW each CE boilers 1999 SNCR startup, eastern bituminous coal
Fuel Tech claimed 30% NOx reduction from baseline of 0.26 lb/mmBtu.
Source: Fuel Tech experience list dated 1/28/2005.

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 25% (initial) NOx reduction for SNCR alone from baseline of 0.65 lb/mmBtu (down to 0.49 lb/mmBtu). Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, also listed in [(1)]ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Mercer Station (2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired
Unit 1 and Unit 2 front wall PC, wet-bottom (slagging ash) eastern bituminous coal
Furnace #11 & #12 1960 vintage April 1999 startup
Furnace #21 & 22 1961 vintage May 1999 startup
Fuel Tech urea-based commercial SNCR installation claimed 30-35% NOx reduction from baseline of 2.0 lb/mmBtu on SNCR alone, down to 1.4 lb/mmBtu. Urea-to-NOx NSR not stated.

Source: Fuel Tech experience list dated 1/28/2005; also listed in [1]ICAC White Paper. (Also see FLGR+SNCR installation summaries for pulverized coal boilers)

SELECTIVE NON-CATALYTIC REDUCTION continued

Pulverized coal-fired boilers

Reliant Energy (formerly GPU Genco) Pulverized Coal
(formerly Sithe, formerly Penelec) Tangentially-fired
Seward # 15 (PA) mid-1990's SNCR startup
Units 4 & 5 eastern bituminous coal
62 & 156 MW CE boilers 1950 & 1957 vintage
Urea-based SNCR (Fuel Tech system), later installed an in-duct SCR to reduce NH_3 slip.
Fuel Tech claimed to lower NOx 35% for SNCR only (55% for combined SNCR/SCR from 0.78 lb/mmBtu baseline). Boilers have since been demolished and replaced with CFBs. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005, [1]ICAC White Paper.

Rochester Gas & Electric Pulverized Coal, Tangentially-fired
Russell Station, Units 1-4 (NY) 1948, 1950, 1953, 1957 vintage
1 x 50 MW, 2 x 65 MW, 1 x 85 MW CE boilers eastern bituminous coal
Urea-based SNCR (Fuel Tech system) SNCR startup prior to 2000
Vendor claimed to lower NOx by 15-27.5% from 0.28 – 0.42 lb/mmBtu baselines. Urea-to-NOx NSR not stated.
Source: Fuel Tech experience list dated 1/28/2005.

HYDROCARBON-ENHANCED AMMONIA SNCR (NOxStar™)

Pulverized coal-fired boilers

Tennessee Valley Authority (TVA) Pulverized Coal twin-furnace, tangentially-fired,
Kingston Power Station (TN) 1955 vintage eastern bituminous coal
Unit 9, 200 MWe CE boiler NOxStar™ startup January 2002
Demonstration of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR installation.
Mitsui Babcock claimed 68% NOx reduction from baseline of 0.55 lb/mmBtu down to 0.17 lb/mmBtu with boosted OFA and NOxStar™ with < 5 ppm ammonia slip; NOxStar™ alone reduced NOx by 53%[22]; boosted OFA only reduced NOx from 0.55 to 0.45 lb/mmBtu (18% reduction). Ammonia-to-NOx NSR not stated.
TVA's website reported that "an earlier version of NOxStar was installed at Kingston Fossil Plant Unit 9 in 2002 with mixed results. NOx reductions were achieved, but the boiler was damaged" (http://www.tva.gov/environment/repotrs/envreports/aer/2003/env_compliance.htm)
Source: [22] Mitsui Babcock Technical paper, October 2003.

Tennessee Valley Authority (TVA) Pulverized Coal, wall-fired
Colbert Station (AL) 1955 vintage
Unit 4, 192 MWe twin-furnace B&W boiler w/ FGR eastern bituminous coal
First commercial installation of NOxStar™ hydrocarbon-enhanced ammonia-based SNCR technology.
Mitsui Babcock showed 80% NOx reduction from baseline of 0.50 to 0.10 lb/mmBtu; using < 0.1% of total boiler heat input for propane input and 1% of total steam flow generated in the boiler for lance cooling[23]; 2004 SNCR system startup. Ammonia-to-NOx NSR not stated.
Source: [23] Mitsui Babcock 2004 Technical paper.

REBURN – GAS, CONVENTIONAL
Pulverized coal-fired boilers

Allegheny Power (formerly West Pennsylvania Power) Pulverized Coal, opposed wall-fired
Hatfield's Ferry Station cell-burner, 1969 & 1972 vintage
Units 2 & 3, 600 MW (nominal) each (B&W boilers) eastern bituminous coal
GE-EER Gas Reburn; 1999 startup (Unit 2) & 2003 (Unit 3)
GE-EER Low NOx burners, boosted OFA, gas reburn system.
GE-EER claimed to lower NOx up to 67% from baseline of 0.60 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation on Unit 2, 68% from 0.62 lb/mmBtu to 0.20 lb/mmBtu on Unit 3. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 35% NOx reduction at 600 MW load with LNB + OFA w/o reburn fuel, and an additional 50% reduction to 0.20 lb/mmBtu with reburn fuel[24].
B&W added 20 OFA ports in 1994 per B&W's experience list. No NOx reduction claims. Source: Sept. 2005 GE-EER experience list; [24] GE-EER 2004 Technical paper. Unit 2 and Unit 3 listed in [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL continued
Pulverized coal-fired boilers)

Conectiv (formerly Delmarva Power & Light) Pulverized Coal, Tangentially-fired
Edgemoor Unit 4 1966 vintage, eastern bituminous coal
160 MW CE boiler 1999 startup
GE-EER Gas Reburn project added gas supply piping, metering, hangers, supports, reburn injectors and cooling air piping; OFA ductwork, injection nozzles and wall ports, field instrumentation. No FGR or OFA booster fans.
Vendor claimed to lower NOx up to 48% from baseline of 0.32 lb/mmBtu to 0.16 lb/mmBtu) at full load with reburn operation. No claims of percent reburn fuel included.
GE-EER technical paper shows approx. 32% NOx reduction for gas reburn with 4-mill operation at 160 MW load from 0.31 lb/mmBtu LNB + OFA baseline w/o reburn fuel (down to 0.21 lb/mmBtu), and 48% NOx reduction for gas reburn with 3-mill operation, to 0.16 lb/mmBtu [24].
Source: Sept. 2005 GE-EER experience list; [24] GE-EER 2004 Technical paper. Listed in [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference)

Dynegy (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Hennepin Unit 1 1966 vintage
71 MW CE boiler eastern bituminous coal
GE-EER Gas Reburn, 1990 startup (not currently operating); GE-EER Orimulsion Reburn, 1997.
DOE Clean Coal demonstration project (included sorbent injection).
Vendor claimed gas reburn w/ OFA lowered NOx up to 67% from baseline of 0.75 lb/mmBtu to 0.25 lb/mmBtu) at full load; 65% reduction from baseline of 0.75 lb/mmBtu down to 0.26 lb/mmBtu with subsequent Orimulsion reburn operation.
GE-EER 2004 technical paper shows 18% gas reburn fuel yielded minimum NOx emissions[6].
Another technical paper showed this 80 MW US DOE Clean Coal demonstration project in January 1991-January 1993 lowered NOx by 67% from 0.75 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 18 percent reburn fuel[5].
Source: Sept. 2005 GE-EER experience list; [6] GE-EER 2004 Technical paper; [5] DOE-NETL 2004 Reburn Conference technical paper, and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Oil reburn installation summaries for pulverized coal boilers).

REBURN – GAS, CONVENTIONAL continued

Pulverized coal-fired boilers)

AES (formerly New York State Gas & Electric (NYSEG)

Greenidge #6 (NY)	Pulverized Coal, Tangentially-fired,	1953 vintage
100 MW CE boiler	GE-EER Conventional Gas Reburn, 1996 startup	

Vendor claimed to lower NOx 55% from 0.63 lb/mmBtu baseline to 0.28 lb/mmBtu at full load with reburn operation burning eastern bituminous coal. Gas Research Institute predicted would achieve 76% (down to 0.15 lb/mmBtu) w/ advanced gas reburn.
GE-EER 2004 technical paper shows 23% reburn fuel yielded minimum NOx emissions around 0.23 lb/mmBtu[(6)].
EPA's "Scorecard on Reburning 6/1/2004" shows a 109 MW t-fired boiler (listed as Greenidge Unit 4) lowered NOx by 50% from 0.50 lb/mmBtu baseline (to 0.25 lb/mmBtu) with 10 percent reburn fuel (no longer operating) [(5)].
Source: Sept. 2005 GE-EER experience list; [(6)] GE-EER 2004 Technical paper; [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired B&W boilers
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	GE-EER Gas Reburn, 2000 startup	

Vendor claimed to lower NOx up to 43% and 45% from 0.60 lb/mmBtu baseline to 0.34 and 0.33 lb/mmBtu) at full load with reburn operation, respectively. No claims of percent reburn fuel included.
Source: 2002 GE-EER experience list. Listed in [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, 1962 vintage
175 MW B&W boiler	western bituminous coal
DOE Clean Coal demonstration project	November 1992-January 1995

Gas reburn demonstration performed with Dept. of Energy and Gas Research Institute 1992-1995.
Existing boiler with 16 burners was retrofitted with low NO_X burners and GE-EER gas reburn OFA, FGR, and reburn injectors. Added OFA booster fan, 800 hp flue gas recirculation fan for injection mass momentum, for increased gas injection mass momentum (which was subsequently removed). The CGR installation portion has since been decommissioned.
Vendor claimed to lower NOx up to 64% from baseline of 0.73 lb/mmBtu to 0.26 lb/mmBtu) at full load with reburn operation.
GE-EER 2004 technical paper shows 15-20% reburn fuel yielded minimum NOx emissions[(6)].
A 2004 DOE-NETL technical paper showed this project achieved 0.46 lb/mmBtu NO_X emissions with low NO_X burners alone (37% reduction), further reduced NO_X by 44% with 12.5 percent reburn fuel[(5)].
A 2001 DOE-NETL technical paper claimed a NOx reduction of 65% at an average reburn gas heat input of 18% of total boiler fuel input, with and without FGR. Demonstrated 70% NOx reduction at higher reburn input rates. Referred to technology as GR-LNB. FGR was added for gas injection momentum but was subsequently removed to reduce fuel input. [(25)]
Source: Sept. 2005 GE-EER experience list; [(6)] GE-EER 2004 Technical paper; [(5)] DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); [(25)] DOE-NETL 2001 Technical paper; also in [(9)] DOE 1999 Topical Report Number 14.

REBURN – OIL, CONVENTIONAL

Pulverized coal-fired boilers

Dynegy (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Hennepin Unit 1 1966 vintage, eastern bituminous coal
71 MW CE boiler 1997 startup
GE-EER Orimulsion Reburn system w/ OFA, claimed orimulsion reburn lowered NOx up to 65% from baseline of 0.75 lb/mmBtu to 0.26 lb/mmBtu at full load with Orimulsion reburn operation (installed after gas reburn was demonstrated in early 1990's). No claims for percent reburn fuel included.
GE-EER 2004 technical paper shows 60% reduction with subsequent Orimulsion reburn [(6)].
Source: GE-EER experience list; [(6)] GE-EER 2004 Technical paper. Orimulsion not mentioned in [(5)] DOE-NETL 2004 Reburn Conference technical paper or DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

New Brunswick Power
Coleson Cove, Bunker C/Orimulsion–fired, opposed-wall
St. John, New Brunswick, Canada
3x 350 MW B&W Boilers
Sixteen new low-NO_X oil/Orimulsion burners, eight reburn burners, nine SOFA ports, two combustion air booster fans, reburn and OFA wall penetration openings, OFA windboxes, ductwork, dampers, and accessories were added[(7)].
Another technical paper showed this reburn system lowered NOx by 78% from 1.0 lb/mmBtu baseline to 0.22 lb/mmBtu at 25 percent reburn fuel input[(5)].
Source: [(7)] B&W 2004 Technical Paper;[(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Georgia Power Pulverized Coal, Tangentially-fired
Scherer Unit 1 1982 vintage
887 MW CE boiler 2000 oil reburn startup
GE-EER Oil Reburn system, claimed to lower NOx from baseline of 0.36 lb/mmBtu.
GE-EER 2004 Technical paper shows reduction up to 48% (to 0.19 lb/mmBtu) at 800 MW load with oil reburn operation. No claims of percent reburn fuel included[(24)].
Source: Sept. 2005 GE-EER experience list shows this as a coal reburn project with eastern bituminous coal, reducing NO_X emissions 33% from 0.36 to 0.24 lb/mmBtu;
[(24)] GE-EER 2004 Technical paper. Not listed in [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL

Pulverized coal-fired boilers

AES (formerly New York State Electric and Gas Milliken Station Unit 1)
Cayuga tangentially-fired, pulverized coal, 1956 vintage
148 MWe, CE boiler eastern bituminous coal
GE-EER micronized coal reburn system 1996 startup (still operating)
US DOE Clean Coal demonstration project from March 1997-April 1999 lowered NOx with this reburn system by 29% from 0.35 lb/mmBtu baseline to 0.25 lb/mmBtu at 14 percent reburn fuel input[(5)]. Not listed in GE-EER's experience list nor in their 2004 technical paper.
Source: [(5)] DOE-NETL 2004 Reburn Conference technical paper and DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – COAL, MICRONIZED, CONVENTIONAL continued

Pulverized coal-fired boilers

E. ON US Holdings (formerly Louisville Gas and Electric)
R.D. Green Station Units 1 & 2 (KY) wall-fired, pulverized coal, vintage unknown
293 MWe, 2 boilers eastern bituminous coal
GE-EER coal reburn system Startup dates: 2003 & 2002, respectively
Vendor claimed to lower NOx up to 57% from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu at full load with reburn operation.
Reburn system listed on EPA's "Scorecard on Reburning 6/1/2004" shows NOx lowered by 44% from baseline of 0.45 lb/mmBtu down to 0.25 lb/mmBtu (with unknown reburn fuel input[(5)]).
Another technical paper showed baseline NOx with existing low-NOx burners was 0.45 lb/mmBtu, and reduced NOx emission 40% to 0.27 lb/mmBtu with OFA, and further reduced NOx emissions 22% down to 0.21 lb/mmBtu with the coal reburn system in operation[26].
Source: [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference);
[(24)] GE Energy 2004 Technical paper, and [(26)] March 2004 Modern Power Systems issue.

Cheng Loong (not in United States)
Unit #1, 250 MWe wall-fired, bituminous pulverized coal, vintage & mfr unknown
GE-EER coal reburn system 2000 Startup (still operating)
Source: GE-EER experience list
Vendor claimed to lower NOx 44% from baseline 0.45 lb/mmBtu to 0.25 lb/mmBtu) at full load with OFA alone; further reduced NOx 28% to 0.18 lb/mmBtu, for 60% overall reduction. Recent (2004) data shows NOx down to 0.14 lb/mmBtu (69% overall) with up to 30 percent reburn fuel[(24)].
Source: [(24)] GE Energy 2004 Technical paper; GE-EER experience list. Listed in [(5)] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – GAS, CONVENTIONAL w SNCR

Pulverized coal-fired boilers)

NRG Somerset Pulverized Coal, Tangentially-fired, vintage
Unit 6 Boiler 8 (NY) GE-EER Conventional Gas Reburn,
120 MW CE boiler Fuel Tech SNCR, 2003 startup
Reburn vendor claimed to lower NOx 55% from 0.45 lb/mmBtu baseline to 0.20 lb/mmBtu at full load with reburn operation burning Venezuelan coal. The SNCR system further reduced NOx emissions 45% down to 0.11 lb/mmBtu, for an overall reduction of 77%.[(26)].
Source: Sept. 2005 GE Energy experience list; [(26)] March 2004 Modern Power Systems issue.

REBURN – FUEL LEAN GAS REBURN (FLGR)

Pulverized coal-fired boilers

Duke Power Company tangentially-fired, pulverized coal
Riverbend Unit 7 eastern bituminous coal 1954 vintage
140 MWe, CE boiler 1998 FLGR startup, gas reburn decommissioned since then
Previously installed ABB/CE's Low NOx Concentric Firing System (LNCFS-1) with Close-Coupled Overfire Air (CCOFA); (pre-mod NOx + combustion mods date not known).
Commercial FLGR installation claimed 34% NOx reduction from full-load baseline of 0.42 lb/mmBtu down to 0.29 lb/mmBtu w/ the combustion modifications and FLGR gas reburn fuel at 7% of total boiler heat input. CO emissions were above 1000 ppm corrected to 3% O_2.[(27)]
Vendor claimed to lower NOx 57% from 0.47 lb/mmBtu baseline to 0.20 lb/mmBtu) at full load with separated OFA alone; further reduced NOx 45% to 0.11 lb/mmBtu with low-NOx burners, OFA, gas reburn, and SNCR, for 77% overall reduction; no claims for amount of reburn fuel[(24)].

EPA's "Scorecard on Reburning 6/1/2004" showed this reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input[5].
Source: [27] ESA, GRI, NGB 1998 Technical paper; [24] GE Energy 2004 Technical paper; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

REBURN – FUEL LEAN GAS REBURN (FLGR) continued
Pulverized coal-fired boilers
Wisconsin Electric Power Company (WEPCO)
Pleasant Prairie Unit 1 DB Riley, turbo-fired PC, Powder River Basin coal
620 MWg 1980 vintage 1999 startup
Fuel Tech listed FLGR installation and claimed 20% NOx reduction from baseline of 0.45 lb/mmBtu (to 0.36 lb/mmBtu). No claims of percent reburn fuel input included.
Source: Fuel Tech experience list dated 1/28/2005. [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference). (Also see FLGR + SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR)
Pulverized coal-fired boilers
Carolina Power & Light (Progress Energy)
Asheville Unit 1 Pulverized Coal, front wall fired
200 MWe DB Riley boiler 1964 vintage, eastern bituminous coal, June 2000 startup
Commercial urea-based Fuel Tech SNCR +FLGR installation claimed 50% NOx reduction from baseline of 0.58 lb/mmBtu (426 ppm) down to 0.29 lb./mmBtu w/ 5 ppm ammonia slip[1]. Low NO_X burners were previously retrofitted in 1997 without separated overfire air[28]. This is 33 % lower than 0.44 lb/mmBtu baseline for SNCR alone. (Also see SNCR installation summaries for pulverized coal boilers). Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating[5].
Another technical paper showed 52% NOx reduction down to 0.28 lb/mmBtu at all loads, from 99 MWg to 207 MWg (48% to 100% MCR) with an average NH_3 slip of 3 ppm. FLGR alone achieved 23% NOx reduction with 6% reburn fuel and < 400 ppm CO at full load. [28]
Source: Fuel Tech experience list, [1]ICAC White Paper; [5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference); [28] CP&L and Fuel Tech 2001 Technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]
Hudson Station, Unit 2 Pulverized Coal, opposed-wall-fired, 1968 vintage
660 MWe Foster Wheeler boiler eastern bituminous coal March 1999 startup
Commercial SNCR + FLGR urea-based Fuel Tech installation claimed 40% NOx reduction from baseline of 0.65 lb/mmBtu (down to 0.39 lb/mmBtu) w/ 10 ppm ammonia slip[1]. This is 20 % lower than 0.49 lb/mmBtu baseline for SNCR alone. Urea-to-NOx NSR not stated.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating[5].
Source: Fuel Tech experience list, [1]ICAC White Paper;[5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).
(Also see SNCR installation summaries for pulverized coal boilers).

REBURN – FUEL LEAN GAS REBURN w/ SNCR (Amine-Enhanced FLGR) continued

Pulverized coal-fired boilers

Public Service Enterprise Group (PSEG) Power LLC [formerly Public Service Electric & Gas of New Jersey (PSE&G)]

Mercer Station	(2) twin-furnace boilers, 320 MWe each, DB Riley turbo-fired	
Unit 1 and Unit 2	front wall PC, wet-bottom (slagging ash) eastern bituminous coal	
Furnace #11 & #12	1960 vintage	May 1999 startup
Furnace #21 & 22	1961 vintage	May 1999 startup

Commercial urea-based Fuel Tech SNCR + FLGR installation claimed 60% NOx reduction from baseline of 1.4 lb/mmBtu (down to 0.56 lb/mmBtu) w/ 5 ppm ammonia slip [1]. This is 72 % lower than 2.0 lb/mmBtu baseline without control. Initial demonstration of AEFLGR coinjected amine-enhanced natural gas into Furnace 22 in 1998. Subsequently installed AEFLGR on both units to reduce NOx starting in May 1999 using (2) levels of AEFLGR retractable gas injectors and (2) levels of SNCR injectors[29].
Urea-to-NOx NSR not stated, goal was NSR < 1.25.
{Note both units have since been retrofitted with low-dust tail-end SCRs in 2004; SNCR systems are still capable and operated as needed, mostly for flyash conditioning to aid ESP performance}
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 1999, but not currently operating[5].
Source: Fuel Tech experience list, [1]ICAC White Paper; [29] PSE&G, FT and ESA 2000 Technical paper;[5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

Wisconsin Electric Power Company (WEPCO)

Pleasant Prairie Unit 1	DB Riley, turbo-fired PC, Powder River Basin coal	
620 MWg	1980 vintage	1999 startup

Fuel Tech urea-based SNCR +FLGR demonstration installation claimed 56% NOx reduction from baseline of 0.45 lb/mmBtu to 0.20 lb/mmBtu w/ 5 ppm ammonia slip[1]. This is 44 % lower than 0.36 lb/mmBtu baseline for FLGR alone.
EPA's "Scorecard on Reburning 6/1/2004" showed this SNCR-enhanced reburn system lowered NOx by 25-30% with 5-10 percent reburn fuel input in 2000, but not currently operating[5].
Source: Fuel Tech experience list, [1]ICAC White Paper and F.T. experience list 0207;
[5] DOE-NETL Scorecard on Reburning 6/1/2004 (from 2004 Reburn Conference).

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR

Pulverized coal-fired boilers

AEP Cardinal Unit 1	Pulverized Coal	cell-burner, opposed wall-fired B&W boiler
600 MW (nominal)	1967 vintage; Low NO_x burners installed in October 1998	

Produced 0.75 lb/mmBtu NOx post-LNB install baseline at full load.
LNBs reduced NO_X 57% from 1.20 down to 0.52*, produce NO_X at approx. 0.57 lb/mmBtu at min. load w/o SNCR (range 0.51 to 0.65) and produce 0.75 lb/mmBtu NO_X at approx. 585 MW (top of load range tested, NO_X range 0.73 to 0.86 lb/mmBtu) [17].
(50) original B&W circular burners were recently replaced on Cardinal Units 2 & 3 by Buckeye Power with DB Riley (now Babcock Power) CCV type low NOx burners.
Source: *Riley Power (Babcock Power Inc.) 8/16/04 experience list; [17] 2000 Fuel Tech technical paper.
(Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy)

Asheville Unit 1	Pulverized Coal, front wall fired	
200 MWe DB Riley boiler	1964 vintage, eastern bituminous coal, June 2000 startup	

Low NO_X burners were previously retrofitted in 1997 without separated overfire air[22]. NOx reduction was 46% from pre-LNB installation baseline of 1.08 lb/mmBtu [12] down to 0.58 lb./mmBtu [28].

(Also see SNCR, and FLGR with SNCR installation summaries for pulverized coal boilers).
Source: [12] 2005 US EPA Docket OAR-2002-0076-0446 Technical Support Document spreadsheet; [28] CP&L and Fuel Tech 2001 Technical paper.

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 5 1956 vintage; eastern bituminous coal
154 MW CE boiler ROFA startup in 2000
Mobotec USA's Rotating Opposed Fire Air (ROFA) is a high velocity boosted separated overfire air system claimed to lower NO_X without retrofitting low-NOx burners. This was the first U.S. installation of Mobotec USA's "Rotating Opposed Fire Air" (ROFA) on a utility boiler, which utilizes a booster fan.
CP&L technical paper claimed to lower NO_X 53% from full-load pre-ROFA baseline 0.60 lb/mmBtu to 0.28 lb/mmBtu with ROFA alone following the installation of ROFA in 2000[18].
Source: [18] CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Carolina Power & Light (Progress Energy) Pulverized Coal, Tangentially-fired
Cape Fear Unit 6 twin-furnace (eight corner), 1958 vintage; eastern bituminous coal
175 MW CE boiler ROFA startup in 2001
This unit's "ROFA" system was installed as part of a "Rotamix" SNCR + ROFA system.
CP&L technical paper shows ROFA alone reduced NOx 57% from full-load pre-ROFA baseline 0.54 lb/mmBtu to a NO_X emission rate of 0.23 lb/mmBtu. [18]
Source: [18] CP&L 2002 Technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Conectiv (formerly Delmarva Power & Light)
Indian River Units 3 & 4 (Millsboro, DE) Unit 3 is front wall-fired, 1974 vintage
178MW and 440 MW Unit 4 is turbo-fired opposed-wall, 1980 vintage
B&W, DB Riley boilers eastern bituminous coal
REI performed CFD modeling on both units for potential SNCR application.
Unit 3 has Riley Low NOx burners (16), (8) front wall and (8) rear wall OFA ports, (8) wall boundary air ports, (66) side wall OFA slots, claimed baseline NOx around 0.37 lb/mmBtu w/o SNCR [20].
Unit 4 has (24) front and rear wall down-fired burners, (28) front and rear wall SOFA ports, claimed NOx around 0.44 lb/mmBtu w/o SNCR [20] {furnace has "Mae West" belt}.
Riley provided 16 CCV low-NOx burners for Unit 3 in 1994, and claimed to reduce NOx emissions by 67% from pre-LNB baseline of 1.05 lb/mmBtu down to 0.34 lb/mmBtu.
Source: [20]REI 1999 Technical Paper; Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see SNCR installation summaries for pulverized coal boilers).

Dayton Power & Light Pulverized Coal, Tangentially-fired
Killen Station, Unit 2 1955 vintage
632 MW CE boiler, bituminous Illinois coal
GE-EER provided low-NOx burners in 1999. Vendor claimed full load NO_X was reduced by 23% from a 0.57 lb/mmBtu baseline down to 0.44 lb/mmBtu.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, wall-fired
Havana Station, Unit 6 1978 vintage
460 MW B&W boiler, bituminous Illinois coal
GE-EER provided modifications to the original B&W dual-register burners, and an OFA system in 2000.
Vendor claimed full load NO_X was unchanged from 0.38 lb/mmBtu baseline.
Source: GE-EER Experience list 2/1/02. (Also see low-dust SCR installation list for pulverized coal boilers)

Dynegy Midwest Generation (formerly Illinois Power) Pulverized Coal, Tangentially-fired
Vermillion Station, Unit 1 1955 vintage
82 MW CE boiler, bituminous Illinois coal
This rotating opposed fire air (Mobotec USA ROFA) system was installed in July 2002, as part of a "Rotamix" SNCR + ROFA system, without low-NOx burners.
Mobotec 2004 technical paper claimed to lower full load NO_X by 62% from 0.58 lb/mmBtu baseline to 0.22 lb/mmBtu in July 2002 (without LNB or SNCR). [21]
Source: [21] Mobotec 2004 technical paper. (Also see SNCR installation summaries for pulverized coal boilers).

Georgia Power Pulverized coal, opposed wall-fired,
Harlee Branch Unit 1 250 MW B&W boiler, 1965 vintage 2003 startup
Harlee Branch Unit 2 359 MW Riley boiler, 1967 vintage 1998 startup
B&W provided 24 DRB-4Z low NOx burners for Unit 1 B&W boiler, 24 DRB-XCL low NOx burners for Unit 2 Riley boiler (believe southeast coast lignite is primary fuel).
Source: B&W's experience list. No NOx reduction claims.

Kansas City Power & Light Pulverized coal, opposed wall-fired, 600 MW B&W boiler
Hawthorn Unit 5 30 burners, 2001 vintage, (Powder River Basin coal)
B&W provided 30 DRB-4Z low NOx burners and 11 OFA ports with the new boiler.
Source: B&W's experience list. No NOx reduction claims.

New England Power Company (NEPCO)
Salem Harbor Station Pulverized Coal, front wall-fired,
Units 1, 2 & 3 1952, 1952, 1958 vintage (eastern bit. coal)
84 MWe x 2, & 156 MWe B&W boilers LNBs startup in 1995, 1995, and 1993
Riley claimed Unit 1 LNBs reduced NOx emissions by 57% from baseline of 1.10 lb/mmBtu down to 0.42 lb/mmBtu; Unit 2's LNBs achieved 42% NOx reduction from a baseline of 0.95 lb/mmBtu down to 0.55 lb/mmBtu; Unit 3's LNBs achieved 60% NOx reduction from a baseline of 1.05 lb/mmBtu down to 0.42 lb/mmBtu.
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list.
(Also see SNCR installation summaries for pulverized coal boilers).

Northeast Utilities (formerly Public Service of New Hampshire)
Shiller Station Pulverized Coal/#6 Fuel oil, front-wall-fired
Units 4, 5, & 6 1952, 1955, 1957 vintage
50 MWe x 3 Foster Wheeler boilers
RJM provided (6) Low NO_x burner modifications per boiler in 1994, 1992, & 1994 respectively;
LNBs reduced NOx 43% from 0.85 to 0.48, 50% from 1.0 to 0.50, and 51% from 0.82 to 0.40 lb/mmBtu.
Source: RJM experience list

LOW NO_x BURNERS (Replacement or modifications) w/ and w/o OVERFIRE AIR continued

Pulverized coal-fired boilers

Potomac Electric Power (formerly West Pennsylvania Power)

Chalk Point Station	Pulverized Coal	opposed wall-fired
Units 1 & 2	1964, 1965 vintage	eastern bituminous coal
360 MW (nominal)	B&W boilers	

DB Riley (now Babcock Power) CCV type low NOx burners retrofitted in 1993 and 1994, respectively. Vendor claimed to lower NOx up to 52% and 50% from 1.35 and 1.40 lb/mmBtu baselines (to 0.65 and 0.70 lb/mmBtu, assumed at full load).
Source: Riley Power (Babcock Power Inc.) 8/16/04 experience list. (Also see Conventional Gas Reburn installation summaries for pulverized coal boilers).

Xcel Energy (formerly Public Service Company of Colorado)

Cherokee Unit 3	Pulverized coal, wall-fired, B&W boiler, 16 burners, 1962 vintage
175 MW	October 1992 baseline testing started (western bituminous coal)

Installed (16) Foster Wheeler Controlled Flow/Split Flame low NO_x replacement burners as part of a DOE Clean Coal Technology gas reburn demonstration performed with Gas Research Institute 1992-1995.
Uncontrolled NOx w/ original B&W flare-type burners was 0.73 lb/mmBtu. Replacement LNBs (assuming OFA included) reduced NO_X 37% to 0.46 lb/mmBtu[25].
Source: [25] DOE NETL 2001 Technical paper.

A.2.2 Technical Literature References for U.S. NOx Control Retrofit Projects:

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APPENDIX B

EERC REPORT

Ash Impacts on SCR Catalyst Performance

ASH IMPACTS ON SCR CATALYST PERFORMANCE

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ASH IMPACTS ON SCR CATALYST PERFORMANCE

EXECUTIVE SUMMARY

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems. The Center lignite fired at the Milton R. Young (MRY) Power Station is highly variable in abundance of various types of ash/slag-forming components. Ash-forming components consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. The alkali and alkaline-earth elements combine with minerals during combustion, resulting in low-melting-point phases that cause a wide range of fireside deposition problems. In addition, the alkali and alkaline-earth elements also form very small particles that are carried into the backpasses of the combustion system and react with flue gas to form sulfates that can cause deposition, blinding, and plugging problems in selective catalytic reduction (SCR) systems. This report analyzes these problems, and concludes that SCR is not a feasible option to control NOx emissions at MRY Power Station because of the high sodium levels present in the coal.

Following is a list of the key problems that are associated with Center lignite which have not been overcome and, in our opinion, make the installation of SCR at the MRY plant technically infeasible for NO_x control.

- Blinding of Catalyst Pores by High Sodium Compounds

  X High levels of alkali and alkaline-earth elements present in the coal fired at the MRY plant produce small particles that react to form sulfates that blind the catalyst pores. The high levels of sodium in the coals combined with calcium will produce low-melting-point eutectic sulfate compounds that will form and melt inside the pores of the catalyst.

  - Alkali and alkaline earth sulfates are enhanced by cyclone fired system. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the ash as a a result of cyclone firing.

  - Sulfate formation is enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.

  - The sulfate reactions are more severe at MRY because of the high temperature where an SCR would be installed. The higher temperature increases the rate of formation of sulfates and rate of pore plugging.

  - The testing conducted by the Germans found catalyst deactivation and blinding occurs when firing coals with lignite or brown coals that have ashes that are rich in alkali and alkaline-earth elements. .

- The findings by the Germans were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-rich sulfate formation that fill and plug the catalyst at both lignite- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or "popcorn ash," plugging the top of the SCR catalyst is a significant problem because of the extremely high deposition rates of the Center coal. When firing Center coal, deposits form on various parts of the boiler requiring continuous sootblowing. The sootblowing of upstream heat-exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, resulting in plugging. In addition, during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

- Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

➢ Cold Side SCR Installation

- High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces significant levels of homogeneously condensed sodium sulfate that pass through the ESP and wet scrubber.

- These small particles have been shown to pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials require sootblowing to remove the particulate and will result in increased opacity.

- Liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems are known to catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates.

ASH IMPACTS ON SCR CATALYST PERFORMANCE

INTRODUCTION

Ash produced during combustion of coal in conventional power systems is a major problem that results in decreased efficiency, unscheduled outages, equipment failures, and increased cleaning. The many ways in which the detrimental effects of ash manifest themselves in a boiler system include fireside ash deposition on heat-transfer surfaces, corrosion and erosion of boiler parts, poor slag flow, and production of fine particulates that are difficult to collect. Decades of research have been conducted to develop a better understanding of the chemical and physical processes of ash formation and deposition in combustion systems. Overviews of ash-related issues and compilations of work by many investigators can be found by referring to the work of Mehta and Benson (1), Schobert (2), Baxter and DeSollar (3), Couch (4), Williamson and Wigley (5), Benson and others (6), Benson (7), Bryers and Vorres (8), Raask (9, 10), and Benson (11). This work has led to a detailed understanding of ash formation and behavior in combustion systems as well as the development of predictive methods (12, 13).

The chemical composition and physical characteristics of ash-forming or inorganic components (mineral and organically associated elements) of the fuel(s) fired have an influence on the following processes in the combustion systems:

- Firing conditions such as cyclone, pulverized coal, and low-NO_x burners
- Transformations of coal inorganic components to ash particulate and vapor-phase species
- Boiler design characteristics, including number of burners, radiant section area, tube bank spacing, access for cleaning, and number of sootblowers
- Ash transport to heat-transfer surfaces in utility boilers
- Erosion wear and sticking
- Ash deposit growth and impact on heat transfer
- Ash blinding and plugging of selective catalytic reduction (SCR) catalysts
- Ash deposit removability

The ash deposition in North Dakota lignite-fired power plants is a major problem that impacts all fireside surfaces of the power plant. The ash problems are due to the variable and complex nature of inorganic components associated with lignite coals (2). Upon combustion, the inorganic components undergo chemical and physical transformations that produce intermediate inorganic species in the form of inorganic gases, liquids, and solids. During the gas-cooling processes in the boiler, the gas-phase species condense and the liquid-phase materials solidify. The abundance of these gas-phase and liquid materials entrained in the bulk gas flow is highly dependent upon coal composition and system operating conditions. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, thermophoresis,

and inertial impaction. The particle sticking and accumulation rates are dependent upon the quantity of ash and the abundance and viscosity of the liquid-phase components. In high-temperature regions of the boiler, high-temperature sodium–calcium–aluminosilicate liquid phases act as the sticky material, causing deposit initiation, growth, and development of deposit strength. As the temperature of the flue gases decreases, the condensation and reaction of flame-volatilized species play a more significant role in the formation of deposits from lignite coals. The formation of sodium and/or calcium magnesium sulfates dominates the deposit accumulation mechanisms at lower temperatures. The aluminosilicate phases are dominant above about 1800°F. Below about 1800°F, the sulfate phases become stable, with an optimum temperature of formation of about 1400°F, and can form at temperatures as low as 300°F.

The most significant problems that prohibit the successful operation of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates and phosphates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16).

INORGANIC COMPOSITION OF LOW-RANK COALS

Inorganic elements in coal occur as discrete minerals, organically associated cations, and cations dissolved in pore water. The fraction of inorganic components that are organically associated varies with coal rank. Lower-ranked subbituminous and lignitic coals have high levels of oxygen, which act as bonding sites for cations such as sodium, magnesium, calcium, potassium, strontium, and barium (other minor and trace elements may also be present in this form). In higher-ranked coals, bituminous and anthracite, inorganic components consist mainly of minerals. Mineral grains are usually the most abundant inorganic component in coal. The major mineral groups found in coals include silicates, aluminosilicates, carbonates, sulfides, sulfates, phosphates, and some oxides.

The behavior of ash produced during coal combustion is related to the abundance, size, and association of mineral grains in the coal. In addition, the association of the mineral grain with the coal matrix influences the temperature and gaseous environment the mineral is exposed to during combustion. A mineral associated with the organic part of a coal particle is said to be included. A mineral that is not associated with organic material is referred to as excluded. The behavior of the organically associated elements, those elements that are atomically dispersed in the coal matrix, must also be measured as to their abundance in the coal. The organically associated elements will react and interact with the other ash-forming constituents during combustion.

The Center lignite is highly variable in abundance of various types of ash/slag-forming constituents. Ash-forming components in the Center lignite are of two types. The first form may constitute up to 50% of the ash and is derived from inorganic elements (sodium, magnesium, calcium, and potassium) associated with oxygen functional in the organic matrix of the coal. The second type consists of mineral grains (sand, clay, limestone, and pyrite). The minerals are discrete particles of ash-forming species and the sources of silicon, aluminum, iron, titanium, and minor amounts of the calcium and potassium. The Center lignite fired at the Milton R. Young (MRY) plant has been examined extensively because of its problem with ash behavior. Analyses

of as-fired and drill core samples have been conducted. The mean and the range of selected components are shown in Figure 1. The results indicate that both the abundance of ash and the abundance of major oxides in the ash vary significantly. In addition, the abundance of alkali and alkaline-earth elements (Na and Ca) varied dramatically. Variations in Si were found to be the most significant. High levels of Ca and/or Na were found for lower-ash coals as compared to high levels of Al and Si associated with higher-ash coals (17, 18).

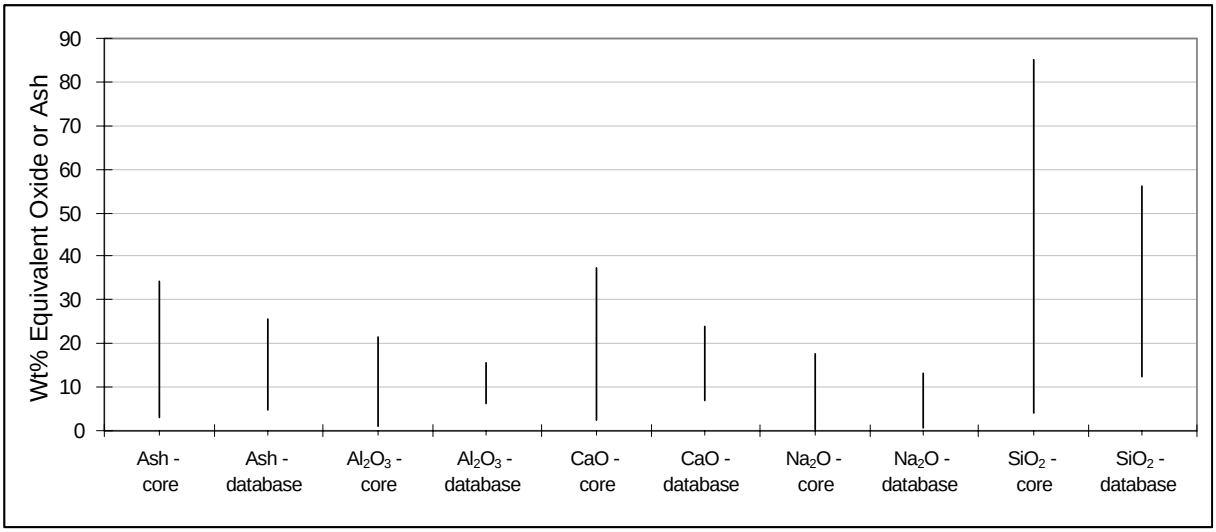

Figure 1. Variability of ash and selected constituents in core analysis database provided by BNI Coal, Ltd. and Minnkota as fired coal analysis database.

The variability of the ash-forming components has been examined for the approximately 5000 samples characterized to date. Wide variations in ash contents and the major ash-forming constituents are observed. During the mining processes, the inorganic components are mixed, and some of the extreme characteristics are diluted (17).

INORGANIC TRANSFORMATIONS AND ASH FORMATION

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species. The inorganic species consist of vapors, liquids, and solids. The partitioning of the inorganic components during combustion to form ash intermediates depends upon the association and chemical characteristics of the inorganic components, the physical characteristics of the coal particles, the physical characteristics of the coal minerals, and the combustion conditions.

The physical transformation of inorganic constituents depends on the inorganic composition of the coal and combustion conditions. The inorganic components can consist of organically associated cations, mineral grains that are included in coal particles, and excluded mineral grains. There is a wide range of combinations of mineral–mineral, mineral–coal,

mineral–cation–coal, and mineral–mineral–cation–coal associations in coal. These associations are unique to each coal sample.

The physical transformations involved in fly ash formation include 1) coalescence of individual mineral grains within a char particle, 2) shedding of the ash particles from the surface of the chars, 3) incomplete coalescence due to disintegration of the char, 4) convective transport of ash from the char surface during devolatilization, 5) fragmentation of the inorganic mineral particles, 6) formation of cenospheres, and 7) vaporization and subsequent condensation of the inorganic components upon gas cooling. As a result of these interactions, the ash has a bimodal size distribution. The submicron component is largely a result of the condensation of flame-volatilized inorganic components. The mass mean diameter of the larger particles is approximately 12 to 15 µm, depending upon the coal and combustion conditions. The larger-size particles have been called the residual ash by some investigators (19) because these ash particles resemble, to a limited degree, the original minerals in the coal. Processes such as ash mineral coalescence, partial coalescence, ash shedding, and char fragmentation during char combustion and mineral fragmentation, all play an important role in the size and composition of the final fly ash. Loehden and others (20) and Zygarlicke and others (21) indicate that three potential modes for fly ash generation can be used to describe fly ash particle-size and composition evolution. The first, "fine limit," assumes that each mineral grain forms a fly ash particle and that the organically associated elements form fly ash particles of less than 2 µm. The second, "total coalescence," assumes one fly ash particle forms per coal particle. The third, "partial coalescence," suggests that the fly ash composition and particle size evolve because of partial coalescence.

The transformations of excluded minerals are dependent upon the physical characteristics of the mineral. Excluded minerals such as quartz (SiO_2) can be carried through the combustion system with its angular structure still intact. Excluded clay minerals can fragment during dehydration, melt, and form cenospheres. The behavior of excluded pyrite depends upon its morphology. Some of the pyrite may be present as framboids. Framboidal pyrite may fragment more easily than massive pyrite particles. In addition, the decomposition of pyrite is very exothermic, and it transforms to pyrrhotite and oxidizes to FeO, Fe_3O_4, and Fe_2O_3 during combustion.

ASH DEPOSITION ON HEAT-TRANSFER AND OTHER SURFACES EXPOSED TO ASH AND FLUE GAS

The characteristics of a deposit depend upon the chemical and physical characteristics of the intermediate ash species, geometry of the system (gas flow patterns), gas temperature, gas composition, and gas velocity. Figure 2 illustrates the ash deposition phenomena in utility boilers. Ash particle accumulations occur via transport of particles to the fireside surfaces (heat transfer, ceramic materials, support materials, SCR catalysts, baghouse materials, and ESP wires and plates) and sticking of the particles. The transport mechanisms important for ash deposition include small-particle mechanisms for particles less than 10 µm that involve thermophoresis, electrophoresis, and vapor-phase and small-particle diffusion; and large-particle mechanisms for particles greater than 10 µm that involve inertial impaction. The ability of larger particles to stick depends upon the quantity and viscosity of the liquid phase on the particle surface.

Thermophoresis is a phenomenon that involves the transport of very small particles as a result of a thermal gradient from hot gases to cooler surfaces. Electrophoresis is the transport of particles because of a difference in charge. Vapor-phase and small-particle diffusion occurs in the boundary layer next to the surface and results in transport of ash to the surface. Inertial impaction is a larger-particle phenomenon where the particles are of a sufficient size and density to leave airflow patterns around the tube and impinge upon the surface of a tube or deposit. Deposits that form in high-temperature regions of the boiler, such as the radiant section, are called slag deposits. Deposits that form in lower-temperature regions of the boiler, such as in the convective pass on steam tubes and lower-temperature surfaces such as SCR catalysts, are called fouling deposits. Slag deposits are usually associated with a high level of liquid-phase components and are exposed to radiation from the flame. This is a description that many researchers use to aid in classification of deposits since some engineers call any type of deposit "slag". Slag deposits are typically dominated by silicate liquid phases, but may also contain moderate to high levels of reduced iron phases such as FeO and FeS. The liquid characteristics of the silicates are highly dependent upon the quantities of Na, Mg, Ca, K, and Fe ash on the silicates. In addition, the initiating layers of slag deposits may consist of very fine particulate and can produce a reflective ash layer. This phenomenon is especially evident when high organically associated calcium subbituminous coal is fired. These coals produce small CaO particles that usually form the initiating layers.

Fouling deposits form in the lower-temperature regions of the boilers and, in most cases, do not contain the high levels of liquid phases that are usually associated with slagging-type deposits. Fouling deposits contain lower levels of liquid phases as compared to slag deposits. The fouling deposit liquid phases usually consist mainly of sulfates that bind the particles together. Fouling deposits typically form as a result of the reaction of gas-phase sulfur oxide species with particles rich in alkali and alkaline-earth elements.

ASH-RELATED EXPERIENCES AT MRY FACILITY

The MRY is a minemouth electrical generating plant located near Center, North Dakota. The station consists of two units: Unit 1, rated at 276 MWg, began production in 1970; Unit 2, rated at 506 MWg, began production in 1977. Both Units 1 and 2 are equipped with B&W cyclone-fired boilers; the Unit 1 boiler has seven cyclones, and the Unit 2 boiler has twelve cyclones. Annual station gross generation is approximately 5.5 million MWh.

BNI Coal Ltd. is the sole coal supplier for the MRY Station. Coal is mined from the nearby Center mine, which consists of three distinct seams varying from 2½–9 feet thick. Coal is strip-mined using two draglines and is loaded with front-end loaders and delivered to the plant with bottom-dump haul trucks. Annual coal production is 4.3 million tons per year.

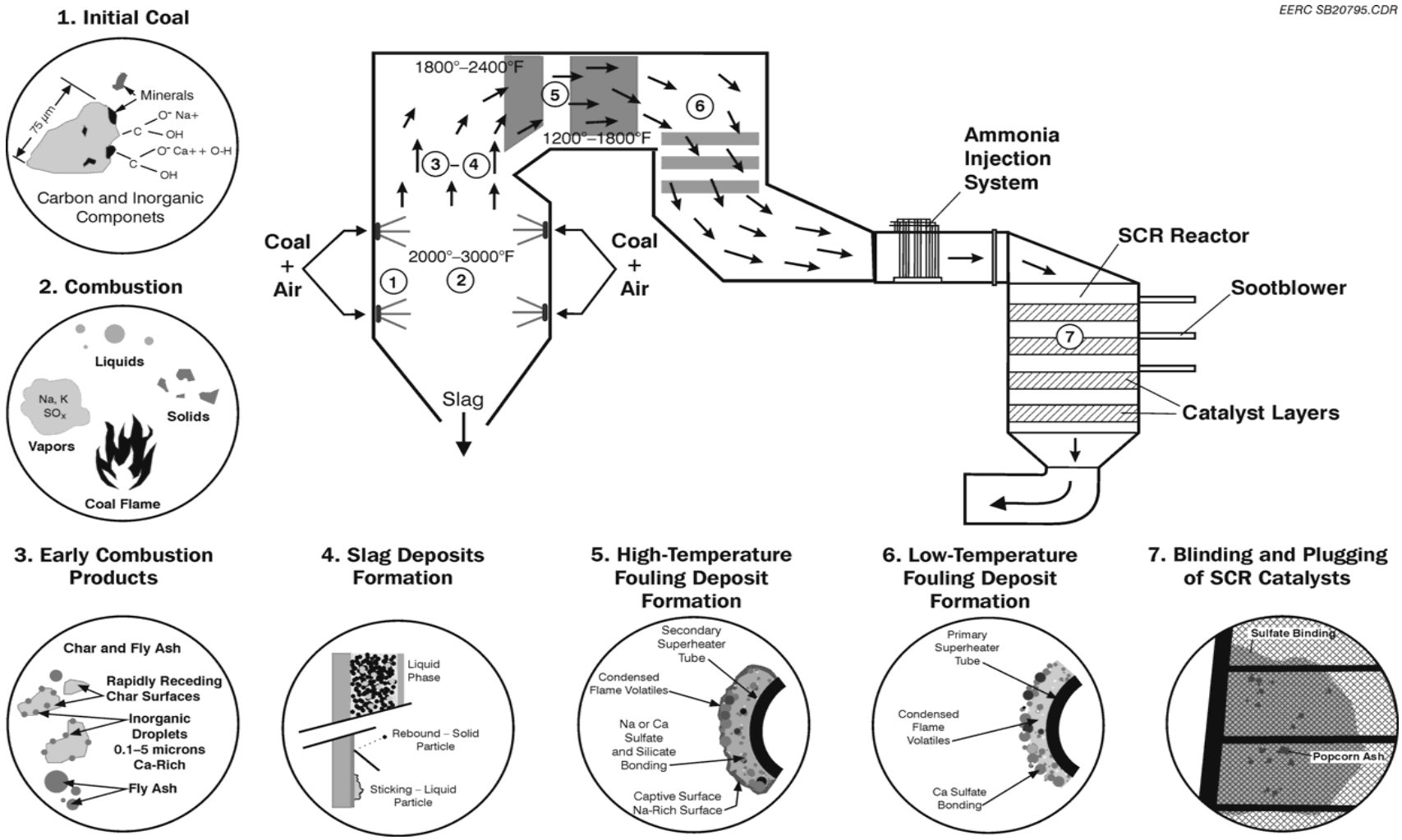

Figure 2. Overall processes of ash deposition typical of a lignite- or subbituminous-fired boiler.

History of Furnace Slagging/Fouling

Prior to 1991, besides annual maintenance outages, load reductions and forced outages due to furnace slagging/fouling were the largest cause of production loss. In 1985, operating guidelines were established that reduced furnace slagging/fouling, including deslagging outages scheduled every six months.

In 1991, a 3-month boiler cleaning cycle was proposed and initiated. The goal of this program was to increase annual generation by running the units at higher sustained loads and scheduling boiler-cleaning outages at 3-month intervals. However, furnace slagging/fouling continued to have a significant impact on plant operations. Success was measured in the number of production days between boiler-cleaning outages.

During the mid-1990s, a major outage every third year was scheduled for each unit. In addition, Unit 1 cleaning outages were scheduled for 80–90-day runs (four cleaning outages per year), and Unit 2 cleaning outages were scheduled for 65–75-day runs (five cleaning outages per year). The problem was that furnace and convection-pass surfaces gradually become coated with ash deposits, which, over time, sootblowers cannot remove. Some of the contributors to the ash deposits were as follows:

- Organically associated sodium is a primary contributor to deposition problems. Sodium is vaporized in the cyclones and condenses on other ash particles, causing them to become sticky and deposit at the furnace exit. The problem is associated with sulfate formation and occurs in the convective pass, including the economizer. Samples show that sodium in the ash varies from 0.6%–13.0%.

- Organically associated calcium is another component that causes deposition problems. Unlike sodium, calcium does not produce a vapor-phase component. Calcium does react with silicate (derived from clays) to cause low-melting-point phases that produce wall deposits and deposits in the high-temperature regions of the convective pass. Calcium also produces very small particles that will be transported to heat-transfer surfaces, resulting in the formation of thin, light-colored layers called reflective ash. These small particles of ash are carried through to the back passes where they are sulfated and can combine with sodium to cause the formation of strongly bonded sulfate-based deposits. Samples show that calcium in the ash varies from 6.8%–24.0%.

- Clay minerals and quartz – Center lignite can contain high levels of illite, which has a 1:3 Al:Si ratio and high levels of potassium, both of which cause wall slagging and high-temperature fouling. Quartz and other clays can significantly contribute to the mass of the deposits. Samples show that ash content varies from 5.0%–25.5%.

Advanced Boiler Performance Indices

Advanced indices are used to relate the coal characteristics as determined by computer-controlled scanning electron microscopy (CCSEM) and chemical fractionation to ash behavior in a coal-fired utility boiler (12). Fuel performance is estimated in terms of slag flow behavior,

abrasion and erosion wear, wall slagging, high-temperature silicate-based convective pass fouling, and low-temperature sulfate-based convective pass fouling. The following indices are used to assess the effects of ash behavior on utility boiler performance:

- Convective-Pass Fouling Indices

Sulfation Index: Indicates the propensity of deposit to form in the convective pass of the utility boiler in the temperature range from 1000°–1750°F. This index is based on the availability of alkali (Na and K) and alkaline-earth (Ca and Mg) elements to react with SO_2 and SO_3 to form sulfates. The sulfates are the primary materials that cause particle-to-particle bonding in high-calcium coals. The sulfates are thermodynamically stable at temperatures below about 1650°F. Index values range from 1 (low) to 10 (severe).

Silicate Index: Indicates the propensity of deposits to form from 1600°–2400°F. This index is related to the formation of deposits in which the silicate material is the primary component that bonds the deposits together. The information used to derive the index includes the size of the minerals such as quartz and clay minerals, availability of alkali and alkaline-earth elements, and viscosity of the silicate liquid phase. Index values range from 1 (low) to 200 (severe).

- Waterwall Slagging

Slagging Index: Indicates the propensity of a deposit to form on the radiant walls from 2000°–3000°F. The basis of the slagging index is the size of the minerals (especially the illite, quartz, and pyrite), association of the calcium (calcite can contribute to slagging), and viscosity of the silicate-based liquid phase. Index values range from 1 (low) to 20 (severe).

- Wear Indices

Abrasion Index: This index indicates the potential for wear of fuel preparation and handling equipment. The wear is related to the hardness of minerals in the coal. The primary minerals of concern include quartz and pyrite. The index values range from 0.1 (low) to 10 (severe).

Erosion Index: This index indicates the potential for wear of boiler parts due to the impaction of fly ash particles. The erosion index is dependent upon the size of the ash/mineral particle, size of the particle, and velocity of the particle. The index values range from 0.1 (low) to 1.0 (severe).

- Cyclone Slagging Index: This index provides information on the slag flow behavior in cyclones. The factors that are included in this index include the partitioning of the ash in the cyclone based on size and association of the ash-forming components in the coal. The partitioning of the ash between the slag and entrained ash can significantly influence the flow behavior of the slag. Standard partitioning criteria have been developed to provide the composition of the slag. The composition is used to estimate the viscosity of the slag as a function of temperature. The index values have several ranges as follows: 1 (low viscosity), 1.5–2.5 (optimum viscosity), >3.0 (slag freezing).

- Strength Development Index: The strength index is based on the ability of the deposited material to develop strength. Strength development is primarily dependent upon the abundance and viscosity of the liquid-phase components in the deposits. Index values less than 0.25 indicate that the material will produce weak deposits; index values of 0.25–0.34 indicate weak-to-moderate-strength deposits; index values of 0.34–0.41 indicate high-strength deposits; and index values >0.41 indicate flowing slag.

Indices were calculated for a range of coals from the Center mine, and the propensity for ash deposition in various portions of the boiler indicates wide variations, as shown in Table 1. The BNI numbers indicate the location in the seams where the coal originated: Kinneman Creek seam (KC), Hagel A (HA), and Hagel (HB). Each seam has a different distribution of minerals and organically associated elements that can have a significant impact on the formation of deposits in the system. Comparison of Center lignite to subbituminous and bituminous coals from other regions of the United States, shown in Table 2, indicates significant differences in the potential to form deposits in the boilers. In all cases, the lignite (not the worst coal from Center mine) from the Center mine has a high propensity to produce deposits as compared to the other coals.

Another indication of the variability of lignites can be illustrated based on the calculation of the temperature where the slag flow would occur. This is defined as the T250 temperature, where the slag viscosity is 250 poise. Frequency distributions of the T250 values for all the data for coals analyzed are illustrated in Figure 3. Calculations of T250 values for 1212 samples obtained from the Center mine database (17) were made using empirical relations derived from CCSEM and chemical fractionation data and knowledge of how ash partitions in the cyclone. Figure 3 shows a bimodal distribution in the T250 based on the Urbain equation calculations. The primary mode was at a value of 2000°F. The secondary mode was at about 2700°F. The results indicate that many of the coals have a sufficiently low T250 for good slag flow. However, coals with T250 at 2700°F are not suitable for maintaining good slag flow.

Figures 4 through 6 illustrate the variations in T250 for the various seams of coals characterized. The HA and HB seam coals appear to have large numbers of samples, with T250 values at or near 2000°F. The KC seam coal, as illustrated in Figure 6, has extremely high T250 values. Based on these data, the KC coals are not favored relative to the slag flow behavior of the ash.

Frequency distributions of cyclone slagging index values indicated significant variations in slagging potentials of coals mined from the three seams, KC, HA, and HB. This information proved particularly useful in planning the mining and firing of coal from the KC seam.

During a July 1999 test burn, the composition of the cores was used to examine and illustrate the variability of the delivered coal quality based on base-to-acid ratio calculated from the ash composition. Figure 7 shows the variation in the base-to-acid-ratio and the seam where the coal was loaded. The base-to-acid ratios were calculated from core data that corresponded to the location in the seam where the coal was mined. There is a significant variation in the base-to-acid ratio for the coals. The coals that have the highest base-to-acid ratio are typically from the HA seam. HB seam coals generally have an intermediate base-to-acid ratio. KC or top-seam coal has the lowest base-to-acid ratio. Lower base-to-acid-ratio coals typically produce slag with high viscosities.

Table 1. Characteristics and Indices Calculated for Selected Center Lignite Samples

BNI No.	41-132HB	41-44KC	41-144HA	41-144HB	41-168KC	41-168HA	41-168HB	41-180KC	41-180HA	41-180HB	41-192KC	41-192HA
Mineral wt%, mineral basis												
Total Quartz Content			18.8	9.8	30.3	8.7	8.8	11.4	20.0	3.9	15.0	17.4
Quartz <10 microns		10.8		6.4	24.6	4.4	4.0	6.8	3.3	2.6	9.7	12.7
Total Kaolinite Content		10.6		10.8	7.7	6.4	1.7	9.5	4.4	2.4	14.3	28.0
Kaolinite Content <10 microns		5.1		6.3	4.5	2.6	0.9	4.8	1.1	0.9	10.2	20.8
Total Montmorillonite		10.7		2.7	6.5	1.7	6.1	7.0	2.3	2.4	7.6	5.1
Total Illite		14.1		9.3	6.6	0.2	28.0	19.1	10.2	1.6	6.8	1.9
Total Pyrite		8.0		26.7	18.9	67.1	19.7	9.1	10.9	57.2	22.6	32.3
Pyrite Content <10 microns		4.5		10.5	2.8	9.8	4.7	2.5	2.5	17.0	6.6	7.0
Gypsum Content		6.5		0.0	1.6	2.7	0.8	5.4	0.0	16.1	2.2	0.0
Proximate (wt% as received)												
Moisture		30.95		41.66	36.24	38.23	37.50	37.90	37.99	38.21	37.85	39.52
Volatile Matter		27.26		25.74	26.32	25.90	24.55	25.11	24.42	25.88	26.13	24.27
Fixed Carbon		26.56		27.97	28.18	29.65	30.37	27.94	29.53	31.54	29.15	30.30
Ash		10.30		4.63	9.26	6.22	7.58	9.05	8.1	4.37	6.88	5.91
Total Sulfur (% as received)		0.94		0.55	1.49	1.08	0.75	0.99	0.64	0.86	0.90	0.85
Btu/lb		6597		6593	6791	6957	6806	6584	6653	7194	6881	6835
% Ash (dry basis)	11.64	10.30		7.94	14.52	10.07	12.13	14.57	13.00	7.07	11.07	9.77
Ash Comp. (wt% equiv. Oxide)												
Na_2O		0.50		10.65	0.82	9.25	8.02	0.46	8.15	11.99	1.48	9.69
MgO		3.30		5.74	3.72	4.90	4.45	3.90	5.00	4.59	6.13	5.10
Al_2O_3		11.90		10.37	9.34	5.64	11.81	12.12	10.19	5.23	10.59	7.46
SiO_2		30.60		14.70	33.71	8.47	30.74	35.57	36.25	5.31	25.80	13.06
P_2O_5		0.20		0.06	0.15	0.42	0.25	0.07	0.26	0.23	0.25	0.24
SO_3		23.00		25.50	21.28	35.25	21.05	18.32	15.93	35.75	24.15	32.75
K_2O		1.20		0.96	0.47	0.62	1.52	1.03	1.22	0.47	0.55	0.60
CaO		16.80		21.00	15.31	18.94	12.10	17.15	14.87	15.43	20.01	18.98
TiO_2		1.30		0.39	0.72	0.29	0.40	0.51	0.29	0.16	0.48	0.28

Continued . .

MnO		0.20		0.03	0.07	0.05	0.04	0.10	0.07	0.04	0.07	0.12
Fe_2O_3		10.30		8.43	14.87	15.95	10.44	7.80	6.84	18.88	10.12	13.29
Cyclone Slagging Index		2.77		1.28	2.5	1.1	2.6	3.3	2.9	0.4	2.2	1.3
Silicate		10.71		102.43	29.47	108.33	109.93	16.29	176.22	137.49	14.19	149.54
Sulfate		9.43		3.57	2.2	5.01	3.46	1.75	3.98	4.4	2.21	3.24
Wall Slagging Index		1.18		11	2.67	10.68	9.27	1.79	8.83	12.63	2.2	10.53
Erosion Index		0.19		0.15	0.17	0.19	0.22	0.21	0.27	0.17	0.17	0.17
Abrasion Index		2.14		0.71	6.46	1.55	1.41	2.25	1.93	0.83	1.75	1.68
Strength Index		0.32		0.66	0.35	1.11	0.35	0.3	0.33	1.32	0.43	0.63

Table 2. Advanced Index Values for Other Coals (12)

Advanced Indices	Lignite North Dakota	Powder River Basin	Bituminous Illinois	Bituminous Appalachian
Cyclone Slagging Index	1.6	2.1	3.5	3.2
Convective Pass Fouling				
Silicate	61.8	23.99	10.36	14.21
Sulfate	4.09	2.88	0	0
Wall Slagging Index	9.28	1.85	1.53	1.66
Erosion Index	0.15	0.17	0.14	0.17
Abrasion Index	0.71	1.96	3.94	1.96

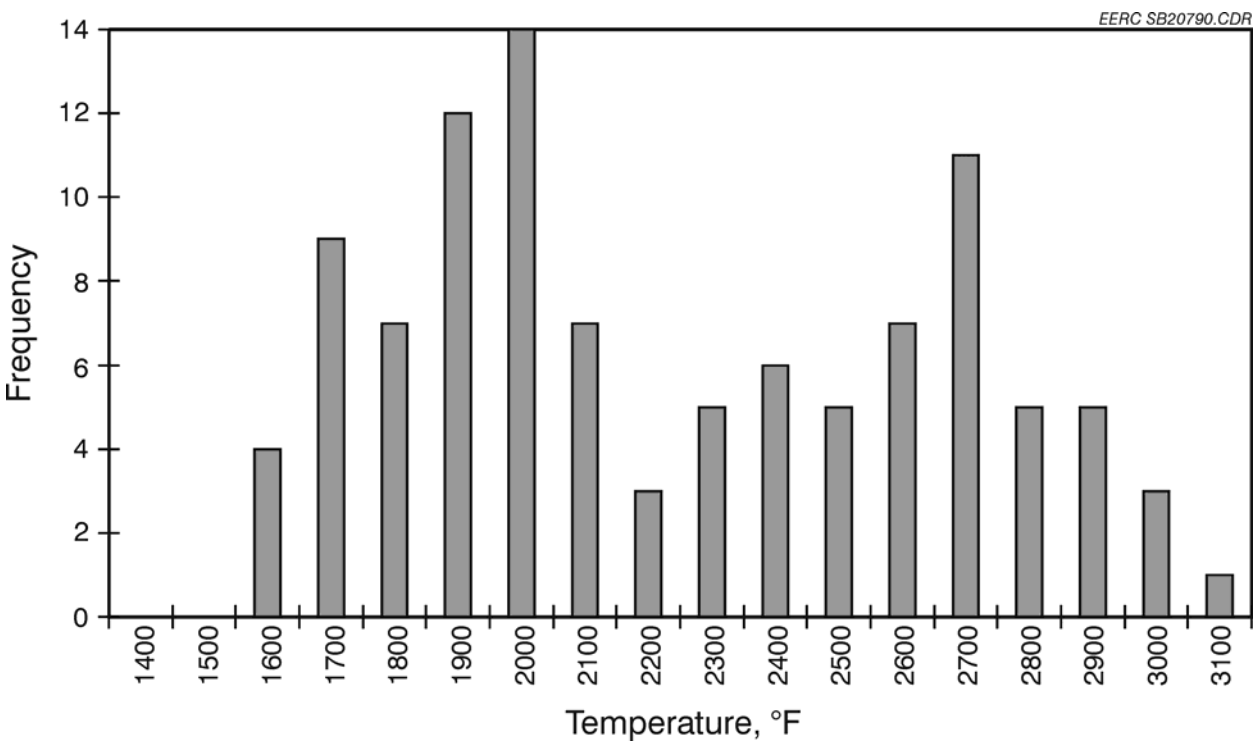

Figure 3. T_{250} frequency distribution for all Coal Quality Management System (CQMS) data, °F.

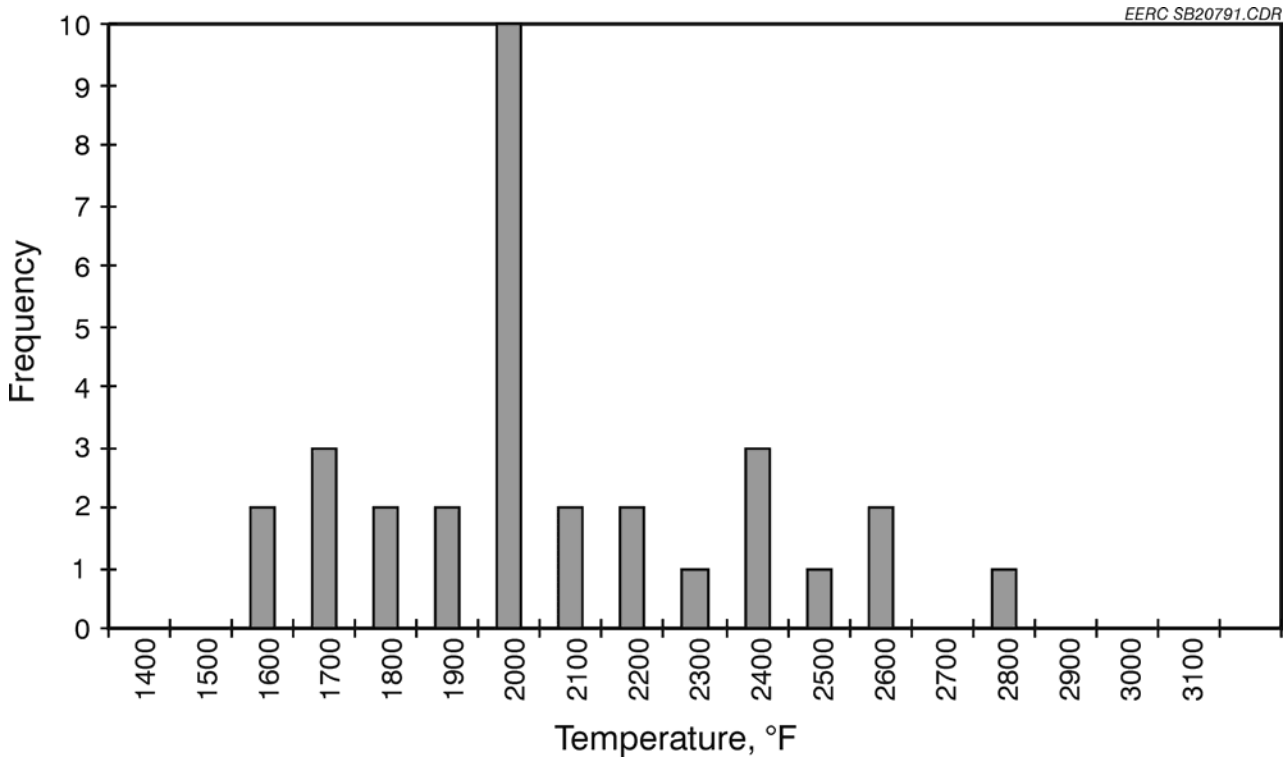

Figure 4. T_{250} distribution for HA seam coal.

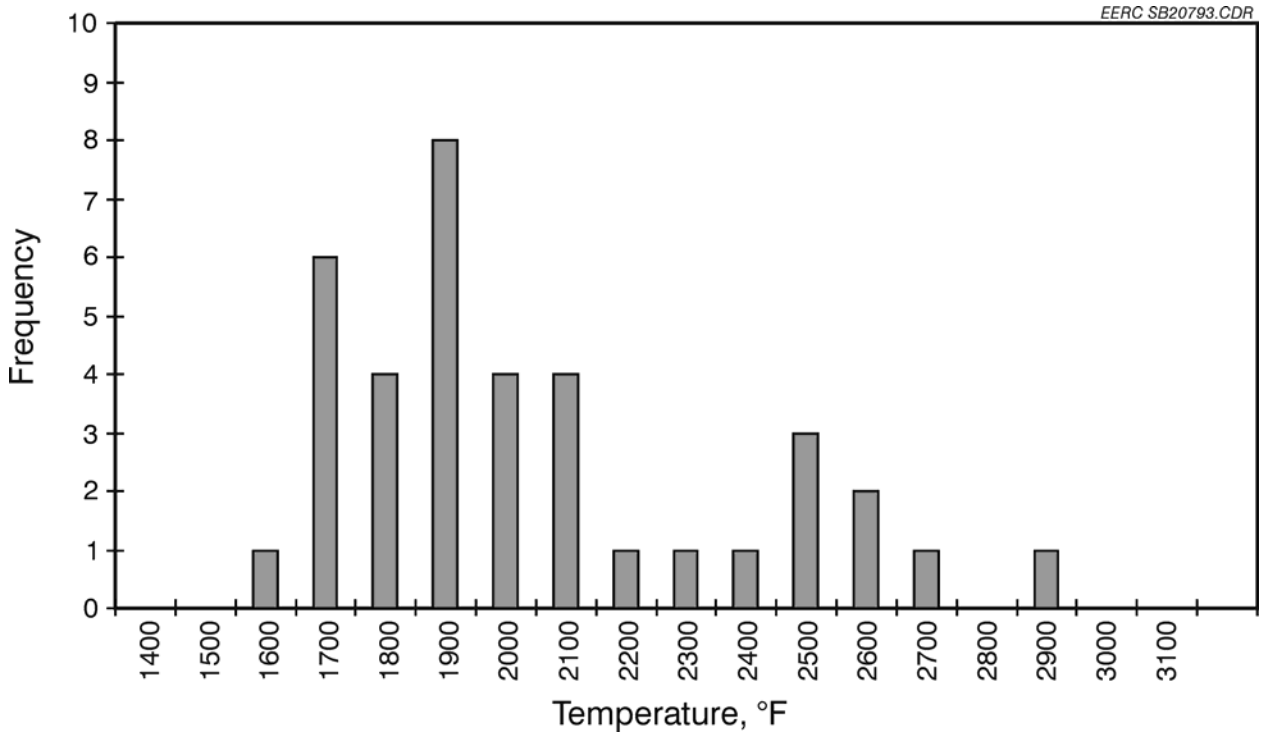

Figure 5. T_{250} distribution for HB seam coal.

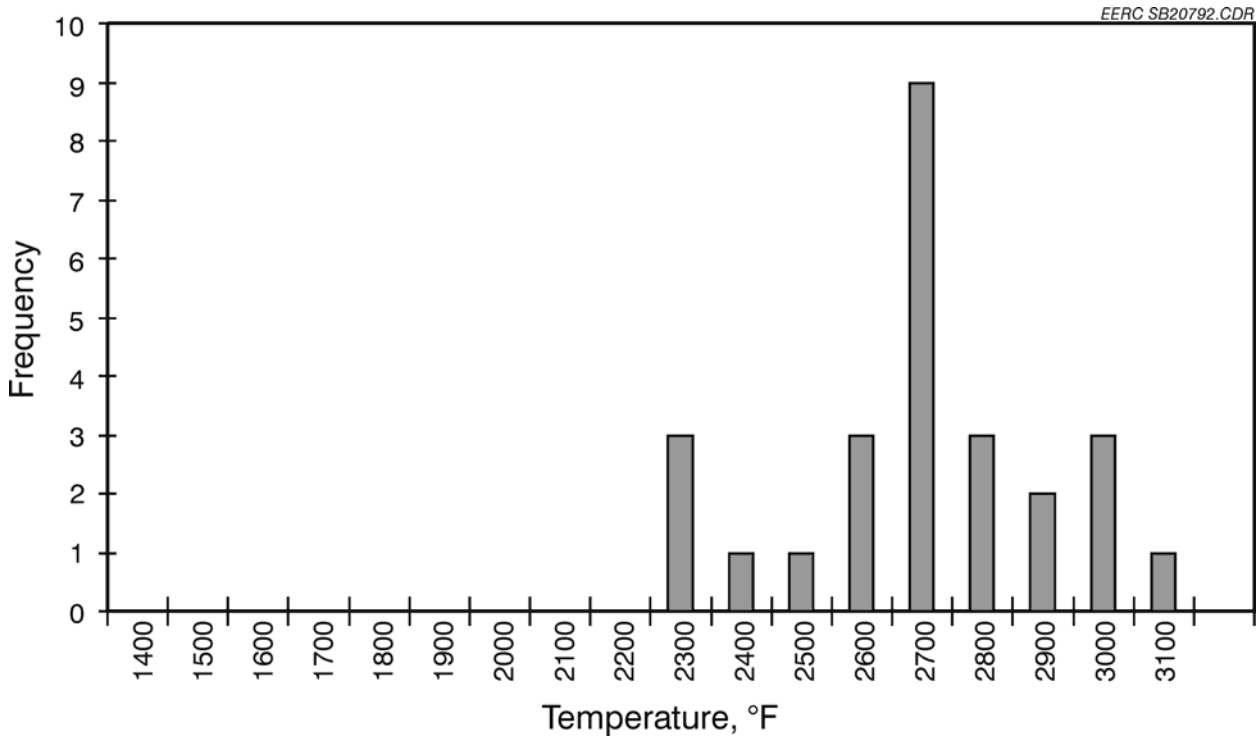

Figure 6. T_{250} distribution for KC seam coal.

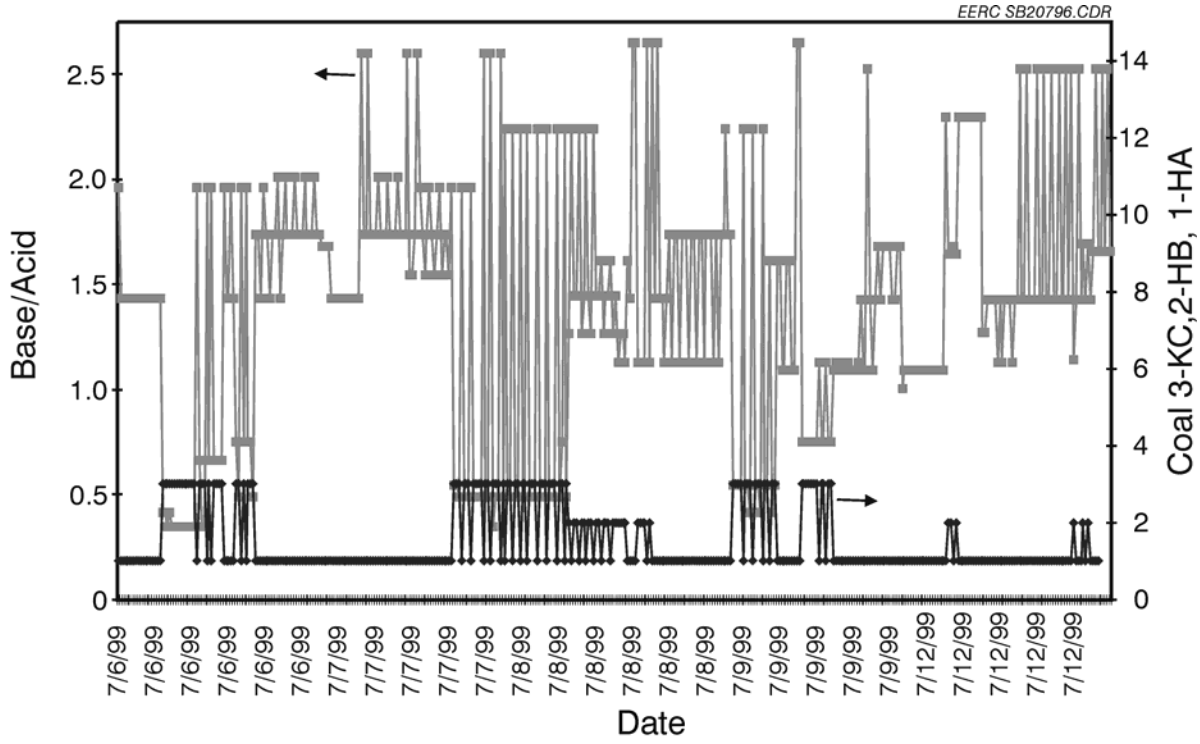

Figure 7. Variations in the delivered coal quality during a test burn period.

Figure 7 shows the sequence of deliveries beginning on July 6 and ending on July 12, 2004. During this period, the majority of the coal delivered was from the HA seam, followed by KC, and HB. Most of the deliveries alternated between KC and HA. Figure 6 shows several instances where significant quantities of KC coal were delivered, on July 6 through July 9. The quantity of KC coal delivered will have the potential to increase the viscosity of the slag and result in poor slag flow from the cyclones.

ASH-RELATED IMPACTS ON SCR CATALYST PERFORMANCE

Ash-related impacts on SCR catalyst performance will depend upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (14–16, 22). The problems currently being experienced on SCR catalysts include the following:

- Formation of sulfate- and phosphate-based blinding materials on the surface of catalysts.

- Carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing on top of the SCR catalysts.

Licata and others (14) conducted tests on a South African and German Ruhr coal and found that the German Ruhr coal significantly increased the pressure drop across the catalyst because of the accumulation of ash. They found that the German coal produced a highly adhesive ash consisting of alkali (K and Na) sulfates. In addition, they reported that the alkali elements are in a water-soluble form and highly mobile and will migrate throughout the catalyst material, reducing active sites. The water-soluble form is typical of organically associated alkali elements in coals. The German Ruhr Valley coal has about 9.5% ash and 0.9 % S on an as-received basis, and the ash consists mainly of Si (38.9%), Al (23.2%), Fe (11.6%), and Ca (9.7%), with lower levels of K (1.85%) and Na (0.85%) (15). Cichanosicz and Muzio (16) summarized the experience in Japan and Germany and indicated that the alkali elements (K and Na) reduced the acidity of the catalyst sites for total alkali content (K+Na+Ca+Mg) of 8%–15% of the ash in European power plants. They also found that alkaline-earth elements such as calcium react with SO_3 on the catalyst, resulting in plugging of pores and a decrease in the ability of NH_3 to bond to catalyst sites. The levels of calcium in the coals that caused blinding ranged from 3%–5% of the ash.

The mechanisms for this type of low-temperature deposition have been examined and modeled in detail at the Energy & Environmental Research Center (EERC) in work termed Project Sodium and Project Calcium in the early 1990s; however, the focus of those projects was specific to primary superheater and economizer regions of boilers and not SCR systems (22, 23). Deposit buildup of this type can effectively blind or mask the catalyst, diminishing its reactivity for converting NO_2 to N_2 and water and potentially creating increased ammonia slip (14). Arsenic and phosphates, which are not uncommon in low-rank coals, may also play a role in catalyst degeneration. Arsenic is a known catalyst poison (14) in applications such as catalytic oxidation for pollution control. Phosphates can occur in low-temperature ash deposits to create blinding effects, and they also occur with arsenic and can cause catalyst poisoning (23).

Lignite and subbituminous coals produce ash that plugs and blinds catalysts (25–28). The problems currently experienced with SCR catalysts include the formation of sulfate- and phosphate-based blinding materials on the surface of catalysts and the carrying of deposit fragments, or popcorn ash, from other parts of the boiler and depositing them on top of the SCR catalysts (14). The most significant problem that limits the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates, phosphates, and possibly carbonates that will form on the surfaces of catalysts and the carryover of deposits that will plug the catalyst openings, resulting in increased pressure drop and decreased efficiency (14–16, 27–28). The degree of the ash-related impacts on SCR catalyst performance depends upon the composition of the coal, the type of firing systems, flue gas temperature, and catalyst design (15–16, 24, 27–28).

In studies (7) the impacts of temperature and the presence of catalyst on the ability of ash to sulfate were examined. The tests were conducted using a thermogravimetric analyzer (TGA). TGA testing was conducted using a <5-µm-size fraction of ash produced from Powder River Basin (PRB) coals and lignites and exposing them to vapor-phase sulfur dioxide with and without catalyst at several temperatures. The aim of the testing was to determine the potential of the formation of sulfates to cause particle-to-particle bonding that leads to the formation of deposits in the temperature range where SCR catalysts are used. The TGA testing is focused on determining the reactivity of the <5-µm ash produced from selected PRB and blends to sulfur dioxide and gas-phase phosphorus species as a function of temperature. Testing was conducted to determine the weight gain with flue gas containing ammonia. The impact temperature on the weight gain due to the formation of sulfates for a PRB blend is shown in Figure 8. The rates of sulfation were found to increase with increased temperature. The results show an increase in the weight gains when ammonia and phosphorus were added. Ground catalyst was mixed with PRB and placed in the TGA. Increases in weight gain were observed when catalyst was added as compared to baseline cases for 100% PRB, as shown in Figures 8 and 9, respectively. The presence of catalyst enhances the formation of sulfates.

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Full-Scale Slipstream Testing

More recently (8), the behavior of ash and mercury in flue gas produced from the combustion of lignite and subbituminous coals from the United States of America in selective catalytic reduction (SCR) systems for nitrogen oxide removal has been examined. Typically, these coals contain ash-forming components that consist of inorganic elements (sodium, magnesium, calcium, and potassium) associated with the organic matrix and mineral grains (quartz, clays, carbonates, sulfates, and sulfides). Upon combustion, these coals produce ash that has an abundance of alkali and alkaline-earth-rich oxide particles (<5 µm) that are carried into the backpasses of the combustion system and react with flue gas to form sulfates and possibly carbonates. The forms of mercury in the flue gas produced from the lignite and subbituminous coals are dominated by the elemental form. Slipstream testing was conducted at two subbituminous-fired power plants and one lignite-fired power plant to determine the impacts of ash on SCR plugging, blinding, and mercury oxidation.

The SCR slipstream system consists of two primary components: the control room and the SCR reactor. The reactor section consists of a catalyst section, an ammonia injection system, and sampling ports for NO_x at the inlet and exit of the catalyst section. The control room houses a computer system that logs data and controls the gas flow rates, temperatures, pressure drop across the catalyst, and sootblowing cycles. The computer is programmed to maintain constant temperature of the catalyst, gas flow rates, sootblowing cycles, and ammonia injection. The computer is equipped with a modem that allows for downloading of data and modification of the operation of the reactor from a remote computer located at the EERC.

Flue gas is isokinetically extracted from the convective pass of the boiler upstream of the air heater. The temperature is typically about 790°F. The flue gases pass through a 4-inch pipe equipped with sampling, thermocouple, and pressure ports. Ammonia is injected into the piping upstream of the reactor section. The reactor consists of a steel housing that is approximately 8.5 inches square and 8 feet long. The reactor section has three components, including a flow straightener, a pulse section or sootblower, and a catalyst test section. A metal honeycomb is used as a flow straightener upstream of the catalyst section and is about 6 inches long. A purge section was installed ahead of the catalyst test section to remove accumulated dust and deposits. The catalyst test section is located downstream of the purge section. The entire catalyst section is insulated and equipped with strip heaters for temperature control. The catalyst test section is 3.28 ft (1 m) in length and houses three catalyst sections. Thermocouple and pressure taps are located in the purge sections for measurements before and after each section.

The induced-draft fan is used to extract approximately 400 acfm (200 scfm) of flue gas from the convective pass of the utility boiler to achieve an approach velocity of 5.2 m/s (17.0 ft/s). The gas velocity is similar to that found in full-scale applications. The total gas flow through the reactor represents a thermal load of approximately 300 kW.

The range of operating conditions for the reactor is listed below:

- Gas temperature: ~700°–800°F
- Gas flow rate: 400–500 acfm
- Approach velocity range: 5.0–5.5 m/sec
- Ammonia injection rate: 0.5:1 with NO_x level
- Tempering air for fan: ~ 50–200 scfm
- Catalyst dP: 0.5–1.0 inches water column
- Fan sized for up to 30 inches water column

The catalyst installed at the Baldwin and Coyote Stations was the Haldor Topsoe catalyst. Topsoe's DNX-series of catalysts comprises SCR DENOX catalysts tailored to suit a comprehensive range of process requirements. DNX-series catalysts are based on a corrugated, fiber-reinforced titanium dioxide (TiO_2) carrier impregnated with the active components vanadium pentoxide (V_2O_5) and tungsten trioxide (WO_3). The catalyst is shaped to a monolithic structure with a large number of parallel channels. The unique catalyst design provides a highly porous structure with a large surface area and an ensuing large number of active sites. The pitch of the catalyst was approximately 6 mm.

The catalyst installed at the Columbia Station was a Babcock Hitachi plate-type catalyst. This catalyst is a TiO_2-based plate catalyst, developed and manufactured by Hitachi. The pitch of the catalyst was approximately 10 mm.

The coals produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels. On a macroscopic level, there were significant observable accumulations that plugged the entrance as well as the exit of the catalyst sections. On a microscopic level, the ash materials filled pores in the catalyst and, in many cases, completely masked the pores within 4 months of operation.

The deposits on the surfaces and within the pores of the catalyst consisted of mainly alkali and alkaline-earth element-rich phases that have been sulfated. The results of this testing found that the <5-µm ash rich in alkali and alkaline-earth elements is captured on the surface and within the catalyst pores. These materials react with SO_2/SO_3 in the flue gas, resulting in the formation of a continuous phase that blinds the catalyst. The ability of elemental mercury to be oxidized across the SCR catalyst was investigated at a North Dakota lignite-fired plant. These results showed no oxidation of mercury across the SCR catalyst.

The reactor was installed at the Baldwin Station and operated for a 6-month time period on the Haldor Topsoe catalyst. The information obtained from testing included pressure drop, sootblowing cycles, and reactor temperatures. Figure 10 show the pressure drop across the catalyst test periods from 0 to 2 months. During the first two months of operation, the pressure was about 0.5 inches of water; at the end of two months, the pressure drop was about 0.8 inches of water, indicating plugging had occurred. The air was pulsed a minimum of every 8 hours in an attempt to maintain cleanliness. The reactor was monitored on a daily basis, and adjustments in pulsing cycles were made in order to minimize deposit accumulation. However, for the first two months, the pressure drop steadily increased. There are several periods where the unit was taken off-line; during those times, the temperature of the catalyst was maintained. At 2-month intervals, a section of catalyst was removed and replaced with a new one.

For Months 2 through 4, the pressure drop was highly variable initially but was about 0.8 inches of water. From Months 4 through 6, the pressure drop was maintained between 0.6 and 0.8 inches of water. This is due to the installation of a fresh catalyst section and leaving two thirds of the catalysts in place that were partially plugged. The gas velocity in the single section of new, clean catalyst was high because of channeling, and the result of the high gas flow was less deposition and accumulation. Gas velocity has a significant impact on the potential for deposits to form. However, at high gas velocity, low NO_x conversion is likely.

The reactor was installed at the Columbia Station and operated for a 6-month period of time with the Babcock Hitachi catalyst. The information obtained from the testing included pressure drop information, sootblowing cycles, and reactor temperature. Figure 11 shows the test periods from 0 to 2 months. The pressure drop across the SCR upon installation was about 0.4 inches of water and increased to an average of about 0.5 inches of water, but ranged from less than 0.4 to greater than 0.8 inches of water. The pressure drop for Months 2 to 4 increased from about 0.5 to 0.7 inches of water because of accumulation of ash. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but increased to over

0.6 inches of water up to about 4100 hours. There was an outage at the plant, and aggressive pulsing of the reactor was conducted; the pressure drop was brought back down to 0.3 but rapidly increased to over 0.5 inches of water within 500 hours.

The same reactor that was installed at the Baldwin Station was moved and installed at the Coyote Station. In addition, the same Haldor Topsoe catalyst type was used in the reactor. The reactor was operated for a 6-month period of time. Figure 12 shows the test periods from 0 to 2 months. As this paper is being prepared, the reactor is still operating on-site. The pressure drop across the catalyst upon installation was about 0.4 inches of water. After only 750 hours, the pressure drop was 1.5 inches of water, indicating significant plugging and blinding. Very aggressive air pulsing was conducted, with little success in removing the deposits. The pressure drop for the catalyst was over two times greater than the pressure drop observed for the Baldwin Station utilizing the same reactor and same catalyst. At about 1700 hours, the reactor was cleaned, and a section of catalyst was removed for characterization. The pressure drop after cleaning was about 0.8 to 1.0 inches of water. The pressure drop did not increase as rapidly because of the higher velocities through the clean section of the catalyst.

The tops of the catalysts were photographed during inspection and sampling of the catalyst sections. Figure 13 shows the ash materials that accumulated on the catalyst inlet after 2 months of operation. The most significant accumulation was noted for the Coyote Station, followed by Columbia and Baldwin. The Coyote Station had some larger pieces of ash deposit material on the surface as well as plugging of the catalyst passages. The Baldwin Station showed some obvious deposition along the walls of the reactor and some accumulation on the inlet sections. The Columbia Station showed more significant accumulation and plugging than the Baldwin Station.

After 4 months, the tops of the catalysts were photographed during inspection and sampling of the catalyst sections, as shown in Figure 14. The most significant accumulation was noted for the Coyote Station and some accumulation for the Baldwin Station.

SCR Ash Deposit Characterization

The characteristics of the ash materials that collected on the catalyst surfaces and pores were characterized by SEM and x-ray microanalysis and, in selected cases, XRD was used to determine the crystalline phases present. The catalysts were sampled after 2, 4, and 6 months. The sections were sampled, and approximately 2.5-cm squares were mounted for SEM analysis on double-stick tape and in epoxy resin. The double-stick tape samples allowed for characterization of the external morphology of the particles and catalyst surface. The samples mounted in resin were cross-sectioned and polished, which allowed for more detailed and quantitative analysis of the bonding materials and materials that accumulated in the pores of the catalyst. Detailed information on all the samples can be found elsewhere (add FPT reference). Examples of two deposit and catalyst analysis are presented here.

The 6-month sample from the Baldwin Station showed extensive sulfation of the alkaline-earth elements present in the deposits. Figures 15a and 15b show regions of the catalyst where all the pores were blocked and a minimal amount of deposit on the surface of the catalyst. Figure

15c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of calcium- and sulfur-rich material, likely in the form of calcium sulfate. The chemical compositions of selected points that indicate the presence of high levels of calcium and sulfur are listed in Table 3. There is much more extensive bonding of the materials with the sulfate matrix as compared to the 2-month sample. In addition, there are some regions of high levels of calcium, aluminum, and sulfur present. The calcium aluminum materials are likely derived from the calcium aluminum phosphate minerals found in the coal fired at this plant.

The 4-month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst. Figure 16 shows the 4-month sample from the Coyote Station. The catalyst showed particles adhering to the surface and completely filling and masking the pores in the catalyst. The external morphology of the catalyst surface shows the masking of the catalyst surface. Chemical compositions of selected points are shown in Table 4. The 4-month sample shows more sulfation than the two months of exposure samples. Figures 16b and 16c shows a higher-magnification view of the deposit that is filling the catalyst pore. The deposit consists of particles of fly ash bonded together by a matrix of sodium-, calcium-, and sulfur-rich material, likely in the form of calcium sulfate. Significant sodium was found in the deposits, as shown in Table 4. The sample shows significant evidence of sulfation after 4 months of exposure and was much more pronounced than the samples for the Baldwin and Columbia Stations that are fired on PRB coals. The presence of sodium enhances the bonding and sulfation of the particles to form a strongly bonded matrix (22).

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SCR Deposit Formation Mechanisms

The mechanism for the formation of deposits that blind SCR catalysts involves the transport of very small particles rich in alkali and alkaline-earth elements, the surface of the catalyst, and reactions with SO_2/SO_3 to form sulfates. The formation of SO_3 from SO_2 is catalyzed by the SCR; this, in turn, increases the reaction rate of SO_3 to form sulfates. In some cases, the alkali and alkaline-earth elements will also react with CO_2 to form carbonates. XRD analysis identified $CaSO_4$ as a major phase and $Ca_3Mg(SiO_4)_2$ and $CaCO_3$ as minor phases.

Lignite and subbituminous coals contain high levels of organically associated alkali and alkaline-earth elements including sodium, magnesium, calcium, and potassium, in addition to mineral phases. The primary minerals present in these coals include quartz, clay minerals, carbonates, sulfates, sulfides, and phosphorus-containing minerals (6).

During combustion, the inorganic components in the coal are partitioned into various size fractions based on the type of inorganic component, their association in the coal, and combustion system design and operating conditions. Significant research has been conducted on ash formation mechanisms and relationships to impacts on power plant performance (1–6, 9–13, 19–21, 29). During combustion, the inorganic components associated with western subbituminous and lignite coal typically are distributed into various size fractions of ash. The smaller size fractions of ash are dominated by partially sulfated alkali and alkaline-earth elements. These ash particles are largely derived from the organically associated cations in the coal. The larger size

fraction has higher levels of aluminum and silicon derived from the mineral fraction of the ash-forming component of the coal. Entrained ash was extracted from the Columbia Station at the point of the inlet to the SCR reactor and was aerodynamically classified and analyzed. The composition of the size fractions was compared to the chemical composition of the ash deposited on and in the catalyst, as shown in Figure 17. The comparison shows that the composition of the particle captured in the SCR catalyst is very similar to the <5-µm size fraction. The deposited material shows significantly more sulfation than the entrained-ash size fraction, indicating that the sulfation process occurs after the particles are deposited in the catalyst.

The mechanism of SCR catalyst blinding when firing lignite or subbituminous coals is shown in Figure 18 (30). The requirements for the formation of deposits that blind SCR catalyst include firing a coal that produces significant levels of <5-µm-sized particles. The particles are transported into the pores of the catalyst and subsequently react with SO_3 to form sulfates. The sulfate forms a matrix that bonds other ash particles. The SCR catalyzes the formation of SO_3 and thereby increases the rate of sulfation (24, 25). The sulfation of CaO increases the molar volume, resulting in the filling of the pore. For coals that have high sodium contents, formation of low-melting-point phases such as pyrosulfates is possible (31). Pyrosulfate materials can melt at temperatures as low as 535°F in coal-fired power systems.

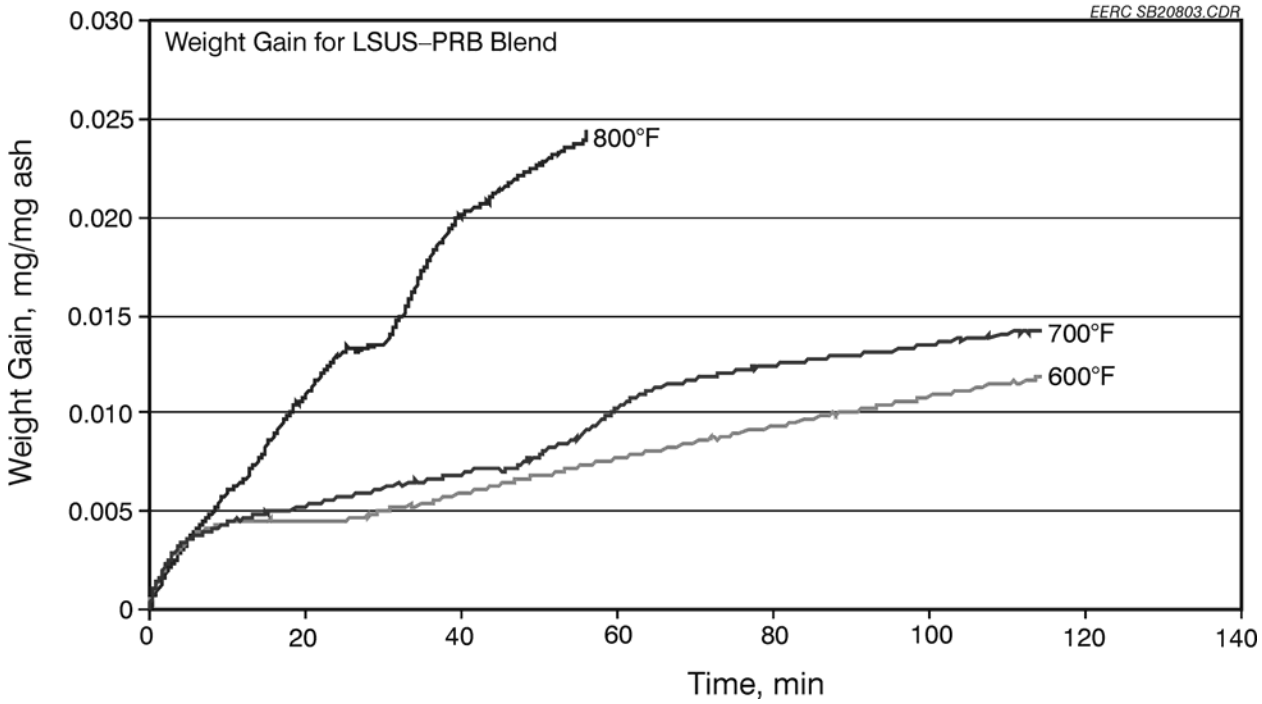

Figure 8. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia at three temperatures.

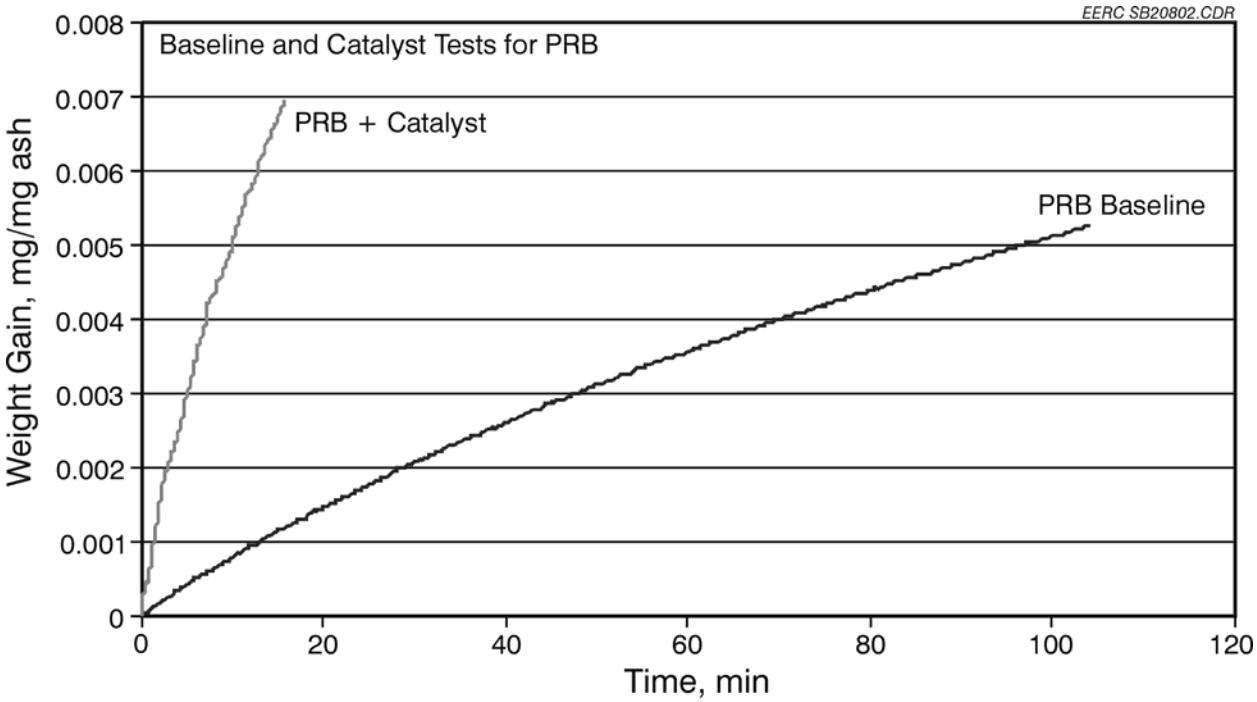

Figure 9. Weight changes for PRB-blend coal ash exposed to flue gases and ammonia with and without SCR catalyst present.

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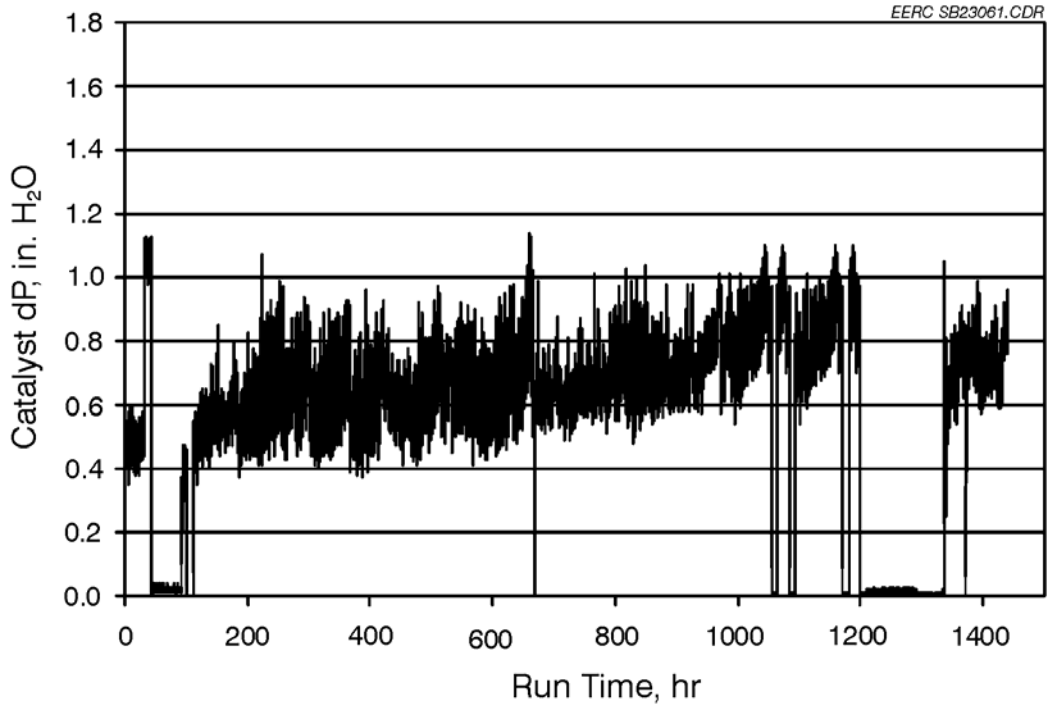


Figure 10. Catalyst pressure drop at Baldwin Station at 0 to 2 months of operation.

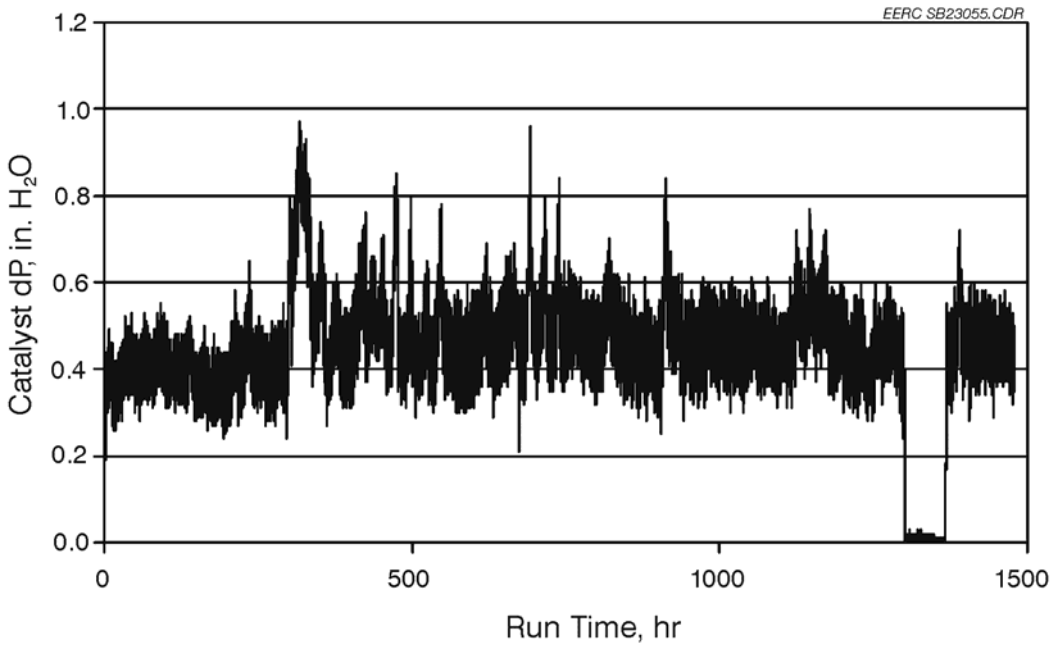


Figure 11. Catalyst pressure drop at Columbia Station at 0 to 2 months of operation.

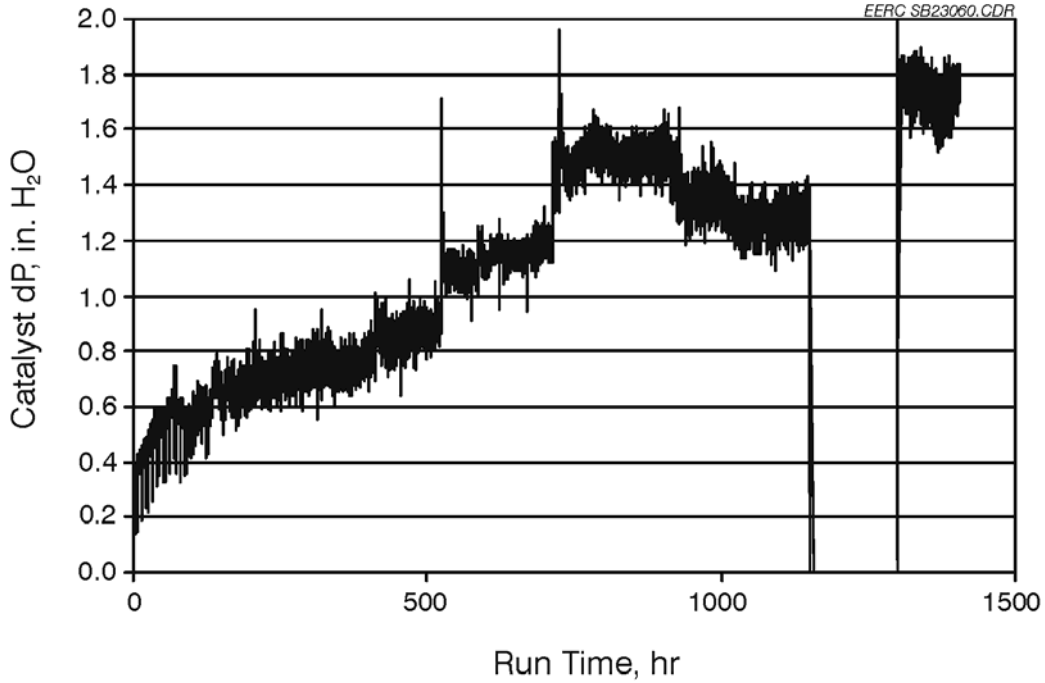
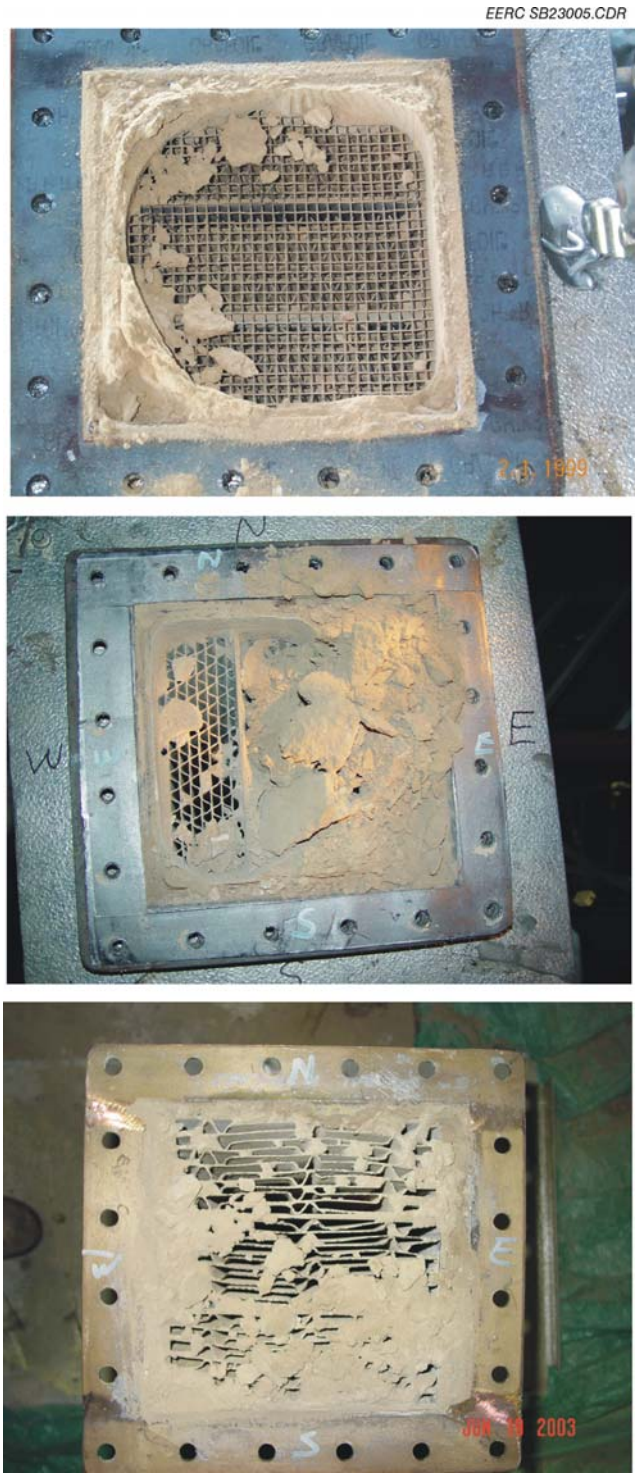


Figure 12. Catalyst pressure drop at Coyote Station at 0 to 2 months of operation.



Baldwin Station after 2 months

Coyote Station after 2 months

Columbia Station after 2 months

Figure 13. Pictures of catalyst inlet after about 2 months of testing at each plant.

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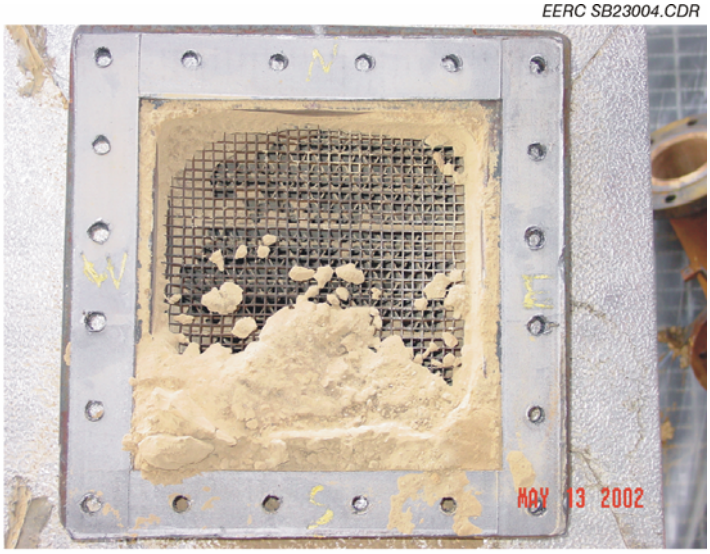
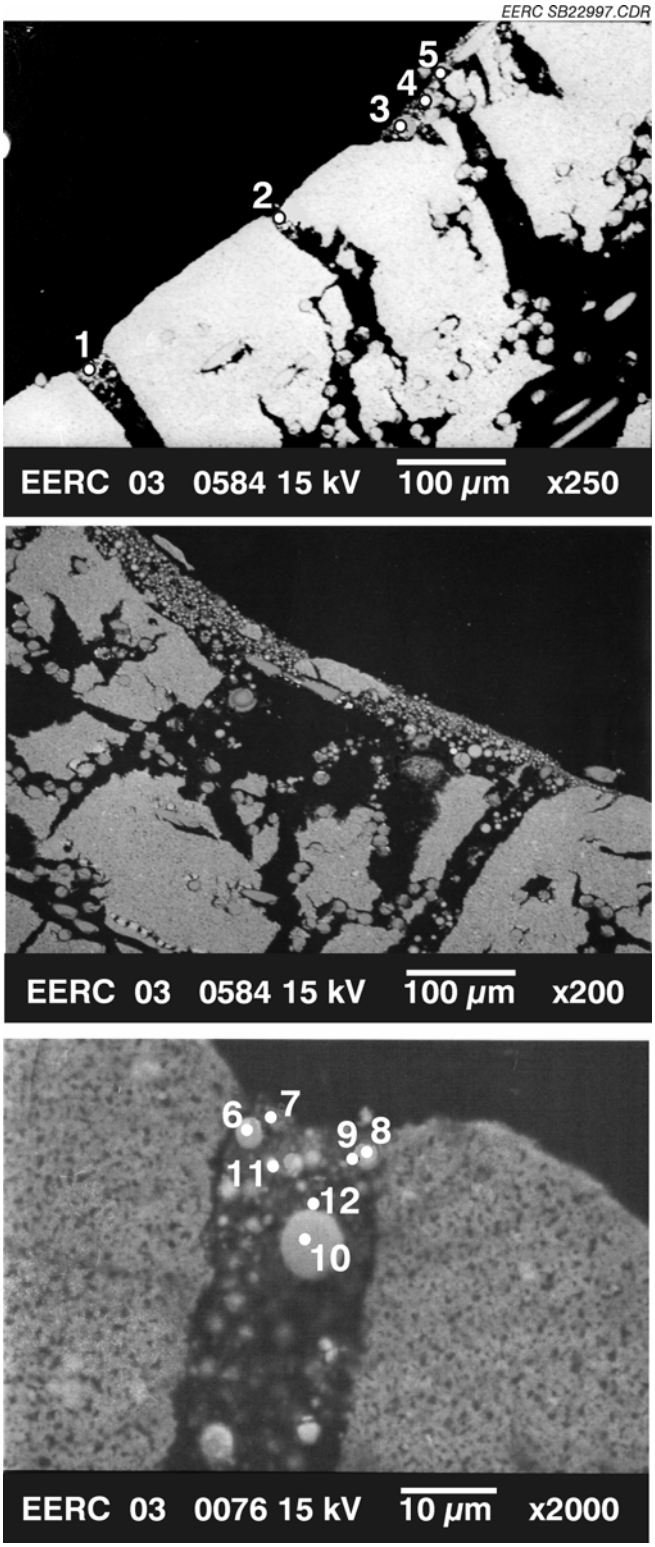


Baldwin Station after 4 months

Coyote Station after 4 months

Figure 14. Pictures of catalyst inlet after about 4 months of exposure to flue gas and particulate.



A

B

C

Figure 15. SEM images of ash collected on catalyst surface at the Baldwin Station after 6 months of exposure. A) and B) low-magnification images of ash deposit on catalyst surface

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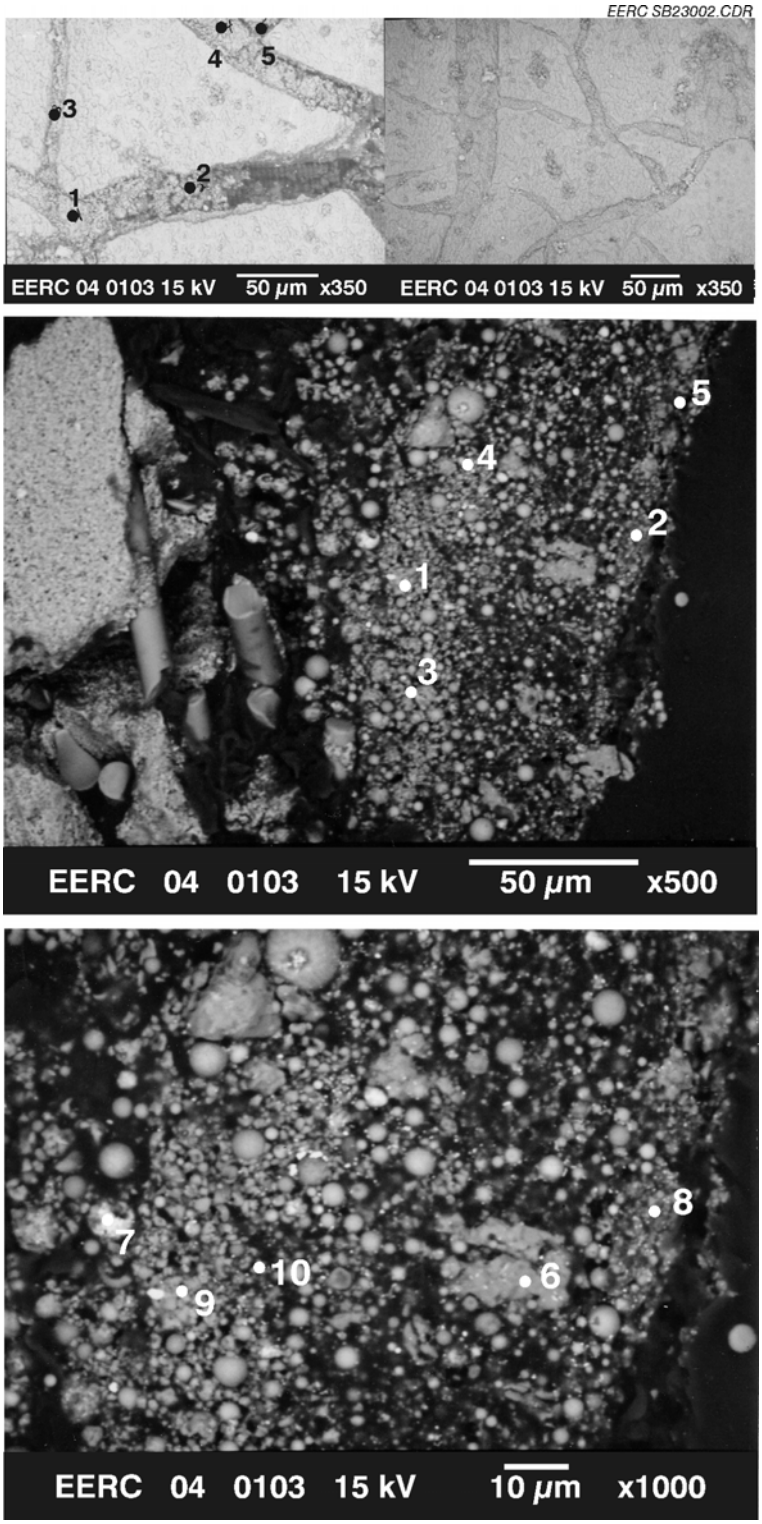
and C) high-magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials.

Table 3. Chemical Composition of Selected Points and Areas in Figure 15

	Chemical composition (normalized wt% equivalent oxide)					
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5	Point 6
1.1.1						
	0.6	1.0	2.1	0.3	0.5	2.7
Na_2O	4.3	2.5	6.3	0.7	1.6	7.6
MgO	14.8	16.0	15.6	15.5	14.7	0.9
Al_2O_3	3.3	7.8	18.8	57.7	7.7	47.3
SiO_2	2.3	2.1	0.5	0.6	1.8	0.0
P_2O_5	30.7	20.4	17.7	0.0	29.0	0.8
SO_3	0.7	0.0	1.0	0.4	0.9	0.9
K_2O	28.8	28.7	28.1	22.5	34.9	28.4
CaO	2.0	7.2	2.2	0.3	1.3	1.1
TiO_2	11.4	12.9	6.2	0.0	7.6	7.9
Fe_2O_3	1.1	1.4	1.4	2.0	0.0	2.5
BaO						
Total	100	100	100	100	100	100
Oxide	Point 7	Point 8	Point 9	Point 10	Point 11	Point 12
1.1.2						
	1.7	0.4	0.5	2.2	1.3	1.7
Na_2O	4.5	6.4	5.9	5.0	3.4	6.4
MgO	5.0	2.4	3.0	19.2	10.8	3.8
Al_2O_3	8.4	18.4	18.5	31.0	17.9	16.7
SiO_2	1.8	0.9	1.0	0.0	1.7	1.2
P_2O_5	37.9	1.7	5.3	0.0	22.5	13.9
SO_3	0.4	0.0	0.0	0.9	0.8	0.0
K_2O	31.4	52.6	49.0	28.9	30.6	45.4
CaO	1.9	6.9	7.4	2.4	2.0	1.1
TiO_2	7.1	5.7	6.0	6.3	6.1	6.5
Fe_2O_3	0.0	4.6	3.5	4.2	2.9	3.3
BaO						
Total	100	100	100	100	100	100



A

B

C

Figure 16. SEM images of ash collected on catalyst surface at the Coyote Station after 4 months of exposure. A) low-magnification image of ash deposit on catalyst surface, B) low-

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magnification image of polished cross section showing particles in a matrix of calcium- and sulfur-rich materials, and C) higher-magnification image of bonding.

1.1.2.1 Table 4. Chemical Composition of Selected Points and Areas in Figure 16

	Chemical composition (normalized wt% equivalent oxide)				
Oxide	Point 1	Point 2	Point 3	Point 4	Point 5
1.1.3					
Na_2O	6.7	1.9	7.1	6.2	3.1
MgO	1.1	1.7	1.1	2.6	3.2
Al_2O_3	2.6	8.8	4.0	4.8	10.5
SiO_2	7.0	21.1	11.3	5.6	32.2
P_2O_5	0.2	2.4	0.0	0.2	0.9
SO_3	54.7	38.5	56.4	57.5	30.4
K_2O	2.0	2.8	0.7	2.8	2.4
CaO	18.0	3.4	15.8	9.3	2.3
TiO_2	0.6	0.8	1.1	1.3	1.5
Fe_2O_3	5.8	5.1	2.1	6.5	9.8
BaO	1.4	13.5	0.5	3.4	3.6
Total	100	100	100	100	100
Oxide	Point 6	Point 7	Point 8	Point 9	Point 10
1.1.4					
Na_2O	9.5	2.6	10.4	8.9	4.4
MgO	1.2	1.9	1.3	3.0	3.7
Al_2O_3	2.6	8.6	4.2	4.9	10.6
SiO_2	6.3	18.2	10.5	5.0	28.9
P_2O_5	0.1	1.9	0.0	0.1	0.7
SO_3	41.8	28.4	44.9	44.5	23.4
K_2O	3.2	4.3	1.2	4.4	3.8
CaO	24.5	4.4	22.5	12.8	3.1
TiO_2	0.6	0.8	1.3	1.5	1.8
Fe_2O_3	7.7	6.6	2.9	8.9	13.2
BaO	2.4	22.3	0.9	5.9	6.3
Total	100	100	100	100	100

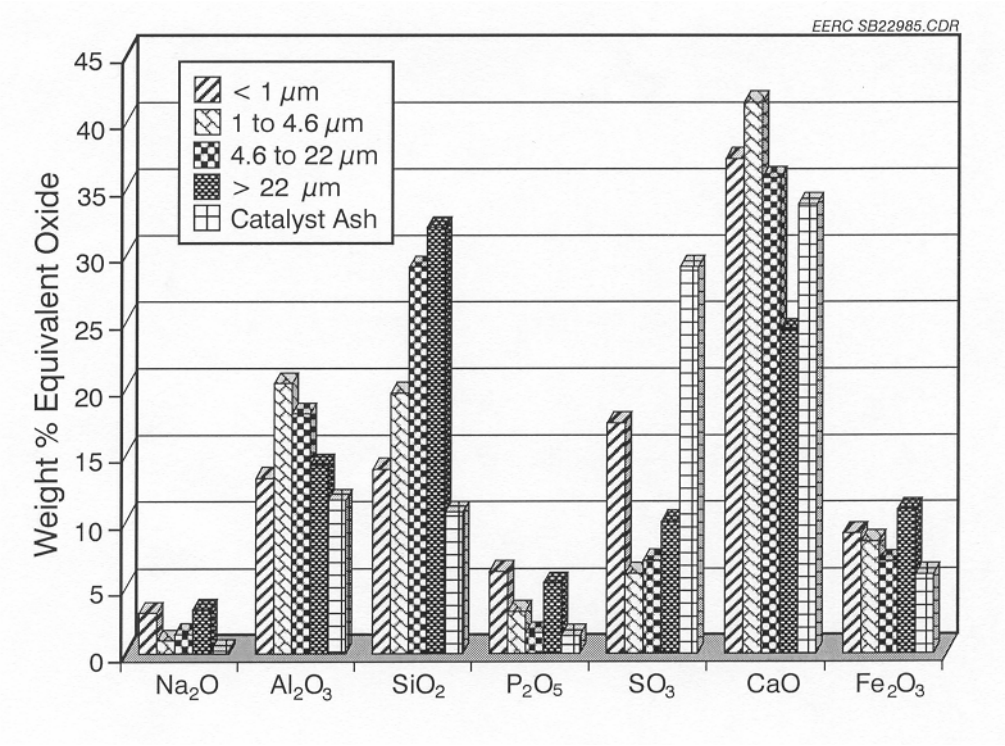

Figure 17. Comparison of entrained ash and deposited ash on catalyst for Columbia Station.

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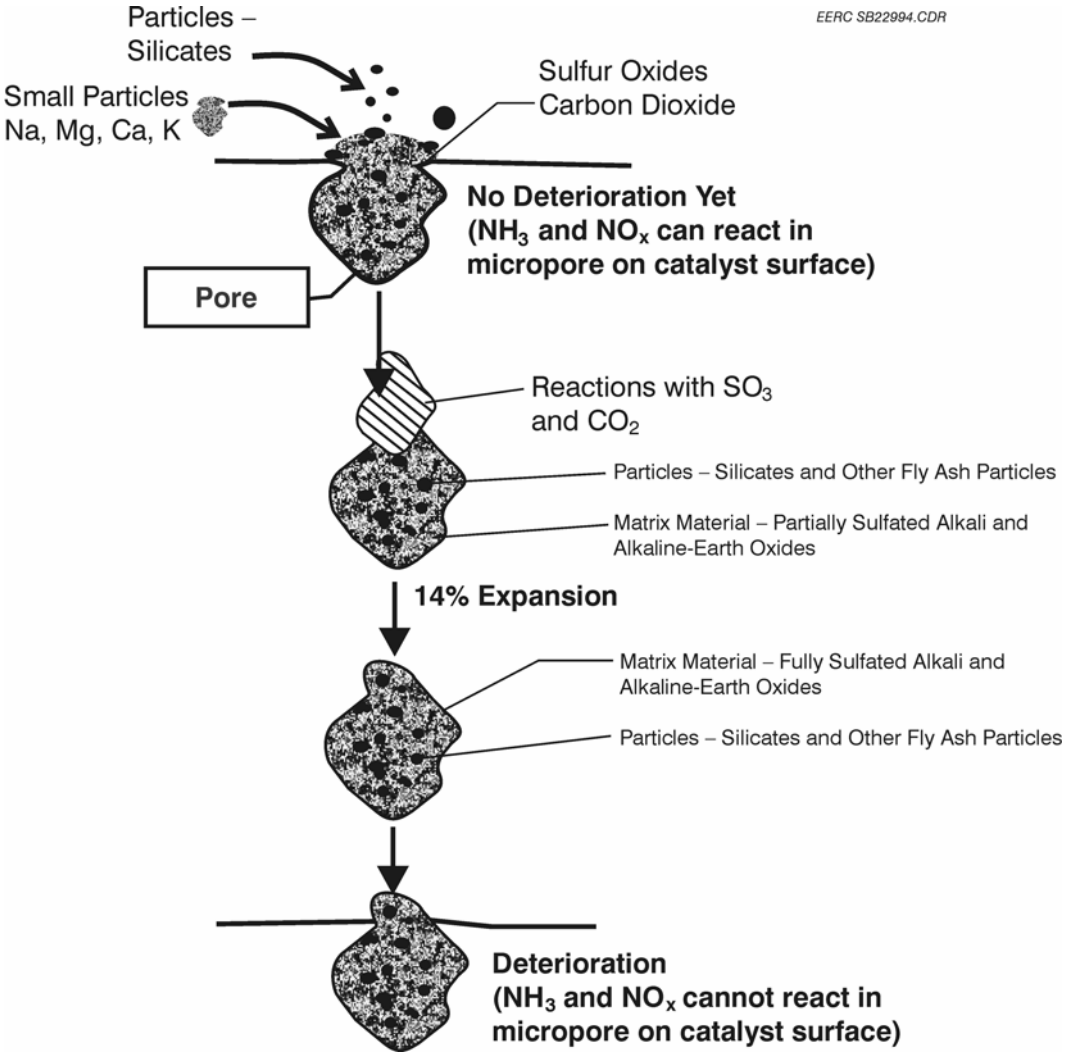

Figure 18. Mechanism of SCR catalyst blinding via the formation of sulfates and carbonates (modified after Pritchard and others [30]).

Low-Temperature Pyrosulfates

The presence of sodium sulfate in the flue gas exiting a scrubber will cause problems to low-dust and tail-end devices such as selective catalytic reduction (SCR) systems for NO_x reduction. There are two problems associated with the fine particulate rich in sodium sulfate on downstream devices. These include accumulation of fine particles on the SCR that, when sootblown, will cause opacity problems, and that the fine particles on the SCR will form pyrosulfates such as $(K_{1.5}Na_{0.5})S_2O_7$ that have melting points as low as 535°F (31) that will blind the catalyst. The presence of these compounds in low-temperature corrosion deposits is well known (32). In addition, the presence of SO_3 enhances the formation of the low-melting-point pyrosulfates (31). The sodium sulfate materials will cause opacity and SCR catalyst

blinding problems that limit the feasibility of the low-dust or tail-end SCR technology for use with high-sodium lignite coals.

The sodium sulfate materials will be transported to the catalyst surfaces by diffusion, electrophoresis, and, possibly, inertial impaction. The particles are held in place by weak electrostatic and van der Waals forces. Once accumulation takes place, the sodium sulfate particles will react with flue gas components, resulting in the formation of pyrosulfates. The formation of pyrosulfates involves the following processes (31):

1. Formation of sulfates such as Na_2SO_4 and K_2SO_4

2. Conversion of SO_2 to SO_3 in the bulk gas phase – catalytically active surface such as an SCR catalyst – $SO_2 + \frac{1}{2} O_2 \rightarrow SO_3$

3. Pyrosulfate formation – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

The melting points of selected pyrosulfate phases are shown in Table 5.

Table 5. Melting Points of Selected Pyrosulfate Compounds

Compound	Temperature, °C	Temperature, °F
$K_3Fe(SO_4)_3$	618	1144
$K_3Al(SO_4)_3$	654	1209
$KFe(SO_4)_2$	694	1281
$Na_3Fe(SO_4)_3$	624	1155
$Na_3Al(SO_4)_3$	646	1195
$NaFe(SO_4)_2$	690	1274
$Na_2S_2O_7$	401	754
$K_2S_2O_7$	300	572
$(K_{1.5}Na_{0.5})S_2O_7$	279	535

Melting points for pyrosulfates between 535° and 770°F have been reported in the literature. Much of the past work has focused on the formation of these phases on tube surfaces. These species contribute to the corrosion of heat-transfer surfaces in coal-fired power plants. The exact melting point depends on the relative amounts of sodium and/or potassium.

There is significant evidence for the formation of sodium-rich fine particulate in full-scale power plants when firing high-sodium-containing coals. For example, Minnesota Power's Boswell Energy Station found that when it fired high-sodium, lower-ash subbituminous coal, it experienced increases in opacity. Hurley and Katrinak (33) conducted a field-testing project on Unit No. 4, a pulverized coal-fired boiler equipped with an electrostatic precipitator and a wet scrubber, to better understand the reasons for the opacity problems. During the field testing, sampling of the coals, flue gases, and scrubber materials was conducted. The particulate in flue gases downstream of the scrubber was aerodynamically classified using an impactor and

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multicyclone. The sized fractions were analyzed to determine the composition of the submicron-sized fraction.

The results of the study indicated that the particulate collected downstream of the scrubber was coal-related and caused by the high sodium content of one of the coals. Vapor-phase sodium condenses in the convective pass to form fine sodium sulfate particles or other Na species that later react with ash particles. Pure Na_2SO_4 particles are too small to be removed by scrubbing.

CONCLUSION: SCR IS NOT FEASIBLE FOR NO_X REDUCTION AT MILTON R. YOUNG

The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be impossible because of the formation of sodium calcium sulfates in the pores of the catalyst. Following is a list of the key roadblocks associated with lignites which have not been overcome and, in our opinion, make the installation of SCR catalyst at the MRY plant technically infeasible for NO_x control.

- High alkali and alkaline-earth elements present in the coal fired at the MRY plant form sulfates that blind the catalyst.
    - Cyclone-firing partitions the ash during combustion. As a result the level of sodium and calcium in the fly ash is enhanced and will increase the SCR catalyst blinding.
    - Sulfate reactions increase with increasing temperature, and the suggested temperature of installation at the MRY facility is higher than typical installations; therefore, sulfation problems are enhanced.
    - Sulfate formation is also enhanced by the presence of an SCR catalyst; this accelerates the sulfation reactions, causing blinding of the catalyst.
    - The high levels of sodium in the coals combined with calcium produces low-melting-point eutectic compounds that will melt on the surface.
    - Sulfates form on the surfaces of catalysts firing PRB coals. Lignites will be several orders of magnitude worse because of the higher levels of sodium.

- The ash components to impact SCR performance in Japan and Europe (14–16) include alkali and alkaline-earth elements that result in sulfate formation. The total calcium content and the sum of the calcium, magnesium, potassium, and sodium provide an indication of the problems that occur. For the coals fired at the MRY power plant, the CaO content ranges from 6.8%–19.99%, and the sum of the alkali and alkaline-earth elements range from 9.33%–29.87% of the ash. The levels of calcium in Center lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.

- The finding or work conducted in Germany and Japan were confirmed by recent SCR catalyst slipstream testing that showed significant evidence of sodium and calcium-

rich sulfate formation that fill and plug the catalyst at both lignite (North Dakota)- and subbituminous-coal-fired power plants. The results of this recent testing showed that the presence of sodium significantly enhanced the formation of bonding of particles and more rapid sulfation, filling of pores, and rapid increase in pressure drop across the catalyst.

- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments, is a significant problem because of the extremely high deposition potential of the coal. The formation of deposits in various parts of the boiler requires continuous sootblowing. The deposit fragments are likely going to be carried with the bulk gas flow to the SCR catalyst, resulting in plugging.

- The variability of the lignite is a problem of unique concern at MRY. The deposition potential of the coal is always changing rapidly, resulting in rapid growth and formation of deposits in various sections of the boiler. Aggressive sootblowing of all fireside surfaces is already required to maintain full-load operation. The sootblowing of upstream heat exchange equipment will cause deposit fragments to be carried back to the SCR catalyst, and during sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

The ash-related impacts of the lignites from North Dakota are the most complex and severe of any coals in the world, and installation of tail-end SCR systems for NO_x reduction will not be possible. The key problems associated with lignites that have not been overcome and, in our opinion, make the installation of tail-end SCR systems at the MRY plant technically infeasible for NO_x control at MRY's Units 1 and 2 are listed below:

X High-sodium lignite coal from the Center Mine Hagel A and B seam coal produces extreme levels of homogeneously condensed sodium sulfate that pass through the wet scrubber. In addition, the cyclone-firing system captures much of the ash as slag, resulting in a decrease in ash that is available for providing condensation sites for vapor-phase sodium compounds upon gas cooling. This results in an increased homogeneous condensation of sodium sulfate.

X These small particles pass through a wet scrubber and will accumulate on surfaces of tail-end SCR systems. The accumulated materials cannot feasibly be resolved through conventional sootblowing and cleaning technologies to remove the particulate.

X Recent testing with subbituminous and lignitic coals indicated a significantly higher level of pore filling and plugging in the catalyst exposed to lignite ash as compare to subbituminous coal ash. The catalyst pores as well as the catalyst surface in the lignite tests were completely coated with a sodium calcium sulfate material, while only pore filling was found in the subbituminous coal testing. The pressure drop across the catalyst exhibited for lignite was 4 to 5 times greater than that found for a catalyst exposed to subbituminous coal ash. The plugging occurred over a 1000 hour test period.

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The formation of liquid pyrosulfate materials at temperatures as low as 535°F from sodium sulfate materials occurs in coal-fired power systems and is well documented. Pyrosulfates will form and cause blinding of tail-end SCR devices. In addition, SCR systems catalyze the formation of SO_3 from SO_2. The presence of SO_3 significantly enhances the formation of the pyrosulfates at MRY to an extreme level that cannot be dealt with effectively using cleaning technologies that exist today.

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APPENDIX C

COST METHODOLOGY

CAPITAL COST ESTIMATE DETAILS FOR NO_X CONTROLS

O&M COST ESTIMATE DETAILS FOR NO_X CONTROLS

C.1 METHODOLOGY FOR ESTIMATED COSTS

The summary economic evaluations of each alternative are presented in the cost impact sections of the main report. Capital and O&M cost estimates for each alternative are presented individually. The Levelized Total Annual Cost (LTAC) for all the alternatives for control of a single pollutant (i.e. NO_X) from a single unit is then presented together with Unit Control Costs. The Levelized Total Annual Cost (LTAC) represents the levelized annual cost of procurement, construction and operation over a 20 year design life, again in current (2006) dollars. As a minimum, the design life for any alternative was taken to be that recommended by "The EPA Air Pollution Control Cost Manual", Sixth Edition, January 2002, EPA/452/B-02-001[i].

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

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

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

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

Therefore:

LACC = CRF x NPV

For the economic conditions described in Table C.1-1 the Capital Recovery Factor was calculated to be 0.08718.

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

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

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

Therefore:

$$LAOMC = OMLF \times A_1$$

For the economic conditions described in Table C.1-1 the Operating and Maintenance Levelization Factor was calculated to be 1.24873.

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

$$LTAC = LACC + LAOMC = (CRF \times P) + (OMLF \times A_1) = 0.08718 \times P + 1.24873 \times A_1$$

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

In order to compare various pollutant control alternatives, the Unit Control Cost and the incremental Unit Control Cost of each alternative were also calculated and tabulated for comparison purposes. The Unit

Control Cost compares control technologies on a basis of dollars expended per ton of pollutant reduced ($/ton). This relationship is graphically depicted in the DCC chart.

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

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

Where,

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

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

Table C.1-1 – Economic Factors(1),(2)

Total Possible Operating Hours per Year	8,760
Amortization Life, Years	20
Cost of Money	6%
Property Taxes, Insurance, %	NA
Conversion Tax (in lieu of property tax)	NA
Amortization Rate for APC Capital Costs	6%
Interest During Construction (IDC)	6%
Discount Rate (used to calculate NPV)	6%
Construction Cost Escalation	3%
Non-Fuel O&M Escalation	2.5%
Fuel (coal and natural gas) Escalation	2.5%
Auxiliary Electric Power Cost, $/MW-hr	$35.00
Urea Cost, ($/ton delivered, 50% aqueous solution)	$380.00
Natural Gas ($/mmBtu)	$7.98

(1) - All financial percentages and unit auxiliary electric power cost were provided by MPC.
(2) - All costs are in 2006 dollars unless noted otherwise.

C.2 NOx CONTROLS - CAPITAL COST ESTIMATES

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

The limitations of these capital cost estimates developed from unit capital cost factors multiplied by unit output are:

- Scope basis uncertainty – inability to precisely determine what scope of supply, including such things as balance-of-plant (BOP) systems and equipment improvements were required, assumed, or accounted for when developing the unit cost factors. Some alternatives may have higher indirect or BOP capital costs than others. Similarly, the inclusion of general facilities, preproduction and inventory costs, and other indirect costs is not known. It is likely that the utility owner's final total expenditure for the implementation of the alternatives, especially options that are most capital cost-intensive, will be greater than the calculated cost estimates.
- Location-specific influences – most NO_X control techniques have been applied primarily to eastern bituminous coal-fired plants located near large metropolitan areas, not in largely rural, upper midwestern United States locales. The amount of space available is dependent on the existing powerplant equipment and building layout and property plot area, versus what is expected to be required for implementing various control technologies. Transportation and local/regional labor costs are also variables.
- Size influences – some technologies' capital costs are more sensitive to "economies of scale" than others.
- Capacity margins – some technologies' may require higher capacity margins to allow sustained operation at high throughput rates over extended periods of time.
- Reliability concerns – some technologies' have been refined to a higher degree, and others may require more component redundancy than others in order to avoid performance reductions and potential outages for failures and repairs or replacements.
- Inflationary influences – the significant increases in 2004-2005 for raw material costs, especially steel and alloys for fabrication of structural and mechanical components, has occurred after many of these technologies were installed in projects upon which the referenced unit capital cost factors were based.

- Market conditions – as demand increases for emission controls, some alternatives become more cost-competitive, while others do not. This can be influenced by the relative supply and demand for the technology and number of suppliers who can furnish it. The demand for some alternatives can also be strongly influenced by the stringency of the local, state, and national regulatory requirements. Schedule for implementation and availability of local/regional labor for installation contractors are also market-driven factors.

The estimated NO_X control costs are in addition to capital costs to provide normal replacements of the existing Milton R. Young Station's major power generating equipment.

C.2.1 Separated Overfire Air Capital Cost Estimates

Installation of separated overfire air systems typically includes windbox and/or secondary combustion air supply duct modifications, boiler waterwall tube openings, airflow distribution devices (dampers/registers), airflow controls and measurement instrumentation, and related structural and electrical tie-ins to the existing plant facilities. A basic separated overfire air retrofit system installed on a lignite-fired cyclone boiler includes ports across the front and rear walls of the upper furnace. The unit capital cost factor is expected to be above the high end of the typical published cost range of $5-10/kW[ii] ($11.5/kW or $5.500,000[3] for MRYS Unit 2), due to the large ducts, relatively tall furnace (compared to typical bituminous coal-fired cyclone boilers), and the need to avoid existing obstructions within the boiler house.

An advanced form of SOFA unique to North Dakota lignite-fired boilers will include relocation of the existing lignite drying system vent port openings from the lower primary furnace to the upper furnace, to be placed at the same elevation as the new SOFA ports. This requires extension of the existing cyclones' lignite drying systems' vent piping to supply the new boiler furnace ports. This retrofit will also close-off the existing FGR ports in the lower front and rear furnace walls of Unit 2, currently coinciding with the existing pre-dry vent ports. These FGR ports may be blocked, or relocated to the lower portion of the upper (secondary) furnace, across the front and rear walls. This is expected to cost in the area of +$9.5/kW or $4,500,000 for Unit 2's additional capital cost over and above the basic SOFA system. Overall, the advanced version of separated overfire air technology is estimated to have an installed capital cost of approximately $10.0 Million ($21.0/kW) for MRYS Unit 2.

C.2.2 Reburn Capital Cost Estimates

C.2.2.1 Coal Reburn Capital Cost Estimates

There is one alternative that includes a new coal reburn system. Capital cost estimates for coal reburn systems are highly dependent on the requirements for reburn fuel preparation and feeding to the boiler. For the purposes of this analysis, the application of a pulverized coal reburn system assumed the need to make extensive additions to the existing fuel preparation equipment in the existing plant facilities and feeding to new furnace injectors. At least two new fine-grind pulverizers, or MPS-89 standard pulverizers followed by dynamic classifiers are expected to supply the amount of finely ground reburn coal for this method.

Addition of new electrical loads for the pulverized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/micro-mills and related new coal reburn equipment, but this has not been confirmed.

The existing crusher bays do not have floor space available to allow the new milling equipment for reburn fuel preparation to be located adjacent to the existing coal crushers. This will require a separate building or addition to the existing powerhouse to be built to provide sufficient space to enclose the new milling and coal silo/handling equipment. Separate modified pulverized coal-style burners or coal injectors will be installed through new openings in the upper furnace front and rear waterwalls at or above the elevation of the existing lignite drying system vent ports, along with new overfire air ports located at a higher elevation, above the reburn fuel injectors. This would have the capacity to supply approximately up to thirty percent of the total full load fuel heat input to the boiler through the coal reburn injectors. This coal reburn system design was not expected to change the existing cyclone silo/feeder arrangement, such that all cyclones would remain operational. To achieve maximum NO_X emission control, only the advanced form of SOFA for pulverized coal reburn was included. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

The installed capital cost of pulverized coal reburn for the cyclone boilers at Milton R. Young Station used in this cost effectiveness analysis was estimated based upon a Clean Air Markets Division [CAMD] of the US EPA dollar per kilowatt unit capital cost factor for cyclones. The installed capital cost estimate of $40.65 Million for MRYS Unit 2's pulverized coal reburn alternative used in this cost effectiveness analysis was estimated based upon applying a 3.5% assumed inflation cost adjustment to the CAMD unit

capital cost factor for cyclones of $82.33/kW (x 1.035 = $85.2/kW) included in a WRAP (Western Regional Air Partnership) draft report[iv] published on their website, dated April 26, 2005. The cost to relocate the lignite drying system vent ports and FGR ports was added to the inflation-adjusted CAMD number ($85.2 + $9.5/kW = $94.7/kW), since coal reburn is expected to include separated overfire air but not the extra costs for the special improvements identified for air-staged lignite-firing in cyclone boilers. This increased the installed capital cost by $4.M for MRY Station Unit 2's coal reburn system to a total of $45,154,000. This does not include the additional particulate matter collection capacity considered necessary to limit the expected negative impact on opacity from this option.

To control particulate matter (PM) emissions that would be expected to increase from installation and operation of pulverized or micronized coal reburn, additional PM collection capacity will be required. A hybrid form of PM collection that supplements the existing electrostatic precipitator's performance, referred to as COHPAC (COmpact Hybrid PArticulate Collector). This was estimated in 2002 dollars at $30,200,000 for MRYS Unit 2's COHPAC[3]. Adjusted by an escalation factor of 1.2623, the installed capital cost of the COHPAC addition was estimated to be $36,013,000 for MRYS Unit 2 in 2006 dollars. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $81,167,000 for MRYS Unit 2 ($94.7 + $75.5 = $170.2/kW).

C.2.2.1 Gas Reburn Capital Cost Estimates

Conventional gas reburn options assume that seventeen percent of the total fuel heat input to the boiler is through the new gas reburn injectors to be located in the lower secondary furnace above the top rows of cyclones. Eight to twelve gas reburn injectors would be expected to be required in this case. Seven percent of the total fuel heat input to the boiler through the gas reburn injectors is assumed to be supplied for the fuel lean gas reburn alternatives. Four to eight gas reburn injectors could be assumed in FLGR™ cases. Gas reburn options assume that a new high-pressure gas pipeline would be brought from near Bismarck, ND approximately twenty six miles. The pipeline diameter is proportional to the amount of fuel required for the specific alternative, ranging from 24 inches for conventional gas reburn to 12 inches for fuel lean gas reburn cases. A station gas main, with new gas trains, consisting of valves, metering, and safety shutoff valves for the front and rear boiler for the gas injectors' supply, would be furnished and installed.

The capital costs for conventional gas reburn alternatives were estimated considering unit capital costs published in published technical literature. One vendor that has supplied numerous domestic utility boiler

gas reburn systems (GE Energy, formerly GE-EER) published $10/kW for gas reburn in a 2001 technical paper[v]. Another source published a 2005 technical paper[vi] that provided a unit capital cost range for gas reburn of $15/kW to $30/kW. Neither source included a detailed scope description nor cost breakdown for engineering, equipment, materials, and labor to install a gas reburn system.

Site-specific needs and challenges identified for applying conventional gas reburn to Milton R. Young Station, and lack of detailed gas reburn project scope and equipment descriptions available in published technical literature leads to a much greater degree of uncertainty with regards to an accurate capital cost estimate for this alternative. For the purposes of this study, the estimated installed capital cost for a conventional gas reburn system with advanced SOFA on MRYS Unit 2 is expected to be approximately $20.5M ($43/kW), which is above the top end of the previously stated range, before adding the new underground gas pipeline capital costs. This study assumed an average unit capacity capital cost factor of $22/kW for conventional gas reburn, plus the additional costs for the advanced form of SOFA over basic SOFA +$4.5M ($9.5/kW), and the new high-pressure gas pipeline. This results in a an estimated installed capital cost for conventional gas reburn system with advanced SOFA on MRYS Unit 2 of $20.5M ($43/kW) plus the new high-pressure gas pipeline costs. Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

Fuel lean gas reburn (without SOFA) capital cost estimates were based upon a late 2004 budgetary proposal[vii] by a vendor (Fuel Tech) with experience in supplying FLGR™ equipment, typically combined with an SNCR system. Estimated capital costs of $3M include budgetary numbers for the equipment installation, including installation management, material and labor, with a +6.0% price adjustment assumed for 477 vs 450 MW for a fuel lean gas reburn system without SOFA on MRY Unit 2, not including the capital cost for the gas supply pipeline. Costs for work outside the vendor's scope, such as balance-of-plant additions plus other indirect costs were estimated to add approximately $1.1M (25% plus 10% contingency) to the adjusted vendor's estimated installed cost of $3.2M for their scope of supply. These adjustments result in a total installed capital cost for FLGR (without SOFA) estimated to be $4.3M plus the capital cost for the gas supply pipeline. Adding the incremental costs for the advanced from of SOFA over no SOFA (+$10M ($21/kW) results in an estimated installed capital cost for a fuel gas reburn system with advanced SOFA on MRYS Unit 2 of $14.3M ($30.0/kW) plus the new high-pressure gas pipeline costs.

The capital cost estimates for the new high-pressure underground gas supply pipeline assumed $7 per inch of diameter per foot of length. This was calculated to be approximately $23M for conventional gas reburning and $11.5M for FLGR™. The cost analysis for each NO_X control alternative involving a particular form of gas reburn assumed that both boilers at Milton R. Young Station select the same alternative that burns natural gas. Therefore, the estimated capital costs for gas reburn alternatives reflect a capacity-based proportional share of the gas pipeline capital costs, avoiding double-counting. This results in an estimated installed capital cost for MRYS Unit 2's share of the gas pipeline to be $15M for the conventional gas reburn alternative and $7.5M for fuel-lean gas reburn alternatives.

The total installed capital costs for conventional gas reburn (with ASOFA) with MRYS Unit 2's share of the total capital cost for the gas supply pipeline estimated to be $35.5M ($74.4/kW). The total installed capital costs for FLGR™ (with ASOFA) with MRYS Unit 2's share of the total capital cost for the gas supply pipeline were estimated to be $21.8M ($45.7/kW). Confirmation of these concepts and cost estimates requires more detailed equipment design and plant layout than has been performed for the purposes of this BACT analysis.

C.2.3 SNCR Capital Cost Estimate

The alternatives that include selective non-catalytic reduction systems assume the use of urea unless noted otherwise. The SNCR systems' preliminary design and estimated capital costs were based upon a 450 MW lignite-fired cyclone boiler in a late 2004 budgetary proposal[7] by a vendor (Fuel Tech) with experience in supplying SNCR equipment. Circulation, metering, dilution, control, and injection equipment is included. A 180,000 gallon field-erected stainless steel storage tank will hold the 50% urea solution (as delivered by truck). Individual and multiple nozzle lances with multiple levels of urea reagent injection will be designed and located to optimize distribution and accommodate various boiler load conditions. Estimated capital costs of $4.9 Million include budgetary numbers for equipment installation, including installation management, material and labor assumed for a SNCR system applied to a 450 MW boiler. Costs for work outside the vendor's scope, such as outdoor reagent storage tank and building enclosure/equipment foundations and containment, and balance-of-plant additions plus other indirect costs were estimated to add approximately $1.9 Million (25% plus 10% contingency) to the vendor's estimated installed cost for their scope of supply. This results in an estimated total capital cost for SNCR (without SOFA) of $6.8M for a 450 MW lignite-fired cyclone boiler.

Applying these adjustments to a 477 MW boiler results in an estimated total installed capital cost for SNCR of $7,120,000 for MRY Station Unit 2 ($14.9/kW).

C2.5 Layered Technology Capital Cost Estimates

Capital costs were generally estimated based upon simple arithmetic addition of individual unit output capital cost factors for combinations of available NO_X reduction technologies, such as SNCR with ASOFA. An advanced form of separated overfire air system included the lignite-fired cyclone boiler equipment changes within the estimated unit capital cost factors.

Adding the advanced SOFA capital cost of $10.0 Million to the previous estimated installed capital cost of $7.12 Million yields a total estimated installed capital cost of $17.128 Million ($35.9/kW) for the SNCR with ASOFA alternative for MRYS Unit 2.

As previously discussed, Lignite (coal) reburn (CR) was assumed to be combined with advanced SOFA and a COHPAC addition considered necessary to limit the expected negative impact on opacity from this option. The installed capital cost of the COHPAC addition was estimated to be $36,013,000 for MRYS Unit 2. When the COHPAC addition was combined with the Lignite Reburn and ASOFA alternatives, the resulting total estimated capital costs were $81,167,000 for MRYS Unit 2 ($94.7 + $75.5 = $170.2/kW).

C.3 Operating and Maintenance Cost Estimates for MRY Station NO_X Control

An evaluation was performed to determine the estimated operating and maintenance cost impacts of installing and continuously operating various feasible NO_X control technologies on Milton R. Young Station Unit 2. These were estimated to be in addition to existing O&M costs to operate and maintain the MRY Station equipment.

The expected loss of electrical power sales from the operation of the specific NO_X control alternative was included as an annualized cost, assuming $35 per megawatt-hour. This was determined to include estimates for:

- Reduction in annual unit output due to an expected negative reliability (i.e. uptime availability) impact for each alternative. This generation reduction was calculated by multiplying the estimated additional numbers of outage hours per year by the average running plant capacity factor for that specific alternative, multiplied by the historic 12-month average unit gross electrical power output (MW_g) determined during the same period as the highest 12-month rolling summation NO_X pounds.
- Net additional auxiliary electric power demand for the added control equipment for each specific alternative based on assumptions for gross horsepower, plus additional power demand for existing fans caused by flue gas pressure drop (COHPAC for additional PM collection capacity), with adjustment for expected reductions in power demand (such as a decrease in existing coal crusher and feeder electric demand for the pulverized coal reburn case).
- The average running plant capacity factor for each alternative, which may also include an expected negative impact on the unit capacity from operation of the technology. This assumes that the control technique limits the gross electrical power output of the Unit (such as causing an increase in flue gas flow) such that the firing rate of the boiler cannot be maintained or raised to compensate for the load impact. Examples are lower boiler thermal efficiency (higher unit heat rate) when firing natural gas (due to higher moisture content of the flue gas).

For the SNCR alternative that involves a chemical reagent injected for NOx control, such as urea, the annual reagent consumption based on an assumed actual stoichiometric ratio (ASR) of moles of equivalent NH_3 injected per mole of uncontrolled NO_X emission estimated at the point of injection, converted to a mass rate (lbs/hr) by multiplying by the estimated annual number of hours of operation and the estimated NOx reduction fraction, and then multiplied by unit reagent cost (for a specific inlet NO_X concentration, emission reduction percentage and ammonia slip level).

General annual maintenance costs were assumed to be 1.5 percent of the estimated installed capital cost for each alternative, except for the coal conveying and grinding equipment portion of the coal reburn alternative, which was assumed to be 3 percent. The periodic bag replacement costs and other COHPAC system maintenance costs were estimated to be approximately 5.3% of the installed capital cost of the additional particulate matter collection equipment.

Additional operating labor costs directly attributable to each alternative were assumed to be zero for all alternatives.

Other operating costs include:

- Reagent dilution water for those alternatives that involve a chemical reagent injected for NOx control, typically four times the amount of urea consumption (assumes urea is a 50% solution as delivered and is injected as a 10% solution); this follows EPA OAQPS convention[1].
- Heat required for urea reagent storage, for those alternatives that involve a chemical reagent injected for NOx control; the source of heat is assumed to be auxiliary electrical power, but could be auxiliary steam (depending on heat source availability and plant preference).
- Additional coal consumption for those alternatives that involve a chemical reagent injected for NOx control to compensate for the heat of vaporization of the reagent dilution water;
  This follows EPA OAQPS convention[1], but is not accepted practice by an experienced SNCR vendor (Fuel Tech) who claims that the heat produced from the exothermic reaction of urea and NO_X is approximately equal to the heat required to evaporate the dilution water. For the purposes of this study, this additional coal consumption has been included in the annual O&M costs.

The sum of the estimated annual O&M costs was multiplied by the O&M levelization factor (1.24873) for each alternative to yield levelized total annual O&M costs.

C.3.1 Separated Overfire Air O&M Cost Estimate

Operation of SOFA is expected to add a small amount of O&M cost, primarily electricity consumed by the conventional SOFA damper electric drive actuator and airflow measuring system transmitter on each port. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected to change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. Maintenance of the new overfire air ports and relocated lignite drying system vent ports (and FGR ports

for Unit 2) is included, assumed to be 1.5 percent of the installed capital cost. This is included in every control alternative's estimated O&M cost.

SOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 2.2% (181 hours per year), for M.R. Young Station Unit 2 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic cyclone slag tapping operational conditions encountered during substoichiometric cyclone operation with SOFA. The expected loss of electrical power sales from the reduction in annual electrical power output due to a decrease in expected Unit availability from ASOFA operation is included in every control alternative's estimated O&M cost.

Boiler furnace waterwall tube maintenance may increase slightly as a result of more fireside corrosion due to substoichiometric cyclone operation with SOFA. There may be some changes in the degradation rate of the boiler's furnace waterwall tubes resulting from exposure of more area of the furnace walls to slightly air-starved conditions during SOFA operation. Such conditions can promote corrosion from sulfur compounds in the furnace gases being created above the cyclones and below the SOFA injection ports. Due to the relatively moderate amounts of sulfur content in the lignite, modest amount of air-staging of the existing cyclones during SOFA operation, and the potential use of recirculated flue gas along the lower furnace walls, the expected change in corrosion rate of the boiler tubes should be minor. This degradation is expected to occur over many years of operation, and normally requires periodic replacement of the deteriorated sections of boiler furnace waterwall tubes to avoid forced outages to repair tube leaks or failed sections. The additional costs associated with potential change in the frequency of furnace wall tube failures and changeouts are difficult to estimate, and have not been quantified.

C.3.2 Reburn O&M Cost Estimates

The alternatives that include a new coal reburn system assume the use of new equipment for preparing the reburn fuel to replace 25% of the MRY Station Unit 2 boiler's total fuel heat input. Two additional lignite silos, with coal feeders and fine-grind pulverizers followed by dynamic classifier(s), are assumed to be located in a new separate building or powerhouse enclosure. Booster fan(s) addition was included because the existing forced draft fans were assumed to be incapable supplying the additional amount of primary air to the fine-grind pulverizers and dynamic classifier(s) for processing and conveying the reburn fuel. Using the existing forced draft, induced draft, and flue gas recirculation fans is not expected

to significantly change the overall amount of fan horsepower demand to be supplied by those fans' electric motors. The expected loss of electrical power sales from the additional auxiliary electric power demand for the reburn milling equipment from an estimated 0.5% (2.5 MW) reduction in net output was included as a cost, assuming $35 per megawatt-hour for MRY Station Unit 2. Electrical power consumed by the increased load on boiler fans to overcome the higher flue gas system pressure drop, plus the COHPAC particulate collection system support equipment was estimated to be a 1.2% (5.8 MW) reduction in net output for Unit 2.

Maintenance of the separate reburn coal injectors, fuel and primary air piping, and reburn fuel milling equipment is expected to be similar to the expenses associated with typical pulverized coal burners. The estimated additional annual maintenance costs for a new micronized coal reburn system was assumed to be 3.0 percent of the installed capital cost, or roughly $1,355,000 per year, for MRY Station Unit 2. The estimated additional annual maintenance costs (inflation adjusted from 2002 to 2006 $) for the COHPAC system was approximately $1,938,000 per year for MRYS Unit 2. Boiler furnace waterwall tube and superheater/reheater tube maintenance may increase slightly as a result of more erosion due to increased particulate emissions or fouling by flyash deposits resulting from coal reburn operation with ASOFA. The additional costs associated with potential change in the frequency of boiler tube failures and changeouts are difficult to estimate, and have not been quantified.

The estimated impacts on operation and maintenance costs for the coal reburn alternative that include a new pulverized or micronized coal reburn system are approximate. The twelve (Unit 2) existing coal crushers for preparing the main (cyclone) fuel fraction will have slightly lower electrical demand. This was estimated as -0.45 MW (-0.09%) for MRYS Unit 2. Addition of new electrical loads for the micronized coal preparation equipment to the existing plant facilities will be required. For the purposes of this preliminary study, it is assumed that additional plant auxiliary electrical power will be available for powering the new pulverizers/classifiers and related new coal reburn equipment, but this has not been confirmed.

Coal Reburn with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers can be routinely established. A Unit availability reduction of 3.7% (3.8% (313 hours per year), for M.R. Young Station Unit 2 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during coal reburn operation with ASOFA. This reduction in annual

electrical power output due to a decrease in expected Unit availability is included in the coal reburn control alternative's estimated O&M cost.

A Running Plant Capacity Factor reduction of 0.5% of annual gross electrical output was assumed for the coal reburn alternative. This would result in an estimated 2.2 MW average load decrease for M.R. Young Station Unit 2. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

Conventional and fuel-lean gas reburn options will involve higher operating costs compared with the existing operation of M.R. Young Station. Natural gas supply was assumed to be available near Bismarck, ND, but this has not been confirmed. The estimated unit cost of this natural gas was assumed to average $7.98/million Btu on a levelized annual cost basis, with a "credit" of $0.71 per mmBtu for avoided cost of consumption of lignite coal reduced by the natural gas heat input. The estimated annual cost of natural gas for the conventional gas reburning alternative applied to MRYS Unit 2 is approximately $50.3M per year. The estimated annual cost of natural gas for the FLGR™ alternative applied to MRYS Unit 2 is approximately $20.8M per year.

The new gas reburn injectors, station gas main and injector gas trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost. Maintenance of separated overfire air nozzles is expected to be similar to the expenses associated with Unit 2's existing flue gas recirculation ports.

C.3.3 SNCR O&M Cost Estimate

The alternatives that include selective non-catalytic reduction systems will involve higher operating costs compared with the existing operation of MRY Station Unit 2. Urea reagent supply was confirmed to be available regionally. The estimated unit cost of this 50% aqueous urea solution was assumed to average approximately $379/ton delivered (2006$). Consumption of urea reagent for SNCR with ASOFA was based upon preliminary numbers allowing for a boiler flue gas exit ammonia slip of 5 ppmvd. These were estimated as approximately 286 gph for SNCR when applied to MRY Station Unit 2 with ASOFA.

New electrical loads are required for high flow urea circulation, in-line and storage tank heating, water dilution, and reagent metering equipment. These auxiliary electrical demands and reagent dilution water usage were calculated based upon equations published in EPA Office of Air Quality Planning and

Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1]. Compressed air for reagent atomization and lance purging and cooling, as well as multiple nozzle lance water cooling are additional demands on the existing plant facilities. These powerhouse building service supplies were assumed to be available, but this has not been confirmed. The new urea reagent injection nozzle lances, reagent pumps, dilution water pumps, and distribution piping/valve trains would add a minor amount of expense to current maintenance requirements, assumed to be 1.5 percent of the installed capital cost.

SNCR with ASOFA is not expected to significantly reduce unit reliability and availability to generate electrical power, assuming urea injection does not impact the ability to maintain consistent combustion and continuous slag tapping under substoichiometric air/fuel operating conditions for MRYS boilers. A Unit availability reduction of 3.2% (263 hours per year), for M.R. Young Station Unit 2 was assumed, which allows for forced or extended scheduled boiler outages that may result from problematic operational conditions encountered during SNCR-related operation with ASOFA. This reduction in annual electrical power output due to a decrease in expected Unit availability is included in the these control alternatives' estimated O&M costs.

A Running Plant Capacity Factor reduction of 0.15% of annual gross electrical output was assumed for the SNCR with ASOFA alternative. This would result in an estimated 0.66 MW average load decrease for M.R. Young Station Unit 2. This expected loss of electrical power sales from the reduction in net output due to this plant capacity impact was included in the estimated annual O&M costs.

C.3.4 Layered Technology O&M Cost Estimates

Operating and maintenance costs for combinations of available NO_X reduction technologies were estimated based upon simple arithmetic addition of individual cost estimates. SNCR was combined with advanced SOFA, as previously shown. Pulverized coal reburn was assumed to be combined with advanced SOFA (and a COHPAC addition for PM control). The auxiliary electrical demands and reagent dilution water usage for SNCR with ASOFA were calculated based upon equations published in EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Oxidation[1].

C.3.5 Summary of O&M Costs Estimates for MRY Station NOx Control

The results of this evaluation for estimated variable operating and maintenance costs for the individual NOx control alternatives are summarized in this section. The expected reductions in Unit availability (uptime) and capacity are included in Tables C.3-1 through C.3-7 for MRYS Unit 2. Tables C.3-5 and C.3-6 for MRYS Unit 2 include the estimated urea reagent and dilution water usage rates and costs for the alternatives that involve SNCR with ASOFA NO_X control technologies.

TABLE C.3-1 – Expected Availability Reductions for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Operating Time			
		Unit Availability(2)	Unit Operating Time(3), hrs/yr	Unit Outage Time(4), hrs/yr	Unit Operating Time Reduction(5), hrs/yr
E	SNCR w/ ASOFA	0.909	7965	795	263
D	Gas Reburn w/ ASOFA	0.919	8048	712	181
C	Coal Reburn w/ ASOFA	0.904	7916	844	313
B	FLGR w/ ASOFA	0.919	8048	712	181
A	Advanced SOFA (ASOFA)	0.919	8048	712	181
	Baseline	0.939	8229	531	0

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline availability is assumed at 93.9 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(3) – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
(4) – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
(5) – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.

TABLE C.3-2 – Expected Capacity Reductions for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction		
		Unit Running Plant(2) Capacity Factor	Unit Generation Reduction(3) kW-hrs/yr	Unit Generation Reduction Cost(4), 1000$/yr
E	SNCR w/ ASOFA	0.951	110,176.095	3,856
D	Gas Reburn w/ ASOFA	0.943	81,416,590	2,850
C	Coal Reburn w/ ASOFA	0.948	130,375.506	4,563
B	FLGR w/ ASOFA	0.949	81,910,024	2,867
A	Advanced SOFA (ASOFA)	0.952	75,859.855	2,655
	Baseline	0.952	0	0

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline running plant capacity factor is assumed at 95.2 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technique.
(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 440 MW.
(4) – Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-3 – Expected Auxiliary Electrical Power Demand Changes for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand (2) kW	Credit(3) kW	Total Net Demand(4) kW	Power Usage(5) kW-hrs/yr	Power Usage Cost(6), 1000$/yr
E	SNCR w/ ASOFA	133.2	0	133.2	1,008,704	35
D	Gas Reburn w/ ASOFA	1	(228)	(227)	(1,724,428)	(60)
C	Coal Reburn w/ ASOFA	8,342	(448)	7,894	59,217,554	2,073
B	FLGR w/ ASOFA	1	(125)	(124)	(949,051)	(33)
A	Advanced SOFA (ASOFA)	1	0	1	7,664	0.3

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 2,484 kW for feed preparation and conveying equipment demand plus 5,857 kW for the COHPAC system addition for PM control.
(3) – The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.
(4) – The total net auxiliary electrical power demand is the sum of the gross demand and credit.
(5) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.
(6) – The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of auxiliary electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
		APC Electrical Power Usage(2) kW-hrs/yr	Unit Generation Reduction(3) kW-hrs/yr	Total Unit Electrical Power Generation Change(4) kW-hrs/yr	Total Unit Electrical Power Generation Change Cost(5) 1000$/yr
E	SNCR w/ ASOFA	1,008,704	110,176.095	111,184,799	3,891
D	Gas Reburn w/ ASOFA	(1,724,428)	81,416,590	79,692,162	2,789
C	Coal Reburn w/ ASOFA	59,217,554	130,375.506	189,593,059	6,636
B	FLGR w/ ASOFA	(949,051)	81,910,024	80,960,972	2,834
A	Advanced SOFA (ASOFA)	7,664	75,859.855	75,867,520	2,655

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity factor which reflects the adjustment for any expected reliability and capacity impacts from the implementation of the control technique.
(3) – Annual electricity generation reduction is annual operating time reduction multiplied by the annual running plant capacity factor resulting from the implementation of the individual NOx control technique multiplied by the 12-month average gross output of 440 MW.
(4) – The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control technique.
(5) – The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.

TABLE C.3-5 – Expected NOx Reagent Usage and Cost Estimates for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	NOx Reduction Reagent Urea Usage(2)			NOx Reduction Reagent Dilution Water Usage(3)	
		lbs/hr	tons/yr	1000$/yr	1000 gal/yr	1000$/yr
E	SNCR w/ ASOFA	2,713	9,826	3,727	9,851	10

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – All cost figures in 2006 dollars.
(3) – Reagent dilution water usage assumes potable water is added to create a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) prior to injection. Dilution water unit cost assumed to be $1.00 per thousand gallons.

TABLE C.3-6 – Expected Heat Input and Equivalent Coal Cost to Evaporate Aqueous Urea for MRY Unit 2 NO_X Controls

Alt. Label(1)	NOx Control Technique	Estimated Annual Average Unit Equivalent Coal Consumption Cost for Aqueous Urea Evaporation		
		Heat Required to Evaporate Aqueous Urea(2), mmBtu/yr	Equivalent Coal Consumption for Heat Input(2), Tons/yr	Coal Consumption Cost(2), 1000$/yr
E	SNCR w/ ASOFA	73,986	5,553	52

(1) – Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) – Heat required to evaporate urea reagent dilution water assumes 900 Btu/lb required based on a 10% urea concentration (4 parts water to 1 part urea solution at 50% concentration) injected for the estimated amount of urea usage. Coal heat content of 6,662 Btu/lb, unit cost of $0.71/mmBtu.

Appendix C References:

[i] EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 1 - Selective Non-Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch1.pdf, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf.

[ii] "Stationary Source NOx and PM Emissions in the WRAP Region: An Initial Assessment of Emissions, Controls, and Air Quality Impacts", October 1, 2003 Western Regional Air Partnership Final Report of the WRAP Market Trading Forum, Section VI: Summary of Emission Controls Available for Large Stationary Sources of NOx and PM (by Reaction Engineering International), available at http://www.wrapair.org/forums/mtf/nox-pm.html

[iv] "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region" WRAP Draft Report EGR Contract Number 30204-101, prepared by Eastern Research Group, Inc., dated April 26, 2005, posted at their website: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf

[v] "Combustion Modification – An Economic Alternative for Boiler NO_X Control" GER-4192 (04/01), Folsom, Blair A, Tyson, Thomas J. GE Power Systems, Schenectady, NY, (2001) posted at their website: http://www.gepower.com/prod_serv/products/tech_docs/en/downloads/ger4192.pdf

[vi] "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities", dated March 2005, posted at their website: http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf

[vii] Budgetary Proposal, Fuel Tech, Inc. NOxOUT® SNCR and SNCR/FLGR® Systems, for one 450 MW cyclone-fired unit, dated December 9, 2004.

Appendix B

Visibility Modeling Detailed Results

Emission Parameters for Minnkota Power Cooperative
BART Modeling Analysis
Milton R. Young Unit 1 & Unit 2

Scenario/ Unit Number	Stack Height		Stack Diameter		Exit Velocity		Exit Temperature		Emission Rate (lbs/hr)			
	Feet	Meters	Feet	Meters	feet/sec	meters/sec	F	K	SO_2	NO_X	PM Fine	PM Coarse
Precontrol												
Unit 1	299.8	91.4	19.0	5.8	60.7	18.5	349.0	449.1	7231.2	2855.2	5.5	36.7
Unit 2	549.7	167.6	24.9	7.6	63.0	19.2	191.8	361.8	6879.0	5364.2	28.1	178.7
Run 1												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	28.1	178.7
Run 2												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	2855.2	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.4	5364.2	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.5	36.7
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	28.1	178.7
Run 3												
Unit 1	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	7231.2	2855.2	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	6879.0	5364.2	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	59.0	18.0	349.0	449.1	0.0	0.0	5.8	38.5
Unit2pm	549.7	167.6	30.8	9.4	59.0	18.0	191.8	361.8	0.0	0.0	21.0	133.7
Run 4												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.8	38.5
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7
Run 5												
Unit 1	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	723.1	1070.7	0.0	0.0
Unit 2	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	1574.0	2011.6	0.0	0.0
Unit1pm	549.7	167.6	23.6	7.2	54.8	16.7	174.2	352.0	0.0	0.0	5.8	38.5
Unit2pm	549.7	167.6	30.8	9.4	54.8	16.7	144.3	335.4	0.0	0.0	21.0	133.7

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	% SO4	% NO3	% PMC	% PMF
	---	---	---	---	---	---	---	---	---	---	---	---
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.101	6.334	2.234	2000	74	51	105	2.8	85.77	14.19	0.02	0.02
98th %tile Delta-DV	1.151	3.257	2.106	2000	265	51	105	2.2	92.11	7.79	0.07	0.03
90th %tile Delta-DV	0.351	2.478	2.127	2000	100	51	105	2.3	81.38	18.42	0.14	0.06
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.83	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.95	30.87	0.13	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	6.180	8.414	2.234	2002	78	53	107	2.8	85.05	14.89	0.03	0.02
98th %tile Delta-DV	2.766	5.021	2.255	2002	26	48	102	2.9	79.59	20.30	0.08	0.02
90th %tile Delta-DV	0.476	2.710	2.234	2002	91	53	107	2.8	82.61	17.36	0.01	0.02
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.457	4.690	2.234	2000	72	82	71	2.8	81.52	18.39	0.06	0.02
98th %tile Delta-DV	1.307	3.413	2.106	2000	217	82	71	2.2	92.58	7.32	0.07	0.03
90th %tile Delta-DV	0.306	2.475	2.170	2000	152	82	71	2.5	82.80	16.99	0.16	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.22	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	4.941	7.174	2.234	2002	73	58	47	2.8	79.73	20.16	0.08	0.03
98th %tile Delta-DV	2.413	4.646	2.234	2002	51	84	113	2.8	84.00	15.92	0.05	0.02
90th %tile Delta-DV	0.506	2.634	2.127	2002	110	82	71	2.3	89.40	10.53	0.05	0.02
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.675	5.908	2.234	2000	74	90	72	2.8	86.93	13.03	0.02	0.02
98th %tile Delta-DV	0.823	2.929	2.106	2000	265	90	72	2.2	89.95	9.96	0.07	0.03
90th %tile Delta-DV	0.260	2.366	2.106	2000	261	90	72	2.2	94.09	5.63	0.20	0.08
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.09	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.89	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	6.042	8.276	2.234	2002	73	90	72	2.8	80.78	19.11	0.08	0.03
98th %tile Delta-DV	2.465	4.699	2.234	2002	39	90	72	2.8	89.53	10.34	0.08	0.05
90th %tile Delta-DV	0.321	2.427	2.106	2002	255	90	72	2.2	95.00	4.58	0.28	0.14
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.150	6.425	2.275	2000	47	97	79	2.9	91.79	8.15	0.04	0.02
98th %tile Delta-DV	1.248	3.587	2.340	2000	336	97	79	3.2	87.73	12.20	0.04	0.03
90th %tile Delta-DV	0.537	2.682	2.145	2000	261	99	81	2.3	98.43	1.20	0.27	0.10
2001												
Largest Delta-DV	4.993	7.332	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.93	19.98	0.06	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	3.121	5.396	2.275	2002	74	97	79	2.9	85.98	13.97	0.03	0.02
98th %tile Delta-DV	1.834	3.980	2.145	2002	111	99	81	2.3	84.27	15.60	0.10	0.03
90th %tile Delta-DV	0.436	2.581	2.145	2002	100	91	73	2.3	86.69	13.26	0.02	0.02

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 33
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 1
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
	---	---	---	---	---	---	---	---	---	---	---	---
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.360	6.593	2.234	2000	74	51	105	2.8	75.04	24.79	0.08	0.09
98th %tile Delta-DV	1.273	3.548	2.276	2000	316	46	46	3	67.31	32.39	0.22	0.08
90th %tile Delta-DV	0.358	2.591	2.234	2000	46	6	6	2.8	34.02	64.43	1.20	0.35
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.478	8.712	2.234	2002	78	53	107	2.8	75.48	24.27	0.14	0.11
98th %tile Delta-DV	3.008	5.262	2.255	2002	26	48	102	2.9	66.05	33.52	0.32	0.11
90th %tile Delta-DV	0.528	2.634	2.106	2002	241	48	102	2.2	94.68	5.14	0.12	0.06
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.588	4.821	2.234	2000	72	82	71	2.8	68.73	30.9	0.28	0.1
98th %tile Delta-DV	1.345	3.451	2.106	2000	217	82	71	2.2	85.57	13.95	0.33	0.15
90th %tile Delta-DV	0.317	2.445	2.127	2000	286	82	71	2.3	65.24	34.25	0.35	0.16
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	5.446	7.679	2.234	2002	73	63	52	2.8	65.53	33.99	0.35	0.12
98th %tile Delta-DV	2.692	4.925	2.234	2002	51	82	71	2.8	71.04	28.62	0.24	0.11
90th %tile Delta-DV	0.554	2.682	2.127	2002	138	82	71	2.3	67.69	31.23	0.76	0.32
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.876	6.11	2.234	2000	74	90	72	2.8	76.78	23.06	0.07	0.09
98th %tile Delta-DV	0.922	3.156	2.234	2000	69	90	72	2.8	61.84	37.64	0.36	0.16
90th %tile Delta-DV	0.278	2.512	2.234	2000	32	90	72	2.8	60.45	39.14	0.23	0.18
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.564	8.797	2.234	2002	73	90	72	2.8	67.55	32.01	0.33	0.11
98th %tile Delta-DV	2.513	4.768	2.255	2002	29	90	72	2.9	69.55	30.13	0.23	0.09
90th %tile Delta-DV	0.339	2.466	2.127	2002	125	90	72	2.3	62.64	37.12	0.05	0.19
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.043	6.319	2.275	2000	47	97	79	2.9	79.16	20.58	0.18	0.09
98th %tile Delta-DV	1.393	3.669	2.275	2000	48	99	81	2.9	73.88	25.93	0.12	0.07
90th %tile Delta-DV	0.585	2.881	2.297	2000	12	99	81	3	72.77	26.8	0.26	0.18
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.287	5.562	2.275	2002	74	97	79	2.9	75.12	24.66	0.14	0.08
98th %tile Delta-DV	1.935	4.274	2.340	2002	312	99	81	3.2	71.84	27.82	0.17	0.17
90th %tile Delta-DV	0.466	2.611	2.145	2002	247	97	79	2.3	96.79	2.20	0.70	0.31

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 17
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 40
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 41
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 20
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 2
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	% SO4	% NO3	% PMC	% PMF
	---	---	---	---	---	---	---	---	---	---	---	---
TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.580	4.814	2.234	2000	72	53	107	2.8	11.93	87.88	0.14	0.05
98th %tile Delta-DV	0.583	2.817	2.234	2000	41	1	1	2.8	6.55	93.18	0.19	0.08
90th %tile Delta-DV	0.200	2.327	2.127	2000	287	46	46	2.3	23.65	76.13	0.15	0.07
2001												
Largest Delta-DV	3.062	5.168	2.106	2001	260	46	46	2.2	97.82	2.07	0.08	0.03
98th %tile Delta-DV	1.219	3.346	2.127	2001	92	52	106	2.3	68.94	30.87	0.14	0.05
90th %tile Delta-DV	0.302	2.429	2.127	2001	144	53	107	2.3	77.98	21.73	0.21	0.07
2002												
Largest Delta-DV	3.954	6.187	2.234	2002	78	45	45	2.8	14.93	84.96	0.06	0.04
98th %tile Delta-DV	1.768	4.023	2.255	2002	29	3	3	2.9	13.56	86.31	0.09	0.04
90th %tile Delta-DV	0.247	2.523	2.276	2002	330	47	101	3.0	15.64	84.29	0.03	0.04
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.396	4.630	2.234	2000	36	82	71	2.8	9.63	90.16	0.14	0.07
98th %tile Delta-DV	0.762	2.889	2.127	2000	98	84	113	2.3	10.23	89.46	0.24	0.07
90th %tile Delta-DV	0.144	2.419	2.276	2000	336	63	52	3.0	4.02	95.71	0.21	0.06
2001												
Largest Delta-DV	3.423	5.657	2.234	2001	64	82	71	2.8	88.52	11.43	0.04	0.01
98th %tile Delta-DV	1.833	3.939	2.106	2001	234	82	71	2.2	99.21	0.62	0.12	0.04
90th %tile Delta-DV	0.419	2.652	2.234	2001	85	82	71	2.8	67.30	32.52	0.12	0.05
2002												
Largest Delta-DV	3.890	6.123	2.234	2002	73	63	52	2.8	11.76	88.06	0.14	0.04
98th %tile Delta-DV	1.522	3.776	2.255	2002	29	85	114	2.9	12.95	86.92	0.10	0.04
90th %tile Delta-DV	0.244	2.414	2.170	2002	154	82	71	2.5	19.45	80.22	0.24	0.09
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.018	4.251	2.234	2000	74	90	72	2.8	19.61	80.31	0.04	0.04
98th %tile Delta-DV	0.528	2.677	2.149	2000	184	90	72	2.4	45.84	53.38	0.56	0.21
90th %tile Delta-DV	0.122	2.292	2.170	2000	164	90	72	2.5	62.36	36.69	0.68	0.27
2001												
Largest Delta-DV	2.417	4.650	2.234	2001	64	90	72	2.8	90.08	9.87	0.03	0.01
98th %tile Delta-DV	1.049	3.176	2.127	2001	92	90	72	2.3	69.93	29.88	0.13	0.05
90th %tile Delta-DV	0.209	2.336	2.127	2001	94	90	72	2.3	87.27	12.70	0.02	0.01
2002												
Largest Delta-DV	4.326	6.559	2.234	2002	73	90	72	2.8	13.02	86.81	0.12	0.04
98th %tile Delta-DV	1.589	3.843	2.255	2002	29	90	72	2.9	13.69	86.19	0.09	0.04
90th %tile Delta-DV	0.148	2.276	2.127	2002	116	90	72	2.3	5.46	94.29	0.18	0.07
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.844	5.119	2.275	2000	47	97	79	2.9	17.17	82.73	0.07	0.03
98th %tile Delta-DV	0.870	3.037	2.167	2000	216	97	79	2.4	20.55	79.22	0.18	0.05
90th %tile Delta-DV	0.277	2.510	2.232	2000	196	91	73	2.7	51.06	47.79	0.82	0.33
2001												
Largest Delta-DV	4.993	7.333	2.340	2001	326	99	81	3.2	87.88	12.05	0.05	0.02
98th %tile Delta-DV	2.003	4.278	2.275	2001	41	91	73	2.9	79.94	19.98	0.05	0.03
90th %tile Delta-DV	0.488	2.720	2.232	2001	208	99	81	2.7	93.60	6.33	0.05	0.02
2002												
Largest Delta-DV	1.721	3.996	2.275	2002	74	97	79	2.9	18.00	81.90	0.06	0.03
98th %tile Delta-DV	0.899	3.239	2.340	2002	312	91	73	3.2	14.82	85.04	0.07	0.08
90th %tile Delta-DV	0.201	2.411	2.211	2002	172	99	81	2.6	37.25	61.19	1.18	0.38

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 18
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 2
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
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TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.153	6.387	2.234	2000	72	53	107	2.8	13.85	85.69	0.34	0.12
98th %tile Delta-DV	1.159	3.392	2.234	2000	69	56	110	2.8	11.29	88.21	0.36	0.13
90th %tile Delta-DV	0.340	2.467	2.127	2000	301	54	108	2.3	3.47	94.82	1.31	0.41
2001												
Largest Delta-DV	3.019	5.125	2.106	2001	260	46	46	2.2	95.13	4.35	0.37	0.14
98th %tile Delta-DV	1.476	3.625	2.149	2001	205	51	105	2.4	86.70	11.94	1.07	0.30
90th %tile Delta-DV	0.332	2.438	2.106	2001	230	41	41	2.2	90.53	7.68	1.40	0.40
2002												
Largest Delta-DV	6.473	8.706	2.234	2002	78	45	45	2.8	16.99	82.74	0.16	0.11
98th %tile Delta-DV	3.080	5.335	2.255	2002	29	3	3	2.9	15.06	84.61	0.23	0.10
90th %tile Delta-DV	0.497	2.624	2.127	2002	294	47	101	2.3	14.54	84.71	0.51	0.24
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.452	5.685	2.234	2000	36	82	71	2.8	11.65	87.78	0.38	0.18
98th %tile Delta-DV	1.332	3.566	2.234	2000	74	67	56	2.8	20.92	78.90	0.08	0.11
90th %tile Delta-DV	0.257	2.384	2.127	2000	119	82	71	2.3	15.13	83.25	1.23	0.38
2001												
Largest Delta-DV	3.474	5.708	2.234	2001	64	82	71	2.8	79.09	20.68	0.16	0.07
98th %tile Delta-DV	1.793	3.899	2.106	2001	234	82	71	2.2	97.90	1.29	0.62	0.19
90th %tile Delta-DV	0.442	2.676	2.234	2001	55	82	71	2.8	65.06	34.64	0.21	0.09
2002												
Largest Delta-DV	6.094	8.327	2.234	2002	73	63	52	2.8	13.44	86.13	0.32	0.11
98th %tile Delta-DV	2.666	4.900	2.234	2002	75	82	71	2.8	17.44	82.13	0.28	0.16
90th %tile Delta-DV	0.410	2.685	2.276	2002	352	71	60	3.0	13.41	86.31	0.18	0.10
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	3.513	5.747	2.234	2000	74	90	72	2.8	21.72	78.08	0.09	0.11
98th %tile Delta-DV	1.068	3.174	2.106	2000	247	90	72	2.2	68.84	28.73	1.68	0.74
90th %tile Delta-DV	0.201	2.307	2.106	2000	239	90	72	2.2	43.86	55.24	0.58	0.32
2001												
Largest Delta-DV	2.419	4.653	2.234	2001	64	90	72	2.8	81.69	18.11	0.14	0.06
98th %tile Delta-DV	1.131	3.364	2.234	2001	84	90	72	2.8	64.16	35.36	0.34	0.15
90th %tile Delta-DV	0.215	2.342	2.127	2001	101	90	72	2.3	84.12	15.80	0.04	0.04
2002												
Largest Delta-DV	6.981	9.214	2.234	2002	73	90	72	2.8	14.69	84.89	0.31	0.11
98th %tile Delta-DV	2.789	5.044	2.255	2002	29	90	72	2.9	15.14	84.54	0.23	0.09
90th %tile Delta-DV	0.259	2.387	2.127	2002	116	90	72	2.3	6.26	93.09	0.47	0.18
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.227	6.502	2.275	2000	47	97	79	2.9	19.67	80.05	0.19	0.09
98th %tile Delta-DV	1.443	3.718	2.275	2000	48	99	81	2.9	19.14	80.64	0.14	0.08
90th %tile Delta-DV	0.494	2.639	2.145	2000	114	91	73	2.3	29.95	68.59	0.87	0.59
2001												
Largest Delta-DV	5.139	7.479	2.340	2001	327	99	81	3.2	71.41	28.32	0.18	0.09
98th %tile Delta-DV	2.042	4.188	2.145	2001	259	97	79	2.3	91.38	8.26	0.26	0.10
90th %tile Delta-DV	0.580	2.791	2.211	2001	179	99	81	2.6	69.45	29.47	0.82	0.26
2002												
Largest Delta-DV	3.117	5.392	2.275	2002	74	97	79	2.9	19.78	79.98	0.16	0.09
98th %tile Delta-DV	1.486	3.654	2.167	2002	239	93	75	2.4	33.81	65.60	0.41	0.18
90th %tile Delta-DV	0.405	2.572	2.167	2002	234	97	79	2.4	38.85	60.11	0.64	0.40

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 20
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 32
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 39
Number of days with Delta-Deciview > 1.00: 22
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 30
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 5

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
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TRNP SOUTH UNIT												
2000												
Largest Delta-DV	4.878	7.111	2.234	2000	74	51	105	2.8	69.15	30.81	0.02	0.02
98th %tile Delta-DV	1.464	3.740	2.276	2000	316	46	46	3.0	60.13	39.82	0.04	0.01
90th %tile Delta-DV	0.412	2.518	2.106	2000	214	46	46	2.2	97.63	2.18	0.15	0.05
2001												
Largest Delta-DV	3.145	5.251	2.106	2001	260	46	46	2.2	94.80	5.09	0.08	0.03
98th %tile Delta-DV	1.576	3.725	2.149	2001	205	51	105	2.4	84.26	15.47	0.21	0.06
90th %tile Delta-DV	0.373	2.479	2.106	2001	224	53	107	2.2	96.76	3.06	0.14	0.04
2002												
Largest Delta-DV	6.961	9.194	2.234	2002	78	53	107	2.8	72.32	27.63	0.03	0.02
98th %tile Delta-DV	3.552	5.807	2.255	2002	26	48	102	2.9	59.46	40.46	0.06	0.02
90th %tile Delta-DV	0.611	2.844	2.234	2002	91	56	110	2.8	63.16	36.81	0.01	0.01
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.135	5.368	2.234	2000	72	82	71	2.8	61.67	38.26	0.05	0.02
98th %tile Delta-DV	1.469	3.575	2.106	2000	217	82	71	2.2	81.65	18.26	0.07	0.03
90th %tile Delta-DV	0.373	2.501	2.127	2000	286	82	71	2.3	58.48	41.43	0.06	0.03
2001												
Largest Delta-DV	4.011	6.244	2.234	2001	64	82	71	2.8	73.23	26.73	0.03	0.01
98th %tile Delta-DV	1.853	3.959	2.106	2001	234	82	71	2.2	98.06	1.77	0.13	0.04
90th %tile Delta-DV	0.488	2.615	2.127	2001	112	58	47	2.3	51.71	48.11	0.15	0.04
2002												
Largest Delta-DV	6.257	8.490	2.234	2002	73	63	52	2.8	58.28	41.64	0.06	0.02
98th %tile Delta-DV	3.026	5.259	2.234	2002	51	82	71	2.8	64.37	35.56	0.04	0.02
90th %tile Delta-DV	0.639	2.766	2.127	2002	138	82	71	2.3	61.20	38.60	0.14	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	4.342	6.576	2.234	2000	74	90	72	2.8	71.00	28.97	0.01	0.02
98th %tile Delta-DV	1.084	3.317	2.234	2000	69	90	72	2.8	54.54	45.37	0.06	0.03
90th %tile Delta-DV	0.341	2.469	2.127	2000	139	90	72	2.3	85.26	14.66	0.05	0.03
2001												
Largest Delta-DV	2.795	5.029	2.234	2001	64	90	72	2.8	76.35	23.62	0.03	0.01
98th %tile Delta-DV	1.321	3.555	2.234	2001	84	90	72	2.8	56.81	43.10	0.06	0.03
90th %tile Delta-DV	0.239	2.473	2.234	2001	55	90	72	2.8	59.90	40.06	0.03	0.01
2002												
Largest Delta-DV	7.443	9.677	2.234	2002	73	90	72	2.8	60.67	39.25	0.06	0.02
98th %tile Delta-DV	2.783	5.017	2.234	2002	39	90	72	2.8	78.00	21.88	0.08	0.04
90th %tile Delta-DV	0.404	2.531	2.127	2002	125	90	72	2.3	55.44	44.52	0.01	0.03
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.473	6.748	2.275	2000	47	97	79	2.9	83.69	16.26	0.04	0.02
98th %tile Delta-DV	1.685	3.960	2.275	2000	70	93	75	2.9	50.80	49.11	0.06	0.03
90th %tile Delta-DV	0.660	2.805	2.145	2000	131	93	75	2.3	57.84	42.02	0.12	0.03
2001												
Largest Delta-DV	5.789	8.129	2.340	2001	327	99	81	3.2	64.91	35.04	0.03	0.02
98th %tile Delta-DV	2.227	4.566	2.340	2001	333	99	81	3.2	64.47	35.44	0.05	0.04
90th %tile Delta-DV	0.596	2.742	2.145	2001	107	97	79	2.3	44.73	55.14	0.09	0.04
2002												
Largest Delta-DV	3.766	6.041	2.275	2002	74	97	79	2.9	68.87	31.09	0.03	0.01
98th %tile Delta-DV	2.195	4.427	2.232	2002	205	91	73	2.7	82.94	16.95	0.08	0.03
90th %tile Delta-DV	0.504	2.800	2.297	2002	31	97	79	3.0	78.62	21.36	0.01	0.01

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 31
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 43
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 34
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 27
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 35
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 42
Number of days with Delta-Deciview > 1.00: 28
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 44
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 38
Number of days with Delta-Deciview > 1.00: 23
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 3
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	% SO4	% NO3	% PMC	% PMF
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TRNP SOUTH UNIT												
2000												
Largest Delta-DV	5.577	7.811	2.234	2000	74	51	105	2.8	54.92	44.99	0.05	0.05
98th %tile Delta-DV	1.647	3.817	2.170	2000	152	54	108	2.5	36.38	62.85	0.57	0.20
90th %tile Delta-DV	0.511	2.638	2.127	2000	101	47	101	2.3	34.53	65.12	0.23	0.12
2001												
Largest Delta-DV	3.297	5.530	2.234	2001	64	46	46	2.8	58.91	40.96	0.09	0.04
98th %tile Delta-DV	2.001	4.235	2.234	2001	84	46	46	2.8	40.75	59.03	0.15	0.06
90th %tile Delta-DV	0.397	2.503	2.106	2001	234	51	105	2.2	94.76	4.72	0.40	0.12
2002												
Largest Delta-DV	8.275	10.508	2.234	2002	73	48	102	2.8	44.60	55.19	0.15	0.05
98th %tile Delta-DV	4.338	6.444	2.106	2002	250	53	107	2.2	63.35	36.16	0.35	0.15
90th %tile Delta-DV	0.780	2.907	2.127	2002	294	47	101	2.3	42.15	57.47	0.26	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	3.754	5.988	2.234	2000	72	82	71	2.8	44.56	55.26	0.13	0.05
98th %tile Delta-DV	1.660	3.766	2.106	2000	217	82	71	2.2	68.22	31.49	0.20	0.09
90th %tile Delta-DV	0.421	2.570	2.149	2000	191	67	56	2.4	91.41	7.97	0.48	0.15
2001												
Largest Delta-DV	4.537	6.771	2.234	2001	64	82	71	2.8	57.23	42.65	0.09	0.04
98th %tile Delta-DV	2.082	4.188	2.106	2001	260	86	115	2.2	87.36	12.37	0.19	0.08
90th %tile Delta-DV	0.517	2.666	2.149	2001	205	58	47	2.4	92.58	6.69	0.54	0.19
2002												
Largest Delta-DV	7.694	9.928	2.234	2002	73	63	52	2.8	40.95	58.83	0.16	0.06
98th %tile Delta-DV	3.703	5.937	2.234	2002	75	82	71	2.8	49.80	49.97	0.14	0.08
90th %tile Delta-DV	0.773	3.006	2.234	2002	91	82	71	2.8	47.25	52.60	0.09	0.06
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	5.037	7.270	2.234	2000	74	90	72	2.8	55.53	44.39	0.04	0.05
98th %tile Delta-DV	1.497	3.730	2.234	2000	69	90	72	2.8	37.02	62.75	0.16	0.07
90th %tile Delta-DV	0.349	2.519	2.170	2000	152	90	72	2.5	53.35	46.14	0.35	0.16
2001												
Largest Delta-DV	3.117	5.350	2.234	2001	64	90	72	2.8	61.14	38.75	0.08	0.03
98th %tile Delta-DV	1.795	4.028	2.234	2001	84	90	72	2.8	39.07	60.70	0.15	0.07
90th %tile Delta-DV	0.272	2.399	2.127	2001	94	90	72	2.3	56.09	43.84	0.04	0.02
2002												
Largest Delta-DV	8.901	11.134	2.234	2002	73	90	72	2.8	43.67	56.12	0.16	0.05
98th %tile Delta-DV	3.057	5.291	2.234	2002	39	90	72	2.8	63.55	36.10	0.22	0.14
90th %tile Delta-DV	0.415	2.564	2.149	2002	198	90	72	2.4	93.95	5.38	0.47	0.20
LOSTWOOD NWA												
2000												
Largest Delta-DV	4.587	6.862	2.275	2000	47	97	79	2.9	67.76	32.07	0.11	0.06
98th %tile Delta-DV	1.965	4.240	2.275	2000	55	91	73	2.9	67.87	31.96	0.09	0.08
90th %tile Delta-DV	0.810	3.085	2.275	2000	65	91	73	2.9	61.71	38.02	0.17	0.11
2001												
Largest Delta-DV	6.953	9.293	2.340	2001	327	99	81	3.2	47.65	52.21	0.09	0.04
98th %tile Delta-DV	2.731	5.070	2.340	2001	333	99	81	3.2	48.63	51.13	0.14	0.10
90th %tile Delta-DV	0.806	2.973	2.167	2001	240	91	73	2.4	70.59	29.06	0.23	0.11
2002												
Largest Delta-DV	4.457	6.732	2.275	2002	74	97	79	2.9	52.05	47.83	0.07	0.04
98th %tile Delta-DV	2.318	4.550	2.232	2002	205	91	73	2.7	71.61	28.05	0.25	0.09
90th %tile Delta-DV	0.601	2.768	2.167	2002	218	99	81	2.4	84.33	15.25	0.21	0.22

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 16
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 52
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 23
Number of days with Delta-Deciview > 1.00: 13
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 36
Number of days with Delta-Deciview > 1.00: 19
Max number of consecutive days with Delta-Deciview > 0.50: 4

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 29
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 37
Number of days with Delta-Deciview > 1.00: 21
Max number of consecutive days with Delta-Deciview > 0.50: 4
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 29
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 50
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2001
Number of days with Delta-Deciview > 0.50: 48
Number of days with Delta-Deciview > 1.00: 27
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 45
Number of days with Delta-Deciview > 1.00: 25
Max number of consecutive days with Delta-Deciview > 0.50: 4

Minnkota Power Cooperative
Milton R. Young Unit 1
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
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TRNP SOUTH UNIT												
2000												
Largest Delta-DV	1.269	3.502	2.234	2000	74	51	105	2.8	37.96	61.85	0.09	0.09
98th %tile Delta-DV	0.265	2.499	2.234	2000	69	56	110	2.8	23.55	75.98	0.35	0.13
90th %tile Delta-DV	0.094	2.221	2.127	2000	109	53	107	2.3	9.18	88.60	1.69	0.53
2001												
Largest Delta-DV	0.592	2.720	2.127	2001	112	51	105	2.3	23.91	75.37	0.57	0.15
98th %tile Delta-DV	0.344	2.620	2.276	2001	328	45	45	3	38.61	61.25	0.08	0.06
90th %tile Delta-DV	0.060	2.188	2.127	2001	101	45	45	2.3	50.01	49.86	0.07	0.06
2002												
Largest Delta-DV	2.023	4.256	2.234	2002	78	45	45	2.8	32.34	67.42	0.14	0.10
98th %tile Delta-DV	0.847	3.081	2.234	2002	64	54	108	2.8	28.28	71.37	0.22	0.13
90th %tile Delta-DV	0.118	2.246	2.127	2002	118	53	107	2.3	41.52	58.16	0.20	0.12
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.116	3.349	2.234	2000	36	82	71	2.8	22.10	77.41	0.33	0.16
98th %tile Delta-DV	0.342	2.469	2.127	2000	98	84	113	2.3	23.30	75.97	0.57	0.16
90th %tile Delta-DV	0.068	2.196	2.127	2000	286	82	71	2.3	28.79	70.86	0.22	0.13
2001												
Largest Delta-DV	0.849	3.082	2.234	2001	64	82	71	2.8	42.62	57.12	0.19	0.07
98th %tile Delta-DV	0.385	2.513	2.127	2001	109	63	52	2.3	22.79	76.20	0.74	0.28
90th %tile Delta-DV	0.079	2.185	2.106	2001	254	83	112	2.2	52.02	46.01	1.46	0.52
2002												
Largest Delta-DV	1.894	4.128	2.234	2002	73	63	52	2.8	26.80	72.76	0.33	0.11
98th %tile Delta-DV	0.734	2.967	2.234	2002	75	82	71	2.8	32.58	67.06	0.23	0.13
90th %tile Delta-DV	0.131	2.237	2.106	2002	248	82	71	2.2	39.07	60.31	0.39	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.042	3.276	2.234	2000	74	90	72	2.8	39.92	59.91	0.08	0.09
98th %tile Delta-DV	0.246	2.480	2.234	2000	69	90	72	2.8	24.81	74.77	0.29	0.13
90th %tile Delta-DV	0.059	2.165	2.106	2000	239	90	72	2.2	67.12	32.25	0.41	0.22
2001												
Largest Delta-DV	0.539	2.772	2.234	2001	64	90	72	2.8	46.77	53.00	0.16	0.07
98th %tile Delta-DV	0.304	2.538	2.234	2001	84	90	72	2.8	26.81	72.78	0.29	0.12
90th %tile Delta-DV	0.041	2.211	2.170	2001	153	90	72	2.5	63.10	35.53	0.99	0.38
2002												
Largest Delta-DV	2.175	4.409	2.234	2002	73	90	72	2.8	29.00	70.61	0.29	0.10
98th %tile Delta-DV	0.790	3.024	2.234	2002	39	90	72	2.8	32.31	67.19	0.32	0.18
90th %tile Delta-DV	0.071	2.198	2.127	2002	117	90	72	2.3	7.64	91.19	0.67	0.51
LOSTWOOD NWA												
2000												
Largest Delta-DV	1.446	3.721	2.275	2000	47	97	79	2.9	36.30	63.46	0.16	0.08
98th %tile Delta-DV	0.421	2.589	2.167	2000	217	91	73	2.4	58.25	40.61	0.85	0.28
90th %tile Delta-DV	0.139	2.479	2.340	2000	363	93	75	3.2	23.15	76.56	0.15	0.14
2001												
Largest Delta-DV	2.207	4.547	2.340	2001	327	99	81	3.2	32.49	67.26	0.16	0.09
98th %tile Delta-DV	0.517	2.857	2.340	2001	355	93	75	3.2	14.59	84.46	0.71	0.23
90th %tile Delta-DV	0.141	2.480	2.340	2001	314	99	81	3.2	19.49	80.24	0.16	0.11
2002												
Largest Delta-DV	0.857	3.133	2.275	2002	74	97	79	2.9	37.79	62.00	0.14	0.08
98th %tile Delta-DV	0.435	2.602	2.167	2002	239	93	75	2.4	56.71	42.83	0.32	0.14
90th %tile Delta-DV	0.102	2.248	2.145	2002	100	91	73	2.3	38.78	61.00	0.12	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 6
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 4
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 2
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 1
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1
2002
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 3
Number of days with Delta-Deciview > 1.00: 0
Max number of consecutive days with Delta-Deciview > 0.50: 1

Minnkota Power Cooperative
Milton R. Young Unit 2
BART Run 4
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
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TRNP SOUTH UNIT												
2000												
Largest Delta-DV	2.255	4.489	2.234	2000	74	51	105	2.8	40.92	58.76	0.15	0.17
98th %tile Delta-DV	0.569	2.845	2.276	2000	316	46	46	3	31.91	67.61	0.35	0.13
90th %tile Delta-DV	0.159	2.287	2.127	2000	98	47	101	2.3	37.13	62.29	0.38	0.21
2001												
Largest Delta-DV	1.149	3.382	2.234	2001	64	46	46	2.8	47.43	52.13	0.31	0.13
98th %tile Delta-DV	0.667	2.900	2.234	2001	84	46	46	2.8	30.36	68.93	0.50	0.21
90th %tile Delta-DV	0.122	2.228	2.106	2001	248	48	102	2.2	87.52	10.40	1.33	0.76
2002												
Largest Delta-DV	3.621	5.854	2.234	2002	78	45	45	2.8	35.44	64.14	0.25	0.17
98th %tile Delta-DV	1.612	3.846	2.234	2002	64	54	108	2.8	31.00	68.38	0.38	0.24
90th %tile Delta-DV	0.238	2.366	2.127	2002	118	53	107	2.3	44.33	55.09	0.35	0.22
TRNP NORTH UNIT												
2000												
Largest Delta-DV	1.716	3.949	2.234	2000	36	82	71	2.8	25.66	73.41	0.63	0.30
98th %tile Delta-DV	0.687	2.921	2.234	2000	74	67	56	2.8	41.89	57.84	0.12	0.16
90th %tile Delta-DV	0.132	2.281	2.149	2000	187	58	47	2.4	90.71	7.99	0.83	0.47
2001												
Largest Delta-DV	1.644	3.877	2.234	2001	64	82	71	2.8	45.70	53.86	0.31	0.13
98th %tile Delta-DV	0.706	2.833	2.127	2001	109	58	47	2.3	26.13	72.08	1.27	0.52
90th %tile Delta-DV	0.162	2.268	2.106	2001	230	82	71	2.2	86.55	10.92	1.72	0.80
2002												
Largest Delta-DV	3.194	5.427	2.234	2002	73	63	52	2.8	29.97	69.30	0.54	0.19
98th %tile Delta-DV	1.397	3.630	2.234	2002	75	82	71	2.8	35.54	63.80	0.42	0.24
90th %tile Delta-DV	0.213	2.341	2.127	2002	110	82	71	2.3	48.55	50.84	0.42	0.18
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	1.926	4.160	2.234	2000	74	90	72	2.8	43.05	56.66	0.13	0.16
98th %tile Delta-DV	0.487	2.720	2.234	2000	69	90	72	2.8	27.15	72.11	0.51	0.23
90th %tile Delta-DV	0.097	2.225	2.127	2000	110	90	72	2.3	8.76	86.96	3.19	1.10
2001												
Largest Delta-DV	1.066	3.299	2.234	2001	64	90	72	2.8	49.81	49.79	0.28	0.12
98th %tile Delta-DV	0.594	2.827	2.234	2001	84	90	72	2.8	29.11	70.18	0.50	0.22
90th %tile Delta-DV	0.082	2.358	2.276	2001	345	90	72	3	39.25	59.94	0.61	0.20
2002												
Largest Delta-DV	3.812	6.046	2.234	2002	73	90	72	2.8	31.97	67.35	0.50	0.18
98th %tile Delta-DV	1.447	3.680	2.234	2002	39	90	72	2.8	37.08	61.97	0.59	0.35
90th %tile Delta-DV	0.133	2.282	2.149	2002	189	90	72	2.4	90.95	6.52	1.77	0.76
LOSTWOOD NWA												
2000												
Largest Delta-DV	2.302	4.577	2.275	2000	47	97	79	2.9	39.98	59.59	0.29	0.14
98th %tile Delta-DV	0.731	3.007	2.275	2000	48	99	81	2.9	39.13	60.53	0.22	0.12
90th %tile Delta-DV	0.264	2.604	2.340	2000	359	97	79	3.2	21.84	77.89	0.13	0.14
2001												
Largest Delta-DV	3.339	5.679	2.340	2001	327	99	81	3.2	35.97	63.60	0.28	0.16
98th %tile Delta-DV	0.863	3.138	2.275	2001	89	99	81	2.9	34.01	65.28	0.49	0.22
90th %tile Delta-DV	0.264	2.409	2.145	2001	96	99	81	2.3	34.38	63.87	1.21	0.55
2002												
Largest Delta-DV	1.635	3.910	2.275	2002	74	97	79	2.9	40.73	58.89	0.24	0.14
98th %tile Delta-DV	0.756	3.031	2.275	2002	76	99	81	2.9	33.01	65.91	0.83	0.25
90th %tile Delta-DV	0.201	2.476	2.275	2002	52	97	79	2.9	41.69	58.00	0.19	0.12

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 9
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 21
Number of days with Delta-Deciview > 1.00: 12
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 7
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 8
Number of days with Delta-Deciview > 1.00: 1
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 5
Max number of consecutive days with Delta-Deciview > 0.50: 1
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 4
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 9
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 16
Number of days with Delta-Deciview > 1.00: 2
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 22
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 3
Max number of consecutive days with Delta-Deciview > 0.50: 3

Minnkota Power Cooperative
Milton R. Young Unit 1 & 2
BART Run 5
2000-2002

						SEQ	ND	% of Modeled Extinction by Species				
	DELTA-DV	DV(Total)	DV(BKG)	YEAR	DAY	RECEP	RECEP	F(RH)	%_SO4	%_NO3	%_PMC	%_PMF
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TRNP SOUTH UNIT												
2000												
Largest Delta-DV	3.279	5.513	2.234	2000	74	51	105	2.8	39.91	59.82	0.13	0.14
98th %tile Delta-DV	0.817	3.092	2.276	2000	316	45	45	3	31.35	68.24	0.30	0.11
90th %tile Delta-DV	0.241	2.369	2.127	2000	109	53	107	2.3	9.98	86.72	2.50	0.80
2001												
Largest Delta-DV	1.671	3.905	2.234	2001	64	46	46	2.8	46.41	53.21	0.27	0.11
98th %tile Delta-DV	0.987	3.221	2.234	2001	84	46	46	2.8	29.56	69.83	0.43	0.18
90th %tile Delta-DV	0.179	2.285	2.106	2001	248	48	102	2.2	87.47	10.70	1.17	0.66
2002												
Largest Delta-DV	5.058	7.291	2.234	2002	78	45	45	2.8	34.50	65.14	0.21	0.15
98th %tile Delta-DV	2.336	4.569	2.234	2002	64	54	108	2.8	30.11	69.36	0.33	0.21
90th %tile Delta-DV	0.354	2.481	2.127	2002	118	53	107	2.3	43.40	56.11	0.30	0.19
TRNP NORTH UNIT												
2000												
Largest Delta-DV	2.656	4.889	2.234	2000	36	82	71	2.8	24.37	74.87	0.51	0.25
98th %tile Delta-DV	0.979	3.212	2.234	2000	74	67	56	2.8	40.71	59.06	0.10	0.14
90th %tile Delta-DV	0.200	2.434	2.234	2000	65	82	71	2.8	34.83	63.06	1.36	0.75
2001												
Largest Delta-DV	2.367	4.601	2.234	2001	64	82	71	2.8	44.70	54.92	0.27	0.11
98th %tile Delta-DV	1.058	3.186	2.127	2001	109	58	47	2.3	25.40	73.08	1.08	0.44
90th %tile Delta-DV												
2002												
Largest Delta-DV	4.597	6.831	2.234	2002	73	63	52	2.8	28.90	70.47	0.46	0.16
98th %tile Delta-DV	2.031	4.265	2.234	2002	75	82	71	2.8	34.66	64.78	0.36	0.20
90th %tile Delta-DV	0.330	2.500	2.170	2002	154	82	71	2.5	45.03	54.16	0.59	0.23
TRNP ELKHORN RANCH												
2000												
Largest Delta-DV	2.791	5.025	2.234	2000	74	90	72	2.8	42.02	57.73	0.11	0.14
98th %tile Delta-DV	0.721	2.954	2.234	2000	69	90	72	2.8	26.39	72.98	0.43	0.20
90th %tile Delta-DV	0.178	2.454	2.276	2000	316	90	72	3	30.15	69.40	0.33	0.12
2001												
Largest Delta-DV	1.551	3.784	2.234	2001	64	90	72	2.8	48.82	50.84	0.24	0.10
98th %tile Delta-DV	0.880	3.113	2.234	2001	84	90	72	2.8	28.37	71.02	0.43	0.19
90th %tile Delta-DV	0.126	2.296	2.170	2001	153	90	72	2.5	64.15	33.83	1.44	0.57
2002												
Largest Delta-DV	5.337	7.570	2.234	2002	73	90	72	2.8	31.03	68.39	0.43	0.15
98th %tile Delta-DV	2.020	4.254	2.234	2002	39	90	72	2.8	37.65	61.51	0.53	0.31
90th %tile Delta-DV	0.195	2.343	2.149	2002	189	90	72	2.4	91.03	6.75	1.56	0.66
LOSTWOOD NWA												
2000												
Largest Delta-DV	3.458	5.734	2.275	2000	47	97	79	2.9	38.71	60.93	0.24	0.12
98th %tile Delta-DV	1.161	3.437	2.275	2000	37	97	79	2.9	23.36	76.08	0.37	0.18
90th %tile Delta-DV	0.393	2.669	2.275	2000	67	97	79	2.9	36.18	63.42	0.25	0.14
2001												
Largest Delta-DV	4.964	7.304	2.340	2001	327	99	81	3.2	34.66	64.98	0.23	0.13
98th %tile Delta-DV	1.332	3.608	2.275	2001	89	93	75	2.9	31.34	68.02	0.45	0.19
90th %tile Delta-DV	0.411	2.751	2.340	2001	314	99	81	3.2	20.85	78.74	0.24	0.17
2002												
Largest Delta-DV	2.366	4.642	2.275	2002	74	97	79	2.9	39.77	59.90	0.21	0.12
98th %tile Delta-DV	1.140	3.285	2.145	2002	131	99	81	2.3	30.86	67.70	1.10	0.34
90th %tile Delta-DV	0.303	2.578	2.275	2002	52	97	79	2.9	40.58	59.15	0.17	0.10

Duration Events Largest Delta-DV

TRNP SOUTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 17
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 13
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 26
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 3

TRNP ELKHORN RANCH
2000
Number of days with Delta-Deciview > 0.50: 10
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 12
Number of days with Delta-Deciview > 1.00: 6
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 2

TRNP NORTH UNIT
2000
Number of days with Delta-Deciview > 0.50: 15
Number of days with Delta-Deciview > 1.00: 7
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 19
Number of days with Delta-Deciview > 1.00: 8
Max number of consecutive days with Delta-Deciview > 0.50: 2
2002
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 18
Max number of consecutive days with Delta-Deciview > 0.50: 4

LOSTWOOD NWA
2000
Number of days with Delta-Deciview > 0.50: 24
Number of days with Delta-Deciview > 1.00: 10
Max number of consecutive days with Delta-Deciview > 0.50: 2
2001
Number of days with Delta-Deciview > 0.50: 28
Number of days with Delta-Deciview > 1.00: 14
Max number of consecutive days with Delta-Deciview > 0.50: 3
2002
Number of days with Delta-Deciview > 0.50: 25
Number of days with Delta-Deciview > 1.00: 11
Max number of consecutive days with Delta-Deciview > 0.50: 4