NORTH DAKOTA
DEPARTMENT of HEALTH

ENVIRONMENTAL HEALTH SECTION
Gold Seal Center, 918 E. Divide Ave.
Bismarck, ND 58501-1947
701.328.5200 (fax)
www.ndhealth.gov

February 1, 2007

FILE

Mr. John Graves
Environmental Manager
Minnkota Power Cooperative
1822 Mill Road
P.O. Box 13200
Grand Forks, ND 58208-3200

Re: BACT Determination
Milton R. Young Station

Dear Mr. Graves:

Enclosed with this letter is a copy of a letter the Department received from the U.S. Environmental Protection Agency which provided comments on the BACT analysis for the Milton R. Young Station and requested specific information to be provided by Minnkota. In addition to the information requested through EPA's letter, the Department requests that Minnkota provide the following:

1. Please provide a statistical analysis of historical as-fired coal data. This should include the range, average and standard deviation for the amount of ash, sulfur, calcium oxide, magnesium oxide, sodium oxide, potassium oxide and heat content. Also provide a separate analysis for core samples of lignite that will be mined in the future. (Note that this is similar to EPA's comment No. 4).

2. The temperature between the economizer and air heaters is described as "much higher than 750 degrees" (p A1-31). Please provide more specific data on the temperatures that would be encountered at the location an SCR would be installed.

3. It is indicated that a low dust SCR would be subject to the same fouling problems as a high dust SCR due to the emission of small (<5 micron) particles containing sodium-calcium-sulfur rich materials. Please provide any existing data on the composition of the particulate matter exiting the electrostatic precipitators.

We ask that you provide a response to these comments, in writing, by March 1, 2007.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 8
1595 Wynkoop Street
DENVER, CO 80202-1129
Phone 800-227-8917
http://www.epa.gov/region08

FEB 2007
Received
Air Quality

Ref: 8ENF-L

Via Fax, US Mail, & Email

January 26, 2007

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1943

Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study

Dear Terry:

The United States Environmental Protection Agency, Region 8 ("EPA") appreciates the trip you and Tom Bachman made to Denver, CO, on January 11, 2007, to discuss EPA's concerns with the Burns & McDonnell Best Available Control Technology ("BACT") Analysis for Nitrogen Oxides ("NO_x") at Milton R. Young Station (MRYS), Units 1 and 2 (hereinafter, "the B&M BACT Analysis"). EPA was pleased to learn at that meeting that the State of North Dakota had provided the concerns memorialized by EPA and Roger Christman to Minnkota Power Company ("Minnkota").

Through this letter EPA is forwarding the non-Selective Catalytic Reduction ("non-SCR") concerns as enclosed comments for your review and your transmittal to Minnkota. This letter also transmits the information EPA presently requires Minnkota to provide pursuant to paragraph 65 of the Consent Decree. Please note that EPA's comments on the non-SCR technology analyses will also require additional information and analysis relevant to the various technologies that are not included in the request for additional information documented within this letter. Should Minnkota need clarification regarding any of the concerns raised by EPA or Mr. Christman on the SCR and/or the non-SCR comments, or the additional information requested, please bring that to my attention so we can continue to proceed through this consultation process expeditiously.

Generally, the written comments from EPA and Roger Christman and the discussion during the January 11th meeting highlighted concerns with Minnkota's incomplete analysis and premature determination of infeasibility of various technologies based upon their interpretation

of Chapter B of EPA's "*New Source Review Workshop Manual – Prevention of Significant Deterioration and Non-attainment Area Permitting*" (Draft October 1990). Additionally discussed were the numerous instances in the B&M BACT Analysis of data deficiencies and failure to provide supporting data.

As a result of the January 11th meeting, both the State and EPA agreed to request additional information pursuant to paragraph 65 of the Consent Decree. EPA agreed to provide North Dakota with additional information to be requested of Minnkota. The State agreed to incorporate EPA's information request in a letter to Minnkota. While EPA reserves the right to request additional information pursuant to paragraph 65 of the Consent Decree, it would like the following information to be provided by B&M or Minnkota within a period of time deemed sufficient by the State. Should the State want to add to this list of information, please do so and then telefax or email the State's draft letter to Minnkota to both me and Brenda Morris at Fax number 303-312-7202. Once the letter is finalized by the State, EPA requests a hard copy for its records.

The following information should be requested from Minnkota at this time:

1. Please provide any and all data and information related to catalyst deactivation rates and NO_x control effectiveness measured at the three facilities tested during the "Ash Impacts on SCR Catalyst Performance" study that is extensively referred to in the "EERC Report" included as Appendix B of the Minnkota NO_x BACT analysis. This should include the original proposal, all test plans, all raw catalyst deactivation and NO_x control data collected during the test, and all final reports and conclusions that were produced for the study's participants. In addition, please provide a quantitative analysis of the application of the multiple engineering solutions (e.g. catalyst rejuvenation and regeneration, acoustic horns, etc.) described by Roger Christman and EPA to address specific concerns highlighted in the BACT analysis and EERC Report and their effect on SCR catalyst deactivation rates and NO_x control effectiveness at MRYS.

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It seems that we should modify the schedule we agreed upon for the consultation process. Please let me know your thoughts regarding any changes to the schedule you laid out in your December 18, 2006 email. I can be reached at 303-312-6776 or by e-mail: hestmark.martin@epa.gov.

Sincerely,

Martin Hestmark
Program Director Air and Toxics
Technical Enforcement Program

Enclosure
cc: Eddie Sierra, Acting Director, ECEJ
Matthew Morrison, USDOJ
Jeff Kodish, OECA,
Albion Carlson, EPA
Brenda Morris, EPA
Douglas Latimer, EPA
Mike Owens, EPA
Hans Buenning, EPA
Ron Rutherford, EPA
Lyle Whitham, NDDH

ENCLOSURE

Summary of Preliminary Non-SCR Issues for the Minnkota NO_x BACT Analysis January 26, 2007

Elimination of Control Options as Technically Infeasible

It appears as though several control options have been eliminated improperly for technical infeasibility at step 2 of the Top-Down BACT analysis. Many of these options appear to have been eliminated as being technically infeasible, simply because they have not been demonstrated on full-scale cyclone boilers that burn North Dakota lignite. While EPA's Draft 1990 *New Source Review Manual* ("*NSR Manual*") does indicate that a technology can be eliminated if it has never been demonstrated in practice on full scale operations, at step 1, many of the control options eliminated by Minnkota have been demonstrated on other power plants. The *NSR Manual* states that when "the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible." It DOES NOT state or indicate that if the technology has not been demonstrated on the **exact** type of unit under review, using the exact same fuel type, that the technology is infeasible.

Under step 1, the *NSR Manual* states, "Technology transfer must be considered in identifying control options. The fact that a control option has never been applied to process emission units similar or identical to that proposed does not mean it can be ignored in the BACT analysis if the potential for its application exists." Under step 2, the *NSR Manual* states "a presumption of technical feasibility may be made by the review authority based solely on technology transfer.... Unless significant differences between source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible unless the source can present information to the contrary." In other words, full-scale demonstration of a technology can be grounds to determine its feasibility, but a lack of full-scale demonstration on the exact unit type under review does not mean that it is infeasible. In cases where the technology has been demonstrated elsewhere, but has not been demonstrated on a cyclone boiler burning North Dakota lignite, the technology should be assumed to be feasible, and Minnkota should conduct an analysis on whether the control option is "available and applicable" to MRYS. This should include comparing the physical and chemical characteristics of the exhaust gas streams under review to those of the unit from which the technology is to be transferred, as well as contacting vendors for availability. Minnkota's analysis does not take this approach. In many cases, as discussed below, Minnkota simply determined the option to be technically infeasible due to a lack of experience with their boiler design and fuel type and improperly eliminated the option at step 2 of the Top-Down BACT analysis.

Hydrocarbon-Enhanced Selective Non-Catalytic Reduction (HE SNCR): Minnkota eliminates this technology primarily based on the fact that it has not been applied to cyclone boilers or units burning lignite or high-slagging western sub-bituminous coals. There are two full scale installations of this technology on eastern pulverized coal-fired boilers. There is some general discussion about the slagging problems that lignite would cause the HE SNCR technology, but it is unclear whether the vendor of this technology would be able to overcome these issues. At this

point, it is unclear whether HE SNCR is technically feasible. Minnkota should provide a more thorough analysis on whether this control option is "available and applicable" (as described in the *NSR Manual*) at MRYS by examining the physical and chemical characteristics of the exhaust stream in terms of technical feasibility and soliciting vendor information. A quantitative analysis of its technical feasibility should be provided and supported with data and vendor statements.

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The baseline emission rate used for calculating the proposed BACT limit is based on the highest NO_x emission rate (0.884 lb/MMBtu) during actual operations from 2001-2005. (p. ES-9) This period also includes the longest reported startup event during that period (61 hours). How does this 30-day baseline compare with the rest of the historical data? Does this emission rate represent a realistic upper bound value, or is it an outlier compared with the majority of the data? If the data point does not reasonably compare with the vast majority of the other data, it does not make sense to set a BACT limit based on an outlier data point.

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UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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Phone 800-227-8917
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Ref: 8ENF-L

Via Fax, US Mail, & Email January 26, 2007

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1943

Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study

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Sincerely,

Martin Hestmark
Program Director Air and Toxics
Technical Enforcement Program

Enclosure
cc: Eddie Sierra, Acting Director, ECEJ
Matthew Morrison, USDOJ
Jeff Kodish, OECA,
Albion Carlson, EPA
Brenda Morris, EPA
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ENCLOSURE

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ERG

MEMORANDUM

TO: Hans Buenning, Albion Carlson, Doug Latimer, Martin Hestmark, EPA Region 8
Sounjay Gairola, Ron Rutherford EPA/ORE HQ

FROM: Roger Christman, Eastern Research Group, Inc.

DATE: January 8, 2007

SUBJECT: Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006)

INTRODUCTION

ERG has been tasked by the U.S. EPA Office of Regulatory Enforcement to provide technical assistance to EPA Region 8 in evaluating the *Report on the Best Available Control Technology (BACT) Analysis For Milton R. Young Station Units 1 & 2*, prepared by Burns & McDonnell (B&Mc), and the appended *Ash Impacts on SCR Catalyst Performance* (Benson, October 2005) prepared by the Energy & Environmental Research Center (EERC) at the University of North Dakota.

REVIEW RESULTS

- As was true of the reports submitted by Minnkota in 2002 and 2003, a substantial amount of "chaff" was included in the Benson report and the bulk of the technical information does not bear on the SCR issue. Much of the discussion deals with phenomena within the boiler that have no relevance to an SCR system downstream of the economizer. The issues that need to be addressed are; 1) fuel variability, 2) high calcium and sodium content in the ash, 3) high overall alkaline material content in the ash, 4) catalyst erosion due to high ash content of the coal, 5) catalyst plugging due to high ash content of the coal and "popcorn" ash from sootblowing operations and, 6) high economizer flue gas exit temperature. These are each discussed below within the context of SCR applicability at MRYS.

- Because of the NO_X SIP Call, SCR units are being installed and started up at a rate not seen since the first round of German units in the late 1980s. The understanding of catalyst deactivation and remedies for deactivation and other SCR problems is moving at a rapid pace. For that reason, the review focused on the SCR literature published in the past few years. Many of the issues raised in the EERC report are addressed in this recent literature.

GENERAL BACKGROUND

To address individual issues, there are a few items that need to be kept in mind throughout the discussion below:

1. **These units are cyclone boilers.** That is very important when looking for operating data that put the MRYS within the "envelope of SCR operating experience." At first blush (and as Benson contends), the higher ash content of North Dakota lignite used at MRYS (Center Mine coal) makes comparison to Powder River Basin (PRB) sub-bituminous coal SCR experience not relevant. Even though the chemical compositions of PRB ash and Center Mine coal ash are very similar, particularly for some of the specific constituents of concern for catalyst deactivation, the quantity of ash in the Center Mine coal is more than twice as high on a per MMBtu basis. It should be noted, however, that for a typical cyclone boiler, only about 30% of the ash ends up as fly ash at full load (B&Mc indicates that MRYS converts 50% of the ash to fly ash and earlier work by Babcock & Wilcox estimated MRYS #2 at 45 % conversion) and for a pulverized coal (PC) fired boiler, about 80% of the ash ends up as fly ash. The result is that SCR catalyst in a wall or corner-fired PRB application is exposed to a similar total quantity of the major constituents of concern (calcium and alkaline material) as catalyst would see at MRYS. There are several PC-fired boilers with SCR in the NO_X SIP Call that burn PRB coal. Since catalyst deactivation due to calcium and other alkaline materials is a "chronic," rather than "acute" phenomenon, deactivation depends on the total time and mass exposure, and the PRB PC-firing data are extremely relevant to the North Dakota lignite issue. However, since the overwhelming amount of ash in any installation does not deposit on the catalyst (it ends up in the ESP hoppers or is emitted), **it is not possible to correlate deactivation rate with total ash in the flue gas.** In the absence of actual deactivation data, comparisons of the total fly ash exposure provide only qualitative indicators and do not support definitive, quantitative statements such as found on page A1-30 of B&Mc; *"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.* **The B&Mc and Benson documents provide absolutely no basis for this quantitative determination.**

2. Because the MRYS units are cyclone fired, **the initial NO_X levels are high;** often twice as high as PC fired units burning comparable coal. Since most (but not all) of the capital cost of SCR depends on flue gas volume and not NO_X concentration sensitive, this makes cyclone boilers excellent SCR candidates in terms of cost effectiveness or $/ton of NO_X removed. Also, the cost data available for NO_X SIP Call units are based on Ozone Season operation of five months per year. If it is presumed that an SCR applied to MRYS is a year round operating unit, the cost effectiveness is further enhanced. Looking at this in another way, "work-arounds" and conservative design can be applied and still result in a cost effectiveness that is well in line with other SCR systems being installed elsewhere.

3. Some of the discussion in both the B&Mc and Benson documents centers around **coal variability,** both in proximate analysis and ash constituent concentrations. Using data from analyses of more than 700 as-fired coal samples, B&Mc states, on page A1-31, that the average ash content of Center Mine coal is 10.5% and can be as high as 25.5%. An examination of the

actual data (provided by Minnkota in 2003) shows that the coal ash content is not particularly variable, with more than 95% of the samples having an ash content between 7% and 15%. Well over 50% of the samples fall between 8% and 11%. The actual maximum content is just under 16%, not 25.5% as stated in the B&Mc report. The higher figure is based on a single sample with none of the more than 700 other samples exhibiting an ash content greater than 16%. Examination of other data associated with the sample confirms that the ash figure is in error (Despite having a roughly average moisture content, the heat content of the sample in question is also roughly average. If the 25.5% ash figure was correct, the sample would have the lowest heat content of the total data set. It does not.). In conclusion, the Center Mine coal does not have unusual variability in ash content and in no case has an ash content five times higher than PRB coal as the B&Mc report implies.

SPECIFIC ISSUES

SCR Applicability

High-Dust SCR

Catalyst Deactivation

Although the B&Mc analysis mentions it, the Benson report correctly ignores one of the primary deactivation mechanisms the caused problems with early SCR systems, particularly those in Europe. The Center Mine coal is both low in arsenic content and high in calcium. (The calcium reacts with the oxidized arsenic in the boiler to form $Ca_3(AsO_4)_2$, which is not a catalyst poison.) These two factors virtually assure that arsenic poisoning would not be a problem at MRYS even though it has been most prevalent in wet bottom boilers like those at MRYS. In addition to catalyst formulation improvements, the addition of small amounts of limestone to the coal prior to combustion has proven to be an effective remedy for high arsenic/low calcium coals. The calcium content of Center Mine coal is well above the amount needed to mitigate arsenic poisoning.

A major constituent of concern is calcium, which can react with SO_3 to plug pores with $CaSO_4$. This has been a much-studied problem and the mechanism involves the calcium-containing particle getting "caught" in a macro-pore of the catalyst and subsequently reacting with SO_3 in the flue gas. The resulting $CaSO_4$ particle is larger in volume than the CaO particle and, in essence, swells to fill the pore. The rate determining step is the original capture of the calcium-containing particle; varying concentrations of SO_2 and SO_3 have little effect on the overall rate of calcium blinding by the clogging of macro-pores. This, again, points to the relevancy of ongoing, lower sulfur PRB SCR operating experience. As noted before, the SCR catalyst at a future MRYS SCR system would see a calcium environment almost identical to a wall-fired PRB coal SCR installation and would have a similar catalyst deactivation rate.

Other alkaline materials (potassium, sodium and magnesium) deactivate catalysts by deactivating individual reaction sites rather than the blinding by macro-pore plugging that was described for

calcium. The average Center Mine coal ash alkaline material content is about 9%. This is somewhat lower than most PRB coals and within the envelope of experience of European installations. A report assessing the European experience as it relates to PRB coals (Cichanowicz & Muzio, 2001), places the range of European SCR experience with these alkaline constituents at 8% to 15% of ash. On page 34 of the Benson report, Benson totally misrepresents this situation by comparing the highest single-sample percentages with average values reported by Cichanowicz and Muzio. Further, the average calcium content of Center Mine coal ash (11.9%) is substantially below the average calcium content for all PRB coal ash. Thus, the coal used at MRYS posses no higher alkaline material poisoning potential than other coals in use at SCR-equipped boilers in Europe and is lower in calcium than PRB-fired units that are successfully using SCR.

In their 2001 SCR survey paper, Cichanowicz and Muzio go further in saying; "Short-term exploratory tests suggested the extreme calcium content of PRB coals promotes alkali poisoning. However, not all catalyst suppliers share this view, and the first commercial installation with PRB coal has not incurred any noticeable deactivation."

In short, the concern about high amounts calcium and other alkaline materials in Center Mine coal expressed in the Benson report is real, but is within the envelope of experience at commercial SCR installations. Although the catalyst deactivation rates may be somewhat higher than the rates experienced at eastern bituminous fired SCR installations, strides in catalyst formulations, catalyst management systems, and more recently, catalyst regeneration processes, have all combined to lower the overall cost contribution of both initial and replacement catalyst in modern SCR systems.

Catalyst regeneration processes have been offered in this country for several years (SCR-Tech, 2001). In general the processes involve physical cleaning (vacuuming), washing in a chemical bath, usually with some form of agitation (physical agitator or ultrasound), neutralization and rinsing (at this point, the process is called rejuvenation and is sometimes an end point) and, re-impregnation with the catalytically-active materials (V, Mo, W, etc.). With either rejuvenation or regeneration, the deactivation resulting from the alkaline materials in ash is almost entirely reversed and the catalyst is returned to full effectiveness. Cost of regeneration is reported to be 25% to 65% of the cost of new catalyst and when used in a well-planned catalyst management sequence, the cost of catalyst as a component of total annual cost can be substantially reduced. (Steag LLC, 2006(a))

Catalyst Erosion

The Benson report cites the high coal ash and frequent sootblowing at MRYS as a basis for predicting unacceptably high catalyst erosion rates if SCR is applied. This prediction ignores the fact that a cyclone boiler partitions the majority of the ash to the slag tapped from the wet bottom of the furnace. The high ash content of the Center Mine coal does, in fact, mean that the ash loadings at the economizer exit of the MRYS units will be fairly high (the B&Mc and Benson reports do not provide any data on ash loadings), but not higher than would be seen for many wall and corner-fired units that are currently fitted with SCR.

SCR vendors have provided a number of measures to avoid the erosion problems that were seen in early Japanese and German installations. First, catalyst layers are now provided with hardened or erosion-resistant leading edges. Japanese catalyst vendors provide a "dummy" layer of ceramic material with the same cell size (pitch) as the real catalyst layers beneath. The "dummy" layer not only protects the underlying catalyst from erosion, but also permits more vigorous sootblowing to deal with the catalyst plugging problems discussed below. Finally, today's SCR designers are much more sophisticated in design measures that insure a more even flue gas velocity distribution across the catalyst layer surface. Although this is driven by the desire for uniform reaction rates across the catalyst bed to achieve the low ammonia slip guarantees required today, it has the additional benefit of eliminating areas of erosion due to high ash velocity and improper "angle of attack".

Catalyst Plugging

Plugging of SCR catalysts by fly ash accumulation and bridging of passages in honeycomb catalysts and between plates in plate-type catalysts has been a problem for designers and catalyst vendors since the first coal-fired installations in the 1970s. The primary response has been more sootblowing equipment and larger catalyst pitch for honeycomb configurations and wider plate spacing for plate-type configurations. These measures, combined with periodic cleaning during boiler outages have, by-and-large, reduced plugging to a manageable SCR problem. Again, because the MRYS units are cyclone fired, the potential for plugging is no greater for these units with their high ash coal than for PC units burning a moderate ash coal. Also, the fact that the MRYS units are brought down for planned boiler deposit cleaning at 120-day intervals provides more opportunity for catalyst cleaning maintenance than is available at the typical power plant.

The "popcorn" ash mentioned in the B&Mc and Benson reports has surfaced in the early years as SCR units on lower rank coals have come on line. It is being addressed by increasing sootblowing frequency and, in some cases, installing a large mesh screen above the first catalyst layer. The Japanese approach of using a hard ceramic "dummy" layer would also aid in dealing with this material. More recently, SCR vendors have developed specially designed screens that are capable of on-line cleaning. These screens and other design measures have completely eliminated popcorn ash as a problem at SCR installations where they have been implemented. (Steag LLC, 2006(b) and Babcock Power, 2006)

High Economizer Exit Temperature

The economizer outlet temperatures for the MRYS units are 50° to 150°F (depending on firing rate and boiler cleanliness) above the ideal SCR operating temperature of about 750°F. Since the higher temperature is essential to the boiler operation, the problem can not be cured by adding more economizer surface or blending ambient air to cool the flue gas prior to an SCR catalyst bed. The MRYS units utilize a rather uncommon firing system variation of cyclone firing. It is called the *Direct-firing Pre-drying Bypass System* in which a higher than typical primary air temperature allows the coal flowing to the cyclone barrel to be partially dried. This keeps the

cyclone barrel hot enough for proper slag viscosity and flow characteristics. This system is applied to very wet coals such as the Center Mine coal.

A "typical" SCR involves an economizer exit temperature of about 750°F when the boiler is operating at full load. When operating at reduced load, the design problem that must be overcome is flue gas that is too cool, perhaps as low as 600°F. This is typically handled by installing an economizer bypass duct with a damper that is gradually opened when boiler load drops below a preset point. The hot bypassed flue gas is mixed with the remaining economizer exit flue gas to maintain the desired 700° to 750°F temperature at the catalyst inlet. Reliable operation of these high-temperature dampers has been problematic, and careful design is necessary to achieve good mixing of the bypass flue gas and the economizer flue gas over the load range. The high temperature case at MRYS may actually present a better situation for high-dust SCR success than the "typical" designs employed on units where the high economizer exit temperatures do not exist.

At MRYS it would be possible to install a small air preheater ahead of the SCR catalyst vessel and split the primary air flow between air preheaters before and after the catalyst. By adjusting the proportion of primary air passing through each air preheater, the temperature of flue gas entering the catalyst could be maintained at the optimum temperature for the particular catalyst formulation selected and the full amount of heat needed for the Direct-firing Pre-drying Bypass System would be extracted. The costs associated with the two air preheaters would be partially offset by the elimination of the air preheater bypass and damper and by the fact that the two air preheaters would each be somewhat smaller than a single preheater. This approach also eliminates the problem that some installations are having with inadequate mixing of economizer bypass flue gas. From an operating standpoint, the two air preheater approach should be superior to the current, "typical" SCR systems.

Low-Dust SCR

A few SCR systems installed on coal-fired boilers have been designed with the SCR catalyst installed after the ESP or baghouse. This approach eliminates virtually all of the poisoning, plugging and erosion problems that have been associated with SCR catalyst. In general, the low dust configuration is slightly more expensive to build than the high dust approach, but the smaller catalyst volume can offset much of the cost of the additional air heater and duct heaters needed to raise the ESP exit gas to SCR operating temperatures. The major cost differential is found in the operating costs associated with the fuel used for the heating of the gas prior to the catalyst. This is typically done with natural gas. Unfortunately, MRYS has no natural gas available. While there are oil-fired duct heaters on the market, their operation is difficult and they would require use of a high distillate such as No. 2 oil and this would further raise the cost of the low-dust approach.

The most viable approach to the required gas heating for MRYS would probably be the use of steam from the host boiler. The utility points to their extremely low cost of fuel at MRYS and steam would undoubtedly be far cheaper than oil. Whether or not the unit would suffer a derating, and if so, how much, would require an analysis of the plant steam cycle and

identification of the current overall bottleneck point for the unit. The optimum point to extract the steam and any possible detrimental effects on the turbine would have to be assessed by a steam cycle engineer.

Miscellaneous Issues

The MRYS units are fitted with tubular air preheaters. Depending upon tube diameter, orientation and sootblower configuration, the tubular design can be better than the more common regenerative air preheater in dealing with removal of ammonium sulfate and ammonium bisulfate deposits in the low temperature portion of the air preheater. The literature contains examples of retrofits where the tubular air preheater was retained and other cases where the tubular air preheater was replaced with a regenerative unit fitted with enameled cold-end baskets for ease of deposit removal. (Cormetech, 2001)

North Dakota Industrial Commission Project FY00-XXXVI-100: Evaluation of Potential SCR Catalyst Blinding During Coal Combustion

The Benson report has detailed discussion of the field test of SCR at Otter Tail Power's Coyote Station. He includes much discussion of plugging and theoretical mechanisms for deposit formation on SCR catalysts. He also includes photos of ash buildup and scanning electron microscope views of catalyst pores with deposits. Although the information he provides is interesting and provides evidence of some loss of catalyst activity, it provides no useful data on how much activity is lost.

The scale of testing carried out in this project is usually associated with observing catalyst life prospects (or said another way, the rate of loss in catalyst activity) rather than physical processes of deposition or plugging. This is because the deactivation mechanisms operate on a micro-scale and can be accurately simulated at this small scale, but the plugging and deposition are influenced by larger processes, such as flow imbalance and countermeasures (sootblowing, horns, screens, baffles, etc.) and are not duplicated on the small scale. Curiously, Benson did not include activity data, even though his early progress reports on the internet indicate that he had this information some time ago. Additionally, the report indicates that inlet and outlet NOx concentrations were tracked and no mention is made of a drop in removal efficiency over time. These quantitative measures of catalyst activity would be useful, whereas the qualitative information he chose to present provides no basis for assessing the applicability and cost of SCR applied to lignite.

The one meter depth of the catalyst is equivalent to one layer of catalyst in a commercial installation. Commercial systems aimed at high removals have three layers, each about three feet thick, and, at various times in the catalyst management cycle, incorporate four layers. Benson's test, then, only simulated the top layer of a multi-layer system. The top layer of any SCR system always takes the lion's share of the abuse from the ash and the activity degrades at a much faster rate than the second and third layer. The top layer continues to protect the lower layers even when its activity has been severely degraded. This is why the first step in most catalyst management schemes usually involves adding a fourth layer and leaving the badly degraded top

layer in place for the second operating period. Benson's project provides no real insight into the effectiveness and survivability of a second or third layer. Catalyst vendors do, however, have sufficient data and experience to extrapolate top layer test data (had Benson provided it) to address full multilayer performance.

The air pulse used to clear deposits is a poor simulation of sootblowing and is much less effective. Sootblowers essentially "blast" the deposits off the leading edges of the catalyst with jets of steam or air. The test rig used in this project merely blew air into the space above the catalyst face, resulting in a pulse of higher velocity. Even though this was much less direct than sootblowing, the pulsing still managed to keep the pressure drop fairly stable for these tests. Most new commercial SCR installations are applying acoustic horns in lieu of sootblowing and find them to be very effective. **Note: The 6mm pitch catalyst used at Coyote is much smaller than currently being specified for coal-fired installations. Vendors are now supplying 9mm, 10mm or even 11mm pitch catalysts. This current industry practice makes Benson's plugging observations essentially obsolete.**

CONCLUSIONS

While catalyst plugging, erosion and more recently, plugging with "popcorn" ash, are problems encountered at various points in the past implementation of SCR on coal-fired boilers, they have all been resolved in more recent installations. Center Mine coal, though high in ash content, does not present problems beyond the experience of today's SCR vendors and with the application of conservative design and some of the latest developments (e. g., popcorn ash screens), SCR could be implemented at Milton R. Young Station.

The calcium content of Center Mine coal ash is well below that of many PRB coals. Pulverized coal boilers firing PRB coals, with their higher proportion of ash as fly ash, have many examples of successful SCR operation in the U.S. Also, the alkaline material content of Center Mine coal ash is within the range of coals being burned at installations in Europe where SCR is being successfully operated. Today, catalyst vendors have a thorough understanding of catalyst deactivation mechanisms and a large store of data that allows them to tailor catalyst formulations for maximum life for various coal and ash analyses and to confidently predict and guarantee the projected life. In addition, the deactivation caused by alkaline ash constituents is susceptible to the catalyst rejuvenation and regeneration processes currently being commercially offered in the U.S. The more persistent deactivation caused by arsenic should be almost entirely absent in the case of the low arsenic/high calcium Center Mine coal ash.

The high economizer outlet temperatures that exist at MRYS can be addressed by providing two air heaters, one before and one after the SCR catalyst box. As noted earlier, this approach would actually be more easily applied and operated than the economizer bypass dampers used in a more "normal" installation where low economizer outlet temperature is the problem to be addressed.

Dr. Benson's report on the slip stream testing at Coyote Station provides no quantitative assessment of catalyst deactivation and no basis for a conclusion that SCR is technically

infeasible on a North Dakota Lignite-fired boiler. Inexplicably, Dr. Benson failed to provide data on catalyst deactivation and NO_x reduction, even though that would be the normal objective of tests at this scale and even though there are indications that these data were, in fact, obtained.

In summary, the B&Mc NO_x BACT analysis and the appended Benson report provide no quantitative basis for a determination of technical infeasibility. In fact, the opposite is true. When examined closely, all of the data demonstrate that the flue gas conditions and ash analyses either fall within the range of experience of successful SCR applications or are easily addressed by extrapolating existing vendor data. All of the problems posed by B&Mc are engineering and economic issues and can be addressed with current knowhow. The high initial NO_x at MRYS, combined with year round operation assures that, even with conservative design (e.g., large pitch catalyst) and application of engineered solutions (e.g., popcorn ash screens, two air heaters), the cost effectiveness will be well within the range of that being experienced with NO_x SIP Call units at this time.

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EPA REGION 8 PRELIMINARY ANALYSIS OF BURNS & McDONNELL BACT ANALYSIS FOR NITROGEN OXIDE AT MILTON R. YOUNG STATION, UNITS 1 AND 2
January 8, 2007

I. Introduction and Summary of EPA's Preliminary Analysis

A. Summary of EPA's Preliminary Analysis

After review of the October 2006 report by Burns & McDonnell (B&M), "NO_x Best Available Control Technology Analysis Study" for the Milton R. Young Station (MRYS), Units 1 and 2, and after review of other pertinent information and studies cited below, EPA's preliminary analysis is that the B&M study lacks sufficient information within the BACT analysis. Specifically, the study excludes Selective Catalytic Reduction (SCR) as a technically feasible control option at step 2 of the five-step Top-Down analysis, while not presenting NO_x control effectiveness or catalyst activity data. As a result, B&M fails to rank SCR against other control options in terms of control effectiveness at step 3, and fails to analyze costs of SCR versus other control options at step 4. EPA questions the reasons cited by B&M for technical infeasibility of SCR. Furthermore, based on a survey of SCR vendors described later in this report, EPA found there are vendors that will offer performance guarantees for this type of application. Further information should be requested, to support the analysis with respect to SCR.

B. Relevant Language from Consent Decree

Under a Federal Consent Decree filed April 24, 2006 in U.S. District Court in North Dakota, Minnkota Power Cooperative Inc. and Square Butte Electric Cooperative ("Defendants") are required, within six months after entry of the Consent Decree, to submit to the North Dakota Department of Health (NDDH) for review and approval, and to EPA for review, a NO_x Top-Down BACT Analysis for each existing coal-fired Unit at the MRYS. The Analysis shall include all information necessary for NDDH to make a BACT determination, and any additional information requested by EPA and NDDH. The Analysis shall include an evaluation of SCR, Selective Non-Catalytic Reduction (SNCR), Over-fire Air (OFA), as well as other NO_x control technologies. (Decree at Paragraph 65.)

NDDH shall review the Analysis and shall develop its BACT determination, which shall be presented to all Parties after consultation with EPA. The determination shall be subject to the dispute resolution process set forth in Paragraph 147 of the Decree. (Decree at Paragraph 66.)

II. EPA Case-Specific Review of Burns & McDonnell & EERC Technical Feasibility Analysis for Selective Catalytic Reduction

A. High-Dust SCR

B&M has eliminated High-Dust SCR as technically infeasible due to issues described below. B&M's analysis utilizes a report by the Energy & Environmental Research Center (EERC). EPA's response on each issue is also described below

Ash Deposition Issue Raised by Burns & McDonnell:

B&M states that North Dakota lignite contains a variable and complex variety of inorganic compounds that contribute to ash deposition. B&M states that 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. B&M states that ash deposition on heat transfer surfaces is a substantial problem for units that fire North Dakota lignite, and that 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.

B&M also states that 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. Powder River Basin (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. B&M states that 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, B&M states, 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.

B&M further states that 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. B&M states that 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. B&M states that 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. B&M further states that high-dust SCR performance and catalyst life will be severely impacted, and that

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.

B&M also states that 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, says B&M, will be prone to air preheater tube fouling and pluggage, requiring extended, frequent outages for cleaning.

EPA Analysis of the Ash Deposition Issue:

The concern about high amounts of ash material causing blinding of macro-pores in the catalyst is real but solvable. Strides in catalyst formulations, catalyst management systems, and recently, catalyst regeneration processes, have all combined to lower the overall cost contribution of both initial and replacement catalyst in modern SCR systems.

Comparison of MRYS to SCR Systems Operating on Powder River Basin Coal

The B&M BACT analysis contends that the higher ash content of North Dakota lignite used at MRYS (Center Mine coal) makes the comparison of SCR feasibility at MRYS to Powder River Basin (PRB) sub-bituminous coal SCR experience not relevant. Even though the chemical compositions of PRB ash and Center Mine coal ash are very similar, particularly for the specific constituents of concern for catalyst deactivation, the quantity of ash in the Center Mine coal is more than twice as high on a per MMBtu basis. However, for a cyclone boiler, only about 30-50% of the ash ends up as fly ash at full load (less at lower loads) and for a wall or corner-fired pulverized coal boiler (PC boiler), about 80% of the ash ends up as fly ash. The result is that SCR catalyst in a PC boiler PRB application is exposed to similar quantities of the major constituents of concern (alkaline material) as a catalyst would be exposed to at MRYS. (For purposes of this analysis, we will refer to wall and corner fired boilers as "PC boilers." Even though cyclone boilers are sometimes referred to as PC boilers, for this document when that term is used, we are not referring to cyclone boilers.) The B&M analysis also suggests that a linear comparison of theoretical total ash or ash constituent rates to SCR catalyst deactivation rates can be made. Although EPA does not believe this to be the case and B&M has not presented any evidence of a quantitative relationship between ash loading and SCR catalyst deactivation rates, EPA has nevertheless examined B&M's arguments related to ash loading.

Table 1 below shows a comparison of the total ash loading for different boiler designs for North Dakota lignite, assuming a reference unit of 1.0 lb/MMBtu for lignite, lignite will have twice the ash content on a per Btu basis, and the conversion to flyash will be 30-50% for cyclone boilers and 80% for PC boilers. As can be seen from this comparison, the theoretical flyash loading for a PC boiler firing PRB boiler (0.4 lb/MMBtu) will be in the same range as what would be expected for a cyclone boiler firing North Dakota lignite (0.3-0.5 lb/MMBtu). There are several PC boilers operating with SCR to comply with the NO_x SIP Call that burn PRB coal in PC boilers. As we will discuss later, catalyst deactivation due to calcium and other alkaline materials is a "chronic," rather than "acute" phenomenon.

Deactivation depends on the total time and mass exposure, and the PRB PC boiler data are extremely relevant to evaluating SCR feasibility for North Dakota lignite.

TABLE 1

Comparison of Ash Loading for North Dakota Lignite vs. Powder River Basin Coal				
Coal Type	Total Fuel Ash Loading (lb/MMBtu)	Total Flyash Loading Cyclone Boiler at 30% Conversion (lb/MMBtu)	Total Flyash Loading Cyclone Boiler at 50% Conversion (lb/MMBtu)	Total Flyash Loading PC Boiler 80% Conversion (lb/MMBtu)
North Dakota Lignite	1.0	0.3	0.5	0.8
Powder River Basin	0.5	0.15	0.25	0.4

There are a couple of important omissions in the quantitative comparison of sodium ash loading presented in the B&M BACT analysis. First, the B&M quantitative sodium loading analysis presented in the application does not make a comparison of North Dakota Lignite on cyclone boilers to PC boilers using PRB coal, which, as discussed above, would have higher ash loading than cyclone boilers burning PRB coal. Furthermore, the sodium loading analysis does not take into account the entire range of alkaline material that would affect ash loading exiting the boiler that is relevant to catalyst plugging. The B&M quantitative analysis appears to focus on the lowest type of flyash-emitting boiler design for PRB coal (cyclone) and the alkaline constituent (sodium) that is higher for North Dakota lignite compared to PRB coal. As shown in Table 1 and explained further below, these ash-loading differences are not as pronounced when evaluating all alkaline materials for PC boilers burning PRB coal. In fact, Table 1 shows that, on a lb/MMBtu basis, total theoretical flyash loading at the economizer exit of a cyclone boiler firing lignite would very similar to that of a PC boiler firing PRB coal.

Another alkaline constituent that has been a concern is calcium, which can react with SO_3 to plug pores as $CaSO_4$. This has been a much-studied problem and the mechanism involves the calcium-containing particle getting "caught" in a macro-pore of the catalyst and subsequently reacting with SO_3 in the flue gas. The resulting $CaSO_4$ particle is larger in volume than the CaO particle and, in essence, swells to fill the pore. The rate determining step is the original capture of the calcium-containing particle; varying concentrations of SO_2 and SO_3 have little effect on the overall rate of calcium blinding by the clogging of macro-pores. This, again, points to the relevancy of ongoing, lower sulfur PRB SCR operating experience. PRB coal has been shown to have approximately 30% more calcium in its ash compared to North Dakota lignite. (Reference: Table 4 from the EERC paper, SCR Catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals published in Fuel Processing Technology.) When considering this difference and the fuel to flyash conversion rates for cyclone versus PC boilers, the SCR catalyst at a future MRYS SCR system would see a calcium environment similar to a PC boiler PRB coal SCR installation and therefore would have a similar catalyst deactivation rate.

Other alkaline materials (potassium, sodium and magnesium) deactivate catalysts by deactivating individual reaction sites rather than the blinding by macro-pore plugging that was described for calcium. The average Center Mine coal ash content for these alkaline constituents is about 9%. (Reference:

November 30, 2002 EERC Report: Ash Impacts on SCR Catalyst Performance. Note that no average Center Mine lignite ash constituent values were given in the October 2006 BACT application. Only wide ranges were given in the October 2006 submittal. These ranges are of little use for making meaningful ash loading comparisons.) This percentage is somewhat lower than most PRB coals and within the envelope of experience of European installations. One of the references cited in the Appendix B EERC report, Cichanowicz & Muzio (2001), places the range of European SCR experience with these alkaline constituents at 8% to 15% of ash. Thus, the coal used at MRYS has similar poisoning potential compared to other coals in use at SCR-equipped boilers in Europe and the U.S.

In their 2001 SCR survey paper, Cichanowicz and Muzio go further in saying; "Short-term exploratory tests suggested the extreme calcium content of PRB coals promotes alkali poisoning. However, not all catalyst suppliers share this view, and the first commercial installation with PRB coal has not incurred any noticeable deactivation." In a May 2002 SCR technology survey paper presented at DOE's SCR/SNCR conference, authors Sanyal and Ellison concluded; "Evolved from two generations of design in the late 70s to the early 80s in Japan and mid 80s in Germany, 2 X 265 MW of Carney's Point and 375 MW of Merrimack are seen to be pioneers of coal fired SCR installations in the USA. Since then, SCR technology has made great strides attaining 93% NO_X removal efficiency, 3 ppm of ammonia slip and 0.5% SO_2 to SO_3 conversion. SCR units on boilers with all three firing modes - cyclone, wall and corner, dry as well as wet bottom, have been successfully commissioned and are in commercial operation. High dust application of SCR technology has been demonstrated on units firing bituminous coal with near to 4% sulfur and PRB coal containing over 25% calcium oxide."

The concern about high amounts of alkaline materials in Center Mine coal expressed in B&M's BACT analysis and described in the Appendix B EERC report is real, though not necessarily unlike operating SCR systems on PC boilers burning PRB coal. As explained above, we believe there is value in successful operating experience realized at current SCR installation at PRB-fired power plants. The problems cited in the BACT analysis are being dealt with at several NO_x SIP Call SCR installations today. In addition, the analysis presents no quantitative analytical information derived from the firing of lignite coal on SCR catalyst deactivation to justify the finding that SCR is infeasible.

Engineering Solutions for SCR Applications at High-Ash Facilities

Plugging of SCR catalysts by fly ash accumulation and bridging of passages in honeycomb catalysts and between plates in plate-type catalysts has been a problem for designers and catalyst vendors since the first coal-fired installations in the 1970s. The primary response has been more sootblowing, on-line cleaning equipment, and larger catalyst pitch for honeycomb configurations and wider plate spacing for plate-type configurations. These measures, combined with periodic cleaning during boiler outages have, by-and-large, reduced catalyst plugging to a manageable SCR problem. Again, because the MRYS units are cyclone fired, the potential for plugging is similar for these units with their high ash coal compared to PC boilers burning a moderate ash coal. Also, the fact that the MRYS units are brought down for planned boiler deposit cleaning at 120-day intervals provides more opportunity for catalyst cleaning maintenance than is available at the typical power plant.

Further demonstrating the ability of SCR designers to use existing knowledge and experience with SCR installations for high ash fuels, the Electric Power Research Institute (EPRI) has advised clients

that based on industry experience on a wide range of SCR installations over the years, SCR designs can accommodate fuel types never before used in practice on a full scale. In a September 7, 2006 letter addressed to TXU Power[1], EPRI stated, "While experience specifically with Texas lignite is limited, this should not prevent suppliers from providing an SCR system that meets these objectives; dealing with a new fuel is similar to the challenge faced by U.S. utilities and their SCR suppliers when first installing SCR systems on plants firing high sulfur bituminous or PRB coals. Neither suppliers nor utilities had prior experience with these fuels, which produce flue gas properties that are very different from those in the Japanese and European plants where SCR has been installed before. Therefore, SCR designers had to rely upon their knowledge, engineering judgment, and experience with these other coals to design SCR systems suitable for these new applications. While some of the first U.S. SCR installations experienced problems (e.g., accelerated catalyst activity decay due to arsenic poisoning in the absence of sufficient calcium in the coal, and catalyst pluggage due to large particle ash), none of these problems prevented the systems from achieving their NOx goals initially and, eventually, maintaining them over the expected life of the catalysts."

Other Ash Deposition Problems on Downstream Components

In regards to B&M's concerns related to ash deposits on other downstream boiler components, we have already pointed out that ash loading of medium ash coals (PRB) fired in PC boilers would be comparable to the ash loading at the MRYS units. Also, as noted above, the fact that the MRYS units are already brought down for planned boiler deposit cleaning at 120-day intervals would provide additional opportunity to clean these accumulations. B&M's discussion of these "other" potential accumulation problems does not reach any definitive conclusions related to the technical feasibility of SCR, so EPA does not see this as a technical barrier to installing SCR at the MRYS units.

Accounting for Catalyst Life & Performance in Top-Down BACT Analysis

Finally, the conclusion reached in the B&M BACT analysis that ash deposition and catalyst pluggage will adversely affect SCR performance (we assume this means control efficiency) and catalyst life does not necessarily support a conclusion that the technology is technically infeasible and that SCR should be eliminated at step 2 of the Top-Down BACT analysis. Furthermore, the B&M analysis presents no quantitative data related to SCR performance and catalyst life to support such a conclusion. Although the catalyst deactivation rates may be somewhat higher than the rates experienced at eastern bituminous fired SCR installations, strides in catalyst formulations and designs, catalyst management systems, and catalyst regeneration processes, have all combined to lower the operational challenges and overall cost contribution of both initial and replacement catalyst in modern SCR systems. However, SCR performance and any real construction and operational costs are factors that would be accounted for under the economic impact stage related to cost effectiveness of SCR (step 4) under the Top-Down BACT analysis.

[1] http://www.reliabletexaspower.com/pdf/og/ltr_epri_9_7_06.pdf

"Popcorn Ash" Issue Raised by Burns & McDonnell:

A second consideration in the application of conventional high-dust SCR technology on a lignite-fired unit, says B&M, is the potential of the SCR reactor catalyst pluggage resulting from carry over of "popcorn ash" from the boiler. B&M states that boilers firing North Dakota lignite have severe problems with ash deposition on boiler surfaces. North Dakota lignite has a high propensity, says B&M, 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. B&M states that carryover 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.

EPA Analysis of the "Popcorn Ash" Issue:

The "popcorn" ash mentioned in the B&M BACT analysis and the Appendix B EERC report has surfaced in the past few years as SCR units on lower rank coals, including those burning PRB coals, have come on line. It is being addressed by increasing sootblowing frequency and, in some cases, installing a large mesh screen above the first catalyst layer. In addition, the Japanese approach of using a hard ceramic "dummy" layer would also aid in dealing with this material. Catalyst layers are now provided with hardened or erosion-resistant leading edges. Japanese catalyst vendors provide a "dummy" layer of ceramic material with the same cell size (pitch) as the real catalyst layers beneath. The "dummy" layer not only protects the underlying catalyst from erosion, but also permits more vigorous sootblowing to deal with the catalyst plugging problems. Additionally, new screen designs are now being successfully installed and operated with on-line cleaning to deal with popcorn ash deposition.

Temperature Issue raised by Burns & McDonnell:

A third issue that impacts the feasibility of installing high-dust SCR technology on the North Dakota lignite-fired units, according to B&M, 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 NOx 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. B&M states that 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. B&M states that 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. B&M further states that this will seriously impact reliable combustion, slag formation and tapping in the cyclone burners. Consequently, says B&M, it is not feasible to modify the Milton R. Young Unit 1's boiler to operate with the lower economizer outlet flue gas temperature.

B&M also states that 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.

EPA Analysis of the Temperature Issue:

The economizer exit temperature for MRYS units will be higher than that of a "typical" coal-fired utility boiler SCR installation, which normally involves an economizer exit temperature of about 750°F when the boiler is operating at full load. When a "typical" unit is operating at reduced load, the design problem that must be overcome is flue gas that is too cool, perhaps as low as 600°F. This is typically handled by installing an economizer bypass duct with a damper that is gradually opened when boiler load drops below a preset point. The hot bypassed flue gas is mixed with the remaining economizer exit flue gas to maintain the desired 700° to 750°F temperature at the catalyst inlet. Reliable operation of these high-temperature dampers has been problematic, and careful design is necessary to achieve good mixing of the bypass flue gas and the economizer flue gas over the load range. The potential engineering challenge at MRYS may actually present a better situation for high-dust SCR success than the "typical" designs employed on units where the high economizer exit temperatures do not exist.

At MRYS it would be possible to install a small air preheater ahead of the SCR catalyst vessel and split the primary air flow between air preheaters before and after the catalyst. By adjusting the proportion of primary air passing through each air preheater, the temperature of flue gas entering the catalyst could be maintained at the optimum temperature for the particular catalyst formulation selected and the full amount of heat needed for the Direct-firing Pre-drying Bypass System would be extracted. The costs associated with the two air preheaters would be partially offset by the elimination of the air preheater bypass and damper and by the fact that the two air preheaters would each be somewhat smaller than a single preheater. This approach also eliminates the problem that some installations are having with inadequate mixing of economizer bypass flue gas. From an operating standpoint, the two air preheater approach should be superior to the current, "typical" SCR systems.

Erosion Issue raised by Burns & McDonnell:

Another consideration, according to B&M, 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%. PRB coal fuel ash content typically averages approximately 5 percent. As previously stated by B&M, a cyclone boiler firing North Dakota lignite converts a significantly greater amount of flyash than a PRB-fired cyclone boiler. Overall, says B&M, this results in a flyash output rate from a cyclone boiler firing North Dakota lignite of approximately 83 lbs/MWhr compared with 21 lbs/MW-hr for a PRB-fired cyclone boiler. High ash contents in the flue gas stream, says B&M, can result in physical erosion of the catalyst. In addition, says B&M, effective on-line cleaning of the high-dust catalyst will likely require steam or compressed air sootblowing. B&M states that 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, says B&M, because of the severe deposition characteristics of the North Dakota lignite ash compared to brown coal.

EPA Analysis of the Erosion Issue:

The high ash content of the Center Mine coal does, in fact, mean that the ash loadings at the economizer exit of the MRYS units will be fairly high, but, as discussed above, it would be roughly the same as typically seen in PC-fired PRB units that are currently fitted with SCR. Sootblowing is common to all coal-fired units and particularly high rates of sootblowing are characteristic of slagging coals and cyclone firing. SCR vendors have provided a number of measures to avoid the erosion problems that were seen in early Japanese and German installations. First, catalyst layers are now provided with hardened or erosion-resistant leading edges, including providing a "dummy" layer, as previously discussed under the popcorn ash section. Finally, today's SCR designers are much more sophisticated in design measures that insure a more even flue gas velocity distribution across the catalyst layer surface. Although this is driven by the desire for uniform reaction rates across the catalyst bed to achieve the low ammonia slip guarantees required today, it has the additional benefit of eliminating areas of erosion due to high ash velocity and improper "angle of attack".

Energy & Environmental Research Center Report (Appendix B):

As part of the BACT analysis by B&M, a report authored by the Energy & Environmental Research Center (EERC), entitled "Ash Impacts on SCR Catalyst Performance" was included as Appendix B. The B&M analysis relies on a passage from the EERC report as part of its determination that SCR would be technically infeasible for the MRYS units. The passage is as follows, "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."

The EERC report included in the MRYS BACT analysis relies heavily on pilot testing that was conducted by EERC at two PRB-fired plants and one North Dakota lignite-fired plant. The MRYS BACT analysis also references this test and the accompanying technical paper, "Ash and Mercury

Behaviour in SCR Catalysts When Firing Subbituminous and Lignite Coals" by the EERC that was published in the February 2005 issue of Fuel Processing Technology magazine. The majority of B&M's technical arguments related to technical difficulties of high-dust SCR for North Dakota lignite appear to have their origin with the results of this pilot testing. It is worth noting that page 578 of the original February 2005 article cited above has nearly identical language to that used in the Appendix B EERC report, except the conclusions differ on the successful application of SCR application of SCR catalysts to lignite coal.

"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 [3,11-14]. The ***degree*** of the ash 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." (Emphasis added)

EPA Analysis of the Energy & Environmental Research Center Report (Appendix B):

It is interesting that EERC characterized the technical problems associated SCR application to lignite-fired boilers as being "limits" in this technical paper, but say that the problems "prohibit" the successful use of SCR in the MRYS BACT analysis Appendix B report. While the former language suggests successful operation of SCR is possible, the later language appears to be crafted specifically for addressing technical feasibility in the context of BACT. However, the conclusions reached in the Appendix B report do not address some of the engineering solutions previously cited and explained below that are available for full-scale SCR applications. Furthermore, EPA Region 8 believes that there may be inherent limitations with the pilot study (that was the basis for both EERC reports) that draws into question the validity of directly applying those conclusions to the range of possible SCR designs of a full-scale application at MRYS. Statements from three major SCR catalyst manufacturers (including Haldor Topsoe, the catalyst manufacturer involved in the pilot testing for North Dakota lignite) suggest that the catalyst deposition and plugging problems experienced during the pilot testing may be exaggerating on a pilot scale and can be solved in a full-scale design and application. This is explained in more detail in Section III of this report.

Other inherent problems associated with directly applying the results of the EERC pilot testing at Coyote Station on North Dakota lignite include:

1) The air pulse used to clear deposits during the pilot test is a poor simulation of sootblowing and is much less effective. Sootblowers essentially "blast" the deposits off the leading edges of the catalyst with jets of steam or air. The test rig used in this project merely blew air into the space above the catalyst face, resulting in a pulse of higher velocity, which is much less direct than sootblowing. Most new commercial SCR installations are applying acoustic horns in lieu of sootblowing and are found to be very effective.

2) The 6mm pitch catalyst used for the pilot testing at Coyote Station is much smaller than currently being specified for coal-fired installations. Vendors are now supplying 9mm, 10mm or even 11mm pitch catalysts. As discussed earlier, larger catalyst pitch is one of several engineering solutions to

address the problem of catalyst plugging for higher ash coal. This current industry practice makes the EERC results based on 6 mm pitch catalyst essentially obsolete.

3) The one meter depth of the catalyst used in the pilot test is equivalent to one layer of catalyst in a commercial installation. Commercial systems aimed at high removals have three layers, each about three feet thick, and, at various times in the catalyst management cycle, incorporate four layers. EERC's test, then, only simulated the top layer of a multi-layer system. The top layer of any SCR system always takes the lion's share of the abuse from the ash and the activity degrades at a much faster rate than the second and third layer. The top layer continues to protect the lower layers even when its activity has been severely degraded. This is why the first step in most catalyst management schemes usually involves adding a fourth layer and leaving the badly degraded top layer in place for the second operating period. EERC's project provides no real insight into the effectiveness and survivability of a second or third layer.

4) The scale of testing carried out in this project is usually associated with observing catalyst life prospects (or said another way, the rate of loss in catalyst activity) rather than physical processes of deposition or plugging. This is because the deactivation mechanisms operate on a micro-scale and can be accurately simulated at this small scale, but the plugging and deposition are influenced by larger processes, such as flow imbalance and countermeasures (sootblowing, horns, screens, baffles, etc.) and are not duplicated on the small scale.

For these reasons, EPA Region 8 questions the direct application of the results of the EERC pilot testing at Coyote Station and the accompanying Appendix B EERC report for purposes of the BACT technical feasibility analysis of SCR at MRYS. The experience and opinions of the SCR supplier that participated in the EERC pilot test indicate that the problems encountered during the pilot test are not determinate of whether SCR plugging experienced during the pilot test would be unresolvable by vendors. To the contrary, statements from Haldor Topsoe offering their SCR catalyst for installation on lignite-fired boilers indicates that the full-scale differences and engineering solutions available today provide evidence that the EERC pilot testing results should not alone be the deciding consideration when evaluating SCR technical feasibility at MRYS.

Burns & McDonnell's Conclusion on Technical Feasibility of High-Dust SCR:

B&M notes that EPA's NSR Manual states that for a technology to be feasible it must "available and applicable". The question is whether SCR technology is "applicable" for a unit firing North Dakota lignite.

B&M further notes that, 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 retrofitted on coal-fired units featuring cyclone boilers. However, B&M states, 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.

B&M notes that the 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, says B&M, it appears that a utility power plant 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.

EPA Analysis of the Burns & McDonnell's Conclusion:

EPA notes that there is considerable experience in the industry to show that use of SCR on North Dakota lignite is technically feasible. EPA has previously articulated this belief in a number of national rulemakings, including the Clean Air Interstate Rule (CAIR), the Best Available Retrofit Technology (BART) Guidelines, and revisions to the New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units (finalized on February 27, 2006). These rulemakings are discussed in more detail in Section III of this report. Furthermore, B&M's assertion that MRYS would not be considered "similar" to those PRB facilities that have successfully installed SCR is not supported by comparing total alkaline ash loading at MRYS to PRB-fired PC units that convert 80% of the fuel-ash to flyash.

EPA understands from the EERC pilot study at Coyote Station using North Dakota lignite, there was noticeable ash build up on the catalyst and concerns with catalyst plugging during the test. While EERC notes that ash deposition problems were most pronounced at Coyote Station, compared to the two test facilities burning PRB coal, it also states generally that all of the coals in the pilot study "produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels." Thus, the conclusions of the study appear to be that deposition issues might be somewhat greater for North Dakota lignite than for PRB coal. Since significant accumulations of ash on the catalyst was also observed during pilot testing at those facilities burning PRB coal and there are numerous examples of PRB coal-fired power plants successfully operating SCR systems, the qualitative results of the pilot testing described by B&M and EERC would not appear to preclude successful operation of SCR on a power plant burning North Dakota lignite. The EERC study does not appear to quantify the effect that the ash accumulation had on microscopic catalyst deactivation rates or overall catalyst performance. Absent such information that reflects the use of currently available full-scale ash loading mitigation designs, pilot testing results may not be evidence that successful implementation of SCR on North Dakota fired units "is going to be impossible," as stated in the Appendix B EERC report.

As noted above, due to the inherent pilot-scale limitations involved in this testing, direct application of the effects and/or magnitude of ash deposition during the EERC pilot study should not be used as the primary basis for determining technical feasibility of SCR at MRYS. In the full-scale installations, these concerns are addressed during the SCR design stage. While combustion of North Dakota lignite in cyclone boilers might present some additional engineering challenges for SCR designers, there are multiple credible solutions that Minnkota should have evaluated before concluding that SCR is not technically feasible.

The October 1990 EPA draft New Source Review Manual (NSR Manual) states that a "demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles, and/or empirical data showing that the technology would not work

on the emissions unit under review, or that ***unresolvable*** technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts, which, in turn, may form the basis for eliminating a control technology." (Page B.20) (Emphasis added) Based on the available information, the problems cited by B&M for application of SCR at MRYS (ash deposition, "popcorn ash", temperature, and erosion) are resolvable through the engineering solutions discussed above. While such engineering solutions may be a cost burden to Minnkota, as noted above, step 2 is not the proper stage of the Top-Down BACT analysis to account for these costs. As described in the NSR Manual, "where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process." (Pages B.19-B.20) Many of the technical feasibility arguments presented in the BACT analysis are centered on decreased catalyst life and performance, increased maintenance and outage time, and plant differences unique to MRYS that preclude SCR feasibility at MRYS. Consistent with the NSR Manual, these concerns are incorrectly incorporated into the Top-Down BACT analysis at step 2 and really should be accounted for as additional costs per ton of pollutant removed at step 4 of the analysis.

Furthermore, the NSR Manual states, "Vendor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on circumstances. However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work. Conversely, lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible. Generally, decisions about technical feasibility will be based on chemical and engineering analyses (as discussed above) in conjunction with information about vendor guarantees." (Page B.20) So, while EPA does not consider vendor guarantees by themselves to be determinate in making technical feasibility decisions, they are a contributing factor in making these decisions. EPA is aware of three catalyst vendors (Haldor-Topsoe, Cormetech, and Argillion) who would be willing to provide performance guarantees for lignite-fired boilers applications.

Based on the criteria discussed above, Minnkota and B&D should have further explored both the full-scale engineering solutions used to address the problems cited in their analysis in conjunction with information from SCR/catalyst vendors to offer performance guarantees to design and install an SCR unit at MRYS. The BACT analysis for MRYS that was submitted relies heavily on the technical problems experienced during the EERC pilot testing at Coyote Station in conjunction with the fact that SCR has not been installed on a cyclone boiler that burns North Dakota lignite. We do not believe that this analysis adequately addresses the criteria cited above. As such, it appears that the case-specific NO_x BACT analysis submitted for Minnkota MRYS is deficient in terms of improperly eliminating SCR from consideration at step 2 of the BACT analysis for technical feasibility.

B. <u>Low-Dust SCR</u>

Burns & McDonnell has eliminated Low-Dust SCR as technically infeasible due to issues described below. EPA's response on each issue is also described below

Catalyst Fouling and Deactivation Issue Raised by Burns & McDonnell:

B&M states that an existing electrostatic precipitator (ESP) 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, says B&M, 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, says B&M, 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, says B&M, 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). B&M states that once such a matrix forms within the catalyst, it can be extremely tenacious and difficult to remove. B&M notes that one catalyst vendor has stated it is their "experience that low-dust catalyst is more difficult to clean than that from high-dust." B&M concludes that low-dust SCR performance and catalyst life could be severely negatively impacted, and that shortened lifespans of the LD SCR catalyst will require premature, extended, frequent outages for replacement.

EPA Analysis of the Catalyst Fouling and Deactivation Issue:

A few SCR systems installed on coal-fired boilers have been designed with the SCR catalyst installed after the ESP or baghouse. This approach eliminates virtually all of the poisoning, plugging and erosion problems that have been associated with SCR catalyst. (Christman Memo, 2/18/03) For the same reasons noted above under the high-dust SCR analysis, the catalyst fouling and deactivation problems may be resolvable technical problems that do not warrant elimination of low-dust SCR under step 2 of the Top-Down BACT analysis. In a recent PSD permitting action for the Deseret Bonanza 110 MW Waste Coal-Fired Circulating Fluidized Bed project, EPA Region 8 did not rule out low-dust SCR based on unresolvable technical feasibility issues with catalyst fouling and deactivation. Similarly, permit applications for three recent Circulating Fluidized Bed projects in North Dakota (MDU Westmooreland Gascoyne, South Hart, and Gascoyne 500MW) did not eliminate low-Dust SCR based on unresolvable technical feasibility issues with catalyst fouling and deactivation. While there would be inherent costs associated with gas-reheat, other possible physical modifications to the plant to accommodate low-dust SCR, and engineering designs to minimize and manage catalyst fouling and deactivation, these factors, consistent with the NSR Manual, should be accounted for when considering the economic impacts of the technology.

Site Space Constraint Issue Raised by Burns & McDonnell:

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 gas-to-gas heat exchanger (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 GTG HE 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, says B&M, in the areas where low-dust SCR systems must be located. The situation is particularly severe, says B&M, 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, says B&M, 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, says B&M, 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, says B&M, 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. B&M concludes that this space subsequently would not be available for a low-dust SCR system.

EPA Analysis of the Site Space Constraint Issue:

While the extent of the physical plant modifications necessary to accommodate low-dust SCR at the MRYS is not entirely clear, the above description does not indicate that the site space constraints at MRYS would necessarily preclude the possible installation of low-dust SCR. It does sound like major and costly equipment relocation may be necessary to provide the space necessary for low-dust SCR. However, consistent with the NSR Manual, "physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility." These costs should be accounted for when estimating the cost and economic impacts of low-dust SCR, but should not be used as a basis for eliminating the technology as technically infeasible.

Burns & McDonnell's Conclusion on Technical Feasibility of Low-Dust SCR:

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, B&M concludes that this control option should be considered technically infeasible for the Milton R. Young Station Unit 1's boiler.

EPA Analysis of the Burns & McDonnell's Conclusion:

As explained above, EPA Region 8 believes that the inherent challenges with installing and operating low-dust SCR at MRYS are resolvable on a technical basis. The fact that a few low-dust SCR applications are currently used in practice indicates that the small-particle catalyst fouling and

deactivation problem described would not preclude the use of low-dust SCR. In fact, EPA Region 8 believes that the dust-loading problems that can be effectively addressed through engineering solutions in a high-dust environment are less problematic than in a low-dust environment. B&D's statement's that "low-dust SCR performance and catalyst life could be severely negatively impacted resulting in premature, extended, frequent outages for replacement" can be minimized by proper SCR design and on-line cleaning. As stated previously, any real costs associated with the construction and maintenance required to operate the low-dust SCR should be accounted for under the economic impacts stage of the Top-Down BACT analysis (step 4). Similarly, physical plant modifications that would be required to accommodate the low-dust SCR (and auxiliary equipment) should be considered in the economic impact evaluation, rather than used as evidence of technical infeasibility.

III. Additional Information Useful to Evaluating Technical Feasibility of SCR at MRYS

A. EPA Headquarters Believes SCR is the Correct Technology for MRYS in Developing the Clean Air Interstate Rule (CAIR)

During the preparation of the CAIR rule, EPA developed a scenario for best controls across coal-fired units in the United States based on an assessment of boiler type, fuel type, and existing controls. This assessment recommended that SCR technology would be the best technology for the two units at MRYS.

Several commenters – Montana-Dakota Utilities Co. (VI.C-0754); Otter-Tail Power Co. (VI.C-0628); Lignite Energy Council (VI.C-0935); Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C. for Texas Lignite Coalition (VI.C-1037); and Basin Electric Power Cooperative (VI.B-0690) -- argued that SCR technology is not feasible for application on lignite-fired boilers. Some of these commenters claimed that an SCR pilot test on a slipstream from a boiler firing lignite had shown catalyst plugging and blinding. One commenter attributed this problem to sulfates of calcium and sodium, which are present in the flue gas stream entering the SCR, as a result of firing of lignite in the boiler. One of these commenters also claimed that SCR was not feasible for boilers firing sub-bituminous.

In its response at VI.B. of the CAIR docket, EPA noted that there is considerable experience in the industry to show that use of SCR on sub-bituminous coals and lignite is technically feasible. SCR is currently in use on several sub-bituminous coal-fired boilers in the U.S. firing Powder River Basin coal.[2] Regarding the use of SCR on boilers firing lignite, EPRI testing of SCR catalyst in a slipstream at the Martin Lake plant showed acceptable results from Texas Lignite.[3] Furthermore, the technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe.[4] From this experience, it can be concluded that SCR can be used on sub-bituminous coal and lignite boilers in the

[2] "SCR Lowest NOx Ranking, 3rd Quarter 2003," McIlvaine Website, www.mcilvainecompany.com, accessed on December 23, 2003 (docket no. OAR-2003-0053-1940)

[3] "Impacts of Texas Lignite Coal on SCR Catalyst Life and Performance: Field Data from TXU's Martin Lake Plant," EPRI Website, www.epri.com, accessed on December 11, 2003 (docket no. OAR-2003-0053-1944)

[4] Email from J. Staudt to S. Khan, Lignite Installation List, July 5, 2004.(docket no. OAR-2003-0053-1946)

U.S. and catalyst suppliers have indicated that they will offer performance guarantees on these applications in the U.S.[5]

In the docket information regarding this issue, one of the SCR catalyst vendors, Argillon, provided a list a SCR installations at EGUs in Europe that burn lignite or similar rank coal, including:

- Riedersbach installations in 1995 and 2001(hard coal/lignite)
- Voitsberg (lignite)
- Dormagen installations in 1994 and 1996 (lignite)

EPA also noted that the commenters have not provided any details of the pilot test that has been mentioned with regards to the plugging and blinding of a catalyst from lignite-generated fuel gases. Without this information, this part of the comment cannot be addressed properly. The EPA's own investigations show that the main reason for this problem was ash build up on the catalyst, which is a problem commonly experienced in pilot test facilities.[6] In the full-scale installations, this concern is addressed during the SCR design stage. The methods used to avoid this problem include duct design to promote ash fallout prior to the SCR, catalyst reactor design to avoid ash build up, and on-line cleaning methods (sootblowers and sonic horns).

In addition, the following catalyst vendors stated that they could provide catalysts/SCR for lignite-fired boilers:

- Haldor-Topsoe. "I can confirm that on a general basis Haldor-Topsoe can and will offer our SCR catalyst for use in lignite-fired boilers, to be installed either before or after ash collectors."
- Cormetech. "Cormetech has no reservations in providing performance guarantees for application of SCR for NOx reduction on lignite-fired utility boilers."
- Argillon. "Generally speaking, yes, Argillon would provide performance guarantees on SCR catalyst on a lignite-fired boiler. In fact, we were recently asked if we would do so for a specific project and we agreed. We believe that our experience with European lignite, our knowledge of the characteristics of the two types of US lignite, our overall experience with many fuels, combined with our in-house flow modeling capability provide us with enough information to design catalyst that performs as specified."

[5] Email From J. Staudt to S. Khan, Response to Comments- IAQR, July 2, 2004 (docket no. OAR-2003-0053-1945)

[6] Email From J. Staudt to S. Khan, SCR on ND Lignite, August 20, 2004 (docket no. OAR-2003-0053-1947)

In a memo dated August 20, 2004, Jim Staudt of Andover Technology Partners to Sikander Khan of EPA CAMD, discussed both the EERC pilot testing results and some of the negative issues raised by B&M and documented how Haldor Topsoe was aware of these issues, but nevertheless felt comfortable providing SCR catalyst.

> "Re: SCR catalyst testing on ND Lignite
>
> Yesterday I spoke with Mr. Flemming Hansen of Haldor Topsoe regarding their experience testing Haldor Topsoe's SCR catalyst on North Dakota Lignite. Haldor Topsoe participated in a program with the University of North Dakota's EERC and Otter Tail Power. In this program their catalyst was tested on a pilot facility burning lignite coal. Flemming's recollection was that the test ran several thousand hours – possibly around 4,000-6,000 hours. Catalyst testing was performed roughly every two thousand hours.
>
> Flemming's recollection was that sudden fly ash build up on the catalyst face occurred during the test. The cause of this sudden build up was determined to be accumulation of ash upstream of the catalyst and sudden dropping of that accumulated ash onto the catalyst face. This, he explained, is a problem that frequently occurs in pilot facilities, but tends to be far less of a concern for much larger, full-scale systems. He explained that this behavior is also similar to that exhibited by PRB coal fly ash, which shares some physical characteristics with Lignite fly ash.
>
> As you are aware, SCR system suppliers perform extensive work – physical and computer flow modeling – to design the SCR reactor to minimize ash build up in full-scale systems. Moreover, cleaning devices are always installed to clean the catalyst on-line. So there are engineering solutions to address fly ash build up. And, as experienced with SCR-equipped boilers that fire PRB coal, SCR systems can be designed to accommodate this fly-ash behavior while providing reliable operation in electric utility plants.
>
> Recall that Haldor Topsoe provided a statement saying that they would offer their SCR catalyst for installation on Lignite-fired boilers either before or after particle collection. This statement was provided on July 2, 2004, after their participation in the pilot test on lignite-fired coal. So, this statement was made, no doubt, with knowledge of this program."

B. SCR Technology is Presumptive BART for Cyclone Boilers in EPA's BART Guidelines

EPA made a specific and informed decision in its BART Guidelines regarding cyclone-fired utility boilers. For all other boiler types, some form of combustion control was deemed to be the presumptive level of control. However, for cyclone units burning any type of coal (bituminous, subbituminous, or lignite), presumptive BART is SCR. SCR was selected because the technology is feasible and cost-effective, especially considering the high baseline flue gas NOx concentrations (e.g., 0.8 lb/MMBtu). The spreadsheet that was used to tabulate BART source control costs for the BART rule showed low SCR costs for MRYS (about $550/ton).

C. February 27, 2006 Final Revisions to 40 CFR Part 60, Subpart Da, New Source Performance Standards for Electric Utility Steam Generating Units Set Final NOx Limit Based on Technical Feasibility of SCR for Lignite-Fired Units.

In its response to public comments on the February 28, 2005 draft NSPS, Subpart Da proposal, EPA rejected comments received on NOx control requirements for lignite-fired units. Specifically, EPA took the same position as it did in the CAIR and BART rules, rejecting commenters' concerns that SCR would not be feasible for lignite units. No legal challenges were made to the final rule regarding EPA's response to the lignite concerns. While the revised NSPS, Subpart Da would apply only to new units, it is further evidence that EPA technical experts believe that SCR can successfully be applied to lignite facilities. The B&M BACT analysis essentially makes the same technical arguments that EPA rejected in this rule package.

D. SCR and Catalyst Vendor Information

As noted above, the following catalyst vendors were comfortable providing catalysts/SCR for lignite-fired boilers:

- Haldor-Topsoe
- Cormetech
- Argillon

In addition, the above-cited memo dated August 20, 2004, Jim Staudt of Andover Technology Partners to Sikander Khan of EPA CAMD, discussed both the EERC pilot testing results and some of the negative issues raised by B&M and documented how Haldor Topsoe was aware of these issues, but nevertheless felt comfortable providing SCR catalyst.

EPA Region 8 also contacted the Institute of Clean Air Companies website to obtain the following list of 21 companies offering "SCR Systems, Equipment, Supplies and Services:"

- ALSTOM POWER
- Argillon LLC
- Babcock & Wilcox
- Babcock Power Inc.
- BASF
- Cormetech, Inc.
- Corning Incorporated
- CRI Catalyst Company
- CSM Worldwide, Inc.
- Epcon Industrial Systems, N.V.
- Fuel Tech, Inc.
- GE Energy Services
- Haldor Topsoe, Inc.
- Hamon Research-Cottrell, Inc.

- Hitachi Power Systems America, Ltd.
- Hitz America Inc.
- Johnson Matthey Stationary Source Emissions Control
- Millennium Chemicals
- Mitsubishi Power Systems Americas, Inc.
- SCR-Tech
- Wheelabrator Air Pollution Control, Inc

EPA Region 8 has visited most of the vendors' websites and found many vendors with experience that would be germane to the MRYS situation. (Others are not vendors for large power plants.) The experience of these companies should be used to supplement the endorsement by three of the SCR catalyst vendors used by EPA in the background research for the CAIR, BART, and NSPS rules. We believe it would be prudent for Minnkota to obtain information and proposals from more than one vendor and involve the NDDH and EPA in their findings.

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Your Touchstone Energy® Partner

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March 19, 2007

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MAR 2007
Received
Air Quality

Re: Consent Decree – July 27, 2006
Minnkota Power Cooperative, Inc., et al
U.S. District Court for the District of ND
Civil Action No. 1:06-CV-034

Subject: Response to EPA Region VIII Comments - January 8, 2007

Gentlemen:

On October 6, 2006, Minnkota submitted in fulfillment of Paragraph 65 of the Consent Decree, the analyses entitled "NOx BEST AVALABLE CONTROL TECHNOLOGY ANALYSIS STUDY for Milton R. Young Station Unit 1" and "NOx BEST AVALABLE CONTROL TECHNOLOGY ANALYSIS STUDY for Milton R. Young Station Unit 2", both dated October 2006. Subsequently, the North Dakota Department of Health faxed

to Minnkota on January 9, 2007, comments on our submittal that they had received from EPA Region 8, and requested we respond to the EPA comments.

Enclosed, please find Minnkota's responses to the **EPA REGION 8 PRELIMINARY ANALYSIS OF BURNS & McDONNELL BACT ANALYSIS FOR NITROGEN OXIDE AT MILTON R. YOUNG STATION, UNITS 1 AND 2,** dated January 8, 2007, and the memorandum from ERG to Region 8, dated January 8, 2007, which accompanied the EPA's analysis.

Should you have any questions concerning this submittal, please contact me at (701) 795-4221.

Sincerely yours,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

c: David Sogard w/encl
Luther Kvernen w/o encl
Craig Bleth w/encl
Kevin Thomas w/o encl
Stu Libby w/o encl
Tom Anseth w/o encl
Young Station File w/encl

MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO EPA COMMENTS
NOx BACT ANALYSIS STUDY
MILTON R. YOUNG STATION UNIT 1 and UNIT 2
REGARDING SCR TECHNICAL FEASIBILITY

March 15, 2007

North Dakota Department of Health's, Environmental Health Section, Division of Air Quality has provided Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") with Region 8 of the United States Environmental Protection Agency's (U.S. EPA or EPA) and their consultant's recent comments regarding their reviews of the Best Available Control Technology (BACT) Analysis Study reports for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station ("MRYS") submitted to the agencies in October 2006.

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced NO_X BACT Analysis Study[1] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS) in accordance with the requirements of a Consent Decree (CD)[2].

Minnkota, along with Burns & McDonnell, and Energy & Environmental Research Center (EERC) of the University of North Dakota, have reviewed the reference memorandum dated January 8, 2007 written by Eastern Research Group, Inc. (ERG)[3] and faxed by the North Dakota Department of Health (NDDH) to Minnkota on January 9, 2007. Attached to this referenced memo was U.S. EPA Region 8's preliminary analysis[4] of Burns & McDonnell's NO_X BACT Analysis. The following are combined responses by EERC and B&McD to the comments by EPA Region 8 and their consultant, Mr. Roger Christman of ERG involving SCR technical feasibility on the two units at MRYS.

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[1] See Reference number 1, October 2006.
[2] See Reference number 2, April 24, 2006.
[3] See Reference number 3, January 8, 2007.
[4] See Reference number 4, January 8, 2007.

The following response follows the outline developed by Mr. Christman in his review.

REVIEW RESULTS (from the January 8, 2007 ERG Memo)
ERG memo, page 1:

"...a substantial amount of "chaff" was included in the Benson report and the bulk of the technical information does not bear on the SCR issue. Much of the discussion deals with phenomena within the boiler that have no relevance to an SCR system downstream of the economizer."

EERC Response:
Christman implies that the Benson report[5] on ash impacts on selective catalytic reduction (SCR) performance includes a substantial amount of "chaff" that has no bearing on the SCR issue. Specifically, he inaccurately indicates that what happens in the boiler has no relevance to what happens in the lower temperatures of the boiler downstream of the flue gas outlet after the primary superheater/economizer. However, what happens early in the combustion process in the boiler defines the flux of material that will be carried back into the lower-temperature regions of the furnace.

Of specific importance in the details presented by Benson (2005) was a discussion of how a cyclone partitions the ash between fly ash and slag and how these processes for lignite coals can enhance ash-related reactions at 600° to 800°F where SCRs are operated. Combustion and gas-cooling processes that impact ash behavior include vaporization, condensation, ash particle formation, and vapor/liquid/solid ash material deposition on heat-transfer surfaces. In addition, the accumulations of ash deposits on heat-transfer surfaces from the body of the boiler through the convective pass including the economizer requires extensive use of soot blowers to remove ash deposits. Some of the removed deposit fragments are entrained with the bulk gas flow and carried through the boiler.

An understanding of what happens in the boiler defines the flux of materials (vapors, liquids, particles, deposit fragments) that will be transported through the boiler with the flue gases. These phenomena are especially important for lignite since the low-temperature ash deposition processes related to alkali and alkaline-earth elements are much more challenging for high-

[5] See Reference number 5, October 2005, included as Appendix B in Reference 1's BACT Analysis reports.

sodium lignite coals as compared to other coals. Sodium readily vaporizes upon combustion and condenses upon gas cooling, creating liquid phases and reactive aerosols.

GENERAL BACKGROUND (from the January 8, 2007 ERG Memo)
ERG memo Item 1, page 2:

> *"These units are cyclone boilers. That is very important when looking at operating data that put the MRYS within the "envelope of SCR operating experience"....At first blush (and as Benson contends), the higher ash content of North Dakota lignite used at MRYS (Center Mine coal) makes comparison to Powder River Basin (PRB) sub-bituminous coal SCR experience not relevant. Even though the chemical compositions of PRB ash and Center Mine coal ash are very similar, particularly for some of the specific constituents of concern for catalyst deactivation, the quantity of ash in the Center Mine coal is more than twice as high on a per MMBtu basis. It should be noted, however, that for a typical cyclone boiler, only about 30% of the ash ends up as flyash at full load (B&Mc indicates that MRYS converts 50% of the ash to fly ash and earlier work by Babcock & Wilcox estimated MRYS #2 at 45% conversion) and for a pulverized coal (PC) fired boiler, about 80% of the ash ends up as fly ash."*

EERC Response:
Christman indicates that the cyclones are very important even though his initial statements indicated what happens in the boiler is not important and the cyclones are part of the boiler. The chemical composition of the ashes derived from lignite and subbituminous coals have similarities in the types of elements present. However, the abundance of elements in that ash between most subbituminous coals and lignite is different.

Figure 1 shows the abundance of sodium and calcium presented as equivalent oxides and ash content of primarily subbituminous and other coals. The additional coals include bituminous coals such as Illinois No. 6, Utah Blind Canyon (Wasatch Basin), and Shoshone (Green River Formation); blends; and Beulah lignite (Fort Union of North Dakota). Based on these analyses, only the Spring Creek subbituminous coal has a high level of sodium that is typical of North Dakota lignite. Spring Creek coal is known to cause significant low-temperature fouling problems and is a coal that was indicated to cause problems associated with sodium deactivation of SCR catalyst coupons at a Michigan power plant as indicated by Flemming Hansen of Haldor Topsoe[6]. All of the other Powder River Basin (PRB) coals have sodium oxide levels in their ash of less than 2 to 3 percent. Figure 2 shows the distribution of sodium

[6] Personal Communication, February 2007. Reference number 6.

oxide in Center lignite. The results of the analysis show that the sodium content is on average 4.4%; however, there is a multimodal distribution of sodium levels in the coal ash.

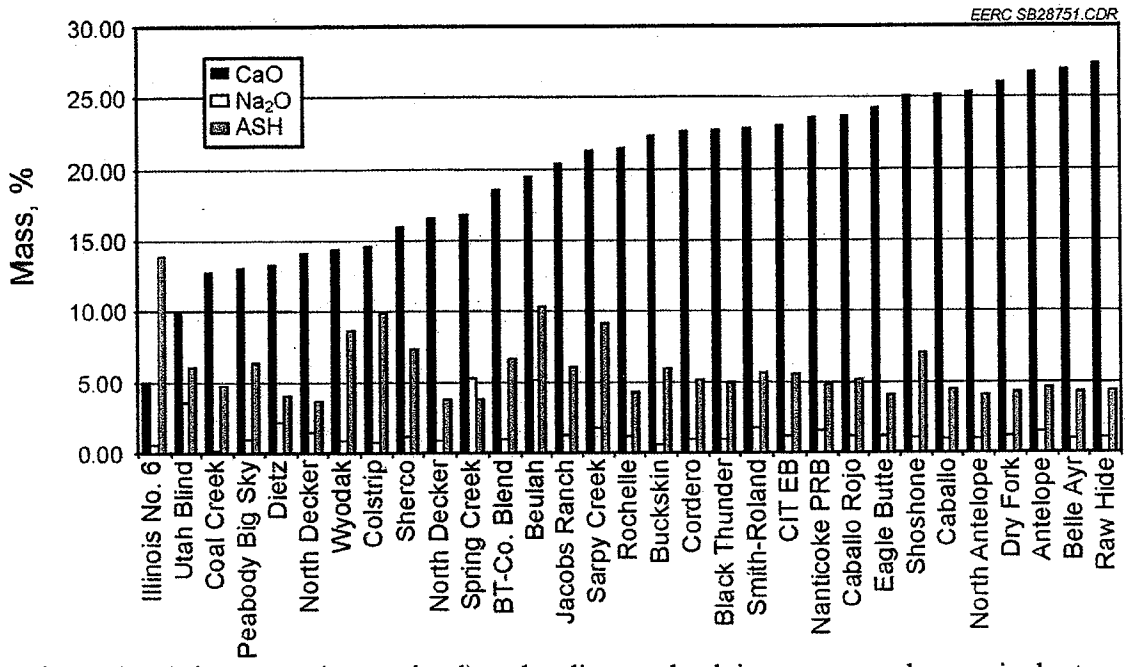

Figure 1. Ash content (as received) and sodium and calcium expressed as equivalent oxides in the ash in coals from the EERC's database.

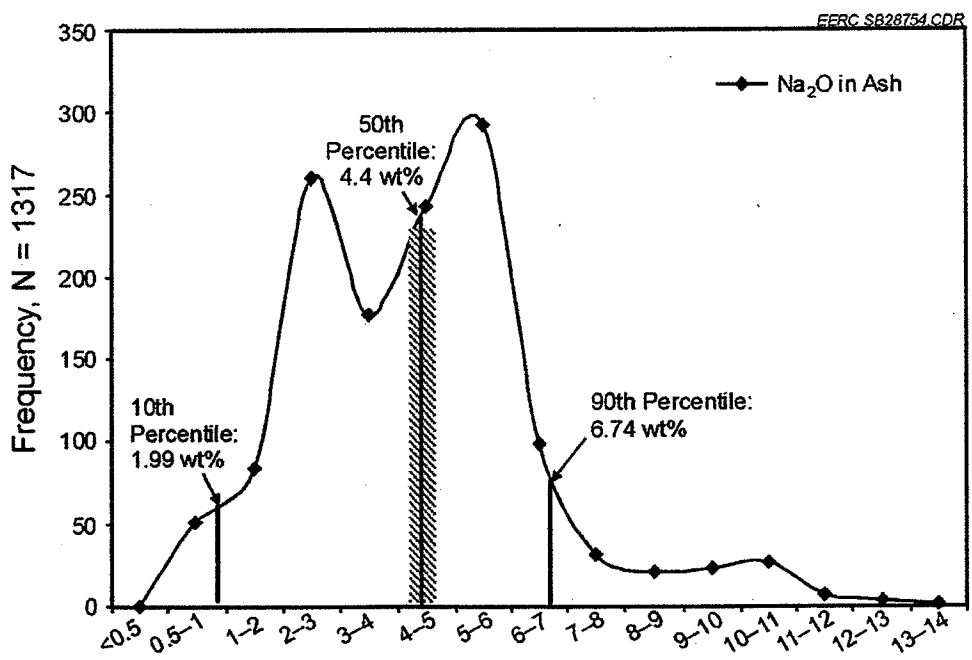

Figure 2. Distribution of sodium (expressed as equivalent oxide) in ash derived from the coals in the Center lignite as-fired database.

Using average compositions is misleading with regard to ash deposition problems. Plants do not burn the average fuel, and problems frequently occur in systems designed to fire fuels based on average properties. As indicated in Figure 2, the MRYS boiler is firing some very high-sodium-containing coals that can cause significant problems. In addition, the sodium in the Center lignite is organically associated, or sometimes referred to as water- or acid-soluble components and based on publications on Haldor Topsoe's Web site, causes catalyst deactivation (Slabiak and Enevoldsen, 2007[7]).

On December 6, 1999, Dr. Heinz Gutberlet and Jürgen Brandenstein from PreussenElektra Engineering of Germany visited the EERC to discuss sodium reactions with SCR catalysts. They expressed their concern regarding deactivation due to sodium. They were specifically concerned with sulfation processes, and came to the EERC because of our extensive experience with high-sodium coals. Later that year, Gutberlet presented their work on sodium deactivation of SCR catalysts when exposed to flue gases produced from firing coals that contain higher soluble sodium levels (Gutberlet, 2000[8]). Flemming Hansen of Haldor Topsoe indicated that soluble or organically associated sodium is the worst kind with respect to SCR catalyst blinding and deactivation (Hansen, 2007[9]).

Mr. Christman does not discuss the enrichment of sodium and other volatile species in the fly ash from cyclone-fired systems. Christman indicates for a typical cyclone that about 30% of the ash ends up as fly ash and the remaining ash ends up as slag. This is based on initial estimates by the original boiler manufacturer Babcock & Wilcox, based on cyclone boilers fired with bituminous coals. This is not the case for lignite-fired boilers at MRYS, where about 45% to 50% of the ash-forming components end up as fly ash. The proportion of ash-forming components that are associated with the organic fraction of the lignite coal is significantly higher than bituminous coals. During combustion in a cyclone, a significant portion of the organically associated elements are either vaporized or form small particles that are swept into the body of the boiler with the combustion gases. The fly ash characteristics

[7] See Reference number 7.
[8] See Reference number 8.
[9] Ibid Reference number 6.

derived from a cyclone as compared to pulverized coal-fired boiler are enriched in the more volatile elements such as sodium and are depleted in some of the less volatile elements that end up in the slag. In wall- or corner-fired systems the enrichment of sodium in the fly ash is not as significant because of the dilution of the other ash-forming components. The ash loading may be less but the melting point and the stickiness of the fly ash are greater for the cyclone units as compared to the pulverized coal units. This creates more deposits on heat-transfer surfaces in the convective pass and requires more cleaning using sootblowers.

GENERAL BACKGROUND (from the January 8, 2007 ERG Memo)
ERG memo page 2, Item 1, additional comments and responses:

> *"It is not possible to correlate deactivation rate with total flyash in the flue gas. It is anticipated that high-dust SCR catalyst life will be shortened from 3-6 years (typical) to as little as 2-12 months, requiring extended, frequent outages for replacement. The B&Mc and Benson documents provide absolutely no basis for this quantitative determination."*

EERC Response:

The SCR catalyst sections that were exposed to the flue gas from the Coyote Station were completely plugged at the end of the testing period. The EERC offered to send them to Haldor Topsoe for evaluation, and the catalyst supplier indicated that the Coyote SCR test catalysts were too plugged and deactivation testing could not be conducted. This discussion was held between Jason Laumb of the EERC and Flemming Hansen of Haldor Topsoe.

B&McD Response:
The BACT Analysis written by Burns & McDonnell did not specifically state that a high deactivation rate was the sole reason for why they anticipated that high-dust SCR catalyst life will be shortened from 3-6 years (typical) to as little as 2-12 months. The lack of published catalyst activity data for the Coyote slipstream SCR catalyst field test precluded Burns & McDonnell from evaluating or including it in the NO_X BACT Analysis Study reports for the Milton R. Young boilers. Pages A1-25 and 26 in Appendix A of the referenced NO_X BACT Analysis Study listed the common influences for catalyst replacement. Pages A1-29 and 30 discussed the specific reasons for the expected severe impacts from difficult-to-remove ash deposits and pluggage of a conventional high-dust catalyst on a unit burning North Dakota lignite.

The accumulation of ash in the Coyote station slipstream SCR catalyst demonstration test after 2 months was documented in Dr. Benson's referenced technical paper. If such an accumulation of flyash (that was not able to be dislodged and removed from the slipstream SCR while on-line) was routinely encountered at a full-scale high-dust SCR catalyst installation during operation on a North Dakota lignite-fired cyclone boiler, increased flue gas pressure drop and reduction of mass flow would occur. This in turn would require increased fan horsepower demands or reduced boiler firing rates. An extended forced outage to remove the ash accumulation, which could damage the catalyst and/or require it to be replaced, would be needed to restore full unit output and catalyst NO_X reduction effectiveness.

GENERAL BACKGROUND (from the January 8, 2007 ERG Memo)
ERG memo, Item 3, page 2 bottom paragraph and page 3, top paragraph - additional comments and responses:

> *"Using data from analyses of more than 700 as-fired coal samples, B&Mc states on page A1-31, that the average ash content of Center Mine coal is 10.5% and can be as high as 25.5%. An examination of the actual data (provided by Minnkota in 2003) shows that the coal ash content is not particularly variable, with more than 95% of the samples having an ash content between 7% and 15%."* ...and... *"In conclusion, the Center Mine coal does not have unusual variability in ash content and in no case has an ash content five times higher than PRB coal as the B&Mc report implies".*

EERC Response:
Center lignite is extremely variable in ash content and in the constituents that make up the ash. Christman focuses attention on averages, and this is a mistake for those who design power systems as well as those who operate them. Typically, it is not the average coal that causes ash-related problems, and it is the excursions from the average that impact the formation of difficult-to-remove deposits on surfaces exposed to flue gases.

Figures 3 and 4 show actual data from the Milton R. Young (MRY) plant on lignite variability that show the extreme variability in both the ash content (moisture-free basis) and base-to-acid ratio ($B/A=[Na_2O+MgO+CaO+K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$). The B/A ratios are an effective way of examining variability and ash behavior performance. The as-fired coal properties in Figure 3 show changes in ash percentage (moisture-free basis) from the arithmetic

average being approximately 50 percent. This means that the amount of ash produced at the high end of the sample range can be double the amount at the low end of the range over a very short period of time. Also included is cyclone performance that indicates slag freezing when the value drops from 7000 to 6000. The need to co-fire fuel oil in one or more cyclones for supplemental heat during slag freezing events is typically triggered by an excursion in ash content and/or low B/A ratio coal.

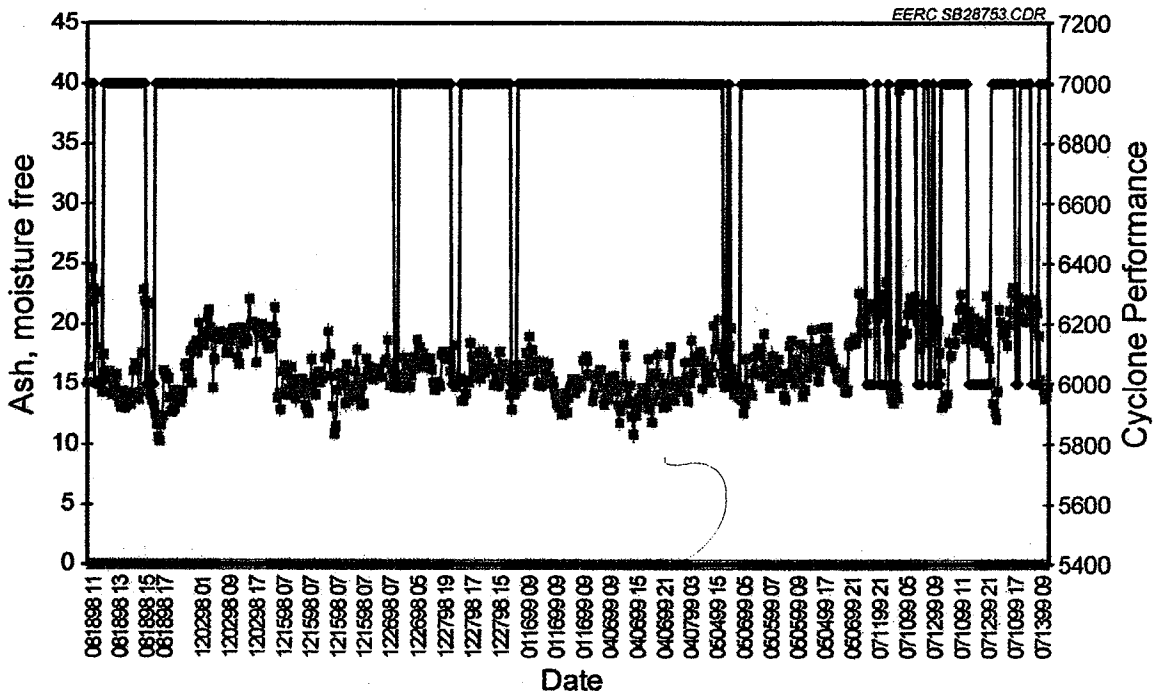

Figure 3. Moisture-free ash content of as-fired coal samples showing variability.

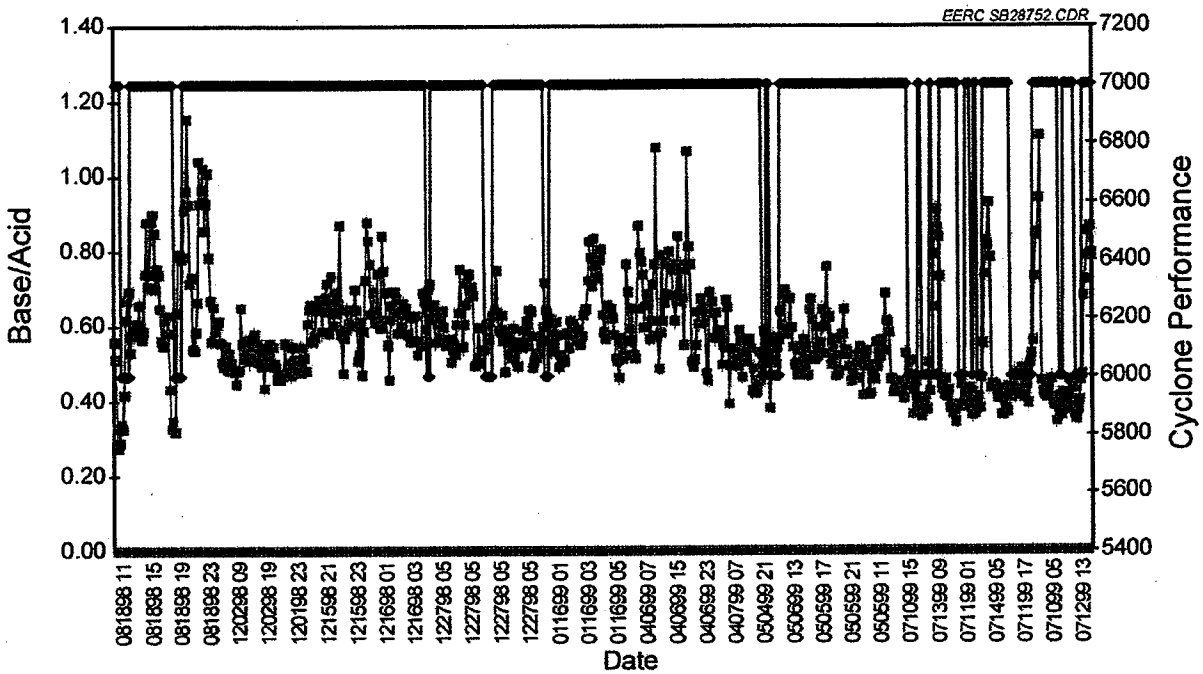

Figure 4. Base-to-acid ratio of as-fired coal samples showing variability.

B&McD Response:
The maximum ash content reported was a number in Minnkota's dataset. While this data point seems atypical, it should be considered as part of the overall Center mine's lignite coal analysis for ash content. The time-dependent (hour-to-hour and day-to-day) variability of the Center lignite coal's heat content and ash composition causes difficulties in being able to maintain adequate slag formation and viscosity in the cyclones, and can result in higher-than-normal amounts of flyash to be emitted from the boiler or fouling of boiler surfaces over a relatively short time span. The ERG's commenter appears to ignore the importance of how these variations negatively impact the hour-to-hour and day-to-day operation of the boilers at MRYS.

SPECIFIC ISSUES (from the January 8, 2007 ERG Memo)

<u>SCR Applicability</u>

High Dust SCR

<u>Catalyst Deactivation</u>
ERG memo page 2, Paragraph 1; page 3, last paragraphs; and pages 7-9:

"SCR catalyst at a future MRYS SCR system would see a calcium environment almost identical to a wall-fired PRB coal SCR installation and would have a similar catalyst deactivation rate."

EERC Response:

Christman ignores the primary deactivation mechanism associated with lignite, and that is sodium. He focused on the impacts of calcium. Sodium is much higher in Center lignite than nearly all PRB coals with the exception of Spring Creek, a northern PRB coal. Most PRB coals contain 0.3% to 2.1% sodium oxide in the ash (Low-Rank Coal Study, 1980[10]). Sodium combines with sulfur and calcium to produce low-melting-point sulfate phases (eutectics) that plug pores and is much more aggressive in plugging pores than just calcium sulfate alone. Christman rightly brings up the other problem of sodium, and that is by deactivating individual reaction sites; this problem has been observed by investigators in Europe with sodium (Topsoe, 1999[11]). In addition, sodium will readily react with vanadium compounds in catalysts resulting in the formation of sodium vanadates (Conn, 1995[12]), which will decrease the catalytic activity of the vanadium forms and cause deactivation.

Regeneration has been attempted in Europe with SCR catalysts exposed to biomass as with high K (similar in chemistry to Na), and they had some significant problem in recovering reactivity (Khodayari and Odenbrand, 2001[13]).

<u>Catalyst Erosion</u> (from the January 8, 2007 ERG Memo)

ERG memo page 4, bottom paragraph 1; page 5, top paragraph:

"The Benson report cites the high coal ash and frequent sootblowing at MRYS as a basis for predicting unacceptably high catalyst erosion rates if SCR is applied. This prediction ignores the fact that a cyclone boiler partitions the majority of the ash to the slag tapped from the wet bottom of the furnace. The high ash content of the Center Mine coal does, in fact, mean that the ash loadings at the economizer exit of the MRYS units will be fairly high (the B&Mc and Benson reports do not provide data on ash loadings), but not higher than would be seen for many wall and corner-fired units that are currently fitted with SCR."

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[10] See Reference number 9, 1980.
[11] See Reference number 10, 1999.
[12] See Reference number 11, 1995.
[13] See Reference number 12, 2001.

EERC Response:
Christman appears to have misunderstood the problem with ash deposition and reentraining the deposit fragments that can cause erosion. The primary superheater and economizer in cyclone-fired boilers are prone to significant fouling that requires frequent sootblowing. This deposition problem is related to the partitioning that occurs in cyclones. The species that are in the fly ash have more calcium and sodium than the bulk coal ash. This results in more sticky materials that create dense deposits on these lower-temperature convective pass heat-transfer surfaces. Ash deposition is more severe for high-sodium lignites fired in cyclone-fired boilers as compared to pulverized coal-fired boilers. This is contrary to Christman's interpretation where he thinks cyclone firing will decrease the ash loading, therefore, decreasing ash deposition. It is not the ash content that causes the catalyst erosion, it is the propensity to produce deposits on the convective pass heat exchange surfaces and when that material is soot-blown it is entrained and the entrained deposit fragments that are not removed ahead of the catalyst cause erosion.

B&McD Response:
ERG's commenter indicates that a cyclone boiler partitions a majority of the ash in the coal as bottom ash. The case for lignite fired in cyclone boilers at MRYS favors slag only slightly more than flyash, where about 45 to 50 percent of the ash forming components end up as fly ash. Ash loading numbers were not provided because the variability of the ash content and higher heating value of the Center Mine lignite coal and the behavior in the cyclones vary. The stickiness of the fly ash is greater for these cyclone units as compared to the PC-fired units. This creates more deposits in the boiler and downstream surfaces.

<u>Catalyst Plugging</u> (from the January 8, 2007 ERG Memo)
ERG memo page 5, middle paragraphs:

> *"Plugging of SCR catalysts by fly ash accumulation and bridging of passages in honeycomb catalysts and between plates in plate-type catalysts have been a problem for designers and catalyst vendors since the first coal-fired installations in the 1970s. The primary response has been more sootblowing equipment and larger catalysts pitch for honeycomb configurations and wider plate spacing for plate-type configurations. These measures, combined with periodic cleaning during boiler outages have, by-and-large, reduced plugging to a manageable SCR problem. Again, because the MRYS units are cyclone fired, the potential for plugging is no greater for these units with their high ash coal than for PC*

units burning a moderate ash coal. Also, the fact that the MRYS units are brought down for planned boiler deposit cleaning at 120-day intervals provides more opportunity for catalyst cleaning maintenance than is available at the typical; power plant."

EERC Response:
The catalysts that were tested at Coyote station were completely plugged and deposits were forming at the exit of the catalyst. These deposits were highly consolidated and bonded by sulfates and are shown in Figure 5. The ash that was responsible for the bulk of the problem was fine particles rich in sodium, calcium and sulfur that caused severe bonding after 2 to 6 months of operation.

Figure 5. Plugging of SCR catalyst and deposits formed downstream of catalyst section after removal.

B&McD Response:
The ERG's commenter believes that the frequent planned boiler deposit cleaning outages will provide more opportunities for catalyst cleaning maintenance than is available at a typical power plant. This opinion ignores several practical limitations that will preclude Minnkota from taking advantage of these outages for such purposes without incurring a negative impact on production. A review of historic outage data shows that over the past 10 years (1997-2006), the typical MRYS Unit 1 boiler cleaning outage was between 67 and 82 hours in duration, but these can be as short as 56 hours and as long as 206 hours. The median Unit 1 boiler cleaning is 78.3 hours, and the average is 90.7 hours. Over this same time period, the typical MRYS Unit 2 boiler cleaning outage was between 64 and 102 hours in duration, but these can be as short as 37 hours and as long as 244 hours. The median Unit 2 boiler cleaning is 89.9 hours, and the average is 89.1 hours. A boiler fireside cleaning outage is typically scheduled for 96 hours (four days) duration.

A high-dust SCR would need to be isolated from the gas path between the boiler and the inlets to the electrostatic precipitator during boiler cleaning outages to prevent the moisture and deposits liberated during off-line boiler fireside surface cleaning from entering the SCR reactor. Beginning the work of removing ash accumulation or catalyst from the SCR reactor(s) will be delayed by 48 to 60 hours after the start of the outages, depending on ambient temperatures, because the inside of the reactor(s) will be too hot for personnel health and safety. Because the length of the boiler cleaning outages is typically less than 4 days (96 hours), that does not leave much time to do any significant catalyst cleaning or replacement work without delaying boiler startup. The estimated amount of time and difficulty in removing lignite ash accumulation from the SCR reactor(s), or replacing fouled catalyst with clean spare catalyst, is expected to require at least 144 hours (6 days), plus 60 hours upfront for allowing the reactor to cool-down. This is based upon the use of mobile industrial vacuum cleaning methods ("super sucker" truck). The total SCR maintenance outage time will be around 200 hours from boiler shutdown end to beginning of startup. The frequency of such SCR maintenance outages are expected to be required at least annually, or more often.

There are basic concerns that using short boiler cleaning outages as SCR catalyst maintenance opportunities could be detrimental to catalyst life due to thermal stresses and passing through various dewpoint temperatures. Bringing the very large mass of ceramic catalyst material and the reactor structure down in temperature and then back up rapidly and any more frequently than absolutely necessary should be avoided. Significant efforts and expense have been paid on numerous high-dust SCR projects to maintain catalyst at temperatures above dew point during short duration or unplanned type outages of similar duration as MRYS boiler cleaning outages. Keeping the SCR catalyst and reactor structure "bottled up and warm" may improve SCR catalyst longevity and the ability to come back up after the boiler maintenance work is completed. ERG's proposed SCR catalyst management strategy has potential pitfalls that may be more detrimental than helpful in extending SCR catalyst life and performance.

There were only two outages other than major scheduled overhauls during the historic ten-year period that appeared to be of sufficient length (greater than 8 days) that could have lent

themselves to significant catalyst cleaning or replacement work without delaying startup: one on Unit 1 and one on Unit 2. Major unit maintenance outages are scheduled every three years. Obviously, the frequency and duration of historical boiler cleaning outages are not sufficient to expect many opportunities for significant catalyst cleaning or replacement work without delaying startup. Extending boiler cleaning outages to perform periodic SCR catalyst maintenance in between major scheduled unit maintenance outages would cause an unacceptable negative impact on each unit's availability to generate electricity.

<u>High Economizer Exit Temperature</u> (from the January 8, 2007 ERG Memo)
ERG memo page 5, bottom paragraph and top paragraphs on page 6.

> *"The economizer outlet temperatures for the MRYS units are 50 to 150°F (depending on firing rate and boiler cleanliness) above the ideal SCR operating temperature of about 750°F. Since the higher temperature is essential to the boiler operation, the problem can not be cured by adding more economizer surface or blending ambient air to cool the flue gas prior to an SCR catalyst bed."*
> (and)
> *"The high temperature case at MRYS may actually present a better situation for high-dust SCR success than the "typical" designs employed on units where the high economizer exit temperatures do not exist."*
> (also)
> *"At MRYS, it would be possible to install a small air preheater ahead of the SCR catalyst vessel and split the primary air flow between air preheaters before and after the catalyst. By adjusting the proportion of primary air passing through each preheater, the temperature of flue gas entering the catalyst could be maintained at the optimum temperature for the particular catalyst formulation selected and the full amount of heat needed for the Direct-firing Pre-drying Bypass System would be extracted. The costs associated with the two air preheaters would be partially offset by the elimination of the air preheater bypass and damper and by the fact that the two air preheaters would be somewhat smaller than a single preheater. This approach also eliminates the problem that some installations are having with the inadequate mixing of economizer bypass flue gas. From an operating standpoint, the two air preheater approach should be superior to the current, "typical" SCR systems."*

B&McD Response:
The ERG commenter correctly identifies that boiler exit flue gas temperatures are excessive and being essential to the North Dakota lignite-fired cyclone boiler operation, and that the problem can't be cured by adding more economizer surface or blending ambient air to cool the flue gas prior to an SCR catalyst. The ideal temperature range for conventional coal-fired SCR catalyst is believed to be 650-750°F, with 700°F being considered the optimum temperature

and 750°F being the maximum normal operating temperature for long-term performance and life.

Hot primary air is used to pre-dry the lignite coal feed and to transport it through the Direct-firing Pre-drying Bypass System where it becomes saturated with evaporated moisture which is vented to the furnace. A portion of the hot primary air is also supplied to pneumatically-convey the separated, partially-dried crushed lignite coal to the active cyclones. At maximum continuous rating (MCR) firing conditions, these drying and conveying primary airflows are approximately one-third of the total preheated mass airflow supplied to each MRYS boiler.

Modulating the proportion of primary air passing through each preheater in series as described in ERG's proposed design will not maintain the SCR catalyst at optimum temperatures. Bypassing a portion of the boiler's primary air around either the lower-temperature or higher-temperature APH will not sufficiently cool the hot boiler outlet flue gas to the desired temperature ranges as discussed below. Conventional coal-fired SCR catalyst will experience rapid deactivation and degradation due to excessively high temperatures in this scheme.

All of the boiler's primary air and secondary combustion air flows must pass through the "small" higher-temperature APH to reduce the boiler outlet flue gas from as high as 960°F for Unit 1 down to 750°F or lower, and as high as 900°F for Unit 2 down to 750°F or lower. All of the boiler's primary air and secondary combustion air flows must also pass through the lower-temperature APH downstream of the SCR reactor in order to further reduce the final APH's outlet flue gas from 750°F down to 350°F or less prior to the existing cold-side electrostatic precipitators (ESPs). Configured for full primary and secondary airflows at MCR firing conditions, this revised series of air preheaters could raise the temperatures of these boiler air streams above 700°F after the upstream APH, suitable for lignite coal drying and combustion air for entry into the cyclones.

Conceptually, this alteration to the ERG-suggested dual APH design scheme can satisfy the basic boiler air temperature requirements for proper lignite coal drying and combustion. It appears that the excessively-high boiler outlet flue gas temperatures may potentially be

reduced to be within the acceptable range for application of conventional high-dust, hot-side SCR technology. A lack of known examples for this specific dual air preheater series design concept, especially in combination with boiler feedwater economizers, makes it difficult to estimate the scope and sizing of the boiler-related equipment. More detailed technical review is required before accurate scope definition with cost and performance estimates of this revised dual APH design scheme can be developed.

The time required to modify existing boiler water, air, and gas systems will be longer and less straightforward than a "typical" high-dust SCR retrofit project that does not involve two separate air preheaters in series and associated ductwork. Significant boiler air and gas ductwork and building structural modifications and additions will be required. There will be a significant negative impact on each unit's availability to generate electricity during the modifications. It would not be accurate to use typical high-dust hot-side SCR $/kW capital cost estimating factors for such site-specific retrofit installations. The unit capital cost capacity factor for SCR retrofits applied to cyclone boilers by the EPA in the cost-effectiveness analysis used for establishing presumptive BART[14] was $100/kW. Burns & McDonnell believes the EPA's cost-effectiveness analysis is unrealistically low and significantly underestimates the expected capital costs required to apply high-dust SCR technology to North Dakota lignite-fired cyclone boilers.

Low-Dust SCR **(from the January 8, 2007 ERG Memo)**
ERG memo page 6, bottom paragraph and page 7 top paragraphs.

> *"The most viable approach to the required gas heating for MRYS would probably be the use of steam from the host boiler... Whether or not the unit would suffer a derating, and if so, how much, would require an analysis of the plant steam cycle and identification of the current overall bottleneck point for the unit. The optimum point to extract the steam and any possible detrimental effects on the turbine would have to be addressed by a steam cycle engineer."*

B&McD Response:
One possible method to reheat MRYS boilers' ESP outlet flue gas is to use steam produced by the boiler. Detailed engineering steam cycle analyses at MRYS would certainly be required for these particular solutions suggested by ERG's commenter.

[14] See Reference number 13, Excel Spreadsheet OAR-2002-0076-0446, page 209.

To achieve a reheated flue gas temperature of 750°F from MRYS boilers' current full-load ESP outlet temperature of 350°F would require a large amount of superheated steam. To cool the flue gas down to approximately 450°F after the low-dust SCR reactor and recapture some of the excess heat prior to the flue gas desulfurization system, a gas-to-gas heat exchanger (GTGHE) could be installed. The recovered heat from the GTGHE at full load would raise the 350°F flue gas temperature up to around 640°F. One or more shell-and-tube heat exchangers would be placed across the flue gas ductwork to raise the flue gas exhausted from the GTGHE downstream of the ESPs to the desired SCR inlet temperature.

Supply steam for reheating the flue gas would need to be in the neighborhood of 900°F, which would only be available from the boiler's main steam outlet (around 1000°F, 2500 psig). For process and safety reasons, this main steam takeoff would need to be attemperated (cooled with boiler feedwater sprays) and pressure-reduced prior to use in the reheat coils. Such a large quantity of high temperature steam suitable for such flue gas reheat in the vicinity of the station's electrostatic precipitator's outlets is not currently available at MRYS.

Additional pressure drop created by the reheat heat exchanger tubes on the flue gas side could be significant, requiring higher capacity induced draft fans and drive motors. Because the flue gas temperature entering the steam coil banks would be around 640°F, the 900°F steam supply would only drop to approximately 700°F, which would still be superheated. The amount of heat transfer per pound of steam supplied would only be approximately 100 Btu/lb, so a large amount of supply steam would need to pass through the steam coils in order to provide the incremental heat transfer. In this scheme, a preliminary thermal analysis indicates that 77 mmBtu/hr and 134 mmBtu/hr is the estimated amount of reheat required to raise the flue gas temperature from 640°F to 750°F at nominal full load output of the MRYS units, respectively. Approximately 42-44% of the entire boiler superheated steam flow would be required for the flue gas steam reheat system at full load (77 x 1,000,000 / 100 = 700,000 lbs/hr vs 1,714,000 lbs/hr for Unit 1 at 235 MWg and 134 x 1,000,000 / 100 = 1,340,000 lbs/hr vs 3,200,000 lbs/hr for Unit 2 at 450 MWg).

Raising the flue gas temperature up to only 700°F would recover less heat in the GTGHE and so the flue gas temperature entering the steam coil banks would be around 590°F. In this scheme, a preliminary thermal analysis indicates that 76 mmBtu/hr and 133 mmBtu/hr is the estimated amount of reheat required to raise the flue gas temperature from 590°F to 700°F at nominal full load output of the MRYS units, respectively. Approximately 41-44% of the entire boiler superheated steam flow would be required for the flue gas steam reheat system at full load.

The use of such large quantities of high temperature steam from the boiler associated with each unit at MRYS for low-dust SCR inlet flue gas reheating to 700-750°F would require major changes to the high, intermediate and low pressure steam turbine stages. Retrofits to boiler reheat superheater and economizer feedwater surfaces would be required. The EPA's NSR Manual 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."[15]

The on-going negative impact on overall unit efficiency will be significant and cause an unacceptable net unit electrical output capacity derate. This is because the high-temperature/high-pressure main steam extracted from the boiler for flue gas reheat would not pass through any stages of the high/intermediate/low pressure steam turbines, so less net electrical energy would be produced.

The time required to modify the components in steam cycle power generation and balance-of-plant systems and boiler gas systems to accommodate such suggested changes would be lengthy. Negative impacts on each unit's availability to generate electricity during the modifications will be a significant.

<u>Miscellaneous Issues</u> (from the January 8, 2007 ERG Memo)
ERG memo page 7, second paragraph.

> *"The MRYS units are fitted with tubular air preheaters. Depending on tube diameter, orientation, and sootblower configuration, the tubular design can be better than the more*

[15] See Reference number 14, Section IV.B., page B.18.

common regenerative air preheater in dealing with removal of ammonium sulfate and ammonium bisulfate deposits in the low temperature portion of the air preheater."

B&McD Response:
The tubular air preheaters at MRYS are not equipped with sootblowers for on-line gas-side surface deposit cleaning. Tubular air preheaters were originally supplied instead of rotary regenerative type, presumably because of the special cyclone boiler combustion air requirements. Lignite-fired cyclone boilers have very high forced draft fan discharge pressures to supply the primary air used for the lignite drying systems. Regenerative air preheaters on these cyclone boilers would have significant leakage of this combustion air into the gas-side. This would not be acceptable.

In addition, several cyclone boilers originally installed with tubular air preheaters have retrofitted rotary regenerative-type APHs as part of the SCR project due to concerns with being able to effectively remove ammonium sulfate and bisulfate fouling from tubular air heater heat transfer surfaces. To conclude that tubular APH is better for cleaning of SCR-enhanced deposits would contradict the body of evidence already out in the utility industry.

North Dakota Industrial Commission project Evaluation of Potential SCR Catalyst Blinding During Coal Combustion (from the January 8, 2007 ERG Memo)
ERG memo page 7, middle and bottom paragraphs, and page 8, top paragraphs:

"The Benson report has detailed discussion of the field test of SCR at Otter Tail Power's Coyote Station. He includes much discussion of plugging and theoretical mechanisms for deposit formation on SCR catalysts. ... Although the information he provides is interesting and provides evidence of some loss of catalyst activity, it provides no useful data on how much activity is lost."
(and)
"Curiously, Benson did not include activity data, even though his early progress reports on the internet indicate that he had this information some time ago. Additionally, the report indicates that the inlet and outlet NOx concentrations were tracked and no mention is made of a drop in removal efficiency over time. These quantitative measures of catalyst activity would be useful, whereas the qualitative information he chose to present provides no basis for assessing the applicability and cost of SCR applied to lignite."
(and)
"Benson's test, then, only simulated the top layer of a multi-layer [catalyst] system.... Benson's project provides no real insight into the effectiveness and survivability of a second or third layer. Catalyst vendors do, however, have sufficient data and experience to extrapolate top layer test data (had Benson provided it) to address full multilayer performance."

(also)
"The air pulse used to clear deposits is a poor simulation of sootblowing and is much less effective... Most new commercial installations are applying acoustic horns in lieu of sootblowing and find them to be very effective. Note: The 6 mm pitch catalyst used at Coyote is much smaller than currently being specified for coal-fired installations. Vendors are now supplying 9mm, 10mm or even 11mm pitch catalysts. This current industry practice makes Benson's plugging observations essentially obsolete."

EERC Response:
The SCR catalysts from Otter Tail Power's Coyote Station were too plugged to run a test on deactivation. Flemming Hansen of Haldor Topsoe did not see any point in trying to get values of catalyst activity. The aim of the project was to determine the rate of loss of catalytic activity. However, the challenges of plugging and blinding due to deposit formation limited our ability to obtain activity data.

The design and operation of the slipstream system was conducted through the consortium. The consortium included the following catalyst vendors: Cormetech, Hitachi, and Haldor Topsoe. During the design, the vendors provided input and approved the design of the reactor, sootblowing system, and data management systems. They also provided input on operating conditions as well as provided the catalyst. The vendors selected the pitch of the catalysts for installation and testing.

B&McD Response:
It may be true that sonic horns are the choice of the industry, but this is not because they are more effective in removing difficult ash deposits. Sonic horns are by far cheaper to buy, cheaper to install, cheaper to maintain, cheaper to operate, and require much less structural steel and platforms. With the vapor phase deposition of compounds onto the catalyst that are a major concern, sonic horns are not expected to be effective on that deposit phenomenon. The theory of sonic horns is to keep the non-adhering fly ash particles moving so the normal gas flow carries them through the SCR reactor. The catalyst fouling described by EERC's paper would happen with normal operation and appears to have much less to do with fly ash entrainment.

CONCLUSIONS (from the January 8, 2007 ERG Memo)
ERG memo page 8, middle and bottom paragraphs, and page 9, top paragraphs:

"The calcium content of the Center Mine coal ash is well below that of many PRB coals....Also, the alkaline material content of the Center Mine coal ash is within the range of coals being burned at installations in Europe where SCR is being successfully operated. Today, catalyst vendors have a thorough understanding of catalyst deactivation mechanisms and a large store of data that allows them to tailor catalyst formulations for maximum life for various coal and ash analyses and to confidently predict and guarantee the projected life."
(and)
"Dr. Benson's report on the slip stream testing at Coyote Station provides no quantitative assessment of catalyst deactivation and no basis for a conclusion that SCR is technically infeasible on a North Dakota lignite-fired boiler. Inexplicably, Dr. Benson failed to provide data on catalyst deactivation and NOx reduction, even though there are indications that these data were, in fact, obtained."
(and)
"In summary, the B&Mc NOx BACT analysis and appended Benson report provide no quantitative basis for determination of technical infeasibility...All the problems posed by B&Mc are engineering and economic issues and can be addressed with current knowhow. The high initial NOx at MRYS, combined with year round operation assures that, even with conservative design (e.g. large pitch catalyst) and application of engineered solutions (e.g. popcorn ash screens, two air heaters), the cost effectiveness will be well within the range of that being experienced with NOx SIP Call units at this time."

EERC Response:
The conclusions of Christman's review do not address the high sodium levels but appear to focus on the lower calcium levels. None of the sodium issues have been resolved. Sodium is a problem in the formation of deposits and in deactivation as indicated by several investigators. The catalyst vendors have not addressed them. Mr. Christman curiously did not address the challenges of sodium even though it is the major problem identified in the reports submitted. On page 3, Mr. Christman did identify other alkaline materials (potassium, sodium, and magnesium) as causing deactivation of catalysts.

B&McD Response:
As previously mentioned by Dr. Benson of EERC, the SCR catalysts from Otter Tail Power's Coyote Station slip stream tests were too plugged for Haldor Topsoe to run a lab test to quantify the amount of deactivation. Because the catalyst activity data for the Coyote slipstream SCR catalyst field test was not available, Burns & McDonnell could not evaluate or include it in the NO_X BACT Analysis Study reports for the Milton R. Young boilers.

There is significant site-specific evidence that fouling of boiler convection heat transfer surfaces occurs rapidly and requires frequent on-line sootblowing and boiler outages for removal. There are major concerns that a severe catalyst fouling and ash accumulation situation will occur on a high-dust, hot-side SCR installation at MRY Station. This will cause NOx removal underperformance and frequent unscheduled interruptions to the operation of the units. The historical durations of the planned boiler deposit cleaning outages are not long enough to perform significant catalyst cleaning or replacement work without delaying startup. Negative impacts on each unit's availability to generate electricity due to these conditions will be significant.

Extensive boiler air and gas ductwork and building structural modifications and additions at MRYS will be required. It would not be accurate to use typical high-dust hot-side SCR $/kW capital cost estimating factors for such site-specific retrofit installations. The time required to investigate, engineer, design, and modify the boiler gas systems at MRYS to accommodate the suggested changes will be longer and less straightforward than a "typical" high-dust SCR retrofit project that does not involve two separate air preheaters in series and associated ductwork. For a low-dust SCR, engineering, designing, and modifying components in MRYS steam cycle power generation and balance-of-plant systems will be substantially greater than previous SCR projects implemented in the United States. A unit efficiency reduction from using main steam extraction for flue gas reheating will be significant and cause an unacceptable net unit electrical output capacity derate. Negative impacts on each unit's availability to generate electricity during the implementation of modifications to accommodate either form of SCR will be a significant detriment to current operations.

The EPA's cost-effectiveness analysis used for establishing presumptive BART by "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [16]. Burns & McDonnell believes the EPA's cost-effectiveness analysis is unrealistically low and significantly underestimates the expected levelized total annual costs required to apply high-dust or low-dust SCR technology to North Dakota lignite-fired cyclone boilers.

[16] See Reference number 15, FR Vol. 70 No. 128, pages 39135 and 39136.

EPA REGION 8 Preliminary Analysis of Burns & McDonnell BACT Analysis for Nitrogen Oxide at Milton R. Young Station, Units 1 and 2
January 8, 2007

I. Introduction and Summary of EPA's Preliminary Analysis

A. Summary of EPA's Preliminary Analysis

EPA R8 report page 1, top paragraph:

"EPA's preliminary analysis is that the B&M study lacks sufficient information within the BACT analysis. Specifically, the study excludes Selective Catalytic Reduction (SCR) as a technically feasible control option at step 2 of the five-step Top-Down analysis, while not presenting NOx control effectiveness or catalyst activity data. As a result, B&M fails to rank SCR against other control options in terms of control effectiveness at step 3, and fails to analyze costs of SCR versus other control options at step 4. EPA questions the reasons cited by B&M for technical infeasibility of SCR. Furthermore, based on a survey of SCR vendors described later in this report, EPA found there are vendors that will offer performance guarantees for this type of application. Further information should be requested, to support the analysis with respect to SCR."

B&McD Response:
Many of the EPA's preliminary analysis comments are similar to those contained in ERG's memo, and therefore, only differentiated comments and responses have been selected and provided herein.

The reasons for the assertion of technical infeasibility of SCR for lignite-fired cyclone boilers were presented in the MRY Station Unit 1 and Unit 2 BACT analysis reports, with additional comments provided herein. The EPA's NSR Manual does not specifically define the operating parameter or performance measure that a particular NO_X control technique or technology would have to achieve to satisfy "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"[17] in order for said alternative to be excluded from further consideration.

[17] Ibid Reference 14, Section IV.B., page B.20.

The severe accumulation of ash and blinding in the Coyote station slipstream SCR catalyst field test after 2 months was documented in Dr. Benson's referenced technical paper. The evident failure of the Coyote slipstream SCR catalyst field test to avoid severe catalyst fouling and ash accumulation led Burns & McDonnell to believe that if such results were routinely encountered at a full-scale high-dust SCR catalyst installation during operation on a North Dakota lignite-fired cyclone boiler, aggressive on-line cleaning and/or frequent extended forced outages would be needed to remove the ash accumulation or remove the catalyst for cleaning in order to restore full unit output and catalyst NO_X reduction effectiveness. Either or both of these maintenance activities could damage the catalyst and/or require it to be frequently replaced.

Two months between SCR catalyst maintenance activities would be an extremely short operating cycle time compared to 36 months typically experienced at other SCR installations. Burns & McDonnell interpreted these field test results as "empirical data showing the technology would not work on the emissions unit under review[18]" for technical infeasibility purposes. Eliminating technically-infeasible alternatives prior to ranking the feasible controls based upon control effectiveness, and then evaluating the impacts of implementing only feasible control techniques and technologies follows the BACT process.

The issue of SCR vendors' willingness to offer performance guarantees for units firing North Dakota lignite is addressed at the end of this response section.

EERC Response:
We spoke to Flemming Hansen of Haldor Topsoe, an SCR catalyst vendor, regarding providing performance guarantees. After describing the characteristics of Center lignite, specifically issues related to sodium, they were very concerned regarding guaranteeing performance. Based on the conversation, it became evident that EPA representatives may have not indicated the levels of sodium and

[18] Ibid Reference 14, Section IV.B., page B.20

the form of sodium in the coal. Haldor Topsoe indicated that the sodium was a major concern and that it causes deactivation, especially the organically associated form. They indicated that they had some experience and found significant deactivation of coupon samples after 6000 to 7000 hours of operation with a coal having elevated levels of sodium (Flemming Hansen, 2007[19]).

II. EPA Case-Specific Review of Burns & McDonnell & EERC Technical Feasibility Analysis for Selective Catalytic Reduction

A. High Dust SCR

EPA R8 report page 1, bottom paragraph:

"B&M has eliminated High-Dust SCR as technically infeasible due to issues described below. B&M's analysis utilizes a report by the Energy & Environmental Research Center (EERC). EPA's response on each issue is also described below."

(and)

Ash Deposition Issue Raised by Burns & McDonnell

EPA R8 report page 2, and page 3 upper paragraphs

(and)

EPA Analysis of the Ash Deposition Issue:

EPA R8 report page 3, middle paragraph:

"The concern about high amounts of ash materials causing blinding of macro-pores in the catalyst is real but solvable. Strides in catalyst formulations, catalyst management systems, and recently, catalysts regeneration processes, have all combined to lower the overall cost contribution of both initial and replacement catalyst in modern SCR systems."

EERC Response:

EPA states that the high amount of ash materials causing blinding of macropores in the catalyst is real but solvable. We spoke to Flemming Hansen of Haldor Topsoe, a catalyst vendor, regarding what has been done to deal with the problems of high-sodium coals with regard to advanced formulations and catalyst regeneration, and he was not aware of any work that had advanced SCR systems for high-sodium applications (Flemming Hansen, 2007[20]).

[19] Ibid Reference number 6.
[20] Ibid Reference number 6.

Regeneration has been attempted in Europe with SCR catalysts exposed to biomass as with high K (similar in chemistry to Na), and they had some significant problem in recovering reactivity (Khodayari and Odenbrand, 2001[21]).

B&McD Response:
It is unclear whether EPA's claimed SCR catalyst improvements cited would translate into preventing the catalyst layers from being susceptible to macro-pore blinding and plugging by calcium-based compounds and the impact on the individual catalyst reaction sites from sodium-based compounds discussed in Dr. Benson's referenced technical paper. The EPA cites no published technical literature that describes the results of testing that definitively documents how long currently available SCR catalysts can survive and provide effective NO_X reduction when exposed to the flue gas and flyash constituents exhausted from combustion and operation of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application such as would be the case at Milton R. Young Station.

Comparison of MRYS to SCR Systems Operating on Power River Basin coals
EPA R8 report page 3, middle paragraph; page 4, and page 5, top and middle paragraphs:

"The concern about high amounts of alkaline materials in Center Mine coal expressed in B&M's BACT analysis and described in the Appendix B EERC report is real, though not necessarily unlike operating SCR systems on PC boilers burning PRB coal...we believe there is value in successful operating experience realized at current SCR installation at PRB-fired power plants. The problems cited in the BACT analysis are being dealt with at several NOx SIP Call SCR installations today."

EERC Response:
The sodium and ash contents of Center lignite are significantly different from PRB coals. EPA indicates that the problems of deposition will decrease because the cyclones take out some of the ash as slag but for lignite, cyclones create additional deposition problems downstream. The cyclones partition the more refractory ash components into the slag and the more volatile components into the

[21] See Reference number 12.

fly ash. The fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components that cause bonding.

EPA discusses ash loadings and the potential impacts on SCR performance. They also discuss the formation of calcium sulfates that can plug pores in catalysts as well as the impacts of other alkaline materials (potassium, sodium, and magnesium) and their potential to deactivate individual sites rather than blinding pores. They fail to recognize the formation of combined phases such as sodium calcium sulfates with low melting points that are very reactive and can both block pores and deactivate individual sites in catalysts. They also fail to recognize that cyclones partition the ash, increasing the proportion of sodium in the smaller particles, resulting in increased propensity for the formation of the complex sulfate phases.

Topsoe (Topsoe, 1999[22]) presented a paper at the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) meeting on SCR–selective non-catalytic reduction (SNCR) on testing conducted with biomass fuels that contain high potassium and sodium and found rapid deactivation in the SCR catalyst. Their data suggest sodium or potassium resembles the ammonium ion and blocks access to the active sites in the catalyst. They indicate that this occurs most readily where the alkali elements are in a soluble form. Topsoe incorrectly assumes that all alkali in coal is not soluble because of work they did on potassium. Potassium is associated in the coal with clay minerals and is not soluble. Sodium in North Dakota lignite is organically associated (soluble form) and is readily available for reactions with catalysts and flue gas species. More recent work conducted by Beck and others (2004)[23] established that sodium correlates with catalyst deactivation activity and that pore condensation of sodium is the major deactivation mechanism.

[22] Ibid Reference number 10.
[23]. See Reference number 16.

Sodium levels at MRYS have a multimodal distribution, and assuming the average sodium level in the ash is not realistic. See the earlier discussion in EERC response to Mr. Christman's review.

B&McD Response:
The discussion in the EPA's preliminary analysis of Minnkota's NO_X BACT Analysis at MRYS ignores the BACT reports' statements that the firing of lignite coal in a cyclone boiler specifically designed and built to pre-dry and burn North Dakota lignite produces fine flyash particles which will enter the pores of the SCR catalyst, react with SO_3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

When considering the much higher sodium content of Center lignite coal ash (lb/mmBtu) compared to PRB coal, the impact on the individual catalyst reaction sites from sodium-based compounds discussed in Dr. Benson's referenced technical paper has largely been ignored by the EPA's commenters. The discussion in the ERG memo and EPA's preliminary analysis implies that macro-pore plugging by calcium would be the only significant catalyst deactivation mechanism, and that this would be within the envelope of experience at commercial SCR installations.

The problems associated with sodium combined with calcium, sulfur, and other alkaline elements at any cyclone boiler firing North Dakota lignite appear to be unpreventable for successful application of SCR catalysts. There is no full-scale long-term documented and published demonstrated experience at commercial SCR installations on large coal-fired boilers with similarly high sodium levels. The tendency of small sodium vapor particles to be generated during the combustion and slagging processes of a North Dakota lignite-fired cyclone boiler has not been adequately addressed by the EPA commenter's discussion.

The lack of published NO_X control effectiveness and catalyst activity data for the Coyote slipstream SCR catalyst field test precluded Burns & McDonnell from

evaluating or including it in the NO_X BACT Analysis Study reports for the Milton R. Young boilers.

As mentioned in the NO_X BACT Analysis Study reports for the MRYS boilers, Electric Power Research Institute, Inc. (EPRI) produced a recent study on the impact of coal type on SCR catalyst life and performance. The EPRI study produced field data 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 Sioux plant's 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.

Burns & McDonnell believes that the flue gas and flyash conditions produced during the combustion and slagging processes of a North Dakota lignite-fired cyclone boiler will be significantly more problematic than the tests at Sioux Station demonstrated, especially due to the lack of firing a coal blend with moderating influences of bituminous coal flyash.

Engineering Solutions for SCR Applications at High Ash Facilities
EPA R8 report page 5, lower paragraphs; and page 6, top paragraph:

"Plugging of SCR catalysts by fly ash accumulation and bridging of passages in honeycomb catalysts and between plates in plate-type catalysts has been a problem for designers and catalyst vendors since the first coal-fired installations in the 1970s. The primary response has been more sootblowing, on-line cleaning equipment, and larger catalyst pitch... These measures, combined with periodic cleaning during boiler outages have, by-and-large, reduced catalyst plugging to a manageable SCR problem."
(and)

"...the Electric Power Research Institute (EPRI) has advised clients that based on industry experience on a wide range of SCR installations over the years, SCR designs can accommodate fuel types never before used in practice on a full scale."

EERC Response:
The issue is not strictly the high ash content of North Dakota lignite, it is the high sodium content of this lignite's ash. The issue for the application of SCR on North Dakota lignite-fired cyclone boilers is a high potential for ash deposition in lower-temperature convective pass surfaces such as the economizer and primary superheater. The high ash deposition rates require continuous cleaning with sootblowers, and the resulting liberated deposit fragments will cause catalyst plugging. The deposit fragments, along with the formation of sulfated sodium- and calcium-rich fine particulate plugging pores of the catalyst, causes plugging of gas paths.

B&McD Response:
For a North Dakota lignite-fired cyclone boiler, aggressive on-line cleaning and/or frequent extended forced outages would be needed to remove the ash accumulation or remove the catalyst for cleaning in order to restore full unit output and catalyst NO_X reduction effectiveness. Either or both of these maintenance activities could damage the catalyst and/or require it to be frequently replaced.

As mentioned in response to a similar statement by the ERG commenter, the estimated amount of time and difficulty for MRYS boilers' SCR maintenance appears to be insufficient to use boiler deposit cleaning outages to perform significant catalyst cleaning or replacement work without delaying startup.

EPRI's statements do not conclusively support the technical feasibility of applying SCR with specific technical evidence that shows proof of the hypothesis that it will be successful on Texas lignite-fired boilers. It also does not suggest or imply that North Dakota lignites are similar to Texas lignites and therefore SCR

should also be successful on such applications. The high ash and moisture content of a Texas lignite-fired unit would result in a different set of challenges for application of high-dust SCR technology. Possible solutions to deal with Texas lignite are not relevant to compare to North Dakota cyclone boilers in this NO_X BACT analysis for MRYS. Already-installed boiler and backend equipment designs on units firing TX vs ND lignites are significantly different, reflective of the approaches the original design engineers took to attack these situations as separate problems. A comparison of the differences between Texas and North Dakota lignites is included in EERC's subsequent response to the EPA's comments regarding the NSPS revisions later in this response document.

Other Ash Deposition Problems on Downstream Components

EPA R8 report page 6, middle paragraph:

"B&M's discussion of these "other" potential accumulation problems does not reach any definitive conclusions related to the technical feasibility of SCR, so EPA does not see this as a technical barrier to installing SCR at the MRYS units."

EERC Response:

Note that it is not the ash loadings, it is the sodium in the lignite ash that causes the deposition. The sodium-related deposition on SCR catalyst will shorten the time between outages for off-line cleaning.

B&McD Response:

The higher amount of ash, sodium, and sulfur in North Dakota lignite combined with calcium and other alkaline elements along with ammonia and SO_3 emitted from a high-dust SCR will exaggerate tubular air preheater and economizer tube exterior surface fouling and plugging problems at any cyclone boiler firing this fuel compared to bituminous or PRB coals. The tubular air preheaters and the built-in economizers at MRYS are not equipped with sootblowers for on-line gas-side surface deposit cleaning. Noting that MRYS boilers' air preheater and economizers would be downstream of the boiler backpass outlets and a high-dust SCR, isolating these components during off-line boiler deposit cleaning or SCR cleaning outages from negative impacts of "dirty air would be challenging and

expensive. Similar estimated amounts of time and difficulty for such off-line downstream deposit removals will also delay unit startups following such outages. These issues were discussed previously in response to ERG's comments.

Accounting for Catalyst Life & Performance in Top-Down BACT Analysis
EPA R8 report page 6, bottom paragraph:

"Finally, the conclusion reached in the B&M BACT analysis that ash deposition and catalyst pluggage will adversely affect SCR performance (we assume this means control efficiency) and catalyst life does not necessarily support a conclusion that the technology is technically infeasible and that SCR should be eliminated at step 2 of the Top-Down BACT analysis...Although the catalyst deactivation rates may be somewhat higher than rates experienced at eastern bituminous fired SCR installations...However, SCR performance and any real construction and operational costs are factors that would be accounted for under the economic impact stage related to the cost effectiveness of SCR (step 4) under the Top-Down BACT analysis."

B&McD Response:
The reasons for the assertion of technical infeasibility of SCR for lignite-fired cyclone boilers were presented in the MRY Station Unit 1 and Unit 2 NO_X BACT analysis reports, with further explanation provided herein. The EPA's preliminary analysis comments minimize the difficulties posed by the higher amount of ash, sodium, and sulfur in North Dakota lignite combined with calcium and other alkaline elements along with ammonia and SO_3 emitted from a high-dust SCR on the two existing North Dakota lignite-fired cyclone boiler at MRYS.

The EPA cites no published technical literature that describes the results of testing that definitively documents how long currently available SCR catalysts can survive and provide effective NO_X reduction when exposed to the flue gas and flyash constituents exhausted from combustion and operation of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application such as would be the case at Milton R. Young Station.

The evident failure of the Coyote slipstream SCR catalyst field test to avoid severe catalyst fouling and ash accumulation after 2 months led Burns &

McDonnell to believe these field test results indicate "empirical data showing the technology would not work on the emissions unit under review[24]" and "unsolvable technical difficulties would preclude the successful deployment of the technique"[25] for technical infeasibility purposes.

EPA Analysis of the Energy &Environmental Research Center Report (Appendix B):

EPA R8 report page 10, middle and bottom paragraphs, and page 11, top and middle paragraphs:

"Other inherent problems associated with directly applying the results of the EERC pilot testing at Coyote Station on North Dakota lignite include..."

EERC Response:

EPA believes that there may be inherent limitations with the pilot study. The following will address the EPA's comments. The catalyst vendors, Haldor Topsoe, Cormetech, and Hitachi, were all involved in the design of the pilot-scale slip stream test system and testing conditions.

1) The pulsing system was designed with the assistance of the catalyst vendors. They provided suggestions on the sootblowing pressures and felt it would be sufficient to remove the deposits.

2) The 6 mm pitch was recommended by the vendors.

3) If the first layer plugs, the gases cannot get to the subsequent layers; significant deposition was noted downstream of the SCR catalyst section installed.

4) Deposition and plugging are significant problems that impact the reliability of the MRY facility.

Haldor Topsoe was the only catalyst vendor willing to provide catalyst for the lignite testing.

The EERC pilot-scale testing was a collaborative effort involving coal-fired utilities, EPRI, DOE, and catalyst vendors. All decisions on system design, plants

[24] Ibid Reference 14, Section IV.B., page B.20

[25] Ibid Reference 14, Section IV.B., page B.20.

for testing, and testing conditions were reviewed and agreed upon by vendors. The EERC comparisons of catalyst blinding for lignite and subbituminous coal testing as well as the sodium deactivation work conducted by other research organizations and catalyst vendors should be used in evaluating technical feasibility of SCR for MRYS.

EPA Analysis of Burns & McDonnell [High-Dust SCR Technical Feasibility] Conclusions

EPA R8 report page 12, middle and bottom paragraphs, and page 13, top and middle paragraphs:

"EPA notes that there is considerable experience in the industry to show that the use of SCR on North Dakota lignite is feasible..."
(and)
"Since significant accumulations of ash on the catalyst was also observed during pilot testing at those facilities burning PRB coal and there are numerous examples of PRB coal-fired power plants successfully operating SCR systems, the qualitative results of the pilot testing described by B&M and EERC would not appear to preclude successful operation of SCR on a power plant burning North Dakota lignite. The EERC study does not appear to quantify the effect that the ash accumulation had on microscopic catalyst deactivation rates or overall catalyst performance. Absent such information that reflects the use of currently available full-scale ash loading mitigation designs, pilot testing results may not be evidence that successful implementation of SCR on North Dakota fired units "is going to be impossible," as stated in the Appendix B EERC report."
(and)
"As noted above, due to the inherent pilot-scale limitations involved in this testing, direct application of the effects and/or magnitude of ash deposition during the EERC pilot study should not be used as the primary basis for determining technical feasibility of SCR at MRYS. In the full-scale installations, these concerns are addressed during the SCR design stage. While combustion of North Dakota lignite in cyclone boilers might present some additional engineering challenges for SCR designers, there are multiple credible solutions that Minnkota should have evaluated before concluding that SCR is not technically feasible."
(and)
"Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility".
(and)
"Many of the technical feasibility arguments presented in the BACT analysis are centered on decreased catalyst life and performance, increased maintenance and outage time, and plant differences unique to MRYS that preclude SCR feasibility at MRYS. Consistent with the NSR Manual, these concerns are incorrectly incorporated into the Top-Down BACT analysis at step 2 and really should be

accounted for as additional costs per ton of pollutant removed at step 4 of the analysis."
(and)
"So, while EPA does not consider vendor guarantees by themselves to be determinate in making technical feasibility decisions, they are a contributing factor in making these decisions. EPA is aware of three catalyst vendors (Haldor Topsoe, Cormetech, and Argillion) who would be willing to provide performance guarantees for lignite-fired boilers applications."
(and)
"Based on the criteria discussed above, Minnkota and B&D should have further explored both the full-scale engineering solutions used to address the problems cited in their analysis in conjunction with information from SCR/catalyst vendors to offer performance guarantees to design and install an SCR unit at MRYS. The BACT analysis for MRYS that was submitted relies heavily on the technical problems experienced during the EERC pilot testing at Coyote Station in conjunction with the fact that SCR has not been installed on a cyclone boiler that burns North Dakota lignite. We do not believe that this analysis adequately addresses the criteria cited above. As such, it appears that the case-specific NOx BACT analysis submitted for Minnkota MRYS is deficient in terms of improperly eliminating SCR consideration at step 2 of the BACT analysis for technical feasibility."

EERC Response:
EPA did not examine the EERC report in detail. The deposition and plugging was much more pronounced for the Coyote Station testing as compared to the Columbia and Baldwin Station. The pressure drop increased much more rapidly and the soot blowing was not as effective. The conclusions made by EPA that the accumulations are similar are incorrect.

The most important unresolvable technical difficulty is the impact of sodium on the formation of bonded sulfate phases that plug and mask the catalyst and on the ability of sodium to deactivate the catalyst.

B&McD Response:
EPA's premise is that SCR experience with other coals and firing methods and references from various rulemaking confirms the technical feasibility of this NOx control technology if it were to be applied to MRYS cyclone boilers; the slipstream SCR catalyst testing was inherently limited in predicting full-scale

application success; and that SCR technology was improperly excluded from the NO_X BACT control and cost-effectiveness analysis.

The EPA's review offered no specific documented and published substantive demonstrated experience with supporting technical data as proof that currently available catalysts can survive and provide effective NO_X reduction when exposed to the flue gas and flyash constituents exhausted from combustion and operation of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application at Milton R. Young Station. Burns & McDonnell disagrees that the lack of SCR catalyst deactivation data from the Coyote slipstream SCR catalysts field test completely refutes the premise of Dr. Benson's referenced technical paper and the Minnkota NO_X BACT Analysis Study conclusions that SCRs are technically infeasible for lignite-fired cyclone boilers.

The EPA's NSR Manual does not specifically define the operating parameter or performance measure that a particular NO_X control technique or technology would have to achieve to satisfy "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"[26] in order for said alternative to be excluded from further consideration.

When a BACT analysis is performed on a new unit, there has typically been significant conceptual and detailed engineering and design work already performed that forms the basis of the subsequent capital cost estimate and associated expected O&M costs for the particular emission control technologies to be employed or that were considered as part of the overall project effort. Performing a BACT analysis on an existing unit should not require similar

[26] Ibid Reference 14, Section IV.B., page B.20.

substantial resources to develop conceptual designs and create technical details that determine the estimated site-specific retrofit costs for overcoming significant technical challenges that would otherwise preclude the ability of the technique or technology from successfully controlling the emissions in question. The EPA's NSR Manual 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."[27] There are no cited examples where successful solutions to such challenges as posed by such highly complex interactions between flyash, flue gas, and gas temperatures produced by lignite firing for SCR coal-fired boiler applications. Burns & McDonnell disagrees with the EPA's inference that the technical arguments described in the referenced MRYS NO_X BACT analyses and EERC report were inadequate.

The issue of SCR vendors willingness to offer performance guarantees for units firing North Dakota lignite is addressed at the end of this response section.

B. <u>Low Dust SCR</u>

EPA R8 report page 13, bottom paragraph:

"Burns & McDonnell has eliminated Low-Dust SCR as technically infeasible due to issues described below. EPA's response on each issue is also described below".

<u>EPA Analysis of [Low –Dust SCR] Catalyst Fouling and Deactivation Issue:</u>

EPA R8 report page 14, middle paragraph:

"A few SCR systems installed on coal-fired boilers have been designed with the SCR catalyst installed after the ESP or baghouse. This approach eliminates virtually all of the poisoning, plugging and erosion problems that have been associated with SCR catalyst... While there would be inherent costs associated with gas-reheat, other possible physical modifications to the plant to accommodate low-dust SCR, and engineering designs to minimize and manage catalyst fouling and deactivation, these factors consistent with the NSR Manual, should be accounted for when considering the economic impacts of the technology".

[27] See Reference number 14, Section IV.B., page B.18.

EERC Response:
Sodium-rich aerosols are a problem that can get through the ESP. These aerosols are known to be present in high sodium coal combustion flue gases. These species are known to produce pyrosulfates. These will cause blinding and deactivation of the low-dust catalyst.

B&McD Response:
The need for a major source of heat to reheat the flue gas stream downstream of the ESP in a low-dust SCR application will require either an expensive natural gas supply pipeline or an unacceptable derate of the net unit electrical output associated with extensive modifications of the components in steam cycle power generation and balance-of-plant systems and boiler gas systems to supply high pressure, high temperature steam as suggested by the EPA and their consultant. The magnitude of such retrofit modifications and risks of failure in applying low-dust SCR technology at MRYS are much greater than is considered reasonable.

EPA Analysis of [Low-Dust SCR] Site Space Constraint Issue:
EPA R8 report page 15, middle paragraph:

"It does sound like major and costly equipment location may be necessary to provide the space necessary for low-dust SCR... These costs should be accounted for when estimating the cost and economic impacts of low-dust SCR, but should not be used as a basis for eliminating the technology as technically infeasible.

B&McD Response:
Significant engineering resources would need to be devoted to investigate and estimate the capital costs of major boiler and air pollution equipment relocations, facility additions, and boilerhouse building modifications required to implement low-dust SCR technology at MRYS. Burns & McDonnell believes the expected levelized total annual costs required to apply low-dust SCR technology to North Dakota lignite-fired cyclone boilers are unacceptably high.

EPA Analysis of Burns & McDonnell [Low-Dust SCR Technical Feasibility] Conclusions:
EPA R8 report page 15, bottom paragraph, and page 16, top paragraph:

"...EPA Region 8 believes that the inherent challenges with installing and operating low-dust SCR at MRYS are resolvable on a technical basis. The fact that a few low-dust SCR applications are currently used in practice indicates that the small-particle catalyst fouling and deactivation problem described would not preclude the use of low-dust SCR. In fact, EPA Region 8 believes that the dust-loading problems that can be effectively addressed through engineering solutions in a high-dust environment are less problematic than in a low-dust environment."

B&McD Response:
As previously stated by the EERC, the EPA fails to recognize that lignite-fired cyclones partition the ash, increasing the proportion of sodium in the smaller particles, resulting in increased propensity for the formation of the complex sulfate phases. The fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components that cause bonding, blinding, and deactivation of individual catalyst reaction sites, even in a low-dust SCR application.

III. Additional Information Useful to Evaluating Technical Feasibility of SCR at MRYS

A. <u>EPA Headquarters Believes SCR is the Correct Technology for MRYS in Developing the Clean Air Interstate Rule (CAIR)</u>

EPA R8 report page 16, middle and bottom paragraphs, page 17 entire, page 18 top and middle paragraphs:

EERC Response:
EPA's cited experience from subbituminous coals and SCR does not have direct application to the North Dakota lignite-fired cyclone boilers at MRYS-because of the high sodium content of the lignite. The SCR experience with German brown coals does not have direct application to ND lignite because of the lower sodium levels of the German coals.

EERC spoke to Flemming Hansen of Haldor Topsoe on February 2, 2007 about the issues associated with high sodium North Dakota lignite. Haldor Topsoe has experience with sodium and potassium from biomass fired systems and their experience has not been good. After describing the issues related to sodium, he was very concerned regarding guaranteeing catalyst performance. It was evident

he was not aware of the details of the levels of sodium and the form of sodium in the coal when he was asked before. Flemming indicated that the sodium in the lignite was a major concern and that it causes deactivation, especially the acid-soluble form. He indicated that they had some experience and found significant deactivation of SCR coupon samples after 6000 to 7000 hours of operation with a coal having elevated levels of sodium.

B. SCR Technology is Presumptive BART for Cyclone Boilers in EPA's BART Guidelines

"EPA made a specific and informed decision in its BART Guidelines regarding cyclone-fired utility boilers [involving application of SCR technology to cyclone boilers for NOx emissions control]....*However, for cyclone units burning any type of coal [bituminous, subbituminous, or lignite], presumptive BART is SCR. SCR is selected because the technology is feasible and cost-effective, especially considering the high baseline flue gas NOx concentrations (e.g. 0.8 lb/MMBtu). The spreadsheet that was used to tabulate BART source control costs for the BART rule showed low SCR costs for MRYS (about $550/ton)."*

B&McD Response:
EPA ignored the numerous comments received for the draft BART guidelines (similar to that cited in the EPA's CAIR discussion for the preceding issue) about the infeasibility of SCR applied to North Dakota lignite[28]. The unit capital cost capacity factor for SCR retrofits applied to cyclone boilers by the EPA in the cost-effectiveness analysis used for establishing presumptive BART[29] was $100/kW.

Burns & McDonnell believes the EPA's cost-effectiveness analysis is inaccurate and significantly underestimates the expected capital plus operating and maintenance costs required to apply high-dust or low-dust SCR technology to North Dakota lignite-fired cyclone boilers.

[28] Available from website www.regulations.gov for the BART Edocket EPA HQ-OAR-2002-0076-0508, pages 185-187.
[29] See Reference 13, Excel Spreadsheet OAR-2002-0076-0446, page 209.

C. February 27, 2006 Final Revisions to 40 CFR Part 60, Subpart Da, New Source Performance Standards for Electric Utility Steam Generating Units Set Final NOx Limit Based on Technical Feasibility of SCR for Lignite-Fired Units

"In its response to public comments on the February 28, 2005 draft NSPS, Subpart Da proposal, EPA rejected comments received on NOx control requirements for lignite-fired units. Specifically, EPA took the same position as it did in the CAIR and BART rules, rejecting commenters' concerns that SCR would not be feasible for the lignite units. No legal challenges were made to the final rule regarding EPA's response to the lignite concerns. While the revised NSPS, Subpart Da would apply only to new units, it is further evidence that EPA technical experts believe that SCR can successfully be applied to lignite facilities. The B&M BACT analysis essentially makes the same technical arguments that EPA rejected in this rule package."

B&McD Response:
Burns & McDonnell rejects the EPA's argument that the lack of a lawsuit protesting the establishment of revised NSPS limits for new electric utility steam generating units (EUSGUs) that require SCRs for NOx control means that this is appropriate technology for a BACT retrofit on existing lignite-fired cyclone boilers. Cyclone boilers are no longer commercially available, so there are no new cyclone boilers being permitted and built. Utility owners of existing North Dakota lignite-fired boilers would not be expected to comment on the draft revisions to the NSPS proposed by the EPA because they apply only to new units with different methods of firing coal than cyclone boilers. It is doubtful that the EPA considered firing lignite in new cyclone boilers would be a possibility when they proposed the draft NSPS standards.

Any recently built or permitted lignite-fired boilers have been predominantly circulating fluidized bed (CFB) type and have not incorporated SCR technology for NOx emissions control. There have been recent permit applications filed for constructing pulverized coal boilers burning Texas lignite that propose to include high-dust SCR technology. However, there are distinct differences between North Dakota and Texas lignites that preclude assuming that this supports the technical feasibility of applying high-dust SCR technology to existing cyclone boilers burning North Dakota lignite.

EERC Response:
North Dakota lignites are substantially different than Texas lignites in composition and fouling tendencies. The following comparison shows the proximate analyses, sulfur contents and heating values for various lignites, plus ash compositional analyses of Texas lignites.

Comparison of North Dakota and Texas Lignites

Data from several sources were compiled for use for comparisons. The sources include the Low-Rank Coal Study[30] (1980) and Kaiser and others[31] (1980). These reports compiled the results from numerous studies involving characterization of lignite resources. Table 1 compares the proximate analysis for Fort Union and Gulf Coast lignites. The analysis shows that lignites from the Gulf Coast typically have higher ash contents than the lignites of the Fort Union Region. Texas lignite is part of the Gulf Coast Region and North Dakota lignite is part of the Fort Union Region.

Table 1. Comparison of Fort Union and Gulf Coast Lignites (Low-Rank Coal Study[32])

	Proximate Analysis, wt%			
Regional Lignites	Moisture	Volatile Matter	Fixed Carbon	Ash
Fort Union Lignites Range	32.5–43.6	23.4–28.3	24.1–34.8	3.2–12.1
Average	37.2	26.3	30.3	6.2
Gulf Coast Region Lignites Range	17.9–45.8	25.7–36.2	19.3–28.7	10.6–22.0
Average	31.3	31.2	25.2	13.7

Table 2 provides detailed information on specific lignite coal seams that are mined in Texas. These analyses show the range of ash content and other components. The ash content varies from mean values of 15% to 42%.

[30] Ibid Reference number 9.
[31] See Reference number 17.
[32] Ibid Reference number 9.

Table 2. Proximate, sulfur, and heating Value of Texas lignites (Kaiser[33] and others, 1980)

		Wilcox east-central	Wilcox northeast	Wilcox Sabine Uplift	Wilcox mean	Jackson east	Jackson south	Jackson mean	Yegua east	Weighted mean north of Colorado River*
					As-received basis					
Moisture	X	32	33	33	33	41	23	37	37	35
	S	4	4	4	4	6	6	10	4	
	R	26	28	29	29	29	27	45	15	
	C	0.12	0.12	0.11	0.12	0.14	0.25	0.27	0.12	
	N	83	79	113	275	169	55	224	29	
Volatile matter	X	29	27	27	28	23	22	23	26	27
	S	3	4	4	4	4	6	4	4	
	R	15	25	24	27	23	37	43	17	
	C	0.10	0.13	0.14	0.13	0.16	0.26	0.19	0.14	
	N	83	79	113	275	169	55	224	29	
Fixed carbon	X	24	25	25	24	15	13	14	19	22
	S	4	4	4	4	4	6	4	4	
	R	23	25	26	31	21	20	24	17	
	C	0.17	0.14	0.18	0.17	0.25	0.42	0.29	0.18	
	N	83	79	113	275	169	55	224	29	
Ash	X	15	15	15	15	21	42	26	18	17
	S	7	8	10	9	10	12	14	8	
	R	31	45	53	53	43	52	60	31	
	C	0.46	0.53	0.67	0.57	0.48	0.29	0.52	0.45	
	N	83	79	113	275	169	55	224	29	
Sulfur	X	1.0	0.8	0.9	0.9	1.3	1.9	1.4	1.0	1.0
	S	0.5	0.4	0.5	0.5	0.7	1.3	0.9	0.4	
	R	2.9	1.7	2.8	3.2	6.4	8.2	8.4	1.6	
	C	0.49	0.46	0.56	0.51	0.50	0.65	0.62	0.43	
	N	76	78	113	267	174	55	229	29	
Btu/lb	X	6,593	6,499	6,441	6,504	4,729	3,972	4,547	5,761	6,095
	S	822	873	1,087	952	942	1,647	1,192	796	
	R	4,673	5,407	6,231	7,293	4,581	8,721	8,721	3,701	
	C	0.12	0.13	0.17	0.15	0.20	0.41	0.26	0.14	
	N	83	79	113	275	174	55	229	29	
					Dry basis					
Volatile matter	X	43	41	41	41	40	28	37	41	41
	S	4	6	6	6	8	8	9	7	
	R	24	32	36	39	45	51	55	27	
	C	0.10	0.13	0.16	0.14	0.19	0.28	0.25	0.16	
	N	65	78	116	259	153	48	201	29	
Fixed carbon	X	35	37	37	37	25	17	24	31	34
	S	7	6	8	7	7	8	8	7	
	R	31	36	42	43	32	27	37	30	
	C	0.19	0.15	0.21	0.19	0.28	0.46	0.34	0.21	
	N	65	78	116	259	153	48	201	29	
Ash	X	22	22	22	22	34	54	39	28	25
	S	9	10	13	11	14	13	16	11	
	R	42	58	71	71	60	59	67	42	
	C	0.43	0.46	0.61	0.52	0.40	0.24	0.41	0.40	
	N	65	78	116	259	153	48	201	29	
Sulfur	X	1.4	1.2	1.4	1.3	2.3	2.2	2.2	1.6	1.5
	S	0.7	0.5	0.8	0.7	0.9	1.0	0.9	0.7	
	R	4.1	2.5	4.3	4.3	5.2	3.6	5.2	2.7	
	C	0.49	0.44	0.55	0.52	0.41	0.44	0.42	0.44	
	N	65	78	113	256	261	48	309	29	
Btu/lb	X	9,715	9,760	9,764	9,750	8,222	5,077	7,733	9,166	9,403
	S	1,468	1,414	1,801	1,605	1,622	2,019	2,036	1,521	
	R	6,036	7,561	10,152	10,152	8,918	7,029	10,926	6,042	
	C	0.15	0.14	0.18	0.16	0.20	0.40	0.26	0.17	
	N	65	78	116	259	261	48	309	29	

*Based on percentage of resources.
X = arithmetic mean.
S = standard deviation.
R = range.
X, S, R in weight percent.
C = S/X = coefficient of variation.
N = number of analyses.
Note: Analyses do not represent a random sample.

[33] Ibid Reference number 17.

Table 3 summarizes ash composition analysis expressed as equivalent oxide. The compositional analyses show that the ash has relatively low sodium and lower calcium content than North Dakota lignite. The problems of SCR catalyst blinding due to the formation of sodium calcium sulfates created from the firing of Texas lignites will be much less severe than for North Dakota lignites.

Table 3. Ash Composition Analysis of Texas lignites (Kaiser and others[34] 1980)

	Wilcox east-central	Wilcox northeast	Wilcox Sabine Uplift	Jackson east	Jackson south[a]	Yegua east
SiO_2	48.53	44.53	40.51	57.58	62.88	53.64
Al_2O_3	17.12	11.39	16.28	20.26	17.49	14.96
TiO_2	1.09	1.14	0.89	0.81	0.82	0.79
CaO	13.20	13.74	12.51	7.49	4.82	9.89
MgO	2.30	2.55	3.03	1.13	0.72	1.81
Fe_2O_3	6.23	7.39	11.46	3.20	2.83	6.61
Na_2O	0.38	0.56	0.80	0.86	3.10	1.23
K_2O	0.84	0.63	0.70	0.84	1.96	1.24
SO_3	9.35	10.87	11.81	7.10	4.62	8.87
P_2O_5	0.11	0.06	0.10	0.05	0.06	0.06
Number of analyses (oxides)	26	21	35	116	design	16

D. SCR and Catalyst Vendor Information

"As noted above, the following catalyst vendors were comfortable providing catalysts/SCR for lignite-fired boilers..."
(and)
"EPA Region 8 also contacted the Institute of Clean Air Companies website to obtain the following list of 21 companies offering "SCR Systems, Equipment, Supplies, and Services..."
(and)
"EPA Region 8 has visited most of the vendors' websites and found many vendors with experience that would be germane to the MRYS situation. (Others are not vendors for large power plants.) The experience of these companies should be used to supplement the endorsement by three of the SCR catalyst vendors used by EPA in the background research for the CAIR, BART, and NSPS rules. We believe it would be prudent for Minnkota to obtain information and proposals from more than one vendor and involve the NDDH and EPA in their findings."

[34] Ibid Reference number 17.

EERC Response:
EERC has already included some comments from discussions with Haldor Topsoe regarding their concerns about the sodium content in North Dakota lignite and its tendencies for catalyst deactivation. Some of the EPA-cited SCR catalyst vendors' websites discuss the problems of sodium and deactivation. However, EPA has not provided a review of that information.

B&McD Response:
EPA's listing of 21 suppliers of *"SCR Systems, Equipment, Supplies, and Services..."* has not been screened to eliminate companies that are not active in the U.S. coal-fired SCR market. Of the 21 companies listed, only eight are active in the domestic coal-fired SCR market. Of those eight companies, only four are considered to be "system suppliers"; three of the eight are catalyst suppliers and one provides reagent systems; one supplies catalyst as well as complete SCR systems. Three of the four coal-fired SCR catalyst suppliers (Haldor Topsoe, Cormetech, and Hitachi) were participants in EERC's slip-stream catalyst field demonstration tests previously described.

EPA's evidence of SCR catalyst vendor's willingness to guarantee performance on a lignite-fired boiler is very general in nature and does not include typical qualifying statements related to the client's need to adhere to specified SCR design conditions, which are yet to be established. It also does not reflect any actual statements of guaranteed life and performance, nor contractual language stating what the vendor would do if the catalyst activity degraded much faster than what the guarantee says.

There are several points that challenge the value of SCR catalyst vendors being willing to offer guarantees. First, from Burns & McDonnell's experience, what a vendor or supplier says pre-bid does not always match what they actually will offer in a firm contract. Second, a commercial guarantee does not mean the system provided by the vendor will work long term; all it means is that based on the language in the contract and the amount of money the supplier has allocated to

cover their risk or exposure, the vendor will guarantee the system performance. Third, commercial contract guarantees always have a finite life, which means the owner of the system only benefits from the vendor's guarantee for 3 years typically. If the catalyst is ruined annually for example, the vendor will replace it two times and include that cost risk in their proposal. That leaves the owner with a huge additional operating cost over the remaining life of the system, which could be 30 or more additional years. The type of commercial guarantee needed for MRYS SCR systems would carry the term "evergreen" with it. This is a contract requirement where the vendor replaces the catalyst at their cost however often it is needed to meet performance and life guarantees. Each time the catalyst needs to be replaced, the warranty period starts over. Typically this is avoided by any and all bidders due to the open-ended cost potential borne by the selected vendor for this type of guarantee and warranty language that such a contract carries with it.

EPA's cited SCR catalyst vendor statements lack substantive language that deals with mitigating the client's risks of failure to meet catalyst activity versus life guarantees, and the concerns recently expressed by Haldor Topsoe when EERC described sodium components in the flue gas. In Burns & McDonnell's opinion, SCR system vendors have not provided adequate documented and published demonstrated catalyst experience with supporting technical information to support these claims. The vendors offered no specific comparative peer-reviewed data as proof that currently-available catalysts can survive and provide effective NO_X reduction when exposed to the flue gas and flyash constituents exhausted from combustion and operation of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application at Milton R. Young Station.

REFERENCES

1 "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc." Final Report, October 2006 submitted by Minnkota to North Dakota Department of Health.

2 Consent Decree filed 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, filed April 24, 2006.

3 ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007. and

4 *EPA Region 8 Preliminary Analysis of Burns & McDonnell BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007* faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

5 *Ash Impacts on SCR Catalyst Performance,* prepared by Steven A. Benson, Ph.D. Energy & Environmental Research Center, University of North Dakota, October 2005.

6 Personal Communication Flemming Hansen (Haldor Topsoe) with Steve Benson (EERC), February 2, 2007.

7 *Topsoe's Corrugated-type DeNOx Catalysts – Characteristics and Operating Experience, T. Slabiak and S. Enevoldsen*, accessed in Haldor Topsoe's website February 13, 2007 at http://www.topsoe.com/site.nsf/vALLWEBDOCID/KVOO-5PGF7F/$file/Cat%20-%20Topsoe's%20corrugated-type%20DeNOx%20Catalysts.pdf.

8 *Deactivation of SCR Catalyst, Prof.-Dr. Heinz Gutberlet, PreussenElektra Engineering, Andreas Schluter, KWH, and Anthony Licata, Technical Advisor, KWH*, DOE-NETL SCR 2000 Conference.

9 *Low-Rank Coal Study*; U.S. Department of Energy Report; DE-AC18-79FC1006, 1980.

10 *"SCR Catalyst Improvements (Full of Noxious Hot Air?)*, by S. Enevoldsen, Haldor Topsoe, presented at the 1999 DOE NETL meeting on SCR-SNCR available from the internet website http://www.netl.doe.gov/publications/proceedings/99/99scr-sncr/enevolds.pdf

11 Conn, R.E., Fuel Processing Technology **1995**, *44*, 95.

12 Khodayari, R.; Odenbrand, C.U. Regeneration of Commercial SCR Catalysts by Washing and Sulphation: Effect of Sulphate Groups on Activity, Appl. Catal. B: Environ. **2001**, *33*, 277–291.

13 *Technical Support Document Methodology For Developing BART NOx Presumptive Limits, Environmental Protection Agency, Clean Air Markets Division, June 15, 2005, OAR-2002-0076-0445*, with Attachments, including Excel Spreadsheet OAR-2002-0076-0446 (1199 pages).

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

15 *Federal Register /Vol. 70, No. 128/ Wednesday, July 6, 2005 / Rules and Regulations, Part III Environmental Protection Agency 40 CFR Part 51, Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule.*

16 Beck, J.; Brandenstein, J.; Unterberger, S.; Hein, K. *App. Catal. B: Environ.* **2004**, *49*, 15–25.

17 Kaiser, W.R.; Ayers, W.B. Jr.; LaBrie, L.W.; Tewalt, S.J.; Pew, E.; Johnson, L.C. Lignite Resources in Texas; 1980.

Minnkota Power
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Your Touchstone Energy Partner

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APR 2007
Received
Air Quality

April 23, 2007

Director, Air Enforcement Division
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Chief, Environmental Enforcement Section
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1595 Wynkoop Street
Denver, CO 80202-1129

Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Re: Consent Decree – July 27, 2006
Minnkota Power Cooperative, Inc., et al
U.S. District Court for the District of ND
Civil Action No. 1:06-CV-034

Subject: Response to NDDH Comments-February 1, 2007
(incl. Resp. to U.S. EPA Region 8 Comments -January 26, 2007)

Gentlemen:

On October 6, 2006, Minnkota submitted in fulfillment of Paragraph 65 of the Consent Decree, the analyses entitled "NOx BEST AVALABLE CONTROL TECHNOLOGY ANALYSIS STUDY for Milton R. Young Station Unit 1" and "NOx BEST AVALABLE CONTROL TECHNOLOGY ANALYSIS STUDY for Milton R. Young Station Unit 2", both dated October 2006. Subsequently, the North Dakota Department of Health (NDDH) on February 1, 2007, forwarded comments on our submittal that they had

received from EPA Region 8, and requested we respond to the EPA comments and their own comments.

Enclosed, please find Minnkota's responses to the NDDH request. Due to the volume of material requested by the U.S. EPA Region 8 in item 1 of their original letter to the NDDH, copies of this material are only being provided U.S. EPA Region 8 and the NDDH, unless request otherwise. This material is being shipped separately from this response, to the U. S. EPA Region 8 and the NDDH.

Should you have any questions concerning this submittal, please contact me at (701) 795-4221.

Sincerely yours,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

c: David Sogard w/encl
Luther Kvernen w/o encl
Craig Bleth w/encl
Kevin Thomas w/o encl
Stu Libby w/o encl
Tom Anseth w/o encl
Young Station File w/encl

MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO NDDH and EPA COMMENTS REGARDING SCR TECHNICAL FEASIBILITY and NON-SCR CONCERNS MILTON R. YOUNG STATION UNIT 1 and UNIT 2 NOx BACT ANALYSIS STUDY

April 18, 2007

North Dakota Department of Health's, Environmental Health Section, Division of Air Quality (NDDH) has provided Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") with their request for information regarding their review[1] of the Best Available Control Technology (BACT) Analysis Study reports[2] for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station ("MRYS") that were originally submitted to the agencies in October 2006. Additional comments from Region 8 of the United States Environmental Protection Agency (U.S. EPA or EPA) were attached.

Burns & McDonnell was retained by MPC as an independent consultant to perform the referenced NO_X BACT Analysis Study of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS) in accordance with the requirements of a Consent Decree (CD)[3].

Minnkota, along with Burns & McDonnell (B&McD), and Energy & Environmental Research Center (EERC) of the University of North Dakota, have reviewed the referenced NDDH letter. The letter dated January 26, 2007 from U.S. EPA Region 8 to the NDDH regarding the EPA's additional comments regarding selective catalytic reduction (SCR) technology feasibility and non-SCR concerns pertaining to the NO_X BACT Analysis was also reviewed. The following are combined responses by EERC and B&McD to the comments by NDDH and EPA Region 8 involving the referenced study reports for the two units at MRYS.

The following responses follow the outline of the NDDH February 1, 2007 letter.

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[1] See Reference number 1, February 1, 2007.
[2] See Reference number 2, October 2006.
[3] See Reference number 3, April 24, 2006.

Center Mine Lignite Coal Ash Content and Variability:

Reference: NDDH letter to Minnkota February 1, 2007 request item number 1:

"Please provide a statistical analysis of historical as-fired coal data. This should include the range, average and standard deviation for the amount of ash, sulfur, calcium oxide, magnesium oxide, sodium oxide, potassium oxide and heat content. Also, provide a separate analysis for core samples of lignite that will be mined in the future. (Note that this is similar to EPA's comment No. 4)."

and

Reference: EPA Region 8 letter to NDDH January 26, 2007 request item number 4.

"Please provide data currently available on the Center Mine coal constituents (presented in Minnkota's October 2006 NOx BACT Analysis), including all available data sampling for future and presently-mined areas of the mine. Please provide the data in terms of averages, in addition to value ranges."

EERC Response:

Historical Center Lignite Coal Database

The historical database was obtained from samples collected for the purpose of testing the impacts of lignite characteristics on plant performance. The database consists of 1317 as-fired samples. The average, standard deviation, maximum, minimum and selected percentiles for ash, sulfur, heating value, and selected ash constituents are included in Table 1.

Table 1. Statistical analysis of Center lignite coal ash, sulfur, heating value, and selected ash constituents.

	Ash[1]	S[1]	Heating value[2]	CaO[3]	MgO[3]	K_2O[3]	Na_2O[3]	B/A[4]
Average	9.64	1.0	6578	13.2	4.0	1.3	4.4	0.7
Standard Deviation	2.0	0.27	179	3.17	0.8	0.4	2.2	0.34
Max	25.5	2.6	7101	24.0	7.1	2.3	13.0	2.5
Min	5.0	0.5	5852	6.8	2.3	0.2	0.6	0.3
90th Perc.	12.51	1.29	6820	19.9	5.7	1.9	8.7	1.26
10th Perc.	7.06	0.72	6359	9.7	3.0	0.6	2.0	0.44
45th Perc.	9.33	0.90	6552	12.2	3.8	1.4	4.1	0.59
55th Perc.	9.75	0.94	6592	12.7	4.0	1.4	4.6	0.64
50th Perc.	9.53	0.93	6572	12.5	3.89	1.4	4.4	0.61

1. Weight percent on an as-fired basis.
2. Heating express as BTU/lb on an as-fired basis.
3. Weight percent of the ash, elemental weight percent expressed as equivalent oxide.
4. B/A is the base to acid weight ratio of the ash constituents ($B/A=[Na_2O+MgO+CaO+K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$).

The use of average coal properties for design and performance of combustion and environmental control systems typically under estimates adverse problems such as fireside ash deposition, opacity, and sulfur emissions. Designs of power systems must consider the challenging coal characteristics in order to develop designs and operating parameters with sufficient flexibility that allow for the combustion of coals that at least represent the 90th and 10th percentile of selected constituents.

In order to better understand the characteristics of the coal, frequency distributions have been plotted for ash and other key components. In addition, the coal characteristics need to be examined in context with other components of the coal. Focusing on single constituents alone without considering the other components in the coal has resulted in costly design errors in the past.

The frequency distributions of components of the coal provide better understanding of the potential challenges. Figure 1 shows the distribution of sodium oxide in Center lignite ash. The results of the analysis show that the lignite ash has a 4.4% average sodium content; however, there is a multimodal distribution of sodium levels in the coal ash. The average properties as well as the minimum and maximum values do not adequately represent the characteristics of the fuel. As indicated in Figure 1, the MRYS boilers are firing some very high-sodium-containing coals that can cause significant problems when sodium reacts with silicate, aluminosilicate, and sulfur species in the furnace and lower temperature regions of the power plant.

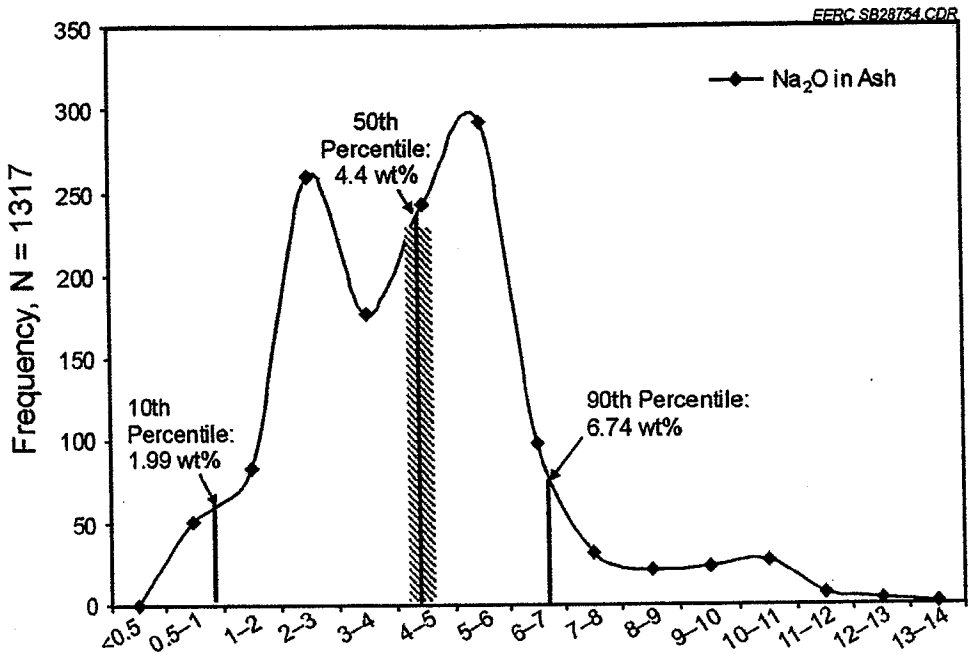


Figure 1. Distribution of sodium (expressed as equivalent oxide) in ash derived from the coals in the Center lignite as-fired database.

Figure 2 shows the frequency distribution of ash constituents. The higher ash content values were not included in the plot. However, a sample with 25.5 % ash is included in the database. Figure 3 shows the distribution of sulfur species. Figures 4 through 6 illustrate the distribution of magnesium, calcium, potassium, respectively. The distribution should be used along with the average, standard deviation, minimum and maximum information to assess ash behavior. The base-to-acid ratio distribution is shown in Figure 7, and heating value distribution is shown in Figure 8.

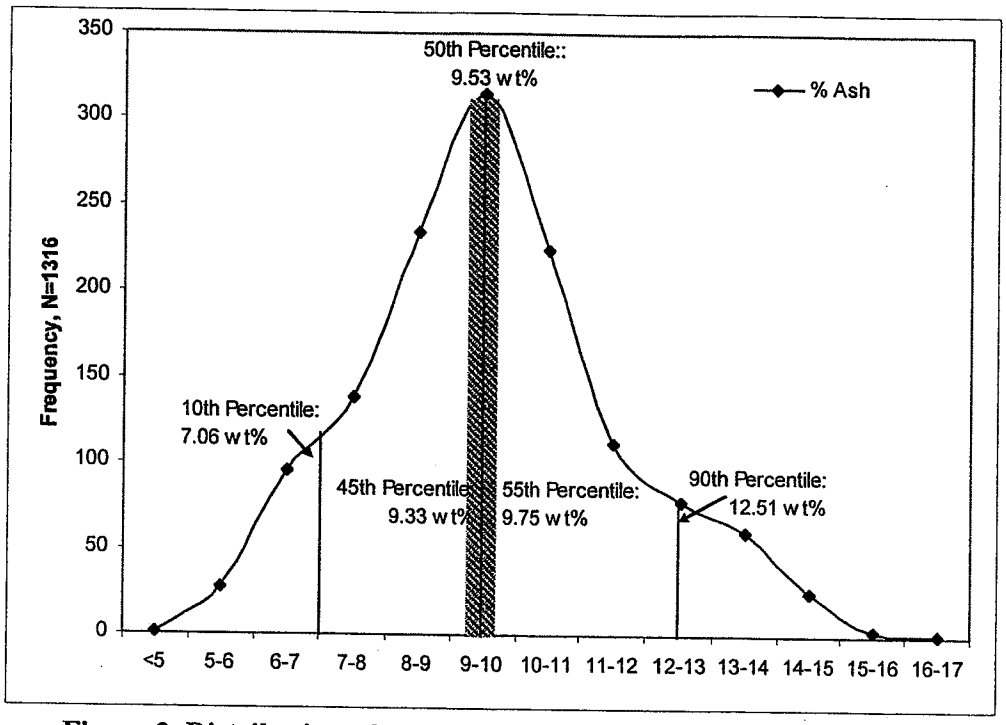


Figure 2. Distribution of ash (weight % on an as-fired basis) in coals from Center lignite as-fired database.

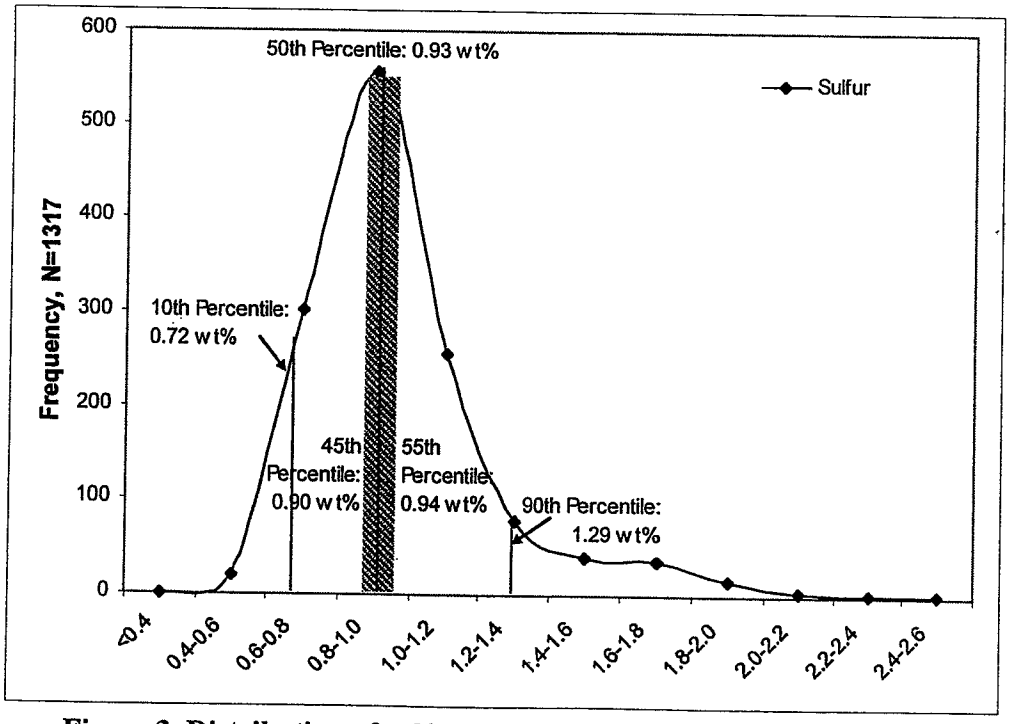


Figure 3. Distribution of sulfur (weight percent on an as-fired basis) in Center lignite as-fired database.

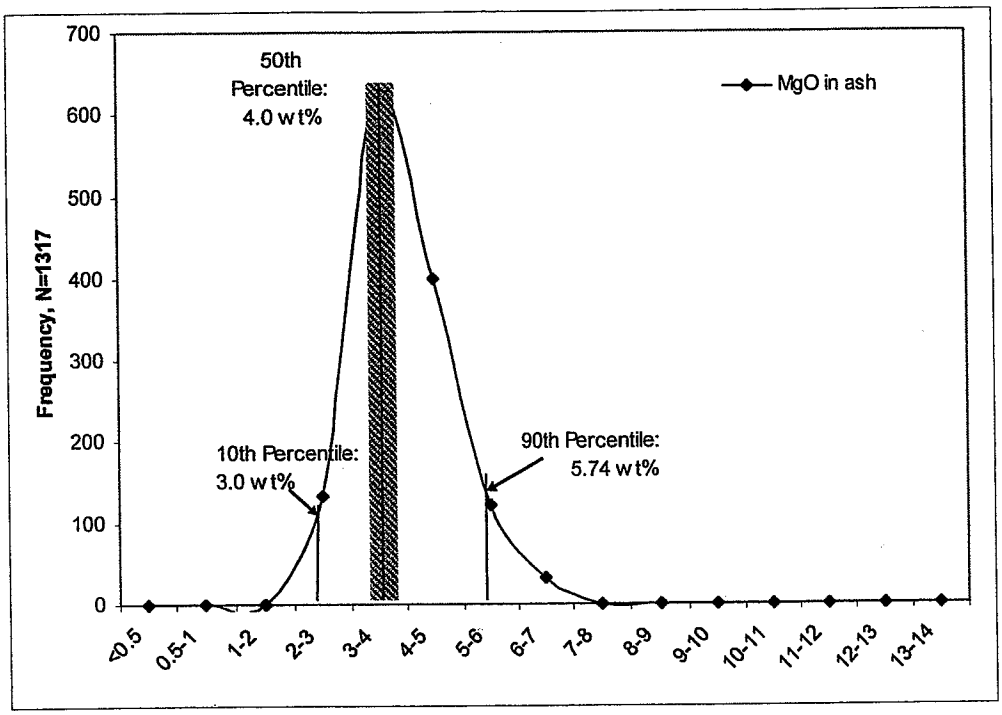


Figure 4. Distribution of magnesium (expressed as equivalent oxide) in ash derived from the coals in the Center lignite as-fired database.

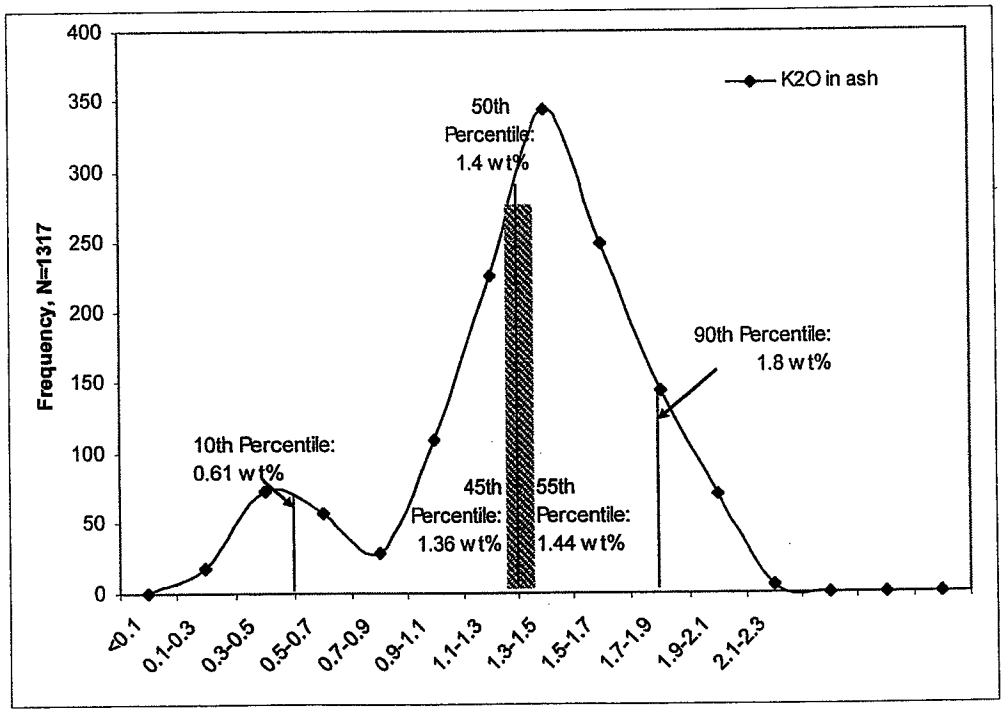


Figure 5. Distribution of potassium (expressed as equivalent oxide) in ash derived from the coals in the Center lignite as-fired database.

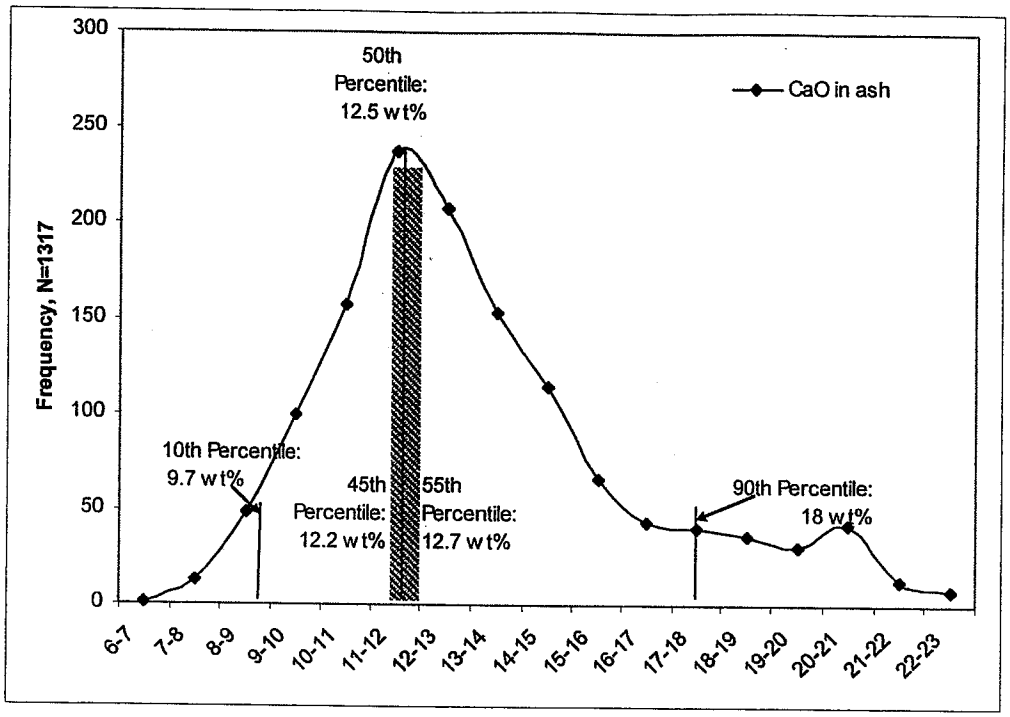


Figure 6. Distribution of calcium (expressed as equivalent oxide) in ash derived from the coals in the Center lignite as-fired database.

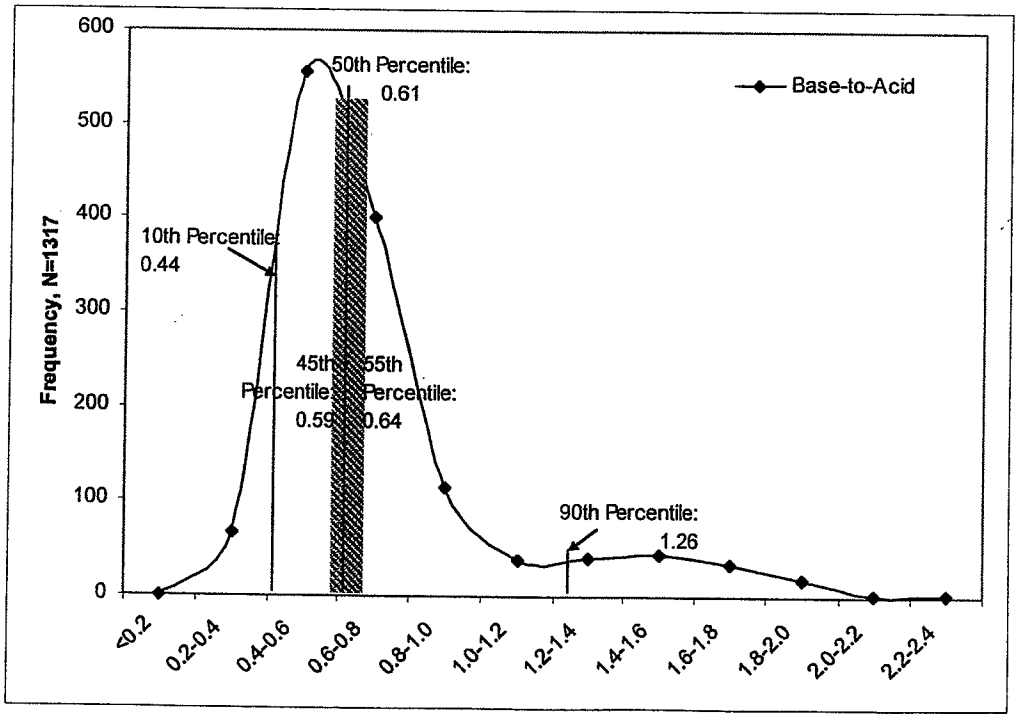


Figure 7. Distribution of ratio of base to acid components of the ash derived from the coals in the Center lignite as-fired database.

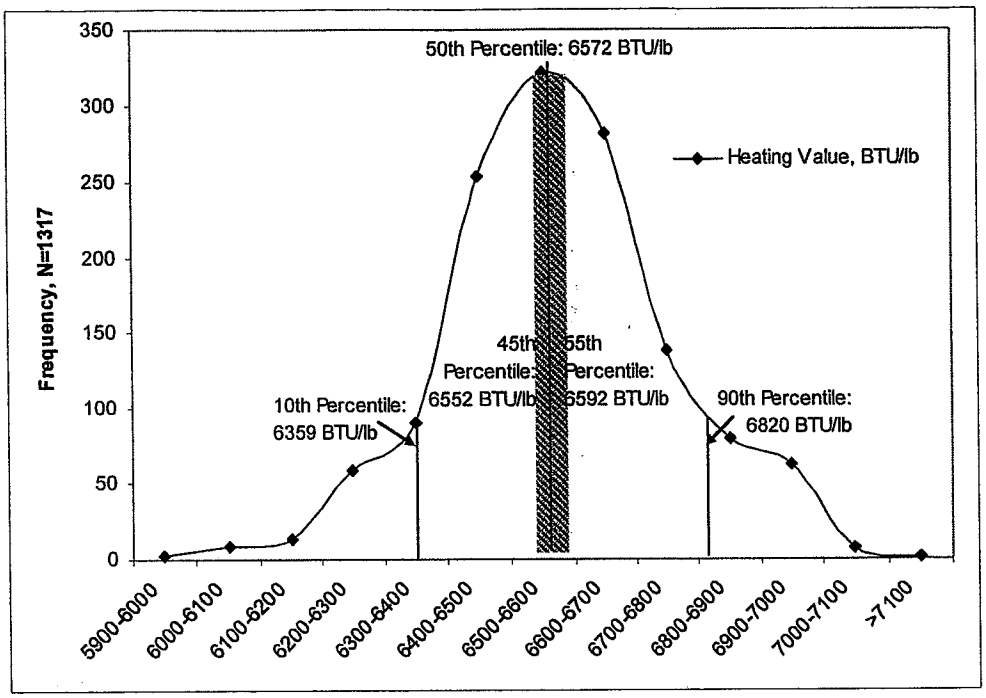


Figure 8. Distribution of heating value determinations (BTU/lb on an as-fired basis) in coals from Center lignite as-fired database.

Using average Center lignite coal compositions is misleading with regard to ash deposition problems at MRYS. Plants do not burn the average fuel, and problems frequently occur in systems designed to fire fuels based on average properties. In addition, the sodium in the Center lignite is organically associated, or sometimes referred to as water- or acid-soluble. This is especially problematic for SCR catalyst deactivation, as previously discussed in response to ERG's memo and EPA's January 8, 2007 preliminary analysis of Minnkota's BACT study[4].

Figures 9 and 10 show actual data from MRYS on lignite variability that show the wide variability in both the ash content (moisture-free basis) and base-to-acid weight ratio ($B/A=[Na_2O+MgO+CaO+K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$). The B/A ratios are an effective way of examining variability and ash behavior performance. The as-fired coal properties show changes in ash percentage (moisture-free basis) from the arithmetic average being

[4] See Reference number 4, March 2007.

approximately 50 percent of the average value. This means that the amount of ash produced at the high end of the sample range can be double the amount at the low end of the range over a very short period of time. Also included is cyclone performance (scale on the right side of Figures 9 and 10) that indicates slag freezing when the value drops from 7000 to 6000. The need to co-fire fuel oil in one or more cyclones for supplemental heat during slag freezing events is typically triggered by an excursion in ash content and/or low B/A ratio coal.

Center lignite is extremely variable in ash content and in the constituents that make up the ash. Typically, it is not the average coal that causes ash-related problems, and it is the excursions from the average that impact the formation of difficult-to-remove deposits on surfaces exposed to flue gases. A Center lignite as-fired coal quality composition database is attached as Appendix A to this document.

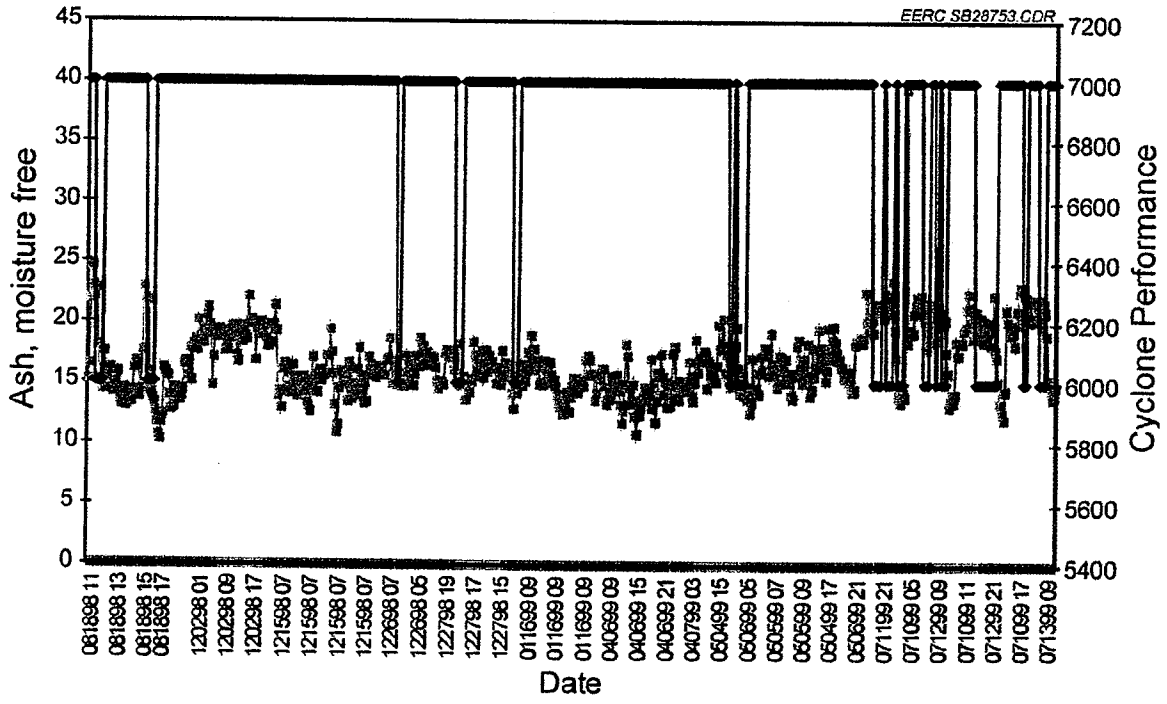


Figure 9. Moisture-free ash content of as-fired coal samples showing variability.

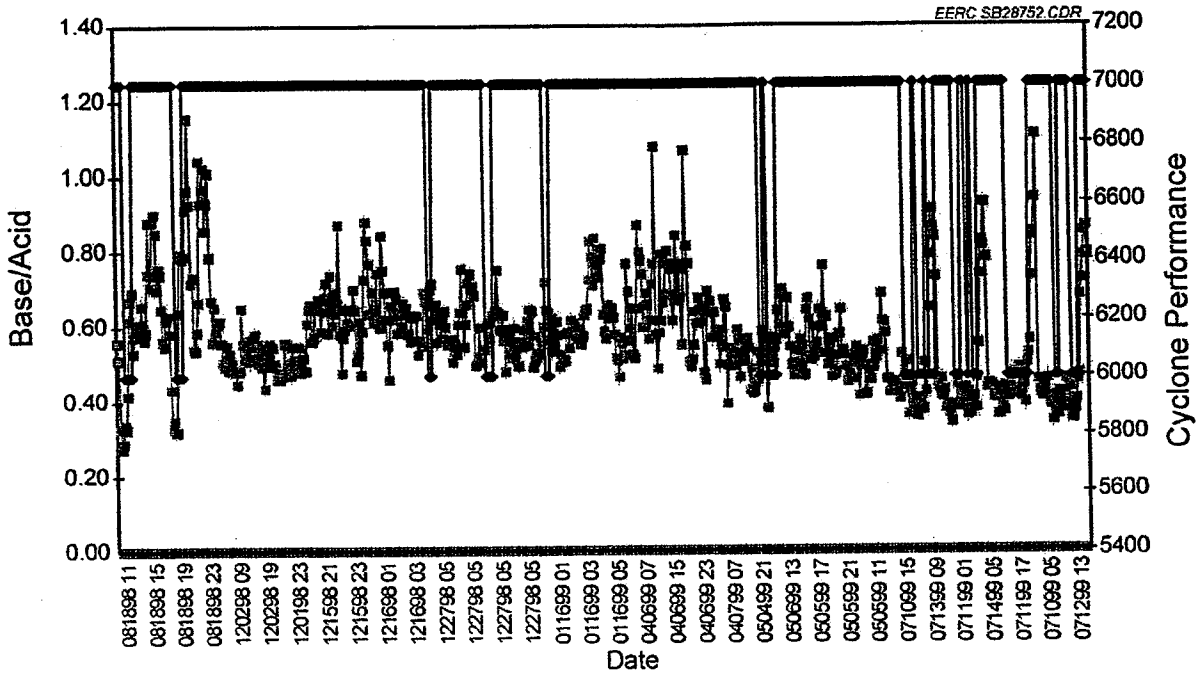


Figure 10. Base-to-acid ratio of as-fired coal samples showing variability.

Future Coal Database

The characteristics of the future coals are shown in Table 2. The projected changes based on core analysis indicate that the level of ash range from an average of 7.1 to 8.3% over the period of time from 2007 to 2010. The range of ash levels shows some extremes up to 32.6% likely due to clay partings in the coal seams. The average values of ash are lower than the as-fired database and do not include coal dilution (inclusion of partings) as a result of mining. Typically dilution at the Center mine can increase the ash content by about 2% based on past comparisons of core and as fired samples. Sodium levels have shown increased levels in the future coals that will likely contribute to increased fouling challenges.

Table 2. Statistical analysis of future coal based on core sample analysis from Center mine.

	Moisture as-rec'd	Ash as-rec'd	Sulfur as-rec'd	Heating Value, as-rec'd	Calcium Oxide	Magnesium Oxide	Potassium Oxide	Sodium Oxide
Sample ID	H_2O (%)	Ash (%)	S (%)	(BTU/lb)	CaO (%)	MgO (%)	K_2O (%)	Na_2O (%)
2007 CORE SAMPLES								
Min	31.8	4.0	0.4	4999	3.5	1.3	0.2	0.7
Max	42.6	24.6	2.8	7216	28.8	8.1	5.3	13.3
Avg.	38.5	7.9	0.9	6694	16.2	5.1	1.0	5.8
Standard Deviation	1.7	3.8	0.4	350	4.9	1.2	0.7	3.5
2008 CORE SAMPLES								
Min	29.8	4.1	0.3	4547	3.0	2.6	0.3	0.6
Max	43.7	32.6	5.6	7108	29.6	8.1	2.8	11.9
Avg.	38.0	8.3	1.0	6672	17.0	5.0	1.0	5.3
Standard Deviation	1.7	4.7	0.7	427	5.9	1.2	0.6	3.4
2009-2010 CORE SAMPLES								
Min	34.3	4.1	0.3	5215	5.0	2.7	0.2	0.5
Max	41.7	23.8	3.0	7180	33.6	8.4	6.9	13.4
Avg.	38.4	7.1	0.9	6787	17.8	5.2	0.9	5.6
Standard Deviation	1.2	2.7	0.5	254	5.0	1.1	0.8	3.4

Figure 11 illustrates the variability of the sodium levels in the Center lignite and the limitations in the use of average coal characteristics.

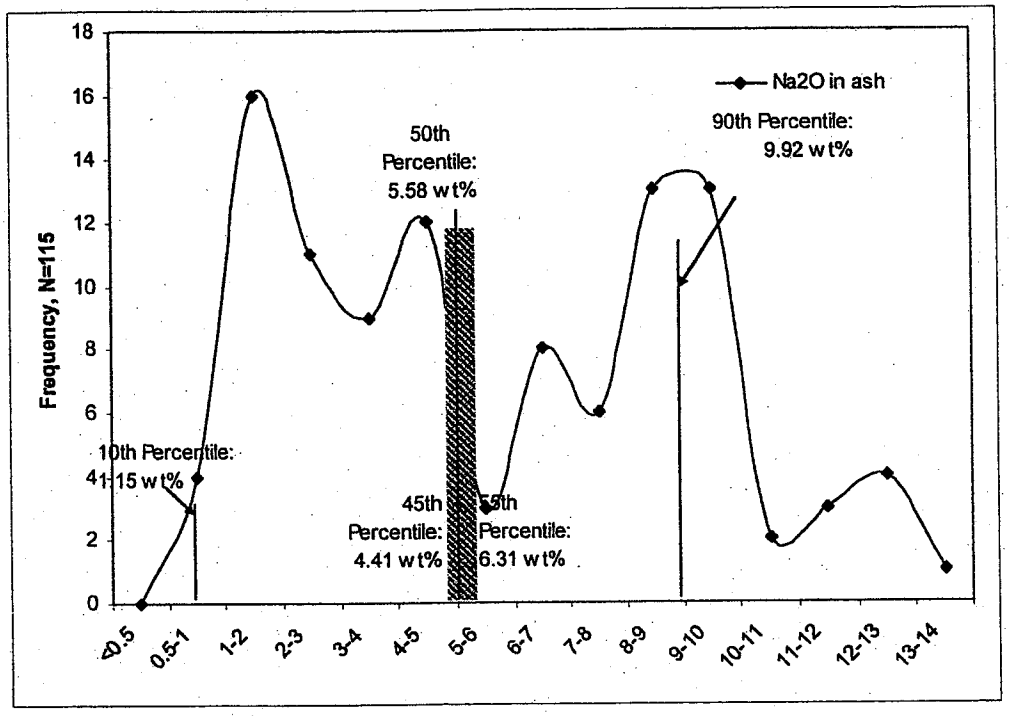


Figure 11. Frequency distribution of sodium levels for drill core samples in 2007.

High Economizer Exit Temperatures:

Reference: NDDH letter to Minnkota February 1, 2007 request item number 2:

> *"The temperature between the economizer and air heaters is described as "much higher than 750 degrees (pA1-31). Please provide more specific data on the temperatures that would be encountered at the location an SCR would be installed".*

B&McD Response:

The following information concerning the boiler outlet and air preheater outlet flue gas temperatures for both Units 1 & 2 is provided:

The primary superheat (PSH) outlet flue gas temperatures for Unit 1 are provided instead of the economizer outlet temperatures. Unit 1 at the M. R. Young Station has a two-pass tubular air preheater (APH). The economizer for Unit 1 is situated between the first and second pass of the air preheater. The flue gas passes on the inside of the tubes of the APH. Consequently, the air preheater does not have sootblowers.

The configuration of the economizer and air preheater physically precludes locating a conventional high-dust SCR upstream of the existing air preheater/economizer on Unit 1 in its current location and configuration. The flue gas temperature is reduced by transferring heat to the boiler's feedwater and the boiler's combustion and drying system air streams, respectively. In addition, temperatures at the existing air preheater outlet for Unit 1 are far below the temperatures needed for operation of a conventional hot-side high-dust SCR. The ideal temperature range for conventional coal-fired SCR catalyst is believed to be 650-750°F, with 700°F being considered the optimum temperature and 750°F being the maximum normal operating temperature for long-term performance and life.

The Unit No. 1 boiler is shut down for cleaning at intervals ranging from approximately 90 to 120 days. The gas temperatures at the PSH outlet vary inversely with the boiler cleanliness during each operating run. Hourly plant operating data for MRYS units at various boiler load and cleanliness conditions for 2002-2003 was reviewed to determine the typical operating temperatures. When returning to service immediately following a boiler fireside cleaning outage, PSH outlet temperatures are typically near the low end of the range listed in Table 3. Note that at low loads and clean conditions, the PSH outlet flue gas temperatures are 170-270 degrees F below the acceptable range for conventional hot-side high-dust SCR catalyst. Near

the end of a run when there are significant ash deposits in the boiler, PSH outlet flue gas temperatures will approach the high end of the operating range shown in Table 3.

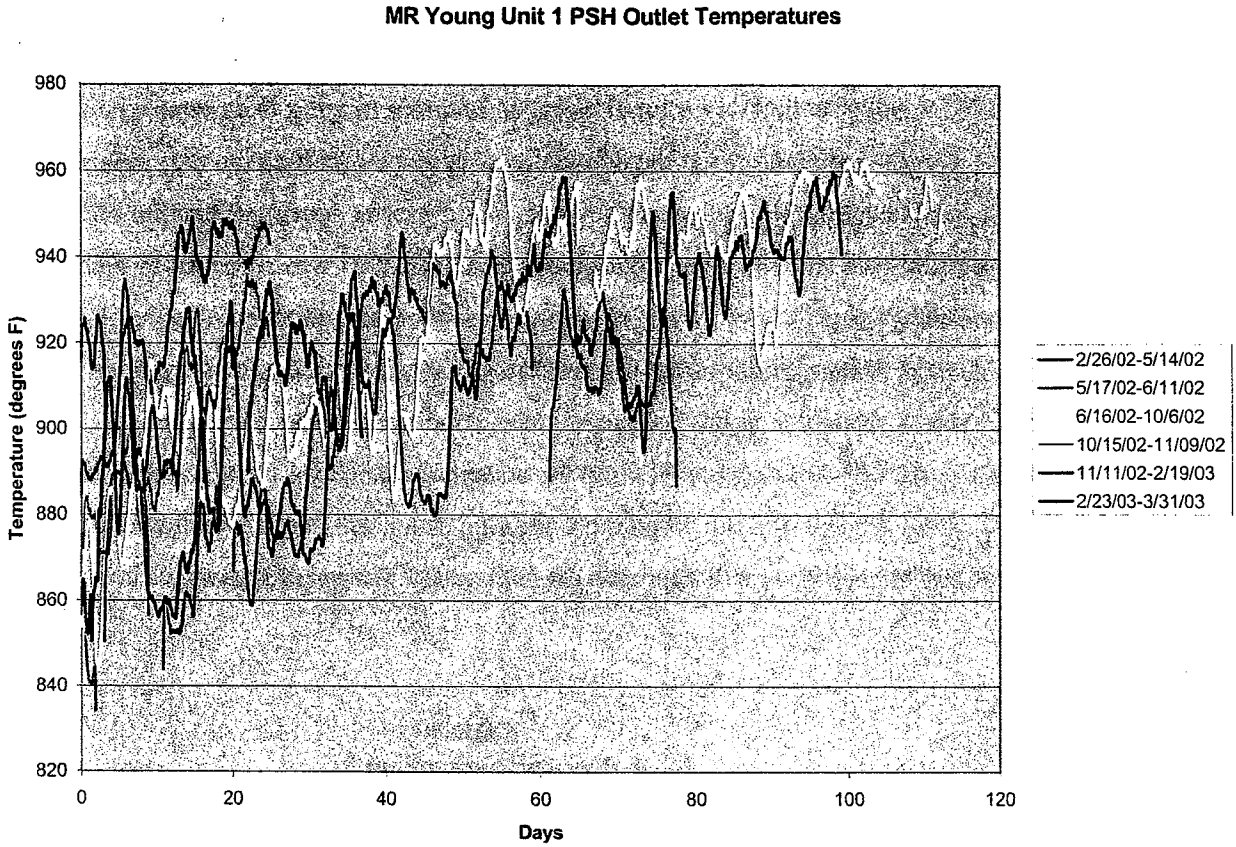
The following table provides a summary of operating temperatures for varying load conditions:

Table 3
M. R. Young Station Unit 1
Flue Gas Operating Temperatures versus Unit Output

Load	**Load Range (MWg)**	**PSH Outlet** (degrees F)	**ESP Exit** (degrees F)
Low	80-120	431-742	177-269
Mid	150-175	656-877	236-320
High	>245.0	840-963	303-355

Reliable temperature data for the Unit 1 air preheater outlet is not available. The temperatures at the Unit 1 air preheater outlet are estimated to be approximately 10 degrees higher than the electrostatic precipitator's (ESP) exit temperatures. Unit 1's PSH full-load flue gas temperatures historically range between 840°F and 960°F, depending upon the cleanliness of the boiler. This is shown in Figure 12. However, there have been instances when Unit 1's PSH full-load average flue gas temperatures have exceeded 1000°F and individual temperature measuring elements (thermocouples) have exceeded 1050°F.

Figure 12. Hourly average Unit No. 1 Primary Superheater outlet flue gas temperature



A portion of MRYS Unit 2 boiler's feedwater heating surface is in a location normally occupied by a traditional conventional economizer section in the convection (back) pass of the boiler. Another economizer portion is located at the inlet ducts to the flue gas recirculation (FGR) fans, which are downstream of the first economizer section, bypassing (upstream of) the two-pass tubular air preheater. The remaining portion of the economizer for Unit 2 is situated between the first and second pass of the APH. The flue gas passes on the inside of the tubes of the APH. Consequently, the Unit 2 air preheater does not have sootblowers.

The configuration of the boiler's economizer and air preheater physically precludes locating a conventional high-dust SCR upstream of the existing air preheater/economizer on Unit 2 in its current location and configuration. The flue gas temperature is reduced by transferring heat to the boiler's feedwater and the boiler's combustion and drying system air streams, respectively.

In addition, temperatures at the existing air preheater outlet for Unit 2 are far below the temperatures needed for operation of a conventional hot-side high-dust SCR.

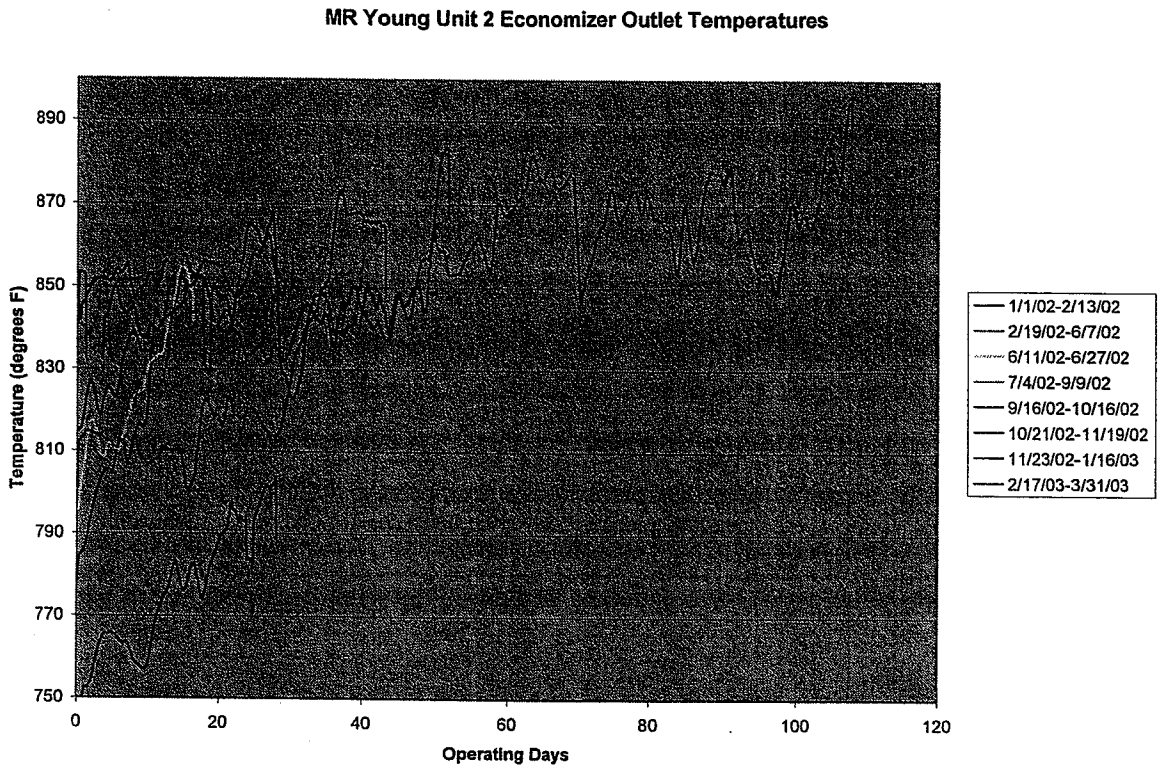
The Unit No. 2 boiler is shut down for cleaning at intervals ranging from approximately 80 to 110 days. The gas temperatures at the conventional boiler outlet location vary inversely with the boiler cleanliness during each operating run. Hourly plant operating data for MRYS units at various boiler load and cleanliness conditions for 2002-2003 was reviewed to determine the typical operating temperatures. When returning to service immediately following a boiler fireside cleaning outage, boiler outlet temperatures are typically near the low end of the range listed in Table 4. Note that at low loads and clean conditions, boiler outlet flue gas temperatures are 170-270 degrees F below the acceptable range for conventional hot-side high-dust SCR. Near the end of a run when there are significant ash deposits in the boiler, boiler outlet flue gas temperatures will approach the high end of the operating range shown in Table 4.

Table 4
M. R. Young Station Unit 2
Flue Gas Operating Temperatures versus Unit Output

Load	Load Range (MWg)	Econ. Outlet (degrees F)	APH Outlet (degrees F)	ESP Exit (degrees F)
Low	150-175	429-746	235-296	228-282
Mid	295-320	675-812	297-345	286-334
High	>>450	776-881	345-368	335-354

Unit 2's boiler-exit economizer-outlet full-load flue gas temperatures historically range from 780 to 880°F, depending upon the cleanliness of the boiler. This is shown in Figure 13. However, there have been instances when Unit 2's average full-load economizer outlet flue gas temperatures have exceeded 930°F and individual temperature measuring elements (thermocouples) have exceeded 990°F.

Figure 13. Hourly average Unit No. 2 Boiler outlet flue gas temperature



Low-Dust SCR Fouling:
Reference: NDDH letter to Minnkota February 1, 2007 request item number 3:

> *"It is indicated that a low dust SCR would be subject to the same fouling problems as a high dust SCR due to the emission of small (<5 micron) particles containing sodium-calcium-sulfur rich materials. Please provide any existing data on the composition of the particulate matter exiting the electrostatic precipitators."*

EERC Response:
As previously discussed in responses to the EPA's January 8, 2007 comments, the MRYS cyclone boilers' fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components, resulting in formation of compounds that cause bonding, blinding, and deactivation of individual catalyst reaction sites, even in a low-dust SCR application. Sodium-rich aerosols can get through the electrostatic precipitator (ESP). These aerosols are known to be present in high-sodium coal combustion flue gases. These species are known to produce pyrosulfates. These will cause blinding and deactivation of the low-dust catalyst[5].

Stack sampling was conducted downstream of the ESP and wet FGD on Unit 2 at the MRY plant. The filters were examined using scanning electron microscopy and x-ray microanalysis to determine the microscopic features and chemical compositions. Two sections of the filter sample were mounted on a graphite planchets using carbon double-stick tape. The first section included filtered material. The second section was taken near the edge of the filter, where there was no deposited material. The filter mounts were coated with carbon for improved conductivity in the microscopy. The filter and the filter edge sample were characterized using scanning electron microscopy morphological analysis. Morphological analysis consists of obtaining images and chemical analyses of selected features in the samples. An image of the collected ash and filter material were taken using backscattered electron imaging, which differentiates between elements based on their atomic number (iron appears brighter than silicon). The chemical compositions of the analysis areas and points were determined through the use of energy dispersive x-ray microanalysis.

[5] Ibid Reference number 4, March 2007, and Reference number 5, February 2007.

Morphological Analysis

Morphological analysis results for the filter sample are shown in Table 5, with a corresponding scanning electron micrograph in Figures 14 and 15. High magnification images of filter regions are shown in Figures16 – 18. The material collected on the filter was very small in diameter, generally less than 10 micrometers with the majority less than one micrometer. Because the particles were so small, mainly overall areas of filtered material were acquired and quantified. Several larger (> 1μm) particles were also analyzed. Due to penetration of the electron beam through the deposited material, two overall areas of the filter edge were analyzed to determine the composition of the filter.

The average composition of the "overall" areas analyzed (randomly-located analysis areas 1-4, not shown in Figure 14), and areas 8-9 (as shown in Figure 14) included about 6.6 wt% sodium and 5.7 wt% sulfur. The filter edge did not contain sodium or sulfur (randomly-located analysis areas 11 and 12, not shown in Figure 14). Areas 11 and 12 are typical of the filter edge region shown in Figure 18. The overall areas of filter materials also contained slightly higher levels of magnesium, potassium, and iron (around 1 wt% more each) than the blank edge of the filter. Several lighter-colored, larger particles characterized contained calcium (15 wt%), silicon (9 wt%) and aluminum (6.6 wt%) (analysis points 5, 7, and 10, Figure 14). One dark particle was characterized (analysis point 6, Figure 14); the particle was about three to four microns in diameter; it contained sodium (6.4 wt%), magnesium (9.8 wt%), sulfur (6.2 wt%), calcium (7.8 wt%), and silicon (10.8 wt%). Some of the lighter colored particles contain elevated levels of barium (analysis point 10, Figure 14 and analysis points 13 and 15, Figure 15). The darker regions in Figure 15 appear to be agglomerations of very small particles that are rich in sodium and sulfur as shown in analysis points 15, and 17. Analysis point 16 in Figure 15 appears to be a coating on the surface of a larger fly ash particle that contains high levels of sodium and sulfur. High calcium particles are also present on the filter shown by analysis points 14 and 18 in Figure 15.

High magnification secondary electron images are shown of the exposed and unexposed filter materials. Figure 16 and 17 show the filter materials that were exposed to the flue gases. The surfaces of the filter strands show small particles or agglomerates of small particles adhering to

the strands. These particles are rich in sodium and sulfur as compared to the filter materials. Figure 18 shows a region of the filter that was not exposed to flue gas and the fiber stands do not have particles bonded to the surfaces.

Table 5. Morphological analysis results for filter sample 001. Results expressed as weight percent on an elemental basis.

Fig.	Pt/Area	Description	Na	Mg	Al	Si	S	Cl	K	Ca	Ti	Fe	Ba	O
14	1*	Overall area - 100x	5.98	1.83	2.62	10.85	3.80	0.00	2.29	11.10	0.00	2.31	0.00	59.21
	2*	Overall area - 100x	5.95	2.40	2.82	10.93	5.42	0.00	2.25	11.30	0.40	2.46	0.00	56.07
	3*	Overall area - 100x	7.31	1.99	2.23	8.73	7.38	0.00	2.28	9.86	0.00	1.11	0.00	59.10
	4*	Overall area - 100x	5.66	2.54	2.20	9.47	5.27	0.00	2.54	10.08	0.00	3.05	1.65	57.56
	5	Light particle	1.21	3.33	5.47	7.65	1.38	0.00	1.40	13.44	0.00	6.76	1.85	57.52
	6	Dark particle	6.40	9.79	1.47	10.75	6.24	0.00	3.76	7.84	0.00	1.06	0.00	52.68
	7	Light particle	0.57	3.99	7.49	8.94	1.74	0.19	1.15	15.67	0.43	3.83	0.00	56.01
	8	Overall area - 100x	8.50	2.62	2.45	10.04	6.81	0.00	2.12	9.26	0.50	2.40	0.00	55.30
	9	Overall area - 100x	5.95	1.97	2.64	11.03	5.58	0.00	2.09	10.21	0.86	1.78	0.00	57.90
	10	Light particle	0.78	4.20	6.78	11.26	0.00	0.00	1.24	15.37	0.00	3.70	5.10	51.56
	11*	Blank edge of filter	0.00	0.93	5.11	20.20	0.00	0.00	0.93	13.83	0.00	0.00	0.00	59.00
	12*	Blank edge of filter	0.00	1.19	4.95	19.69	0.00	0.00	1.16	16.52	0.00	0.59	0.00	55.91
15	13	Small, light particles	3.00	3.30	3.10	7.72	2.91	0.00	1.40	11.02	0.00	3.49	1.89	62.18
	14	Small bonded particles	2.93	1.25	1.02	10.04	6.99	0.00	4.06	29.33	0.00	5.38	2.93	36.08
	15	Large dark particle	10.25	9.68	0.00	1.41	22.60	0.00	3.74	2.16	0.00	0.00	0.00	50.15
	16	Large dark particles	13.40	11.82	0.00	1.30	10.30	0.00	2.28	0.96	0.00	2.17	0.00	57.78
	17	Small bonded particles	4.39	3.56	2.17	10.95	6.88	0.00	2.77	14.02	0.51	2.83	0.00	51.92
	18	Small bonded particles	1.49	2.82	5.86	10.45	4.93	0.00	3.19	26.01	1.19	8.23	0.00	35.84
Average		**Overall areas**	**6.56**	**2.23**	**2.49**	**10.17**	**5.71**	**0.00**	**2.26**	**10.30**	**0.29**	**2.18**	**0.27**	**57.52**
		Light particles	**1.39**	**3.71**	**5.71**	**8.89**	**1.51**	**0.05**	**1.30**	**13.88**	**0.11**	**4.44**	**2.21**	**56.82**
		Dark particles	**10.02**	**10.43**	**0.49**	**4.49**	**13.05**	**0.00**	**3.26**	**3.65**	**0.00**	**1.08**	**0.00**	**53.54**
		Small bonded particles	**2.94**	**2.54**	**3.02**	**10.48**	**6.27**	**0.00**	**3.34**	**23.12**	**0.57**	**5.48**	**0.98**	**41.28**
		Filter edge	**0.00**	**1.06**	**5.03**	**19.94**	**0.00**	**0.00**	**1.04**	**15.18**	**0.00**	**0.30**	**0.00**	**57.46**

* = areas not specifically noted or shown in electron micrograph Figure 14.

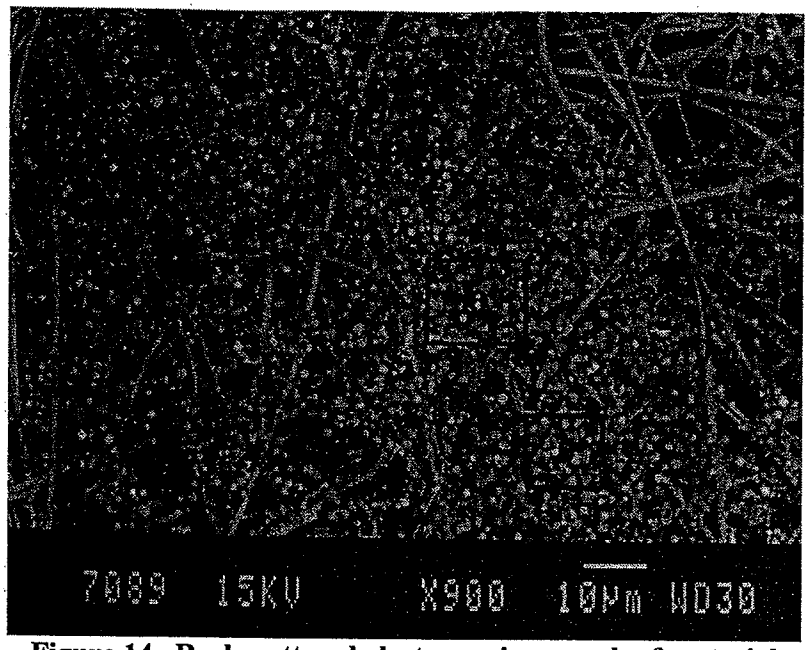


Figure 14. Backscattered electron micrograph of material on filter sample 001, showing analysis areas and points 1 through 10.

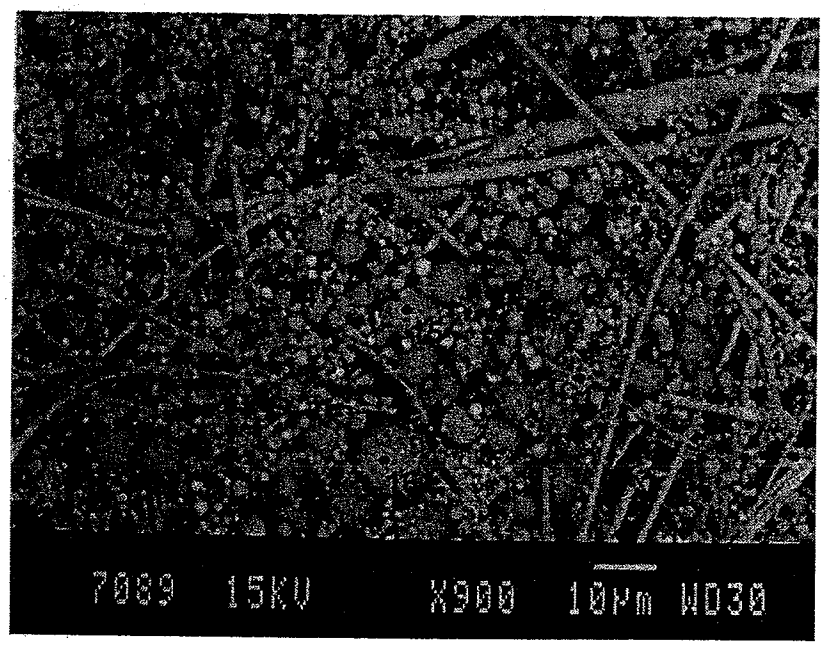


Figure 15. Backscattered electron micrograph of material on filter sample 001, showing analysis areas and points 13 through 18.

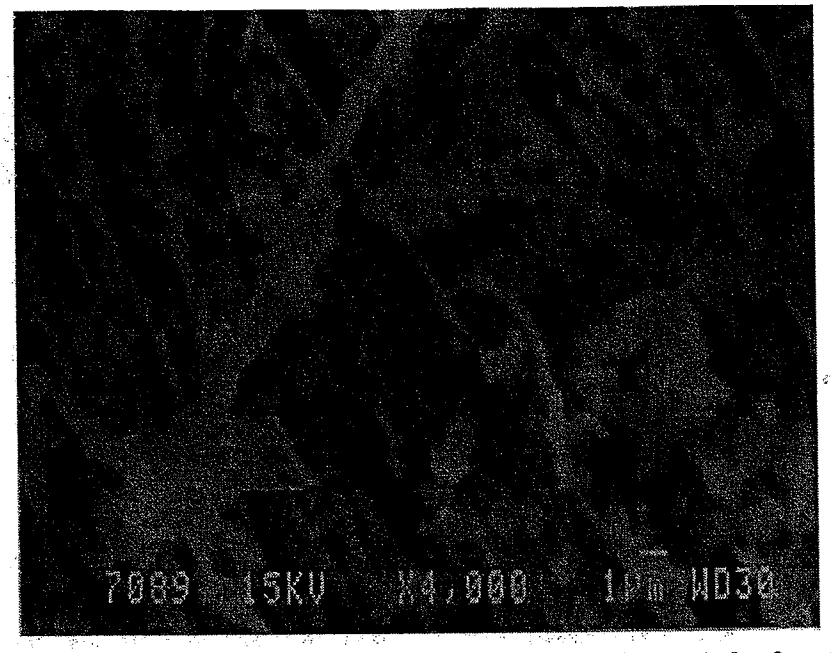


Figure 16. High-magnification secondary electron micrograph of material on filter sample 001, showing fine particles condensed on filter.

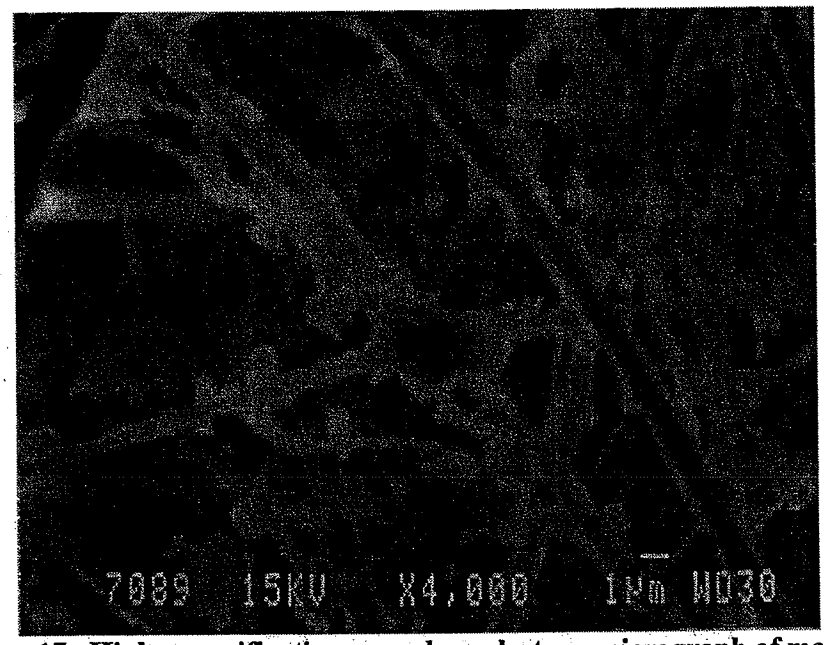


Figure 17. High-magnification secondary electron micrograph of material on filter sample 001 (MTI 07-089), showing fine particles condensed on filter.

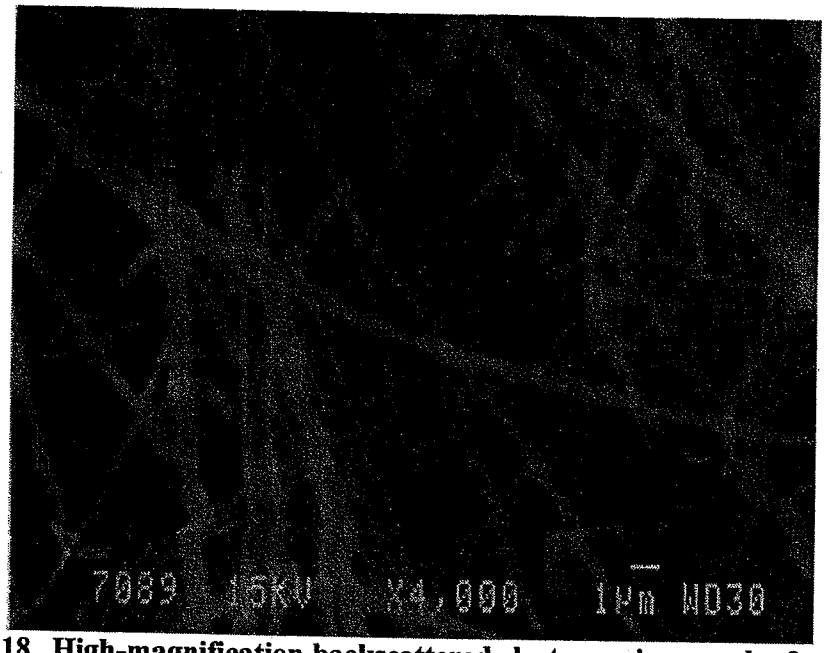


Figure 18. High-magnification backscattered electron micrograph of material on filter sample 001 (MTI 07-089), showing clean region of filter (near filter edge).

The following responses follow the outline of the EPA Region 8's January 26, 2007 letter.

SCR Deactivation:
Reference: EPA Region 8 January 26, 2007 letter to NDDH request item number 1:

> *"Please provide any and all data and information related to catalyst deactivation rates and NOx control effectiveness measured at the three facilities tested during the "Ash Impacts on SCR Catalyst Performance" study that is extensively referred to in the "EERC Report" included as Appendix B of the Minnkota NOx BACT analysis. This should include the original proposal, all test plans, all raw catalyst deactivation and NOx control data collected during the test, and all final reports and conclusions that were produced for the study's participants. In addition, please provide a quantitative analysis on the application of the multiple engineering solutions (e.g. catalyst rejuvenation and regeneration, acoustic horns, etc.) described by Roger Christman and EPA to address specific concerns highlighted in the BACT analysis and EERC Report and their effect on SCR catalyst deactivation rates and NOx control effectiveness at MRYS."*

EERC Response:
The SCR catalyst sections that were exposed to the flue gas from the Coyote Station were completely plugged at the end of the testing period. The EERC offered to send them to Haldor Topsoe for evaluation; the catalyst vendor indicated that the Coyote SCR test catalysts were too plugged and deactivation testing could not be conducted. The lack of published catalyst activity data for the Coyote slipstream SCR catalyst field test is a result of the severity of the catalyst fouling from North Dakota lignite ash. EERC has already included some comments from February 2007 discussions with Haldor Topsoe regarding their concerns about the sodium content in North Dakota lignite and its tendencies for catalyst deactivation[6] in their responses to the EPA's January 8, 2007 comments[7]. The requested data is available; this information has been copied, compiled, and due to its volume, will be submitted separately.

Information on catalyst deactivation rates and NO_X reduction effectiveness for the Baldwin and Columbia Station slip-stream SCR catalyst field testing was determined and some of the information was in the final report. EERC recently received information from Hitachi on catalyst deactivation for the catalysts at Columbia. This information is included in the EERC data compiled and being submitted to the NDDH.

[6] Ibid Reference number 4, March 2007 and Reference number 5, February 2007.
[7] Ibid Reference number 4, March 2007.

Regeneration has been attempted in Europe with SCR catalysts exposed to biomass as with high potassium (elemental symbol K, similar in chemistry to sodium, Na), and they had some significant problem in recovering reactivity (Khodayari and Odenbrand, 2001[8]).

B&McD Response:
A quantitative analysis on the application of the multiple engineering solutions suggested by the EPA's commenter mentioned above has not been performed. Significantly more time would be required. A definitive analysis would require pilot-scale slipstream SCR reactor testing on the flue gas streams emitted from the boilers at MRYS over a significant length of time to simulate real-time effects of gas and flyash constituents and their interactions with the catalyst. Using assumptions of the effectiveness of solutions suggested by EPA's commenter[9] based on use of theoretical data developed from laboratory testing and/or empirical data gathered from other high-dust SCR installations that do not treat flue gases produced from cyclone boilers firing North Dakota lignite coal would be hypothetical. Such a theoretical quantitative analysis of EPA's claimed SCR catalyst improvements cited and whether this would actually be translatable into preventing the catalyst layers from being susceptible to macro-pore blinding and plugging by calcium-based compounds and the impact on the individual catalyst reaction sites from sodium-based compounds discussed in Dr. Benson's referenced technical paper would be speculative.

Burns & McDonnell believes it would not be accurate to burn lignite or use flyash samples collected from a MRYS electrostatic precipitator with artificial flue gas to simulate catalyst fouling and blinding phenomenon in a laboratory- or pilot-scale test setting. This would not realistically duplicate conditions representative of actual operation in treating flue gases produced from cyclone boilers firing North Dakota lignite coal in order to evaluate the effectiveness of the suggested catalyst cleaning and management methods.

Performing a quantitative analysis would require substantial resources to develop slip-stream SCR catalyst test equipment designs and operational conditions to address the significant technical challenges that were evident in the reference field demonstration testing at Coyote

[8] See Reference number 6.
[9] See Reference number 7, January 2007.

station. It is unreasonable that the EPA expects that such an in-depth investigation is required under a BACT analysis.

Performing a BACT analysis on an existing unit should not require substantial resources to be expended to perform detailed quantitative analyses as requested above. Such analyses need to be based upon site-specific data in order to develop a realistic technical basis that would support estimated site-specific NO_X emissions reduction performance and catalyst deactivation rates. Without such an investigation as described, solutions for overcoming significant technical challenges that would otherwise preclude the ability of the technique or technology from successfully controlling the emissions in question would appear to be hypothetical. The EPA's NSR Manual 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."[10] The quantitative analysis on the application of the multiple engineering solutions suggested by the EPA's commenter mentioned above is not required and will not be performed as requested.

It may be true that sonic horns are the technology of choice for utility coal-fired SCR reactor applications, but this is not because they are more effective in removing difficult ash deposits. Sonic horns are by far cheaper to buy, cheaper to install, cheaper to maintain, cheaper to operate, and require much less structural steel and platforms. With the vapor phase deposition of compounds onto the catalyst that are a major concern, sonic horns are not expected to be effective on that deposit phenomenon. The theory of sonic horns is to keep the non-adhering fly ash particles moving so the normal gas flow carries them through the SCR reactor. The catalyst fouling described by EERC's paper would happen with normal operation and appears to have much less to do with fly ash entrainment.

[10] See Reference number 10, Section IV.B., page B.18.

SCR Vendor Guarantees:
Reference: EPA Region 8 January 26, 2007 letter to NDDH request item number 2:

> *"Although EPA's Draft 1990 NSR Workshop Manual recognizes that vendor guarantees by themselves are not sufficient to show that a technology is feasible, vendor guarantees can contribute to a technical feasibility determination in some situations. In light of statements EPA has received from three SCR vendors (Haldor Topsoe, Cormetech, and Argillon) indicating they would provide performance guarantees on SCR lignite applications, please provide additional vendor information, from multiple vendors, that Minnkota believes is more specific to MRYS than the statements received by EPA and cited in EPA's analysis submitted to North Dakota on January 8, 2007. We would expect that the catalyst suppliers cited above would be among the vendors contacted by Minnkota."*

EERC Response:
EERC has already included some comments from February 2007 telephone discussions with Haldor Topsoe regarding their concerns about the sodium content in North Dakota lignite and its tendencies for catalyst deactivation[11].

B&McD Response:
A query of SCR catalyst vendor's willingness to guarantee performance on a lignite-fired boiler to address comments in EPA's cited documents mentioned above has not been completed. Additional time is required. The information on SCR performance guarantees for MRYS applications has been requested; it will be submitted separately when it is available. A copy of the information request letter and attachments issued to the SCR vendors is attached (Appendix A).

System and equipment vendors have a self-interest to sell technology that they offer, and to manage financial risks by specifying the limits of their system design in case of potential operating conditions that cause performance problems that prevent achievement of guarantees and/or warranty claims. There are several points that challenge the value of catalyst vendors being willing offer "guarantees". First, from Burns & McDonnell's experience, what a vendor or supplier says pre-bid does not always match what they will actually offer in a firm contract. Second, a commercial guarantee does not mean the system provided by the vendor will work long term; all it means is that based on the language in the contract and the amount of money the supplier has allocated to cover their risk or exposure, the vendor will guarantee the system

[11] Ibid Reference number 4, March 2007 and Reference number 5, February 2007.

performance. Third, commercial contract performance guarantees and warranties always have a finite life, which means the owner of the system only benefits from the vendor's warranty for three years typically. If the catalyst is ruined annually for example, the vendor will replace it two times and include that cost risk in their proposal. That leaves the owner with very large additional operating and maintenance costs over the remaining life of the system, which could be 30 or more additional years. Such additional costs are difficult to predict and estimate, especially when the technology has been installed on non-similar applications or in limited numbers that do not have as severe operating conditions as could occur at MRYS.

The type of commercial performance guarantee or warranty needed for potential MRYS SCR system contract would carry the terms "make-good" and "evergreen" with it. This is a contract requirement where the vendor that enters into the contract has to do whatever is necessary to meet the performance guarantee; in this example, the system vendor would likely include a "pass-through" guarantee from their catalyst supplier. The catalyst vendor would replace the catalyst at their cost however often it is needed to meet performance guarantees and lifespan warranty. Each time the catalyst needs to be replaced under an "evergreen" warranty, the warranty period starts over. Typically this is avoided by any and all bidders due to the open-ended cost potential borne by the selected vendor for this type of guarantee and warranty language that such a contract carries with it.

MRYS Boiler Cleaning Outages:
Reference: EPA Region 8 January 26, 2007 letter to NDDH request item number 3:

> *"The Minnkota MRYS NOx BACT analysis includes discussion of periodic boiler outages that are required to address the slagging effects of the Center Mine lignite. Please provide historical dates of these outage periods and their duration for the previous 10 years. Also, please provide an estimate of boiler outage frequency that would be expected due to SCR maintenance, based on information collected in response to items 1 and 2 of this list."*

B&McD Response:
Information to estimate MRYS boiler outage frequency expected for high-dust SCR maintenance based upon a query of SCR catalyst vendors mentioned in item 2 above is not available at this time. Additional time is required.

A review of historic outage data shows that over the past 10 years (1997-2006)[12], the typical MRYS Unit 1 boiler cleaning outage was between 67 and 82 hours in duration, but these can be as short as 56 hours and as long as 206 hours. The median Unit 1 boiler cleaning is 78.3 hours, and the average is 90.7 hours. Over this same time period, the typical MRYS Unit 2 boiler cleaning outage was between 64 and 102 hours in duration, but these can be as short as 37 hours and as long as 244 hours. The median Unit 2 boiler cleaning is 89.9 hours, and the average is 89.1 hours. A boiler fireside cleaning outage is typically scheduled for 96 hours (four days) duration.

A high-dust SCR would need to be isolated from the gas path between the boiler and the inlets to the electrostatic precipitator during boiler cleaning outages to prevent the moisture and deposits liberated during boiler fireside surface cleaning from entering the SCR reactor. Beginning the work of removing ash accumulation or catalyst from the SCR reactor(s) will be delayed by 48 to 60 hours after the start of the outages, depending on ambient temperatures, because the inside of the reactor(s) will be too hot for personnel health and safety. Because the length of the boiler cleaning outages is typically less than 4 days (96 hours), that does not leave much time to do any significant catalyst cleaning or replacement work without delaying boiler startup. The estimated amount of time and difficulty in removing lignite ash accumulation from the SCR reactor(s), or replacing fouled catalyst with clean spare catalyst, is expected to require at least 144 hours (6 days), plus 60 hours upfront for allowing the reactor to cool-down. This is based upon the use of mobile industrial vacuum cleaning methods ("super sucker" truck). The total SCR maintenance outage time will be around 200 hours from boiler shutdown end to beginning of startup. The frequency of such SCR maintenance outages are expected to be required at least annually, or more often.

There were only two outages other than major scheduled overhauls during the historic ten-year period that appeared to be of sufficient length (greater than 8 days) that could have lent themselves to significant catalyst cleaning or replacement work without delaying startup: one on Unit 1 and one on Unit 2. Major unit maintenance outages are scheduled every three years.

[12] See attached 2-page spreadsheet "MRYS Boiler OUTAGES (1997-2006).xls", reference number 9.

The frequency and duration of historical boiler cleaning outages are not sufficient to provide enough opportunities expected to be required for significant catalyst cleaning or replacement work without delaying startup. Extending boiler cleaning outages to perform periodic SCR catalyst maintenance in between major scheduled unit maintenance outages will cause negative impacts on each unit's availability to generate electricity.

There are basic concerns that using short boiler cleaning outages as SCR catalyst maintenance opportunities could be detrimental to catalyst life due to thermal stresses and passing through various dewpoint temperatures. Bringing the very large mass of ceramic catalyst material and the reactor structure down in temperature and then back up rapidly and any more frequently than absolutely necessary should be avoided. Significant efforts and expense have been paid on numerous high-dust SCR projects to maintain catalyst at temperatures above dew point during short duration or unplanned type outages of similar duration as MRYS boiler cleaning outages. Keeping the SCR catalyst and reactor structure "bottled up and warm" should improve SCR catalyst longevity and the ability to come back up after the boiler maintenance work is completed. The EPA's consultant's proposed SCR catalyst management strategy has potential pitfalls that may be more detrimental than helpful in extending SCR catalyst life and performance.

Elimination of Control Options as Technically Infeasible:
Reference: EPA Region 8 January 27, 2007 letter to NDDH, Enclosure – Summary of Preliminary Non-SCR Issues for the Minnkota NOx BACT Analysis, January 26, 2007:

> *"It appears as though several control options have been eliminated improperly for technical infeasibility at step 2 of the Top-Down BACT analysis. Many of these options appear to have been eliminated as being technically infeasible, simply because they have not been demonstrated on full-scale cyclone boilers that burn North Dakota lignite....In cases where the technology has been demonstrated elsewhere, but has not been demonstrated on a cyclone boiler burning North Dakota lignite, the technology should be assumed to be feasible, and Minnkota should conduct an analysis on whether the control option is "available and applicable" to MRYS."*

This precedes the presentation of concerns about the elimination of specific control options as discussed below:

Hydrocarbon-Enhanced Selective Non-Catalytic Reduction (HE SNCR):

> *"it is unclear whether HE SNCR is technically feasible. Minnkota should provide a more thorough analysis on whether this control option is "available and applicable" (as described in the NSR Manual) at MRYS by...soliciting vendor information. A quantitative analysis of its technical feasibility should be provided and supported with data and vendor statements."*

B&McD Response:
The October 2006 MRYS NO_X BACT analysis was performed using technical literature available in the public domain, proprietary vendor customer experience information, and limited engagement of selected vendors for capital cost, operating and maintenance costs, and emissions performance estimates along with Burns & McDonnell's technical expertise. This analysis approach meets the requirements of the EPA's NSR Manual.

A detailed query of the potential availability and applicability of hydrocarbon-enhanced (HE) selective non-catalytic reduction (SNCR) on a lignite-fired cyclone boiler from the single vendor mentioned in the October 2006 MRYS NO_X BACT Analysis reports has not been performed. Additional time would be required.

It is important and appropriate to specify the composition of the Center lignite coal and ash constituents and boiler configuration sufficiently to provide a sound basis for allowing the HE-SNCR vendors' reviews and qualified responses. HE-SNCR design conditions that are reasonably reflective of actual operating conditions and boiler fouling experience are yet to be established. The lack of detailed development of MRYS unit-specific HE-SNCR injection lance design schemes to deal with the high boiler fouling conditions and varying boiler gas temperatures and loads will require HE-SNCR design operating conditions to be assumed before workable design concepts have been confirmed.

Substantial resources would be required to be expended by Minnkota in order to supply actual boiler furnace operating environment data to an HE-SNCR technology vendor for them to attempt to confirm the information previously supplied in the BACT submittal. Soliciting definitive vendor information and performing a BACT technical feasibility and impacts analysis on HE-SNCR technology if applied to the existing lignite-fired cyclone boilers at

MRYS needs to be based upon customer data in order to develop a realistic technical basis that would support estimated unit-specific HE-SNCR NO_X emissions reduction performance, capital and operating and maintenance (O&M) costs. Without such an investigation as described, solutions for overcoming significant technical challenges that would otherwise preclude the ability of the technique or technology from successfully controlling the emissions in question would appear to be hypothetical. The EPA's NSR Manual 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."[13] Therefore, the quantitative analysis requested by EPA Region 8 of the technical feasibility involving the application of HE-SNCR at MRYS is not required and will not be performed.

Although the EPA's NSR Manual[14] serves as a guide for conducting a NO_X BACT analysis, there are additional similar regulatory requirements applicable to MRYS boilers to consider. The North Dakota Department of Health has determined that MRYS Unit 1's and Unit 2's boilers are BART-eligible. The Regional Haze Regulations and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule were published in the Federal Register on July 6, 2005[15]. It is interesting to note that other non-cyclone BART-eligible boilers burning North Dakota lignite did not mention or evaluate HE-SNCR technology as a possible NO_X control alternative in their BART analyses.

<u>Reburn with SNCR:</u>

> *"Minnkota did not analyze whether the* [gas reburn with SNCR] *technology combination would be "available and applicable" to MRYS, as described in the NSR Manual.... Minnkota should provide a more thorough analysis on whether this control option is "available and applicable" (as described in the NSR Manual) at MRYS by...soliciting vendor information. A quantitative analysis of its technical feasibility should be provided and supported with data and vendor statements."*

B&McD Response:
A detailed query of the potential availability and applicability of fuel reburn technology combined with SNCR on a lignite-fired cyclone boiler from the reburn technology vendors has

[13] See Reference number 10, Section IV.B., page B.18.
[14] See Reference number 10, October 1990.
[15] See Reference number 8, FR Vol. 70, No. 128 pages 39134 – 39136, and 39171 – 39172, July 2005.

not been performed. As mentioned in Appendix A1 of the October 2006 MRYS NO_X BACT Analysis reports, while SNCR may potentially be installed downstream of separated overfire air and various types of fuel reburn, there is a lack of demonstrated experience of this combination on cyclone boilers. Only one example of gas reburn with SNCR, applied to a tangentially-fired boiler, was found in available technical literature.[16]

Moreover, the very high capital and O&M costs already estimated for coal and gas reburn technologies with ASOFA in Section 3 of the October 2006 MRYS NO_X BACT Analysis reports showed that such alternatives were significantly above the BACT Dominant Controls Cost Curves for MRYS Unit 1 and Unit 2. Thus, even if fuel reburn technology combined with SNCR were available and applicable to lignite-fired cyclone boilers, the average and incremental unit control costs ($ per ton) would not be expected to be on the NO_X BACT Dominant Controls Cost Curves for MRYS Unit 1 and Unit 2. Such reburn with SNCR alternatives would thus be considered as "inferior", and would not be considered as BACT.

Substantial resources would be required to be expended by Minnkota in order to supply actual boiler furnace operating environment data to an Advanced Reburn - SNCR technology vendor for them to provide information to support the requested analysis. Soliciting definitive vendor information and performing a BACT technical feasibility and impacts analysis on Advanced Reburn - SNCR technology if applied to the existing lignite-fired cyclone boilers at MRYS needs to be based upon customer data in order to develop a realistic technical basis that would support estimated unit-specific Advanced Reburn - SNCR NO_X emissions reduction performance, capital, and operating and maintenance (O&M) costs. Without such an investigation as described, solutions for overcoming significant technical challenges that would otherwise preclude the ability of the technique or technology from successfully controlling the emissions in question would be hypothetical. The EPA's NSR Manual 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."[17] The quantitative analysis requested by EPA Region 8 of the technical feasibility involving the application of Advanced Reburn - SNCR at MRYS is not

[16] Ibid reference number 2, page A1-49.
[17] See Reference number 10, Section IV.B., page B.18.

required by the EPA's NSR manual under these circumstances and therefore will not be performed.

It is interesting to note that other non-cyclone BART-eligible boilers burning North Dakota lignite did not mention or evaluate reburn with or without SNCR technology as possible NO_X control alternatives in their BART analyses.

Rich Reagent Injection (RRI):

> *"there does not appear to be an analysis of whether the RRI meets the "available and applicable" criteria described in the NSR Manual for elimination under step 2. If RRI would be less effective for the reasons cited in Minnkota's application, that would result in a lower ranking under step 3 and possible elimination under step 4. At this time, it does not seem appropriate to eliminate RRI under step 2. Minnkota should provide a more thorough analysis on whether this control option is "available and applicable" (as described in the NSR Manual) at MRYS by...soliciting vendor information. A quantitative analysis of its technical feasibility should be provided and supported with data and vendor statements."*

B&McD Response:
Since the publication of the MRYS NO_X BACT Analysis report, two commercial Rich Reagent Injection systems have completed design, fabrication, and installation in late 2006 at Ameren Sioux Unit 1 and Unit 2. Full optimized routine operation is expected to begin by early May, 2007. Although RRI NO_X emissions reduction technology appears to satisfy the "available" criteria (as described in the NSR Manual for technical feasibility) for potential application on the cyclone boilers at MRYS, the substantive issue is "applicability". The expected insurmountable difficulties in achieving consistent control effectiveness from this technology if applied to modestly air-starved cyclone combustion on these lignite-fired boilers and the reasons for technical infeasibility of RRI at MRYS were included in Appendix A1 of the October 2006 NO_X BACT Analysis reports.

A query of the single RRI licensee mentioned in the MRYS NO_X BACT analysis, and a quantitative analysis of its technical feasibility for the expected boiler operating conditions has not been performed. The transient variability of the fired lignite coal at MRYS was discussed in Appendix A1 of the October 2006 NO_X BACT Analysis reports. This variability makes it

impossible to accurately predict realistically achievable NO_X emissions reductions even with sophisticated computational fluid dynamics (CFD) modeling of the MRYS boiler combustion reactions and in-furnace NO_X reduction processes associated with RRI technology under reasonably realistic boiler operating conditions. This is due to the static (i.e. steady-state) nature of the boiler furnace operating conditions assumed to exist in order to simulate the performance of modestly air-starved cyclone combustion on these lignite-fired boilers with varying heat and air inputs to individual cyclones using CFD modeling techniques. Because of the dynamic variability of the higher heating value of the fuel burned and the lack of ability to precisely control the actual stoichiometry in real-time on an individual cyclone basis, RRI CFD model predictions would be unrealistic and thus these vendor statements would not be reflective of realistically achievable NO_X emissions reductions. Substantial resources would be required to be expended by Minnkota in order to supply actual boiler furnace operating environment data to a RRI vendor for them to attempt to confirm the information previously supplied in the BACT submittal. Even with such boiler data or CFD model results, there would still be the question of trying to estimate how much of the time the dynamic variability of the individual cyclones impacts the estimate of realistically achievable NO_X emissions reductions. The analysis requested by EPA Region 8 is beyond what is required for a BACT analysis as discussed previously. Therefore, the analysis will not be performed.

Rotating Opposed Fire Air (ROFA):

> *"Minnkota should provide a more thorough analysis on whether this control option is "available and applicable" (as described in the NSR Manual) at MRYS by...soliciting vendor information. A quantitative analysis of its technical feasibility should be provided and supported with data and vendor statements."*

B&McD Response:
A detailed query of the potential availability and applicability of ROFA technology on a lignite-fired cyclone boiler from the single vendor mentioned in the October 2006 MRYS NOx BACT Analysis reports has not been performed. Burns & McDonnell has reviewed available ROFA technical literature, attended sales presentations and participated in discussions with ROFA vendor personnel regarding the application of ROFA to cyclone boilers, including lignite-fired units. As an engineer and design/builder of numerous commercial separated overfire air systems specifically designed for cyclone-fired boilers, Burns and McDonnell

believes that ROFA technology is not superior to the evaluated version of SOFA in the October 2006 MRYS NO_X BACT Analysis to warrant such a vendor query and quantitative analysis.

As mentioned in the MRYS NOx BACT analysis, "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"[18]. Applying ROFA to a North Dakota lignite-fired cyclone would not allow an overall reduction in furnace exit NO_X or excess air without incurring a risk of slag "freezing" in the cyclones and potential reductions in unit load combined with forced outages to restore full-load firing, similar to the advanced version of SOFA included in the BACT analysis alternatives. With a similar functional aspects and expected impacts, ROFA does not offer any significant advantages in lignite-fired cyclone-specific application of separated overfire air technology. The quantitative analysis of the technical feasibility involving the application of ROFA at MRYS is not required by the EPA's NSR manual under these circumstances and therefore will not be performed as requested.

Control Efficiency for SNCR:
Reference: EPA Region 8 January 26, 2007 letter to NDDH, Enclosure – Summary of Preliminary Non-SCR Issues for the Minnkota NOx BACT Analysis, January 26, 2007:

> *"...it appears as though the SNCR control will only be achieving approximately 30% reduction. (p 3-18) AP-42 states that SNCR can achieve NOx reductions between 30-60%. Many recent PSD permit applications also include discussion of SNCR being able to achieve NOx control in the 60% range or higher. Considering that Minnkota's cyclone boiler will have high uncontrolled NOx emissions (even considering the ASOFA), the high end of this range should have been considered in the BACT analysis. Minnkota's analysis really provides no technical discussion on why it ruled out higher capabilities of SNCR control and why they used the control efficiency that is proposed."*

[18] Ibid Reference number 2, October 2006, page A1-5.

B&McD Response:
There were pertinent references in Appendix A1 of the MRYS NOx BACT analysis discussing long-term examples where SNCR has been applied for NOx emission control on two cyclone-fired boilers, achieving reductions around 30 percent from high uncontrolled baseline levels[19]. There was also another relevant cyclone boiler SNCR demonstration test listed in Appendix A2 of the MRYS NO_X BACT analysis that controlled NO_X in this same 30 percent range. NO_X control effectiveness of SNCR is highly boiler-specific. It is important to note that PSD permit applications are for new boilers; there are no new cyclone boilers being built, and few new boilers (other than CFB boilers) are required to install and operate SNCR. The cited AP-42 NO_X emissions rate reduction percentage for SNCR application on coal-fired boilers isn't applicable to the specific conditions expected at the MRYS boilers.

"The emission factor is a representative value that attempts to relate the quantity of a pollutant released to the atmosphere...In most cases, these factors are simply averages of all available data of acceptable quality, and are generally assumed to be representative of long-term averages for all facilities in the source category (i.e. a population average).[20]" However, the EPA also states that "Emission factors in AP-42 are neither EPA-recommended emission limits (e.g., best available control technology or BACT, or lowest achievable emission rate or LAER) nor standards (e.g., National Emissions Standard for Hazardous Air Pollutants or NESHAPS, or New Source Performance Standards or NSPS). Use of these factors as source-specific regulation compliance determinations is not recommended by the EPA"[21]. The AP 42 "Table 1.1-2 NO_X Control Options For Coal-Fired Boilers" on page 1.1-15 in Chapter 1 of the reference lists SNCR as having 30-60% NOx reduction potential, but this does not agree the discussion in the text in page 1.1-9, where SNCR "in limited applications, NOx reductions of 25 to 40 percent have been achieved"[22].

Burns & McDonnell estimated the level of emission reductions expected from SNCR based on information from an experienced urea-based SNCR vendor. B&McD believes that 60 percent

[19] Ibid Reference number 2, October 2006, page A1-17.
[20] See Reference number 11, Introduction page 1, January 1995
[21] Ibid Reference number 11, Introduction page 2, January 1995.
[22] Ibid Reference number 11, External Combustion Sources, pages 1.1-9 and 1.1-15, September 1998.

reduction of NO_X emissions is inappropriate, and not reflective or realistic for long-term levels of control at MRYS.

Selection of 30-day Average BACT Emission Limit:
Reference: EPA Region 8 January 26, 2007 letter to NDDH, Enclosure – Summary of Preliminary Non-SCR Issues for the Minnkota NOx BACT Analysis, January 26, 2007:

> *"The baseline emission rate used for calculating the proposed BACT limit is based on the highest NOx emission rate (0.884 lb/MMBtu) during actual operations from 2001-2005 (p. ES-9). This period also includes the longest reported startup event during that period (61 hours). How does this 30-day baseline compare with the rest of the historical data? Does this emission rate represent a realistic upper bound value, or is it an outlier compared with the majority of the data? If the data point does not reasonably compare with the vast majority of the other data, it does not make sense to set a BACT limit based on an outlier data point."*
> and
> *"Furthermore, the baseline emission rate used for calculating the 30-day limit is based on the highest 30-day period during actual operations from 2001-2005, which included the longest startup event. If this highest 30-day period was used as the baseline to calculate the 30-day average limit, and the worst-case startup event occurred during this historic 30-day period, it is not necessary to include the recommended "startup adjustment" (+0.041 lb/MMBtu) per startup event with this limit.*

B&McD Response:
According to MRYS Unit 1's October 2006 BACT Analysis[23], the control effectiveness calculations were determined based upon the highest historical 12-month rolling NO_X emission summation operating conditions for Milton R. Young Station boilers during years 2001-2005. MRYS Unit 1's highest 12-month NO_X mass emissions summation (lbs) divided by the summation of the same 12-month period's heat input (mmBtu) was determined, with a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MW_g.[24] This highest equivalent annual average pre-retrofit baseline level of unit NO_X emissions for MRYS Unit 1's boiler of 0.849 lb/mmBtu was for the 12-month period ending October 30, 2004. Similarly, MRYS Unit 2's highest 12-month NO_X mass emissions summation (lbs) divided by the summation of the same 12-month period's heat input (mmBtu) was determined, with a corresponding average unit heat input rate of 4,885 mmBtu/hr and unit

[23] Ibid Reference number 2, page 3-42.
[24] Ibid Reference number 2, Unit 1 BACT, page 3-15.

gross electrical output of 440 MW_g.[25] This highest equivalent annual average pre-retrofit baseline level of unit NO_X emissions for MRYS Unit 2's boiler of 0.786 lb/mmBtu was for the 12-month period ending April 30, 2004.

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. 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[26]. This reflects unit NO_X emissions that were generated during periods of high unit operations.

A review of Unit 1's boiler outages during this 30-day period revealed an outage of almost 40 hours in duration immediately prior to the start of this 30 consecutive day period. This boiler outage ended on 12/16/03 at 04:31 hours, and startup, as defined in the NOx BACT Analysis for Unit 1, was completed after 23:00 hours on 12/16/2003[27]. Emissions from the 12/16/2003 return to service boiler startup were not included in the highest historical 30-day rolling NO_X emission period, which began at 00:00 hours on 12/17/2003 and ended after 23:00 hours on 1/15/2004. Two short-duration boiler "trips", where the unit was not generating electricity for off-site distribution, occurred during this 30-day period: the first outage started at 12/30/2003 at 23:24 hours and ended at 00:57 hours on 12/31/2003; the second outage started on 12/31/2003 at 01:40 hours and ended at 01:54 hours on this same date. Unit 1's return to service following these outages involved "hot" starts with average short-term emissions that were higher than the steady-state average NO_X emission rate (0.985 lb/mmBtu during the nine consecutive hours of startup versus the average emissions excluding startup of 0.883 lb/mmBtu). Unit 1's startup following the first late December 2003 outage was interrupted by

[25] Ibid Reference number 2, Unit 2 BACT, page 3-15.
[26] Ibid Reference number 2, Unit 1 BACT, page 3-42.
[27] Ibid Reference number 2, Unit 1 BACT, page 3-44.

the second boiler "trip"; the second hot boiler startup was completed after 09:00 hours on 12/31/2003.

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 1 was 4,264 mmBtu/hr, and the average gross unit electrical power output was 450.2 MW_g for the same 30-day period[28]. This reflects unit NO_X emissions that were generated during periods of high unit operations. A review of Unit 2's boiler outages during this 30-day period revealed no outages. The last previous unit outage was a boiler cleaning outage ending on 2/18/2002.

MRYS operating conditions during the highest historical 30-day rolling NO_X emission periods for years 2001-2005 were then compared to the highest 12-month historic pre-control baseline period 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.

It was coincidental that the highest historical 30-day rolling NO_X emission period for MRYS Unit 1 (December 17, 2003 through January 15, 2004) was within the same highest 12-month historic pre-control baseline period (ending on October 30, 2004). The longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005 occurred during the 61-consecutive hour period from June 27-29, 2005[29]. Note that this did not fall either within the 30-day or the 12-month highest historic rolling average NO_X mass emission periods.

The highest historical 30-day rolling NO_X emission period for MRYS Unit 2 (March 7, 2002 through April 5, 2002) was not within the same highest 12-month historic pre-control baseline

[28] Ibid Reference number 2, Unit 2 BACT, page 3-42.
[29] Ibid Reference number 2, Unit 1 BACT, page 3-45.

period (ending April 30, 2004). The longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005 occurred during the 115-consecutive hour period from October 25-30, 2001[30]. Note that this did not fall within either the 30-day or the 12-month highest historic rolling average NO_X mass emission periods.

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 and Unit 2.

A statistical analysis of all the 30-day rolling periods for baseline pre-control NO_X emission rates during the calendar years 2001-2005 from each MRYS unit was not performed. However, looking at monthly total NO_X mass emissions (lbs) for Unit 1 reveals that January 2004 was the peak month, and was close in time to the actual highest 30-day rolling total NO_X mass emissions (lbs) that occurred ending January 15, 2004. The January 2004 peak monthly mass total was approximately 5% higher than January 2003's mass emissions, and several other high months were within approximately 7% of the January 2004 peak. The average Unit 1 NO_X emission rate during January 2004 was 0.854 lb/mmBtu, which is 3.5% lower than the 0.884 lb/mmBtu highest 30-day rolling average unit rate. Unit 2's monthly peak NO_X mass emissions were in March 2001, which was not close in time to the actual highest 30-day rolling total NO_X mass emissions (lbs) that occurred ending April 5, 2002. January 2001 was only slightly lower (-0.04%) than March 2001's peak monthly NO_X mass emissions. The average Unit 2 NO_X emission rate during March 2001 was 0.847 lb/mmBtu, which is 3.2% lower than the 0.874 lb/mmBtu highest 30-day rolling average unit rate.

[30] Ibid Reference number 2, Unit 2 BACT, page 3-45.

The selected highest baseline pre-control 30-day rolling average NO_X unit emission rates for MRYS Unit 1 and Unit 2 boilers are considered to be realistic upper bound cases, not "outliers". The NSR Manual does not specify the percentile of absolute worst case emissions that the upper bound case chosen to represent the source's baseline pre-control emissions rate must satisfy.

The recommended 30-day Rolling Average unadjusted (i.e. steady-state) BACT NO_X emission rates do not include the impact of the worst-case startup events for either MRYS Unit 1 or Unit 2. The "startup adjustment" as described in the October 2006 MRYS Unit 1 and Unit 2 NO_X BACT Analysis reports is appropriate as the recommended (unadjusted) 30-day Rolling Average NO_X Emission Rate permit limitations basically reflect steady-state rates.

BACT Limit 18-Month Trial Period:
Reference: EPA Region 8 January 26, 2007 letter to NDDH, Enclosure – Summary of Preliminary Non-SCR Issues for the Minnkota NOx BACT Analysis, January 26, 2007:

> *"EPA has concerns with Minnkota's proposal for an 18-month trial period for establishing a final BACT limit (p.ES-11). This proposal appears to be in direct conflict with the process for establishing and potentially revising the NOx BACT limits set forth in Sections V.B & I of the Consent Decree. Therefore, EPA believes the proposed 18-month trial period for establishing a final BACT limit in Minnkota's BACT analysis cannot be accepted."*

B&McD Response:
The 18-month trial operating period recommended in the October 2006 MRYS Unit 1 and Unit 2 NO_X BACT Analysis reports was proposed to allow Minnkota to demonstrate the actual control system capabilities of the combined NO_X BACT emissions reduction system[31]. This recommendation was made to account for the lack of experience in applying the selected BACT NOx emissions controls on lignite-fired cyclone boilers, without regard to the restrictions stated in the Consent Decree.

Paragraph 73 of the referenced Consent Decree states "The Settling Defendants shall submit any petition for any Unit under this Paragraph no later than six (6) months after the final

[31] Ibid Reference number 3, Unit 1 page 3-49 and Unit 2 page 3-49.

compliance date specified for that Unit in Paragraph 67".[32] Paragraph 67 requires that MRYS Unit 1 and Unit 2 shall achieve and maintain a Phase II 30-Day Rolling Average NO_X Emission Rate established by the NDDH through its NO_X BACT Determination beginning no later than December 31, 2011 and December 31, 2010, respectively. This does not preclude an early installation of Consent Decree Phase II NO_X emission reduction systems with associated commissioning at Milton R. Young Station prior to the CD compliance dates for MRYS Unit 1 and Unit 2, respectively. This could allow Minnkota to gain operating experience in advance of the June 30, 2012 and June 30, 2011 deadlines for submitting a petition. If the Settling Defendants do not accelerate the schedule for Phase II NO_X control implementation, recognizing that the CD apparently does not allow an 18-month trial demonstration period following the stated final compliance dates, the applicant will have to make use of the petition process as described in the CD in this circumstance, if appropriate.

[32] Ibid Reference number 3, April 2006, page 23.

REFERENCES

1 North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Determination Milton R. Young Station*, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.

2 "*BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc.*" and a separate "*BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative*", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "*BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc. Final Report, October 2006*" submitted by Minnkota to North Dakota Department of Health.

3 Consent Decree filed 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, filed April 24, 2006.

4 Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative "*Responses To EPA Comments NOx BACT Analysis Study Milton R. Young Station Unit 1 And Unit 2 Regarding SCR Technical Feasibility, March 15, 2007*".

5 Personal Communication Flemming Hansen (Haldor Topsoe) with Steve Benson (EERC), February 2, 2007.

6 Khodayari, R.; Odenbrand, C.U. Regeneration of Commercial SCR Catalysts by Washing and Sulphation: Effect of Sulphate Groups on Activity, Appl. Catal. B: Environ. **2001**, *33*, 277–291.

7 ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006)*, written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007. and *EPA Region 8 Preliminary Analysis of Burns & McDonnell BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007* faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

8 *Federal Register /Vol. 70, No. 128/ Wednesday, July 6, 2005 / Rules and Regulations, Part III Environmental Protection Agency 40 CFR Part 51, Regional Haze Regulations*

and Guidelines for Best Available Retrofit Technology (BART) Determinations; Final Rule.

9 MRYS Boiler Outages (1997-2006).pdf (from plant data spreadsheet).

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

11 *AP 42, Fifth Edition Compilation of Air Pollutant Emission Factors, Volume 1: Stationary Point and Area Sources, Introduction to AP 42, Volume 1, Fifth Edition, January 1995, and Chapter 1, External Combustion Sources, September 1998,* available from EPA's website, accessed on 2/2/2007 at: http://www.epa.gov/ttn/chief/ap42.

12 *Technical Support Document Methodology For Developing BART NOx Presumptive Limits, Environmental Protection Agency, Clean Air Markets Division, June 15, 2005, OAR-2002-0076-0445*, with Attachments, including Excel Spreadsheet OAR-2002-0076-0446 (1199 pages).

APPENDIX A -

SCR System Suppliers and SCR Catalyst Suppliers (for sending SCR Vendor Query Information Request via email, 4/18/2007)

SCR Vendor Query Information Request (and Attachments), April 2007

Milton R. Young Station Boiler Outages, 1997-2006 (2 pages)

SCR System Suppliers

Company	Contact	Address	Phone / E Mail
Alstom Power	Chuck Nordhausen	11245 South Lewis Drive Olathe, KS 66061	Telephone: 913-393-2585; cell 651-492-7420 Fax: 913-393-1996 Email: Charles.nordhausen@power.alstom.com
Babcock & Wilcox	Steve Moorman	2096 Edgcumbe Road St. Paul, MN 55116	Telephone: 651-690-3795 Fax: 651-699-0084 Email: samoorman@babcock.com
Babcock Power Environmental	Rich Abrams	5 Neponset Street Worcester, MA 01615	Telephone: 508-854-1140 rabrams@babcockpower.com
Hitachi Power Systems	David Paz	5615 Kirby Drive, Suite 850 Houston, TX 77005	Telephone: 713-690-0495; Fax: Cellular phone: 713-870-7827 David.paz@hal.hitachi.com

SCR Catalyst Suppliers

Company	Contact	Address	Phone / E Mail
Argillon (formerly Siemens)	Cindy Khalaf	5895 Shiloh Road Suite 101 Alpharetta, GA 30005	678 341 7520 cindy.khalaf@argillon.com
Ceram	John Cochran	7304 W. 130th St Suite 140 Overland Park, KS 66213	913 239 9896 john.cochran@ceram-usa.com
Cormetech	Scot Pritchard	Treyburn Corporate Park 5000 International Drive Durham, NC 27712	919 595 8708 pritchardsg@cormetech.com
Haldor Topsoe	Flemming Hansen	17629 El Camino Real Suite 300 Houston, TX 77058	281 228 5120 fgh@topsoe.com
Hitachi Power Systems America, Ltd.	Tony Favale	645 Martinsville Rd Basking Ridge, NJ 07920	908 605 2758 anthony.favale@hal.hitachi.com

INFORMATION REQUEST

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at North Dakota lignite-fired Units 1 and 2 at Minnkota's North Dakota Milton R. Young Station (MRYS). Burns & McDonnell has described the unit-specific SCR system design conditions and site-specific technical challenges in this document and its attachments.[1] Burns & McDonnell requests information regarding the following:

- Burns & McDonnell requests that the vendor provide detailed information regarding the post-combustion controlled emission rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time, with appropriate pre-controlled baseline emission data. That is, Burns & McDonnell requests information that supports a level of emission reductions that could be guaranteed over the course of time, and not merely performance test or limited-duration emissions data.
    - Data of source-specific boiler and SCR design and operating parameters, along with lignite coal quality characteristics (analytical data) representative of the lignite-fired coal-burning boiler operations associated with long-term post-combustion controlled emission rates that SCR systems have achieved as identified also needs to be provided.
    - If provided, non-full scale laboratory, pilot or bench-scale exposure testing, short-term full-scale compliance or acceptance test data shall be clearly identified as such.
- Burns & McDonnell requests definitive statements of expected guaranteed life and control effectiveness performance for SCR catalyst when located in high-dust, hot-side applications at MRYS. These statements will need to be supported by detailed descriptions of the vendor's interpretation of the technical information Burns & McDonnell has provided, the vendor's awareness of proven methods of dealing with

[1] Please also see EPA Docket References listed under reference number 1 at the back of the background attachment document regarding emission reductions achieved through the application of SCR systems.

similar site-specific applications, the vendor's own qualifications and experience, and any stated or assumed design and operational requirements. That is, the guarantee must specifically reference the site-specific operating conditions at MRYS, with an SCR system calibrated to operate in that environment.

- Burns & McDonnell requests definitive statements regarding BMcD's serious concerns involving catalyst blinding and deactivation due to high sodium concentrations along with sulfate and other known components in the flue gas expected from cyclone boilers firing North Dakota lignite. Burns & McDonnell has provided an analysis of the lignite fuel fired at MRYS, and the guarantee must specifically discuss the impact of this particular fuel on SCR system and catalyst performance and longevity.
- Burns & McDonnell requests a detailed description of the vendor's approach to mitigating the Minnkota's risks of failure to meet NO_X emissions control requirements and catalyst activity versus life guarantees, stating what the vendor would do to improve the probability of success prior to initial operation, and how they would respond if the emission control effectiveness and catalyst activity did not match the expectations of the guarantee.

Burns & McDonnell understands that the vendor will be required to make certain assumptions regarding SCR system design operating conditions, because detailed development of MRYS unit-specific design schemes to deal with the high boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite have not been confirmed. Recognizing that such SCR design details are not currently available, SCR system and catalyst vendors are requested to review the technical information Burns & McDonnell has provided. This data is offered as a supplement to the vendors' own technical knowledge, commercial experience, and proprietary data to aid in the understanding of technical feasibility of installing and successfully operating and maintaining currently-available coal-fired SCR system technology on the referenced North Dakota lignite-fired cyclone boilers. Burns & McDonnell has

provided detailed site-specific data in the attachments following the information request and background sections.

REQUEST BACKGROUND

Burns & McDonnell was retained by Minnkota Power Cooperative Inc. ("Minnkota") and Square Butte Electric Cooperative ("Square Butte") to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" that includes an evaluation of Selective Catalytic Reduction (SCR) technology for the Milton R. Young Station. NO_X BACT Analysis study reports for MRYS Unit 1 and Unit 2 were submitted to the North Dakota Department of Health (NDDH), and U.S. EPA in October, 2006. EPA's Office of Regulatory Enforcement and Region 8 of the United States Environmental Protection Agency have issued comments regarding these agency's reviews of the NO_X BACT Analyses for MRYS Unit 1 and Unit 2 in January, 2007. This information request is part of Minnkota's response to the EPA's comments.

A basic issue to be resolved in order to address the EPA's comments is:

- Would continuous exposure of available high-dust SCR catalyst to current flue gas temperatures and flyash with high sodium concentrations along with sulfate and other known components in the flue gas expected from MRYS cyclone boilers cause severe catalyst fouling, deactivation, and degradation resulting in unacceptable long-term NO_X emission control effectiveness, catalyst life, and cost-effectiveness?

The information requested needs to include vendor comments responsive to the above question. The SCR system and catalyst vendors' technical judgments and abilities need to be utilized to evaluate the current operating conditions and identify solutions to address boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite. Vendor responses need to consider historic MRYS boiler outlet flue gas temperature data provided as an attachment to this document that show wide variations with boiler fireside cleanliness and load.

Data, and other information involving SCR catalyst related issues, provided as an attachment, should also be reviewed[2]. This provided information is offered as a supplement to the vendors' own technical knowledge, commercial experience, and proprietary data to aid in the understanding of technical feasibility of installing and successfully operating and maintaining currently-available coal-fired SCR system technology on the referenced North Dakota lignite-fired cyclone boilers.

There are a number of issues that appear to challenge the technical feasibility of selective catalytic reduction (SCR) technology for NO_X emission control for Milton R. Young Station Unit 1 and Unit 2. There are significant concerns that historic and current boiler outlet flue gas temperatures are excessively-high at medium to high loads, and inadequate at low loads to support consistent long-term operation of SCR technology on lignite-fired cyclone boilers. The absence of full-scale SCR operation on any boilers firing North Dakota lignite coal and demonstrated susceptibility of a slip-stream SCR catalyst to severe fouling resulting from the actions of the emitted flue gases and flyash from a similar lignite-fired cyclone boiler are known from available vendor experience lists and reference technical literature[3]. Dealing with boiler heat transfer surface slag and ash deposit accumulation cleaning fragments and catalyst ash deposit removal operations anticipated at the Milton R. Young Station would be required. These concerns are described in subsequent attachments to this document.

The SCR catalyst vendors' responses need to specifically address serious concerns involving catalyst blinding and deactivation due to high sodium concentrations along with sulfate and other known components in the flue gas expected from cyclone boilers firing North Dakota lignite. Detailed site-specific lignite coal and ash composition data is provided in the attachments.

[2] Please see attachments to the background attachment document.
[3] Please see reference number 2 at the back of the background attachment document.

ATTACHMENT A Section Headings:

- General background: Unit descriptions and capacity ratings
- Regulatory background, including BACT Analysis information
- Considerations for technical feasibility for NOx controls
- Feasibility of SCR for lignite-fired cyclone boiler NOx control
- Design basis of SCR for MRYS lignite-cyclone NOx control
- Unit startups for lignite-cyclone NOx control

Additional Attachments:

- *Center Lignite Coal Quality Characteristics, March 2007*, with data primarily provided by the Energy & Environmental Research Center (EERC) of the University of North Dakota, (34 pages)
- Original boiler manufacturer's predicted performance data sheets and side elevation view drawings for each MRYS boiler (Babcock & Wilcox), (4 pages)

GENERAL BACKGROUND

The Milton R. Young Station includes two cyclone-furnace, lignite-fired steam-electric generating units (SEGUs) owned by Minnkota and Square Butte. The units both fire 100 percent North Dakota lignite supplied from the adjacent mine, near Center, North Dakota. Unit 1 has seven cyclone furnaces, with a nominal 235 MW net design output capacity rating, is typically capable of sustained output of approximately 253 MW_g (gross), has a gross design output "nameplate" capacity rating of 257 MW_g and has an ultimate short-term maximum gross output (URGE) rating of 278 MW_g. Unit 1 is owned and operated entirely by Minnkota. Unit 2 has twelve cyclone furnaces, with a nominal 439 MW net design output capacity rating, is capable of sustained output of approximately 462 MW_g (gross), has a gross design output "nameplate" capacity rating of 477 MW_g and has an ultimate short-term maximum gross output (URGE) rating of 512 MW_g. Unit 2 is owned by Square Butte, and operated by Minnkota.

Unit 1 and Unit 2 at Milton R. Young Station are cyclone-fired boilers. 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. Firing lignite in these cyclone boilers requires high drying and combustion air temperatures and pressures to support ignition and slagging conditions within the cyclones and lower furnace.

REGULATORY BACKGROUND

The NDDH is responsible for establishing a NO_X BACT Determination for MRYS Unit 1 and Unit 2, which includes the specific control technologies to be installed, and a specific 30-Day Rolling Average NO_X Emission Rate limitation (lbs/MMBtu) for compliance purposes. NDDH's BACT Determination for MRYS Unit 1 and Unit 2 will also address specific NO_X emission limitations during Unit startups.

The October 2006 NO_X BACT Analysis study reports for MRYS Unit 1 and Unit 2 identified 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, mainly unaffected by unit shutdowns, startups, or malfunctions. The corresponding 30-day average hourly NO_X mass emission rates, unit heat input rates, and gross unit electrical power output for the same 30-day periods, as well as shorter and longer periods, are provided in a table at the end of this section.

The application of separated overfire air (SOFA) for NO_X emissions control on Milton R. Young Unit 1's and 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, is expected to be installed on both units at M.R. Young Station. Due to the short-term variability of the combustible and ash components of North Dakota lignite supplied from the adjacent mine, 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. Table 1 shows the expected steady-state NO_X emissions rate and reduction performance at MRYS for ASOFA operation alone. ASOFA technology was assumed to be applied in combination with other NO_X emissions control technologies evaluated for MRYS in the NO_X BACT analysis.

TABLE 1 – Basic Combustion NO_X Control for MRY Station Unit 1 and Unit 2 Boilers with Expected Control Performance(1)

NO_X Control Technique	Unit 1 Emission Rate (lb/mmBtu)	Unit 1 Control Percentage	Unit 2 Emission Rate (lb/mmBtu)	Unit 2 Control Percentage
Advanced Separated Overfire Air (ASOFA)	0.53	40	0.52	40.5
Pre-control Baseline	0.88	-	0.87	-

(1) - Control percentages are relative to an average pre-control emission baseline based on continuous operation at highest pre-control 30-day rolling NOx summation mass emissions divided by the 30-day heat input summation. Emission rates and control percentages have been rounded up and down for this analysis.

The highest historic 24-hour average pre-control baseline NO_X mass emission rates are also provided in a table at the end of this section.

CONSIDERATIONS FOR TECHNICAL FEASIBILITY OF NO_X CONTROLS

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 furnaces. It also results in producing a flyash that has severe deposition characteristics.

Both boilers at MRYS 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 and the propensity to form flyash with high fouling tendencies in North Dakota lignite-fired boilers.

For lignite-fired cyclone boilers at MRYS, approximately 45% to 50% of the ash-forming components of the coal end up as fly ash. The proportion of ash-forming components that are associated with the organic fraction of the lignite coal is significantly higher than bituminous coals. During combustion in a cyclone, a significant portion of the organically-associated elements are either vaporized or form small particles that are swept into the body of the boiler with the combustion gases. The fly ash characteristics derived from a cyclone as compared to pulverized coal-fired boiler are enriched in the more volatile elements such as sodium and are depleted in some of the less volatile elements that end up in the slag.

Detailed information and analysis data regarding Center lignite coal and ash constituents are provided in the attached "Center Lignite Coal Quality Characteristics" document.

Ash deposition in each boiler and air preheater is a significant operational challenge for the MRY facility. Significant equipment and manpower resources are devoted to on-going removal of fireside ash accumulations. This fouling is so severe that even with numerous furnace and convection pass steam sootblowers and water cannons, unit outages must be conducted at regular intervals to clean each boiler (approximately every 80-120 days).

The primary superheater (PSH) tubes are located in the rear convection pass of MRYS Unit 1's boiler where a conventional economizer would typically be placed. PSH outlet flue gas temperatures for Unit 1 are much higher than 750 degrees F because of the boiler design and severe boiler fireside fouling that raises the furnace exit gas temperature as the boiler gets dirty. PSH outlet flue gas temperatures for Unit 1 are measured instead of the economizer outlet temperatures. Flue gas temperatures at the PSH outlet vary inversely with the boiler fireside cleanliness during each operating run. Hourly plant operating data for MRYS units at various boiler load and cleanliness conditions for 2002-2003 was reviewed to determine the typical operating temperatures. Table 2 provides a summary of Unit 1's operating temperatures for varying load conditions:

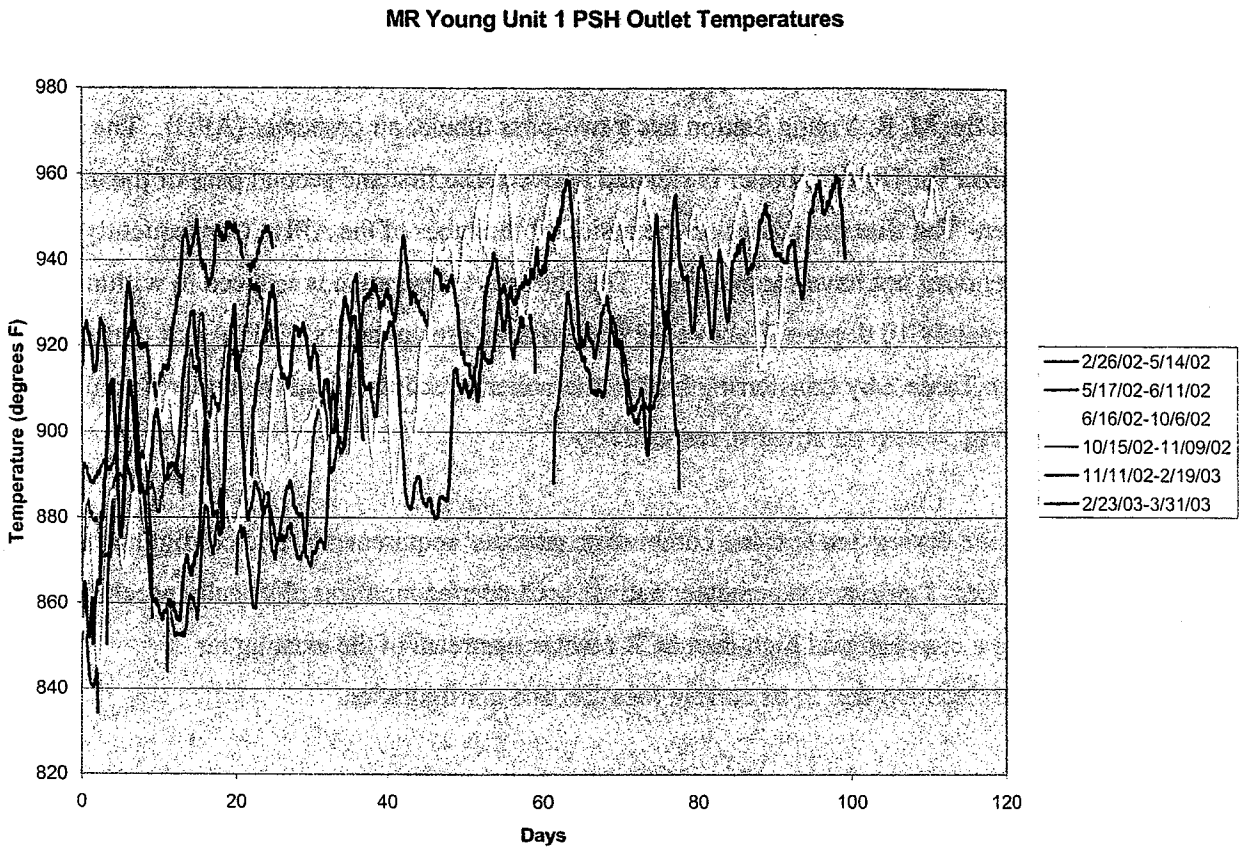
TABLE 2
M. R. Young Station Unit 1
Flue Gas Operating Temperatures versus Unit Output

Load	Load Range (MWg)	PSH Outlet (degrees F)	ESP Exit (degrees F)
Low	80-120	431-742	177-269
Mid	150-175	656-877	236-320
High	>245.0	840-963	303-355

Unit 1's PSH average full-load flue gas temperatures historically range between 830°F and 960°F, depending upon the cleanliness of the boiler. The MRYS Unit 1 boiler is shut down for off-line fireside ash deposit removal cleaning outages at intervals ranging from approximately 90 to 120 days. When returning to service immediately following a boiler fireside cleaning outage, PSH outlet temperatures are typically near the low end of the ranges listed in Table 2. Near the end of a run when there are significant ash deposits in the boiler, full-load PSH outlet flue gas temperatures will approach the high end of the operating range shown in Table 2. This is shown in Figure 1. However, there have been instances when Unit 1's PSH full-load flue gas temperatures have exceeded 1000°F and individual temperature measuring elements (thermocouples) have exceeded 1050°F.

Note that at low loads and with clean boiler fireside conditions, the Unit 1 boiler's PSH outlet flue gas temperatures are 170-270 degrees F below the acceptable range for a conventional SCR reactor. At full-load and dirty boiler fireside conditions, Unit 1's PSH outlet flue gas are 150 to 250 degrees F above the temperatures considered optimum for high-dust catalyst for coal-fired SCR applications.

Figure 1. Hourly average Unit No. 1 Primary Superheater outlet flue gas temperature



The MRYS Unit 1 boiler's convection pass and air heater/economizer configurations are specially designed to produce very hot primary air and secondary combustion air. This is needed to promote rapid drying and ignition of the high-moisture lignite fuel. Primary air at approximately 700°F is used to pre-dry the lignite coal feed and to transport it through the coal conditioning system called the "Direct-firing Pre-drying Bypass System", where it becomes saturated with evaporated moisture which is vented to the furnace. A portion of the hot primary air is also supplied to pneumatically-convey the separated, partially-dried crushed lignite coal to the active cyclones. At maximum continuous rating (MCR) firing conditions, the drying and conveying primary airflows are approximately one-third of the total preheated mass airflow supplied to each MRYS boiler. Configured for full primary and secondary airflows at MCR firing conditions, the existing air preheater raises the

temperatures of these boiler air streams to around 700°F, suitable for lignite coal drying and combustion air for entry into the cyclones.

Unit 1 at the M. R. Young Station has a two-pass tubular air preheater (APH). The economizer for Unit 1's boiler is situated between the first and second pass of the air preheater. The flue gas passes on the inside of the tubes of the APH. Consequently, the air preheater does not have sootblowers. The flue gas temperature is reduced to within approximately 10 degrees F above the electrostatic precipitator's (ESP's) exit temperature shown in Table 2 by transferring heat to the boiler's feedwater and the boiler's combustion and drying system air streams, respectively.

The lignite drying and cyclone combustion process' requirements, and configuration of the MRYS Unit 1 primary superheater and air preheater/economizer physically precludes locating a conventional high-dust SCR reactor upstream of the existing air preheater/economizer in its current location and configuration.

Similar descriptions and tables of operating data and information are provided for MRYS Unit 2 below.

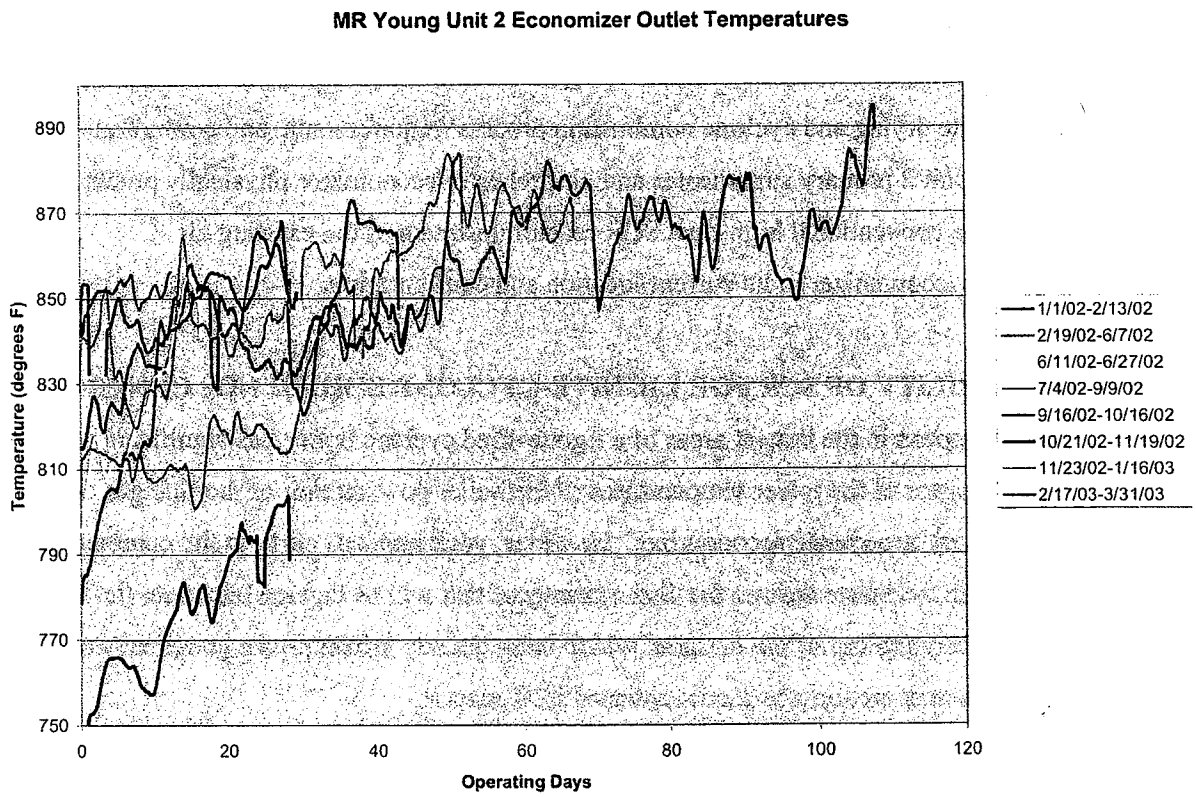
TABLE 3
M. R. Young Station Unit 2
Flue Gas Operating Temperatures versus Unit Output

Load	Load Range (MWg)	Economizer (Boiler) Outlet (degrees F)	APH Outlet (degrees F)	ESP Exit (degrees F)
Low	150-175	429-746	235-296	228-282
Mid	295-320	675-812	297-345	286-334
High	>450	776-881	345-368	335-354

Unit 2's full-load boiler economizer outlet flue gas temperatures historically range between 750°F and 900°F, depending upon the cleanliness of the boiler. The MRYS Unit 2 boiler is shut down for off-line fireside ash deposit removal cleaning outages at intervals ranging from

approximately 80 to 110 days. As the boiler gets dirty, full-load boiler economizer outlet flue gas temperatures will approach the high end of the operating range shown in Table 3. This is shown in Figure 2.

Figure 2. Hourly average Unit No. 2 Boiler outlet flue gas temperature



Note that at low loads and with clean boiler fireside conditions, the Unit 2 boiler's economizer outlet flue gas temperatures are 170-270 degrees F below the acceptable range for a conventional SCR reactor. At full-load and dirty boiler fireside conditions, Unit 2's boiler economizer outlet flue gas are 50 to 150 degrees F above the temperatures considered optimum for high-dust catalyst for coal-fired SCR applications.

One portion of the MRYS Unit 2 boiler economizer feedwater heating surface is located in a space normally occupied by a traditional conventional economizer section in the back pass of

the boiler. Another portion is located at the two inlet ducts to the two flue gas recirculation (FGR) fans, downstream of the first economizer section, upstream of the two-pass tubular air preheater. The remaining portion of the economizer for Unit 2 is situated between the first and second pass of the APH. The flue gas passes on the inside of the tubes of the APH. Consequently, the air preheater does not have sootblowers. This is shown in a side elevation view of the original boiler's arrangement included as an attachment.

The lignite drying and cyclone combustion process' requirements, and configuration of the MRYS Unit 2 primary superheater and air preheater/economizer physically precludes locating a conventional high-dust SCR reactor upstream of the existing air preheater/economizer in its current location and configuration.

FEASIBILITY OF SCR FOR LIGNITE-CYCLONE BOILER NO_X CONTROL

What happens in the hottest areas of a lignite-fired cyclone boiler has significant relevance to what happens in the lower temperatures of the boiler downstream of the flue gas outlet after the primary superheater/economizer. However, what happens early in the combustion process in the boiler defines the flux of material that will be carried back into the lower-temperature regions of the furnace, which subsequently influence the gases and entrained materials that are input to a conventional SCR reactor.

Of specific importance in the details presented in a technical paper by Benson[4] (2005) and included in the October 2006 NO_X BACT analysis for MRYS Unit 1 and Unit 2 was a discussion of how a cyclone partitions the ash between fly ash and slag and how these processes for lignite coals can enhance ash-related reactions at 600° to 800°F where SCRs are operated. Combustion and gas-cooling processes that impact ash behavior include vaporization, condensation, ash particle formation, and vapor/liquid/solid ash material deposition on heat-transfer surfaces. In addition, the accumulations of ash deposits on heat-transfer surfaces from the body of the boiler through the convective pass, including the Unit

[4] See Reference number 3, October 2005, at the end of this attachment document.

2 boiler outlet economizer, requires extensive use of soot blowers to remove ash deposits. Some of the removed deposit fragments are entrained with the bulk gas flow and carried through the boiler.

An understanding of what happens in the boiler defines the flux of materials (vapors, liquids, particles, deposit fragments) that will be transported through the boiler with the flue gases. These phenomena are especially important for lignite since the low-temperature ash deposition processes related to alkali and alkaline-earth elements are much more challenging for high-sodium lignite coals as compared to other coals. Sodium readily vaporizes upon combustion and condenses upon gas cooling, creating liquid phases and reactive aerosols.

Using average compositions is misleading with regard to ash deposition problems. Plants do not burn the "average fuel", and problems frequently occur in systems designed to fire fuels based on average properties. In addition, the sodium in the Center lignite is organically associated, or sometimes referred to as water- or acid-soluble. This is especially problematic for SCR catalyst deactivation. This is important for the SCR system vendors and catalyst suppliers to consider in answering the questions of technical feasibility of installing and successfully operating and maintaining currently-available coal-fired SCR system technology on the referenced North Dakota lignite-fired cyclone boilers.

DESIGN BASIS OF SCR FOR MRYS LIGNITE-CYCLONE BOILER NO_X CONTROL

SCR system design operating conditions are required to be assumed because detailed development of MRYS unit-specific design schemes to deal with the wide range of boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite have not been confirmed. SCR vendors are requested to review the technical information provided to aid in their evaluations for development of opinions and descriptions offered to address the expected guaranteed life and control effectiveness performance for SCR catalyst when located in high-dust, hot-side applications at MRYS. SCR catalyst exposure to excessively-high boiler outlet flue gas temperatures at

medium to high loads, and low temperatures at low loads, and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite require effective solutions which have not been developed, while considering future operation of separated overfire air systems, to allow for potential application of SCR technology at MRYS.

Detailed information and analysis data regarding Center lignite coal and ash constituents are provided in the attached "Center Lignite Coal Quality Characteristics" document.

Side elevation views of the MRYS Unit 1 and Unit 2 boilers and APHs are shown in the second attachment. The original predicted performance data sheets for each boiler are also included in the second attachment. Factors affecting unit design and operating parameters for technical feasibility considerations of a conventional high-dust SCR system are listed in Table 4. Highest historic 24-hour average, 30-day average, and 12-month average boiler NO_X unit and mass emissions, heat input rates, and gross unit electrical generating outputs for MRYS Unit 1 and Unit 2 are listed in Table 5.

Table 4 – MRYS Unit Design and Operating Parameters

Design Unit Operating Characteristics[1]	Unit 1 Design	Unit 2 Design
Boiler Type	Cyclone	Cyclone
Boiler Manufacturer	B&W	B&W
Boiler Design Heat Input Capacity (nameplate), mmBtu/hr	2,510	4,696
Unit Nameplate Generator Output Capacity, MW_g (gross)	257	477
Unit Nominal Full Load (NFL) Output, MW_g (gross)	235	450
Boiler Heat Input for Unit NFL Output, mmBtu/hr	2,508	4,814
Boiler Excess O_2, %, (wet, NFL)	3.17	4.04
Boiler Excess Air, % (NFL)	21.3	28.5
Fly Ash Portion of Total Ash, % (NFL)	45	50
Typical Maximum Continuous Rating (MCR) output, MW_g	253	462
Maximum Unit Output (URGE) Rating, MW_g	278	512
Boiler Firing Conditions for Flue Gas Flow Calculations:		
Boiler Heat Input, mmBtu/hr	2,852	4,740
Coal Higher Heating Value, Btu/lb as-received	6,578	6,578
Coal Flow Rate for heat input, lb/hr	433,500	720,500
Fly Ash Portion of Total Ash, %	50	50
Flue Gas Conditions at the boiler flue gas outlet:		
Boiler Excess O_2, %, (wet)	2.87	4.77
Boiler Excess Air, %	19.0	35.4
Flue Gas Mass Flow Rate, lb/hr	3,811,000	7,117,000
Flue Gas Volumetric Flow Rate, acfm	2,502,000	4,371,000
Flue Gas Temperature, degrees F	910	818
Flue Gas Pressure, in. w.g.	-11.5	-13.5
Boiler Outlet Maximum SO_2, lb/mmBtu	3.0[2]	3.0[2]
Boiler Outlet Maximum SO_2, lb/hr	8,970	15,474
Average Boiler Heat Input for SO_2, mmBtu/hr	2,990	5,158
Expected Boiler Outlet Maximum 30-day average SO_3, lb/hr	135[3]	236[3]

(1) – Boiler unit operating parameters are provided for more than one load or output condition.

(2) – Boiler Outlet Maximum SO_2 lb/mmBtu is based on 1.0% S and 6,578 Btu/lb higher heating value content in the as-received lignite coal.

(3) – Boiler Outlet Maximum SO_3 lb/hr is based on the assumed conversion of 1.5% of the boiler outlet SO_2 to SO_3 upstream of any flue gas treatment. This conversion percentage has not been confirmed by actual boiler outlet flue gas test measurements. The SO_2 lb/mmBtu and lb/hr values have not been reduced by this assumed SO_3 conversion.

Table 5 – MRYS NOx Emissions and Operating Conditions

Boiler NOx Emissions and Related Unit Operating Conditions	Unit 1 Design	Unit 2 Design
Highest 24-hr Average NO_X mass rate (at stack), lb/hr	3,213[1]	4,562[3]
Avg 24-hr NO_X unit rate (at stack) for highest mass rate, lb/mmBtu	1.025[1]	0.930[3]
Avg 24-hr Boiler Heat Input for highest mass rate, mmBtu/hr	3,135[1]	4,901[3]
Highest 24-hr Average Gross Unit Output, MW_g	256.2[2]	470.2[4]
Highest 30-day Average NO_X mass rate (at stack), lb/hr	2,642	3,726
Avg 30-day NO_X unit rate (at stack) for highest mass rate, lb/mmBtu	0.884	0.874
Avg 30-day Boiler Heat Input for highest mass rate, mmBtu/hr	2,990	4,264
Avg 30-day Gross Unit Output for highest mass rate, MW_g	246.7	450.2
Highest 12-mo Average NO_X mass rate (at stack), lb/hr	2,330	3,840
Avg 12-mo NO_X unit rate for highest mass rate (at stack), lb/mmBtu	0.849	0.786
Avg 12-mo Boiler Heat Input for highest mass rate, mmBtu/hr	2,744	4,885
Avg 12-mo Gross Unit Output for highest mass rate, MW_g	244.4	439.8
Average Capacity Factor for NO_X period, % of Unit NFL	94.1	89.5

(1) – Averages based upon highest actual 24-hour daily period, years 2001-2005, occurred on the same day for unit emissions rate, hourly mass rate, and hourly heat input rate; same-day average 24-hour gross unit output was 249.2 MWg.

(2) – Averages based upon highest actual 24-hour daily period, years 2001-2005; highest 24-hour average gross unit output (MWg) did not occur on the same day as listed unit emissions rate, hourly mass rate, and hourly heat input rate; same day 24-hour average unit emissions rate was 0.831 lb/mmBtu, 24-hour average hourly mass rate was 2,454 lb/hr, and 24-hour average hourly heat input rate was 2,955 mmBtu/hr.

(3) – Averages based upon highest actual 24-hour daily period, years 2001-2005, occurred on the same day for unit emissions rate, hourly mass rate, and hourly heat input rate; same-day average 24-hour gross unit output was 452.5 MWg.

(4) – Averages based upon highest actual 24-hour daily period, years 2001-2005, highest 24-hour average gross unit output (MWg) did not occur on the same day as unit emissions rate, hourly mass rate, and hourly heat input rate; same day 24-hour average unit emissions rate was 0.858 lb/mmBtu, 24-hour average hourly mass rate was 4,427 lb/hr, and 24-hour average hourly heat input rate was 5,158 mmBtu/hr.

UNIT STARTUPS FOR LIGNITE-CYCLONE BOILER NO_X CONTROL

NDDH's BACT Determination for MRYS Unit 1 and Unit 2 will also address specific NO_X emission limitations during Unit startups. Because this determination has not been finalized, and generating high uncontrolled NO_X emissions during startup periods will significantly impact 30-day rolling average NO_X emissions, it is unclear what emission limits may be imposed to MRYS Unit 1 and Unit 2 that address Unit startups. It is anticipated that NO_X emissions produced during startup periods will need to be controlled, recognizing inherent limitations associated with the boilers and technologies selected and installed at MRYS.

As described below, the duration and frequency of recent MRYS Unit startups are important considerations for SCR system vendors in evaluating technical feasibility of installing and successfully operating and maintaining currently-available coal-fired SCR system technology. Comments regarding potential solutions and expected impacts of MRYS Unit startups shall address the ability to maintain SCR control effectiveness during and after startup, and related catalyst life expectations for NO_X emissions reductions on the referenced North Dakota lignite-fired cyclone boilers.

Although the definition of a startup event and the corresponding startup period is not required by a BACT analysis, defining start-ups is provided. This helps to address the specific boiler conditions and emission control 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 the MRYS 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 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 1 or 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 1 and Unit 2 accounts for conditions where cyclone refractory materials replaced during boiler overhauls must be cured by extended low-firing heating cycles, 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. Startups are 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 boiler has been out-of-service (i.e. without fuel firing or megawatt output). Cold starts are defined as starts after the boiler has been without fuel firing for more than 72 hours, warm starts are after the boiler has been without fuel firing for more than 8 hours and less than 72 hours, and hot starts are when the boiler has been without fuel firing for less than 8 hours.

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

- From an hourly emissions standpoint, there was a total of 60 distinct unit startup periods in the five year period, of which six were considered "cold" and 29 were considered "warm", with the balance; as "hot" or interrupted; there were 74 total unit outages, and startup events following multiple unit "trips" in short succession with outage durations less than two hours were counted as one startup period.
- Minimum startup duration was approximately 10 hours for a "hot" start following a boiler master fuel interruption (Unit "trip");
- Maximum startup duration with an extended ramp-up period until full load was reached was 61 hours (0500 hours on 6/27/2005 until 1800 hours on 6/29/2005). This

startup was considered ended 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.

- 7.0 hours per start average for warm-up (i.e. fired operation at zero megawatt output);
- 18.0 hours per start average for ramp-up (i.e. operation above zero megawatts until full load output is achieved);
- Average startup from fuel firing initiation until full load is reached was 25.1 hours.

Analysis of MRY Station Unit 2 operations data from 2001 through 2005 revealed:

- From an hourly emissions standpoint, there was a total of 62 distinct unit startup periods in the five year period, of which 17 were considered "cold" and 20 were considered "warm", with the balance; as "hot" or interrupted; there were 76 total unit outages, and startup events following multiple unit "trips" in short succession with outage durations less than two hours counted as one startup period.
- Minimum startup duration was approximately 14 hours for a "hot" start following a boiler master fuel interruption (Unit "trip");
- Maximum startup duration with an extended ramp-up period until full load was reached was 115 hours (2000 hours on 10/25/01 until 1500 hours on 10/30/01). This startup was considered ended upon reaching a generator output of 451 MW (gross). The criteria of a 6-hour average heat input rate of more than 4800 million Btu per hour was not reached during this startup.
- 7.9 hours per start average for warm-up (i.e. fired operation at zero megawatt output);
- 23.4 hours per start average for ramp-up (i.e. operation above zero megawatts until full load output is achieved);
- Average startup from fuel firing initiation until full load is reached was 31.3 hours.

There are certain boiler operating conditions that need to exist before the advanced SOFA system can be effectively operated with associated boiler combustion procedures for NO_X emissions control at MRYS:

- The numbers of active cyclones and continuous coal firing rates must be enough to establish sufficient:
  - coverage of molten slag on the actively-fired cyclone barrel surfaces and drainage of the slag from the bottom of the boiler; and
  - 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.

The amount and duration of sustained boiler heat input required to establish the operating conditions described above during startup periods are 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 during startup periods and low-load operation are specific to each individual boiler, and are not currently known. The ability to effectively limit NO_X emissions during startup periods and low-load operation following implementation of advanced SOFA is currently uncertain. This could impact NO_X emissions during startups when boiler conditions are suitable for ASOFA operation but flue gas outlet temperatures are not adequate for effective operation of a [potential application of] high-dust SCR.

In a similar line of reasoning, the minimum firing rates of lignite-fired cyclone boilers required to successfully initiate the effective operation of a [potential application of] high-dust SCR technology are not currently known. This could impact NO_X emissions during startups potentially when boiler conditions are not suitable for ASOFA operation but flue gas outlet temperatures are adequate for effective operation of a [potential application of] high-dust SCR.

It should be noted that MRYS cyclone boilers can emit flue gases with NO_X concentrations in excess of 1.0 lb/mmBtu during Unit startups and also during steady-state operation without air-staged combustion associated with a separated overfire air system.

Descriptions of potential solutions needed for proper boiler combustion and continuous slag tapping while limiting NO_X emissions during startup periods, including potential use of a high-dust SCR technology installation will need to recognize inherent limitations associated with the boilers and technologies evaluated and considered technically feasible for selection and installation at MRYS.

TECHNICAL and EPA REFERENCES:

1. EPA Docket References for SCRs:

   EPA-HQ-OAR-2003-0053-1939
   EPA-HQ-OAR-2003-0053-1944
   EPA-HQ-OAR-2003-0053-1945
   EPA-HQ-OAR-2003-0053-1946
   EPA-HQ-OAR-2003-0053-1947
   EPA-HQ-OAR-2003-0053-1948
   EPA-HQ-OAR-2003-0053-1949
   EPA-HQ-OAR-2003-0053-1950
   EPA-HQ-OAR-2003-0053-1951
   EPA-HQ-OAR-2003-0053-1952

2. "*Ash Impacts On SCR Catalyst Performance*", Steven A. Benson, Ph.D., Energy & Environmental Research Center (EERC) of the University of North Dakota", October 2005.

Additional Attachments:

3. *Center Lignite Coal Quality Characteristics, April 2007*, with data primarily provided by the Energy & Environmental Research Center (EERC) of the University of North Dakota, (34 pages).

4. Original boiler manufacturer's predicted performance data sheets and side elevation view drawings for each MRYS boiler (Babcock & Wilcox), (4 pages).

The Energy & Environmental Research Center (EERC) of the University of North Dakota is recognized as the primary source of the following data. EERC has extensive experience investigating the deposition characteristics of North Dakota lignite ash. This data must be considered for impacts to the overall technical feasibility and design criteria of any SCR system proposed for Unit 1 and Unit 2 cyclone boilers that fire North Dakota lignite coal at the Milton R. Young Station of Minnkota Power Cooperative, Inc. (Minnkota) and Square Butte Electric Cooperative (Square Butte).

Center Lignite Coal Quality Characteristics

North Dakota lignite has high levels of alkali and alkaline earth elements present in the ash. These elements react with aluminosilicates producing low viscosity (low melting point silicate based liquids) phases and with sulfur producing sulfates and pyrosulfate. These elements contribute to the formation deposits on ceramic/refractory surfaces, cyclones, heat transfer surfaces, SCR catalysts, and gas filters. Formation of these deposits will lead to operability problems, with the potential to shut down the system. Lignite composition is highly variable, and therefore will contribute to a range of challenges. As a result of these challenges and efforts to identify problematic species a significant database of selected North Dakota lignite, specifically Center lignite, which will provide the basis for the projection of potential challenges.

Lignite fired at the Milton R. Young (MRY) plant is mined from three seams, the Kinneman Creek (KC), Hagel A (HA), and Hagel B (HB). The results of analysis and interpretations for selected samples indicate that coal from the Kinneman Creek (KC) seam typically has higher ash content and most of the ash is derived from minerals in the coal. This has been ascertained by comparing the mineral content with the dry ash content of the coals. The sodium content for KC coal is much lower than the HA and the HB coal. The base-to-acid ratio is lower for the KC as compared to the HA and HB lignite. The low base-to-acid ratio results in high-viscosity slag or ash materials that have presented challenges to slag flow at MRY Unit 1 and Unit 2. High base-to-acid ratio materials, along with high sodium, can contribute to the formation of very difficult to remove deposits on heat transfer surfaces and creates a cohesive ash that bonds together in the electrostatic precipitator (ESP) causing challenges in removing the material from the ESP flyash collection hoppers.

As-fired Database

The as-fired coal database consists of 1316 samples of coal collected using sampling systems on Unit 2. Table C1 summarizes the analysis of the database using averaging and selection of a coal type based on sodium content of the ash and other criteria. The goal is to identify coal or coals that can be used to assist in identifying feasible technologies that can utilize Center lignite. The challenges in the use of averages is that once the averages are calculated and compared to the database they do not represent any typical coal samples in the database.

The average cases identified for Case 1 in Table C1 is an average of all data. Case 2a is the average of coals having sodium levels in the ash at or above the 95th percentile. Case 2b is a blend of the average Case 1 with 25% of the high sodium case from 2a. Case 2c is the average composition of the coal at the 95th percentile. Case 2d is a blend of the coal at the 95 percentile with 75% of Case 1 coal. Case 3 is an average of a challenging coal type based on sodium content above the 95th

percentile, ash content at the 10th percentile, sulfur at the 50th percentile, and iron content at the 50th percentile.

Figures C1 through C6 show the frequency distributions with the 10th, 50th, and 90th percentile values for sodium in ash, ash content, heating value, sulfur content, and base-to-acid ratio in the as-fired database for Center lignite coal.

Table C1. Average compositions derived from the as-fired database - Center Lignite Coal

1. Average composition, normalized to 100%

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.13	9.64	0.98	6578	25.26	27.96	11.74	13.22	8.95	4.01	0.07	0.12	1.34	36.23	4.43	18.49	0.47	0.72

2. Average composition blended with high-Na2O (at/at and above 95th perc):

2a. Average composition of coal(s) containing Na2O at or above 95th Perc, normalized to 100%

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.90	6.22	0.75	6932	25.83	30.04	7.73	19.12	9.62	5.74	0.06	0.26	0.58	20.10	10.22	24.86	0.27	1.66

2b. Blend 2a coal with 1 coal, use 75% Na2O from 1 and 25% Na2O from 2a

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.13	9.64	0.98	6578	25.26	27.96	11.74	13.22	8.95	4.01	0.07	0.12	1.34	36.23	5.88	18.49	0.47	0.72

2b normalized to 100%: CANDIDATE PERFORMANCE COAL

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.13	9.64	0.98	6578	25.26	27.96	11.68	13.15	8.90	3.99	0.07	0.12	1.33	36.04	5.85	18.39	0.47	0.72

2c. Average composition of coal(s) containing Na2O at 95th Perc, normalized to 100%

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.77	7.06	0.82	6851	25.85	29.33	8.33	16.45	9.74	5.36	0.06	0.25	0.92	24.12	8.81	24.41	0.31	1.38

2d. Blend 2c coal with 1 coal, use 75% Na2O from 1 and 25% Na2O from 2c

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.13	9.64	0.98	6578	25.26	27.96	11.74	13.22	8.95	4.01	0.07	0.12	1.34	36.23	5.52	18.49	0.47	0.72

2d normalized to 100%:

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.13	9.64	0.98	6578	25.26	27.96	11.72	13.20	8.94	4.00	0.07	0.12	1.34	36.17	5.51	18.46	0.47	0.72

3. CANDIDATE DESIGN COAL - Na2O>90th Perc, Ash-10th Perc, S - 50th Perc B/A > 90th Perc, Fe2O3 = 50th Perc *Slide 25

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
38.13	7.00	0.76	6785	25.30	29.58	9.45	17.93	9.42	5.17	0.08	0.17	0.86	26.35	8.24	20.68	0.35	1.18

4. Average Composition, with the upper 5% of high sodium cases removed.

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
37.1	9.8	1.0	6658.9	25.2	27.9	11.9	12.8	8.9	3.9	0.1	0.1	1.4	36.9	4.1	18.0	0.5	0.7

4a. CHALLENGING DESIGN COAL -- Average Composition, with the upper 5% of high sodium cases removed, at the 90th Perc Na2O.

Moisture	Ash	Sulfur	Btu	Volatile Matt	Fixed Carbo	Al2O3	CaO	Fe2O3	MgO	MnO2	P2O5	K2O	SiO2	Na2O	SO3	TiO2	Base/Acid Ratio
38.08	12.56	1.303	6767	26.22	29.2	13.823	16.6	11.1	4.8	0.1	0.2	1.8	44.2	6.75	24.8	0.6	0.95

See notes below Table C2 for sample analytical basis.

Table C2 summarizes the average, maximum and minimum values for the entire as-fired coal database. The ranges on the various components can be very large. For example, the ash content ranges from 5 to 25%. Sodium oxide content ranges from 0.6 to 13% of the ash.

Table C2. Average, maximum, and minimum of basic coal analysis for all the coals in the as-fired database - Center Lignite Coal

ID NUMBER	Moisture	Ash	Sulfur	Btu	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Basic total	Acid Total	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2			
Average	37.1	9.64	1.0	6578.1	25.3	28.0	11.7	0.5	13.2	8.9	4.0	0.1	0.1	1.3	36.0	4.4	0.4	18.4	0.5			0.7
Max	39.4	25.5	2.6	7101.0	31.1	31.2	15.6	1.2	24.0	24.7	7.1	0.3	1.0	2.3	56.0	13.0	37.0	34.5	0.7			2.5
Min	33.6	5.0	0.5	5852.0	22.3	13.7	6.3	0.2	6.8	5.4	2.3	0.0	0.0	0.2	12.3	0.6	0.2	8.1	0.2			0.3
90th Perc.	38.10	12.51	1.29	6820	26.5	29.9	14.2	0.8	19.9	12.2	5.7	0.1	0.4	1.9	46.0	8.71	0.6	26.3	0.6			1.26
10th Perc.	35.95	7.06	0.72	6359	24.3	26.1	9.6	0.4	9.7	7.1	3.0	0.1	0.0	0.6	22.7	1.99	0.2	14.4	0.4			0.44
45th Perc.	37.17	9.33	0.90	6552	25.2	28.0	11.6	0.5	12.2	8.3	3.8	0.1	0.1	1.4	37.0	4.09	0.3	17.3	0.5			0.592
55th Perc.	37.37	9.75	0.94	6592	25.4	28.3	12.0	0.5	12.7	8.7	4.0	0.1	0.1	1.4	38.4	4.61	0.4	18.0	0.5			0.637

1. Ash weight percent was determined on an "as-fired" lignite coal basis.
2. BTU (higher heating value) content expressed on an "as-fired" lignite coal basis.
3. Constituent weight percent of the ash, elemental weight percent expressed as equivalent oxide.
4. B/A is the base to acid weight ratio of the ash constituents ($B/A=[Na_2O+MgO+CaO+K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$).

Table C3 shows the average, maximum, and minimum values obtained for the coal samples that have sodium oxide contents in the ash at and above the 95th percentile.

Table C3. Average, maximum, and minimum of basic coal analysis for coals with sodium contents at and above the 95th percentile form the as-fired database - Center Lignite Coal

ID NUMBER	Moisture	Ash	Sulfur	Btu	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Basic total	Acid Total	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2			
Average	37.9	6.3	0.8	6929	25.8	30.0	7.7	0.8	19.0	9.6	5.7	0.1	0.3	0.6	20.0	10.2	0.7	24.8	0.3			1.7
Max	38.7	8.8	1.2	7101	28.1	31.2	11.1	1.0	23.6	14.8	7.1	0.1	0.4	1.5	34.7	13.0	0.9	31.8	0.4			2.2
Min	36.5	5.0	0.5	6638	24.5	27.8	6.3	0.5	14.8	6.0	4.9	0.1	0.1	0.4	14.5	8.7	0.5	15.2	0.2			1.0
90th Perc.	38.24	6.95	0.92	7004	26.25	30.51	8.93	0.85	21.08	12.32	6.27	0.07	0.33	0.77	25.89	11.19	0.8	28.6	0.3			1.94
10th Perc.	37.57	5.59	0.58	6835	25.36	29.35	6.64	0.68	17.03	7.23	5.11	0.05	0.16	0.46	16.84	9.10	0.6	19.9	0.2			1.26
45th Perc.	37.88	6.13	0.72	6932	25.78	30.05	7.48	0.75	18.88	9.17	5.67	0.06	0.26	0.52	18.59	10.04	0.7	25.3	0.3			1.689
55th Perc.	37.96	6.24	0.76	6937	25.85	30.16	7.58	0.77	19.29	9.43	5.77	0.06	0.28	0.55	19.17	10.18	0.7	26.0	0.3			1.744

See notes below Table C2 for sample analytical basis.

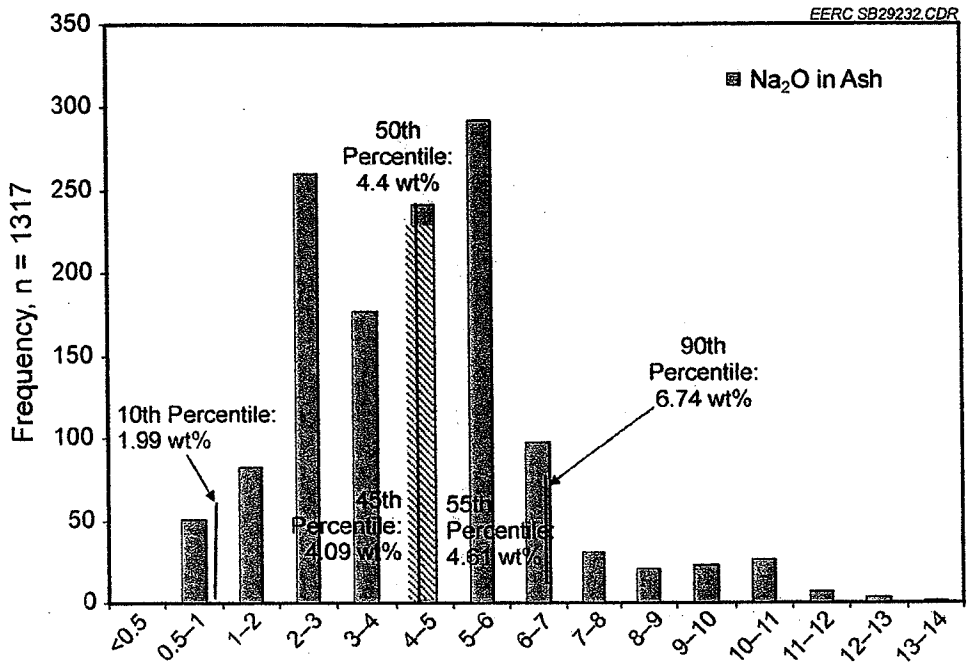


Figure C1. Frequency distribution of sodium oxide contents for the entire as-fired Center lignite coal database.

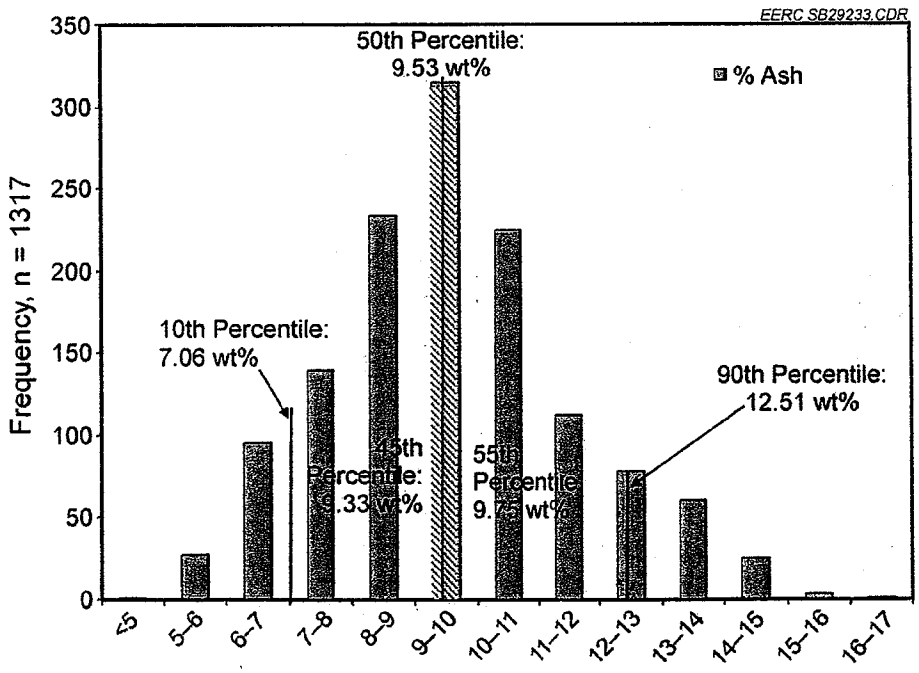


Figure C2. Frequency distribution of ash content for the entire as-fired Center lignite coal database. (one sample with 25.5 % ash content was counted in the database sample frequency = 1317 but not shown in the plot of data for this graph)

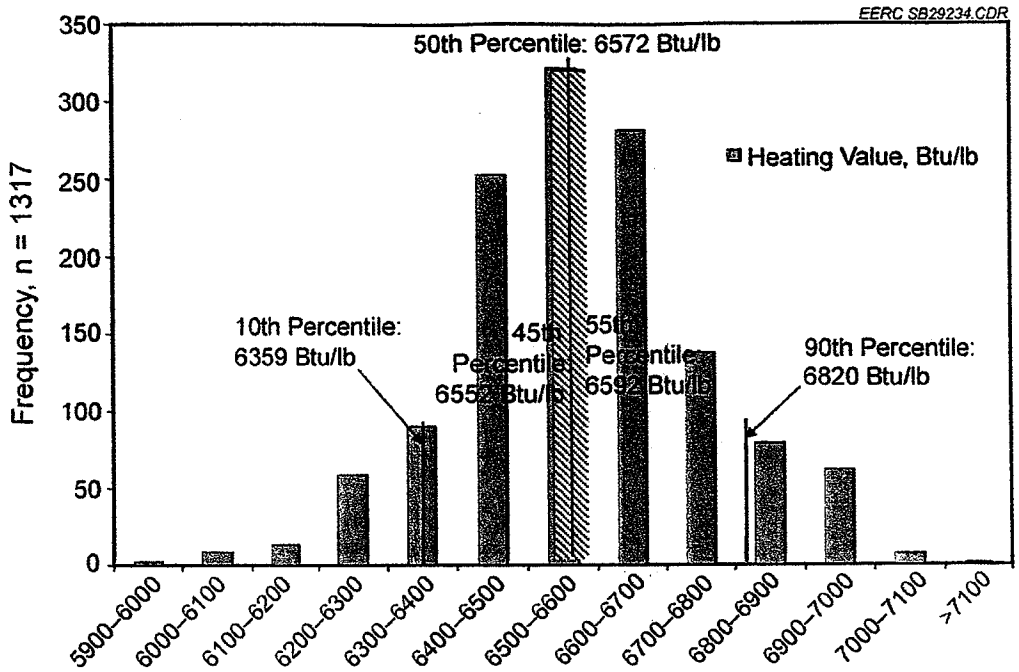


Figure C3. Frequency distribution of heating value in BTU/lb for the entire as-fired Center lignite coal database.

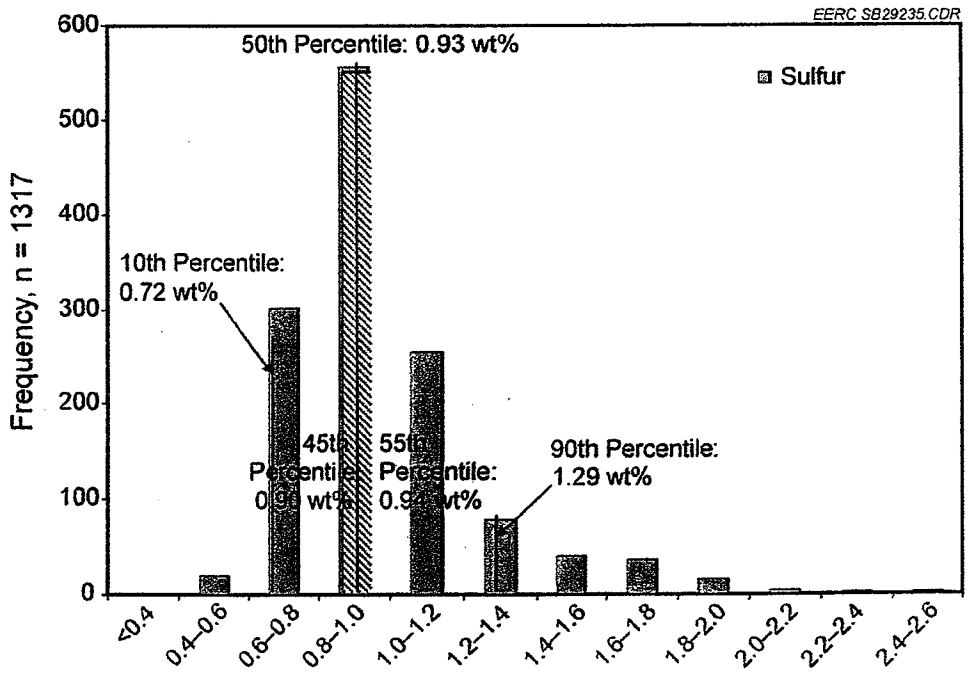


Figure C4. Frequency distribution of sulfur content for the entire as-fired Center lignite coal database.

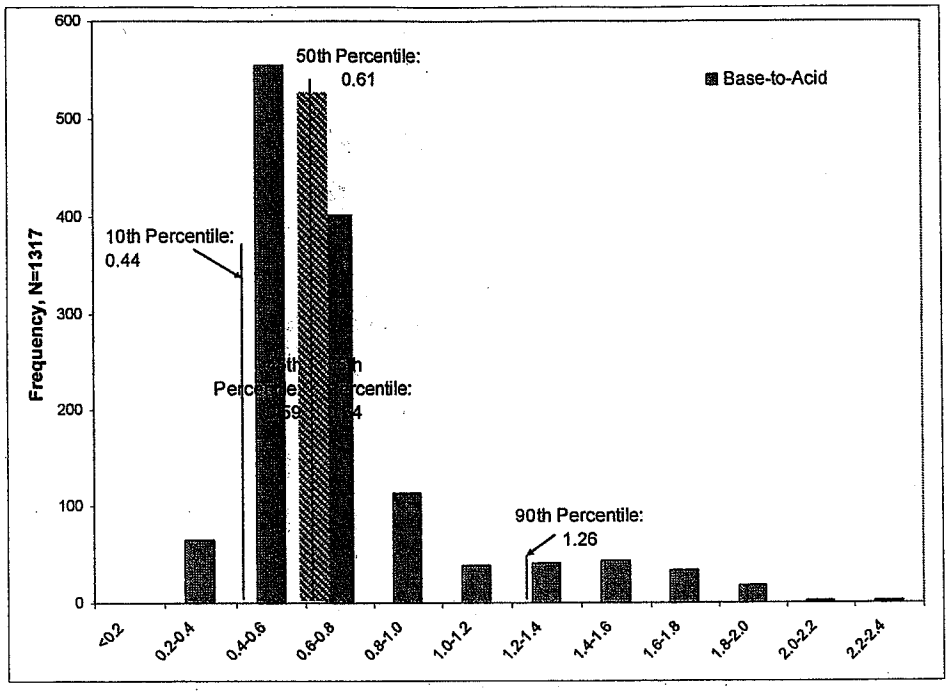


Figure C5. Frequency distribution of the base-to-acid ratio for the entire as-fired Center lignite coal database.

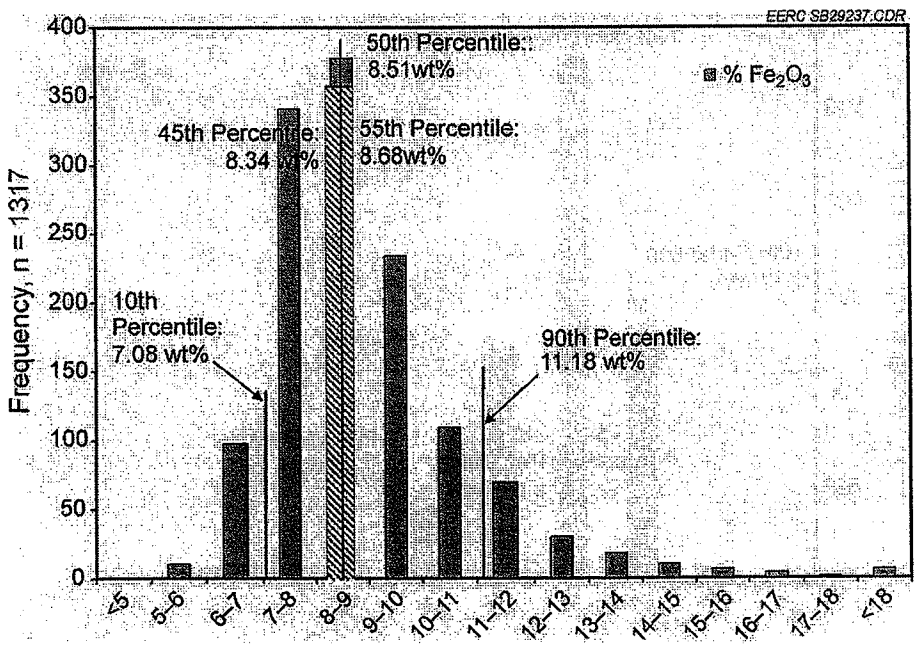


Figure C6. Frequency distribution of the iron oxide content for the entire as-fired Center lignite coal database.

Core Database - Center Lignite Coal

The Center lignite coal core database was analyzed using methods similar to that used for the as-fired database. Table C5 provides an overview of the average, minimum, maximum, and selected percentiles for the entire database of over 3000 samples.

Table C5. Summary of Core database, showing average, minimum, and maximum values, and selected percentiles for available data - Center Lignite Coal

	Moisture as-rec'd	Ash as-rec'd	Sulfur as-rec'd	Btu as-rec'd	Volatile Matter	Fixed Carbon	Aluminum Oxide	Barium Oxide	Calcium Oxide	Iron Oxide	Magnesium Oxide	Manganese Dioxide	Phosphorus Pentoxide	Potassium Oxide	Silicon Dioxide	Sodium Oxide	Strontium Oxide	SO3	Titanium Dioxide	Undetected	Base/Acid Ratio
							Al_2O_3	Ba	CaO	Fe_2O_3	MgO	Mn	P_2O_5	K_2O	SiO_2	Na_2O	Sr	SO_3	TiO_2		
Average	37.41	8.41	1.2	6730	25.9	28.3	10.3	0.5	15.6	11.0	4.4	0.1	0.1	0.9	29.0	4.8	0.4	21.8	0.5	0.4	1.1
Max	38.4	22.2	6.0	7686	31.8	38.6	21.5	3.4	29.7	44.2	9.1	0.6	3.4	2.9	65.3	16.2	0.9	35.8	1.3	3.0	3.0
Min	33.4	3.7	0.3	5603	21.7	18.2	2.1	0.0	6.2	2.9	0.3	0.0	0.0	0.2	10.0	0.3	0.1	7.2	0.0	-2.9	0.3
90th Perc.	38.29	12.14	1.8	7007	27.2	30.6	13.5	0.9	21.6	18.2	5.9	0.1	0.3	1.6	44.8	9.8	0.6	29.3	0.7	2.4	2.1
10th Perc.	36.17	5.54	0.6	6387	24.6	25.8	7.0	0.2	9.9	5.3	3.0	0.0	0.0	0.4	14.8	0.9	0.2	14.3	0.3	-1.5	0.4
45th Perc.	37.54	7.55	1.0	6741	25.9	28.2	9.9	0.4	14.7	9.3	4.2	0.1	0.1	0.8	26.6	3.5	0.4	21.2	0.4	0.2	0.9
55th Perc.	37.74	8.21	1.1	6804	26.1	28.7	10.7	0.5	15.8	10.6	4.5	0.1	0.1	0.9	30.0	5.0	0.4	22.6	0.5	0.6	1.0
50th Perc.	37.65	7.83	1.0	6775	26.0	28.5	10.3	0.5	15.2	10.0	4.3	0.1	0.1	0.9	28.4	4.2	0.4	21.9	0.5	0.4	0.9

See notes below Table C2 for sample analytical basis.

Comparison of As-Fired and Core Databases with Future Center Lignite Coal Composition Projections

Ten-year weighted averages for percent ash, total sulfur, sodium in ash, heating value, and base-to-acid ratio were calculated based on the data for future Center Lignite characteristics, which projected coal quality to the year 2064. The weighted averages are summarized for five- and ten-year spans in Tables C5 and C6, respectively. The weighted averages were determined using the yearly forecasted production quantity and the yearly forecasted coal quality for all seams. The ten-year averages were compared to the average from the BNI core database and to the frequency distribution for the Minnkota as-fired Center lignite coal database.

Table C5. Weighted averages heating value, sulfur, sodium oxide in ash and base/acid ratio for projected 5 year spans - Center Lignite Coal

Average – 5-year spans	Total Lignite Production, x1000 tons	Btu/Lb	Ash (%)	Sulfur (%)	Sodium (%) - in Ash	Base/Acid Ratio
2006 - 2010	22506.41	6630.47	8.98	0.85	5.40	1.21
2011 - 2015	26104.13	6448.82	9.96	0.87	4.97	1.27
2016 - 2020	40261.8	6399.03	9.20	0.84	4.49	1.13
2021 - 2025	39861.75	6375.41	9.71	0.88	4.49	1.72
2026 - 2030	38970.98	6599.33	8.94	0.84	5.89	1.39
2031 - 2035	39996.39	6608.67	8.64	0.83	5.69	1.08
2036 - 2040	40099.49	6585.56	9.25	0.85	4.98	1.03
2041 - 2045	40150.75	6560.63	9.13	0.83	5.99	1.17
2046 - 2050	40017.32	6591.68	8.79	0.76	6.38	1.22
2051 - 2055	40115.88	6554.88	7.67	0.64	4.58	1.51
2056 - 2060	40138.38	6523.99	8.28	0.68	5.46	1.00
2061 - 2064	32044.57	6471.77	8.34	0.72	6.25	1.46

See notes below Table C2 for sample analytical basis.

Table C6. Weighted averages heating value, sulfur, sodium oxide in ash and base/acid ratio for projected 10 year spans - Center Lignite Coal

Average – 10-year spans	Total Lignite Production, x1000 tons	Btu/Lb	Ash (%)	Sulfur (%)	Sodium (%) - in Ash	Base/Acid Ratio
2006 - 2015	48610.55	6532.92	9.50	0.86	5.17	1.24
2016 - 2025	80123.55	6387.28	9.45	0.86	4.49	1.42
2026 - 2035	78967.37	6604.06	8.78	0.84	5.79	1.24
2036 - 2045	80250.24	6573.09	9.19	0.84	5.48	1.10
2046 - 2055	80117.38	6574.56	8.23	0.70	5.48	1.36
2056 - 2064	72182.96	6500.81	8.31	0.70	5.81	1.20

See notes below Table C2 for sample analytical basis.

The ten-year averages were compared to the average from the BNI core database and to the frequency distribution for the Minnkota as-fired Center lignite coal database.

The ten year averages for percent ash, total sulfur, percent sodium oxide in ash, base/acid ratio, and heating values of Center lignite coal were plotted on the frequency distribution plotted based on the BNI core as-fired database in Figures C7-11.

Figure C7 shows the projected future ash values of Center lignite coal compared to the as fired database. The data from 2006-2015 show similar data to the as fired database with decreasing levels of ash in the latter years.

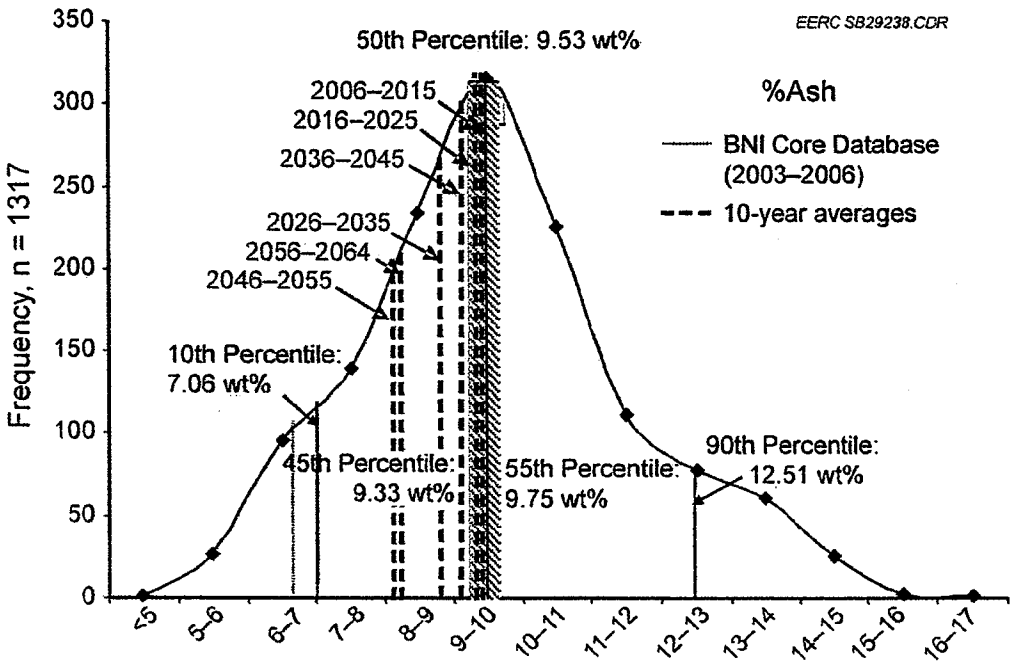


Figure C7. Ash frequency distribution for as-fired database compared to 10 year averages and weighted Core Database values - Center Lignite Coal

Similarly for the sulfur content depicted in Figure C8, this graph shows the sulfur level in the near term will be similar to the BNI core as-fired database for Center lignite coal but will be dropping in future 10 year intervals.

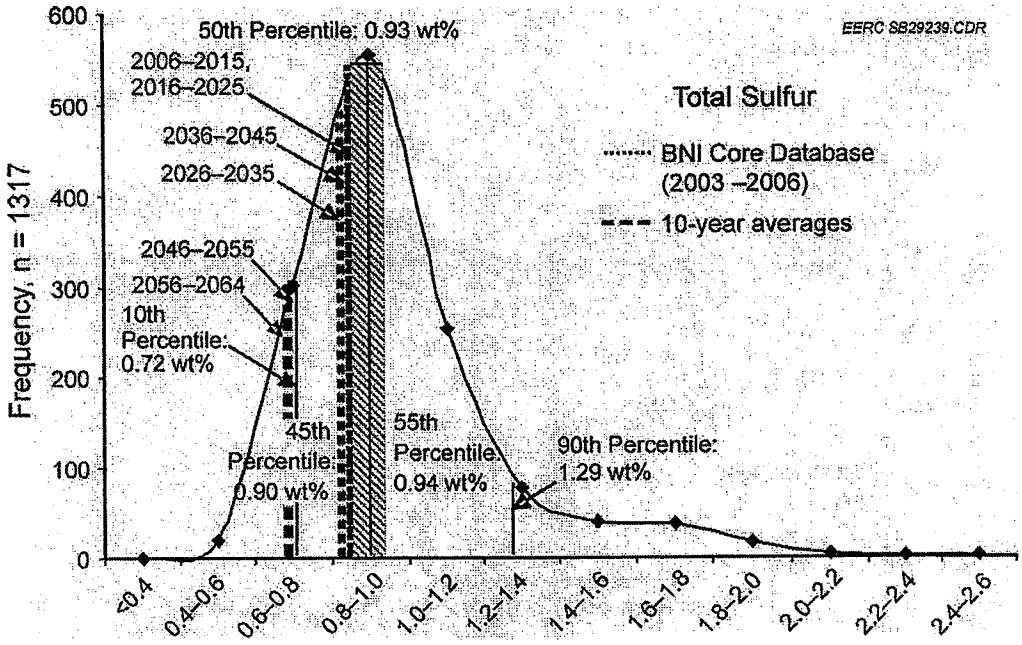


Figure C8. Total sulfur frequency distribution for as-fired database compared to 10 year averages and weighted Core Database values - Center Lignite Coal

The frequency distribution of the sodium content of the ash in Center lignite coal is shown in Figure C9. The projections for the future have similar sodium levels to the upper mode of sodium contents in the BNI core as-fired database for Center lignite coal. The sodium content of the future coals appear to be decreasing initially from the upper mode and then increasing from 2036-2064.

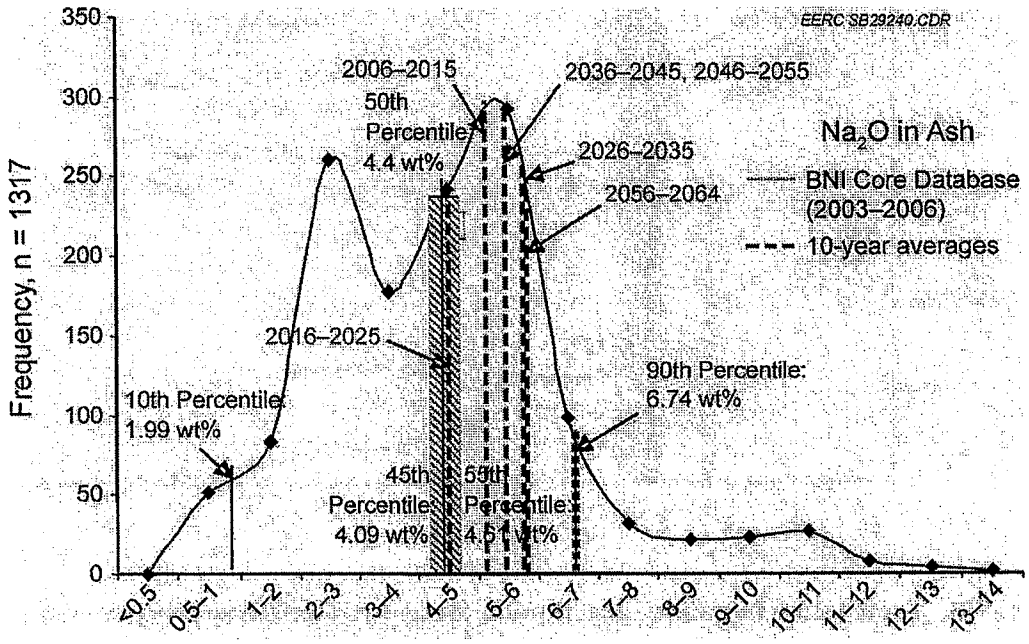


Figure C9. Sodium oxide in ash frequency distribution for as-fired database compared to 10 year averages and weighted Core Database values - Center Lignite Coal

The base to acid ratio of Center lignite coal shown in Figure C10 indicates coals typical of lower ash contents and high levels of sodium, calcium, potassium and iron relative to silicon, aluminum and titanium. This information suggests that the future coals will have a higher propensity on average to cause low temperature fouling than coals fired over the past several years.

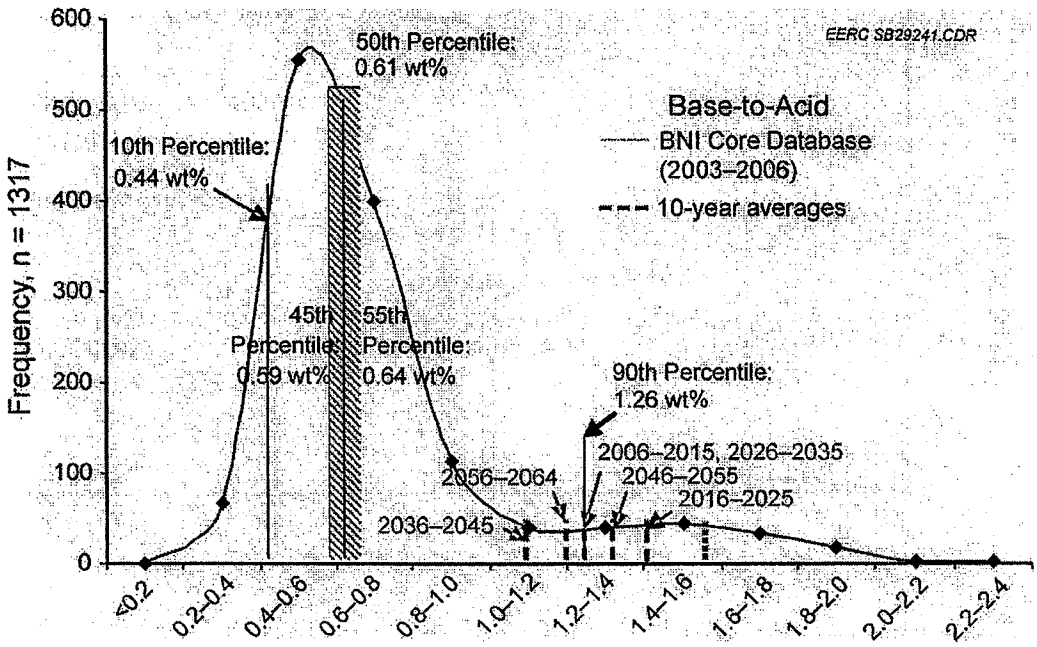


Figure C10. Base to acid ratio of ash frequency distribution for as-fired database compared to 10 year averages and weighted Core Database values - Center Lignite Coal

Figure C11 shows the distribution of the heating value measurements for the Center lignite coal as-fired database compared with future coal properties indicate similar values, with a decrease in 2016-2025.

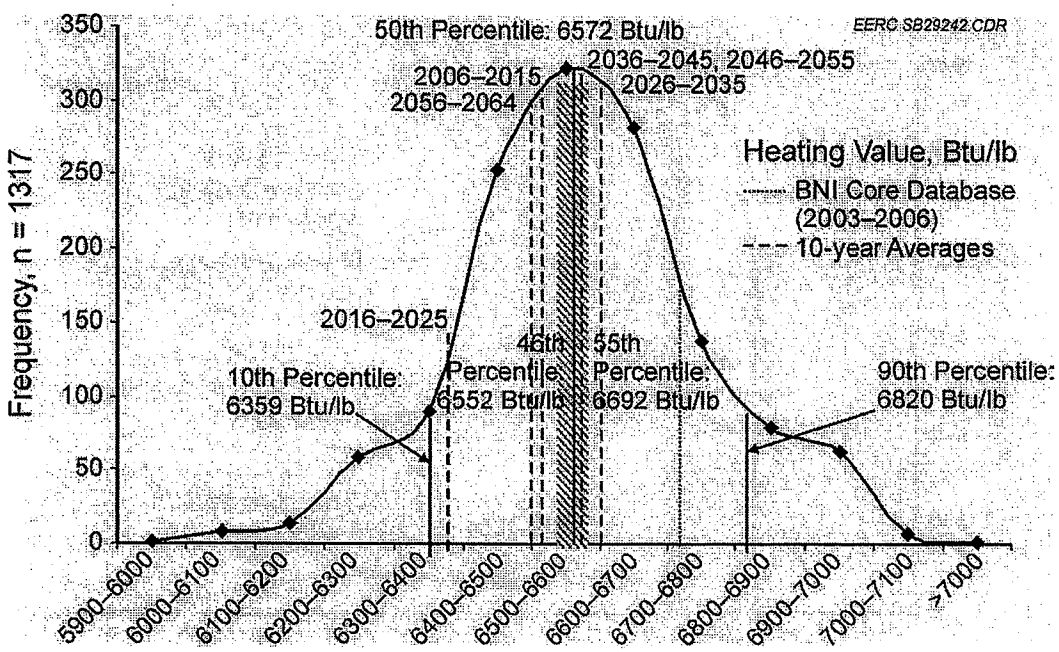


Figure C11. Heating value frequency distribution for as-fired database compared to 10 year averages and weighted BNI Core Database values - Center Lignite Coal

Available Alkali and Alkaline Earth Element Analysis

Sodium in Center lignite is associated in the ground water and with the organic matrix of the coal (Benson and Holm, 1985; and Schobert, 1995). Very little of the sodium is associated with the mineral fraction of the coal such as clays. During combustion the sodium in the water soluble and organic association will vaporize and become dispersed in the gas stream. Combustion Engineering [Alstom] conducted an analysis of the impact of soluble and organically associated sodium along with fouling potential (Singer, 1981). The results of the analysis are summarized in Table C7. The soluble alkali is shown for lignite and subbituminous coals is very high, with North Dakota Lignite and Montana high sodium subbituminous coals having the highest available sodium for low temperature fouling processes.

Table C7. Comparative alkali content analysis for U.S. Coals (Singer, 1981).

Rank Region	Lignite ND	Sub B MT	Lignite TX (Yegua)	Lignite TX (Wilcox)	hvBb UT	hvAb PA	Lignite TX (Wilcox)
HHV, Btu/lb, Dry Basis	10640	12130	7750	9710	12870	13200	8420
Ash Composition (%)							
SiO_2	20.0	33.9	62.1	52.3	52.5	51.1	57.9
Al_2O_3	9.1	11.4	15.1	17.4	18.9	30.7	21.8
Fe_2O_3	10.3	10.8	3.5	5.3	1.1	10.0	3.9
CaO	22.4	21.0	6.2	9.4	13.2	1.6	7.1
MgO	6.4	2.7	0.7	3.2	1.3	0.9	2.1
Na_2O	5.0	5.8	3.6	0.9	3.8	0.4	0.7
K_2O	0.5	1.6	1.9	1.2	0.9	1.7	0.8
TiO	0.4	0.7	0.9	1.2	1.2	2.0	1.1
SO_3	21.9	12.0	6.1	9.6	6.2	1.4	4.4
Fouling Potential	Severe	High	High	Moderate	Moderate	Low	Low
Lb Ash/10^6 Btu, Dry Basis	9.0	4.6	43.3	20.1	7.9	10.2	34.4
Acetic-Acid-Soluble							
Sodium (Na, ppm)	3980	2680	9650	1030	1120	250	340
Potassium (K, ppm)	...	...	1230	85	85	...	110
Alkali in Ash, % Wt.							
Na_2O	5.0	5.8	3.6	0.9	3.8	0.4	0.7
K_2O	0.5	1.6	1.9	1.2	0.9	1.7	0.8
Equiv. Sol. Alkali in Ash, % Wt. of Ash							
Na_2O	5.58	6.45	3.88	0.71	1.49	0.15	0.16
K_2O	...	...	0.44	0.04	0.08	...	0.05
% Sol. Alkali of Total (Equiv. Sol. Na_2O)/ (Na_2O in Ash)	112	111	108	79	39	38	23
(Lbs Sol. Na)/ (10^6 Btu Fired)	0.374	0.221	1.245	0.106	0.087	0.018	.040
(Lbs Sol. Na)/(lb Ash/ 10^6 Btu Fired)	0.044	0.048	0.223	0.005	0.014	0.002	0.001

The vaporized sodium is free to react with, and/or deposit on, entrained ash particles and heat transfer surfaces. A method called chemical fractionation has been developed to provide data on the associated of elements in coals (Benson and Holm, 1985). Elements removed by water (H_2O) are primarily associated with water-soluble minerals (e.g., alkali sulfates). Exchangeable ions, principally elements associated with salts of organic acids, are removed by ammonium acetate (NH_4OAc). Hydrochloric acid (HCl) removes elements associated with acid-soluble minerals (carbonates and oxides). Elements remaining in the final residue are presumably associated with insoluble silicate and sulfide minerals. Recent analysis of as-fired Center lignite samples collected during testing at MRY are summarized in Tables C8 and C9. The sodium oxide contents of the coals ranged from 5.92 to 9.24 % of the ash during a month-long testing program at MRY conducted primarily for mercury (Benson et al., 2006).

Table C8. Proximate and ultimate analysis of Center Lignite fired in MRY Unit 2.

	Overall		Baseline Testing		Long-Term Testing	
Parameter, Unit	**Average**	**Std. Dev.**	**Average**	**Std. Dev.**	**Average**	**Std. Dev.**
Proximate						
Moisture, wt%	35.8	0.8	35.8	0.7	35.8	0.9
Volatile Matter, wt%	27.2	0.8	28.0	0.5	26.8	0.5
Fixed Carbon, wt%	29.6	0.9	28.9	0.9	29.9	0.7
Ash, wt%	7.46	1.26	7.25	0.49	7.56	1.55
Ultimate						
Hydrogen, wt%	6.84	0.12	6.92	0.04	6.78	0.14
Carbon, wt%	40.1	0.9	39.6	1.4	40.5	0.4
Nitrogen, wt%	0.77	0.02	0.75	0.01	0.79	0.01
Sulfur, wt%	0.95	0.21	0.79	0.01	1.05	0.22
Oxygen, wt%	43.7	1.5	44.9	1.0	42.9	1.3
Heating Value, Btu/lb	6768	212	6614	240	6870	150

Weight percentages and higher heating value (Btu/lb) expressed on an "as-fired" lignite coal basis.

Table C9. Triplicate and Average MRY Coal Ash Elemental Oxide Compositions, wt%

Elemental Oxide	4/12–15/05	4/26–28/05	5/11/05	Average	Std. Dev.
SiO_2	20.6	22.0	32.7	25.1	6.6
Al_2O_3	9.45	11.2	12.2	11.0	1.4
TiO_2	0.37	0.64	0.62	0.54	0.15
Fe_2O_3	9.35	6.38	6.05	7.26	1.82
CaO	17.3	23.5	14.4	18.4	4.6
MgO	6.29	7.56	6.07	6.64	0.80
Na_2O	7.39	5.92	9.24	7.52	1.66
K_2O	0.72	0.60	1.31	0.88	0.38
P_2O_5	0.17	0.09	0.12	0.13	0.04
SO_3	27.4	21.2	16.1	21.6	5.7
BaO	0.56	0.43	0.77	0.59	0.17
Total	99.6	99.4	99.5	99.5	0.1

Constituent weight percentages expressed on an "as-fired" lignite coal basis.

Average chemical fractionation results for the three MRY coal samples are presented in Table C10. Average results are presented because the chemical fractionation results for all three samples were statistically similar with standard deviations of <1%. Certain elements (e.g., Si, Al, and Ti) are not included in Table C10 because they were not removed significantly during the extraction procedure. These insoluble elements are generally associated with the aluminosilicate (e.g., mixed clays and kaolinite [$Al_2Si_2O_5(OH)_4$]), silicate (e.g., quartz [SiO_2]), and oxide (e.g., rutile [TiO_2]) mineral components of the MRY coal.

About 20% of the Na in MRY coal was water-soluble, suggesting that it occurs dissolved in moisture or as a salt (e.g., NaCl and $NaSO_4$). The remaining Na was extracted using NH_4OAc, indicating an organic association. Essentially all of the Ca and Mg in MRY coal were extracted using NH_4OAc and HCl indicating an organic and carbonate association. These results indicate a significant proportion of the sodium will vaporize and be available for downstream reactions.

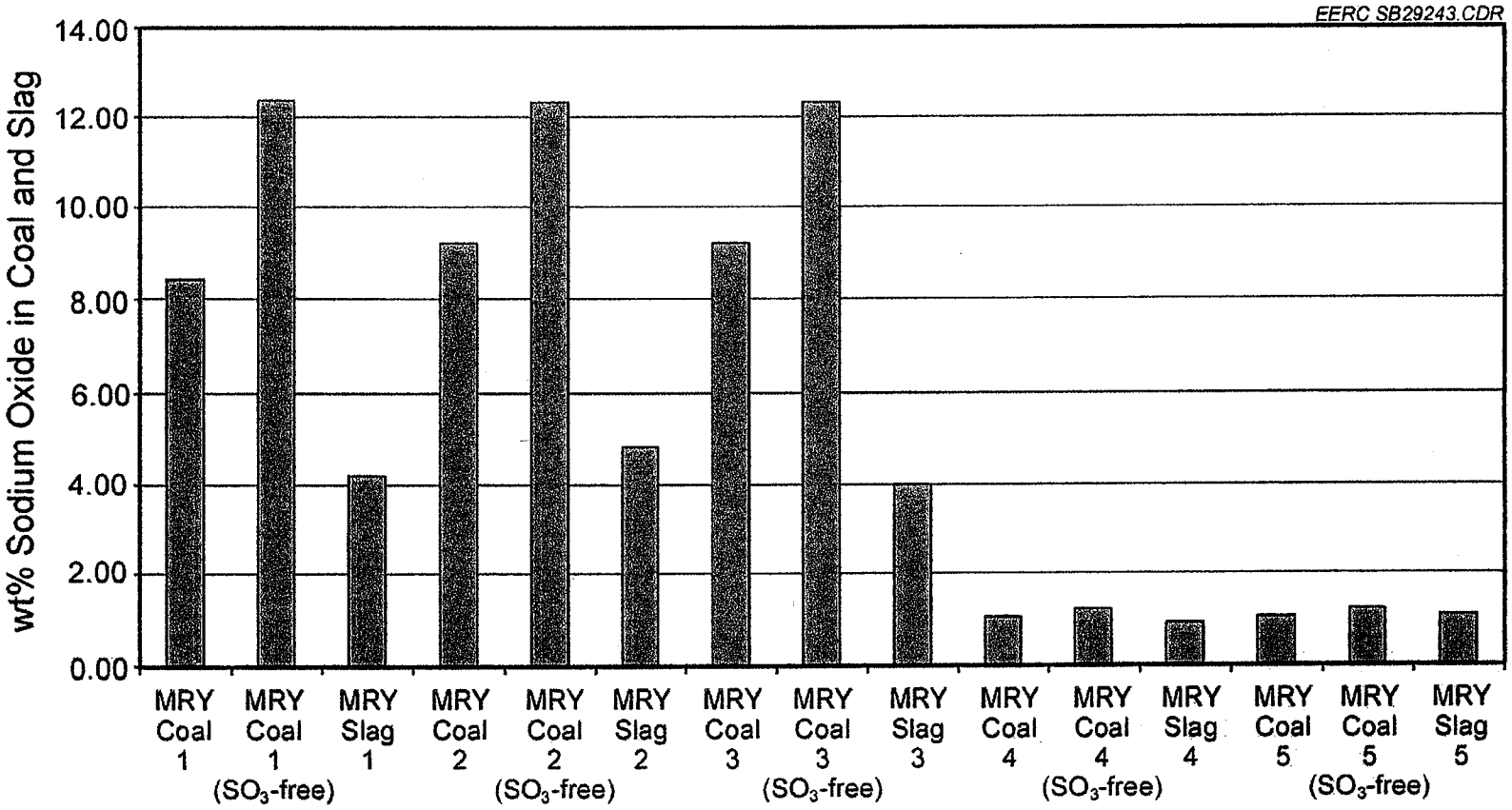
Table C10. Average MRY Coal Chemical Fractionation Results, % removed

Element	H_2O Soluble	NH_4OAc Soluble	HCl Soluble
Fe	<5	<5	39
Ca	<5	51	45
Mg	7	60	27
Na	17	81	<5
K	<5	6	<5

Partitioning of Sodium in MRY Unit #2

The partitioning of the ash forming constituents between the slag and coal is shown in Figure C12. The results show that the sodium present in the as-fired coal ash presented with and without SO_3. The retention of sulfur in the ash is an artifact of the ashing procedure. Comparing the level of sodium in the slag as compared to the coal fired for the high sodium cases, only about half of the total sodium present in the coal is retained in the slag. The slag samples were recovered from the slag tap for the boiler. These slag samples include deposits that fall from the walls and the high temperature convective pass.

Figure C12. Comparison of sodium levels in Center lignite coal and slag samples.



Figures C13 and C14 show actual data from the Milton R. Young (MRY) plant on the time-dependency of lignite variability that show the changes in both the ash content (moisture-free basis) and base-to-acid ratio (B/A=[Na_2O+MgO+CaO+ K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]). The B/A ratios are an effective way of examining variability and ash behavior performance. The variability in ash (moisture-free basis) shows extreme changes in as-fired coal properties. Also included is cyclone performance that indicates slag freezing when the value drops from 7000 to 6000.

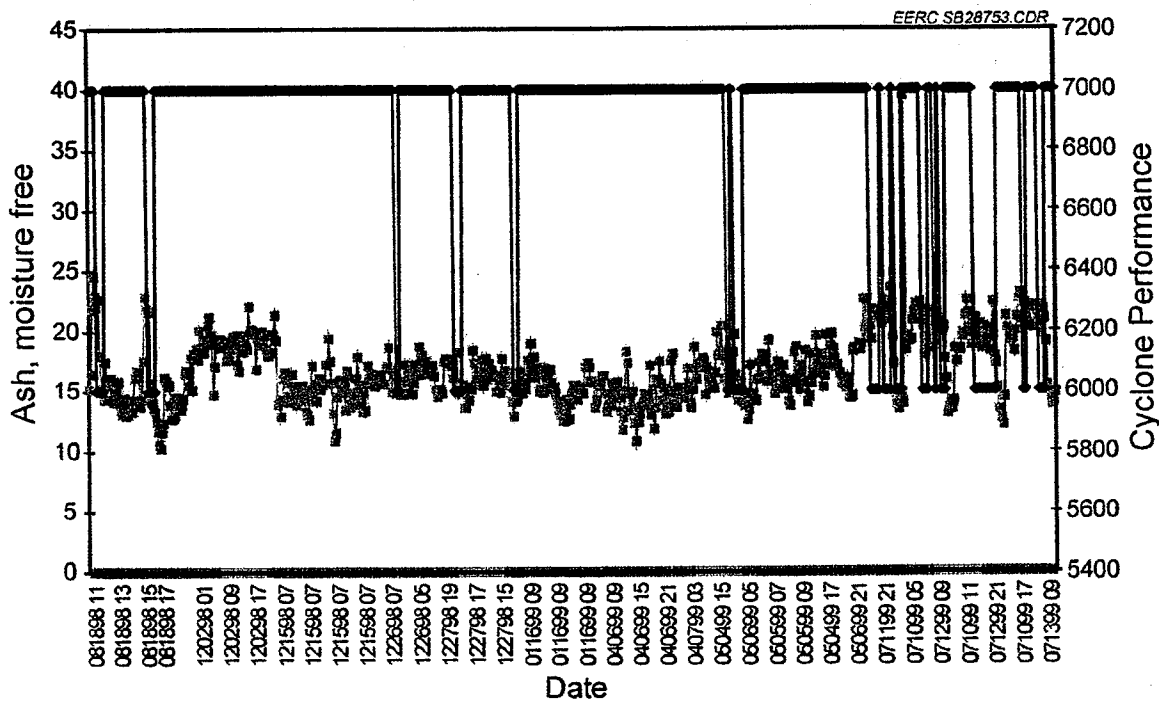


Figure C13. Moisture-free ash content of as-fired coal samples showing variability.

The need to co-fire fuel oil in one or more cyclones for supplemental heat during slag freezing events is typically triggered by an excursion in ash content and/or low B/A ratio coal.

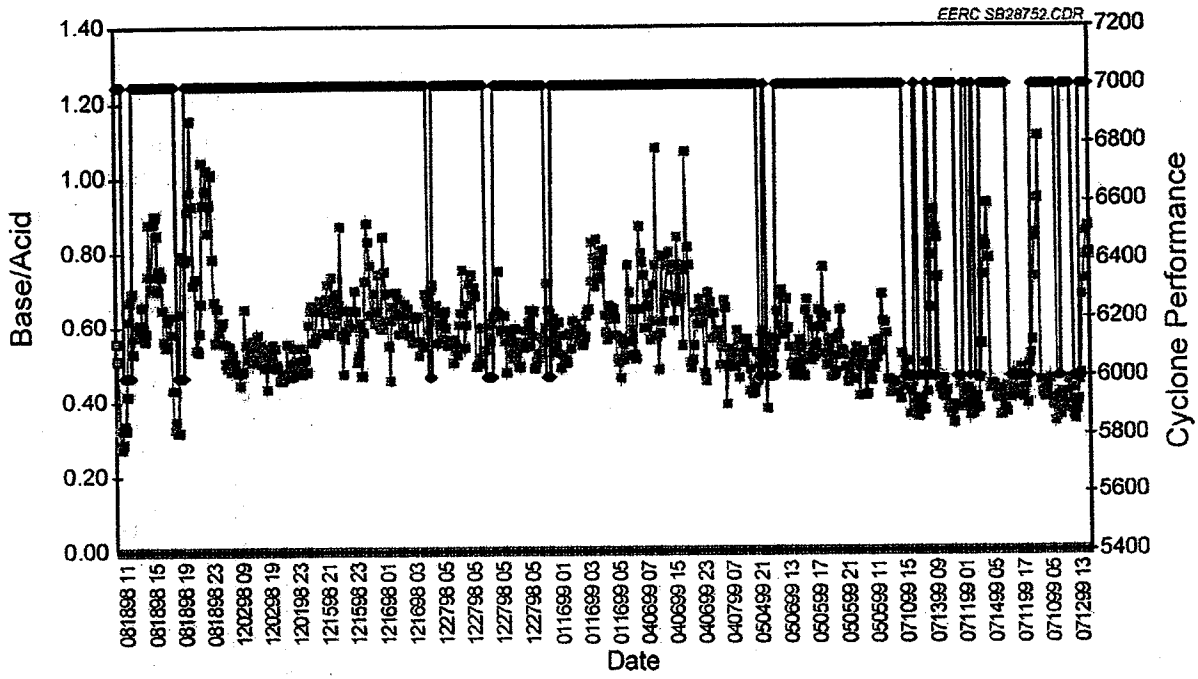


Figure C14. Base-to-acid ratio of as-fired coal samples showing variability.

Near-Future Coal Database

The characteristics of the near-future coals are shown in Table C11. The projected changes based on core analysis indicate that the level of ash range from an average of 7.1 to 8.3% over the period of time from 2007 to 2010. The range of ash levels show some extremes up to 32.6% likely due to clay partings in the coal seams. The average values of ash are lower than the as-fired database and do not include dilution as a result of mining. Typically dilution at the Center mine can increase the ash content by about 2% based on past comparisons of core and as fired samples. Sodium levels have shown increased levels in the future coals that will likely contribute to increased fouling challenges.

Table C11. Statistical analysis of future coal based on core sample analysis from Center mine.

2007 CORE SAMPLES

	Moisture as-rec'd	Ash as-rec'd	Sulfur as-rec'd	Heating Value, as-rec'd	Calcium Oxide	Magnesium Oxide	Potassium Oxide	Sodium Oxide
Sample ID	H_2O (%)	Ash (%)	S (%)	(BTU/lb)	CaO (%)	MgO (%)	K_2O (%)	Na_2O (%)
Min	31.8	4.0	0.4	4999	3.5	1.3	0.2	0.7
Max	42.6	24.6	2.8	7216	28.8	8.1	5.3	13.3
Avg.	38.5	7.9	0.9	6694	16.2	5.1	1.0	5.8
Standard Deviation	1.7	3.8	0.4	350	4.9	1.2	0.7	3.5

2008 CORE SAMPLES

Min	29.8	4.1	0.3	4547	3.0	2.6	0.3	0.6
Max	43.7	32.6	5.6	7108	29.6	8.1	2.8	11.9
Avg.	38.0	8.3	1.0	6672	17.0	5.0	1.0	5.3
Standard Deviation	1.7	4.7	0.7	427	5.9	1.2	0.6	3.4

2009-2010 CORE SAMPLES

Min	34.3	4.1	0.3	5215	5.0	2.7	0.2	0.5
Max	41.7	23.8	3.0	7180	33.6	8.4	6.9	13.4
Avg.	38.4	7.1	0.9	6787	17.8	5.2	0.9	5.6
Standard Deviation	1.2	2.7	0.5	254	5.0	1.1	0.8	3.4

Fine Particulate in Scrubbed Flue Gas Emissions at MRY Station

MRYS cyclone boilers' fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components that cause bonding, blinding, and deactivation of individual catalyst reaction sites, even in a low-dust SCR application. Sodium-rich aerosols are a problem that can get through the electrostatic precipitator (ESP). These aerosols are known to be present in high-sodium coal combustion flue gases. These species are known to produce pyrosulfates. These will cause blinding and deactivation of low-dust SCR catalyst.

Stack sampling was conducted downstream of the ESP and wet FGD on Unit 2 at the MRY plant. The filters were examined using scanning electron microscopy and x-ray microanalysis to determine the microscopic features and chemical compositions. Two sections of the filter sample were mounted on a graphite planchets using carbon double-stick tape. The first section included filtered material. The second section was taken near the edge of the filter, where there was no deposited material. The filter mounts were coated with carbon for improved conductivity in the microscopy. The filter and the filter edge sample were characterized using scanning electron microscopy morphological analysis. Morphological analysis consists of obtaining images and chemical analyses of selected features in the samples. An image of the collected ash and filter material were taken using backscattered electron imaging, which differentiates between elements based on their atomic number (iron appears brighter than silicon). The chemical compositions of the analysis areas and points were determined through the use of energy dispersive x-ray microanalysis.

Morphological Analysis of Fine Particulate

Morphological analysis results for the filter sample are shown in Table C12, with a corresponding scanning electron micrograph in Figures C15 and C16. High magnification images of filter regions are shown in Figures C17 – C19. The material collected on the filter was very small in diameter, generally less than 10 micrometers with the majority less than one micrometer. Because the particles were so small, mainly overall areas of filtered material were acquired and quantified. Several larger (> 1μm) particles were also analyzed. Due to penetration of the electron beam through the deposited material, two overall areas of the filter edge were analyzed to determine the composition of the filter.

The average composition of the "overall" areas analyzed (randomly-located analysis areas 1-4, not shown in Figure C15), and areas 8-9 (as shown in Figure C15) included about 6.6 wt% sodium and 5.7 wt% sulfur. The filter edge did not contain sodium or sulfur (randomly-located analysis areas 11 and 12, not shown in Figure C15). Areas 11 and 12 are typical of the filter edge region shown in Figure C19. The overall areas of filter materials also contained slightly higher levels of magnesium, potassium, and iron (around 1 wt% more each) than the blank edge of the filter. Several lighter-colored, larger particles characterized contained calcium (15 wt%), silicon (9 wt%) and aluminum (6.6 wt%) (analysis points 5, 7, and 10, Figure 14). One dark particle was characterized (analysis point 6, Figure C15); the particle was about three to four microns in diameter; it contained sodium (6.4 wt%), magnesium (9.8 wt%), sulfur (6.2 wt%), calcium (7.8 wt%), and silicon (10.8 wt%). Some of the lighter colored particles contain elevated levels of barium (analysis point 10, Figure C15 and analysis points 13 and 15, Figure C16). The darker regions in Figure C16 appear to be agglomerations of very small particles that are rich in sodium and sulfur as shown in analysis points 15, and 17. Analysis point 16 in Figure C16 appears to be a coating on the surface of a larger fly ash particle that contains high levels of sodium and sulfur. High calcium particles are also present on the filter shown by analysis points 14 and 18 in Figure C16.

High magnification secondary electron images are shown of the exposed and unexposed filter materials. Figure C17 and C18 show the filter materials that were exposed to the flue gases. The surfaces of the filter strands show small particles or agglomerates of small particles adhering to the strands. These particles are rich in sodium and sulfur as compared to the filter materials. Figure C19 shows a region of the filter that was not exposed to flue gas and the fiber stands do not have particles bonded to the surfaces.

Table C12. Morphological analysis results for filter sample 001.
Results expressed as weight percent on an elemental basis.

Fig.	Pt/Area	Description	Na	Mg	Al	Si	S	Cl	K	Ca	Ti	Fe	Ba	O
C15	1*	Overall area - 100x	5.98	1.83	2.62	10.85	3.80	0.00	2.29	11.10	0.00	2.31	0.00	59.21
	2*	Overall area - 100x	5.95	2.40	2.82	10.93	5.42	0.00	2.25	11.30	0.40	2.46	0.00	56.07
	3*	Overall area - 100x	7.31	1.99	2.23	8.73	7.38	0.00	2.28	9.86	0.00	1.11	0.00	59.10
	4*	Overall area - 100x	5.66	2.54	2.20	9.47	5.27	0.00	2.54	10.08	0.00	3.05	1.65	57.56
	5	Light particle	1.21	3.33	5.47	7.65	1.38	0.00	1.40	13.44	0.00	6.76	1.85	57.52
	6	Dark particle	6.40	9.79	1.47	10.75	6.24	0.00	3.76	7.84	0.00	1.06	0.00	52.68
	7	Light particle	0.57	3.99	7.49	8.94	1.74	0.19	1.15	15.67	0.43	3.83	0.00	56.01
	8	Overall area - 100x	8.50	2.62	2.45	10.04	6.81	0.00	2.12	9.26	0.50	2.40	0.00	55.30
	9	Overall area - 100x	5.95	1.97	2.64	11.03	5.58	0.00	2.09	10.21	0.86	1.78	0.00	57.90
	10	Light particle	0.78	4.20	6.78	11.26	0.00	0.00	1.24	15.37	0.00	3.70	5.10	51.56
	11*	Blank edge of filter	0.00	0.93	5.11	20.20	0.00	0.00	0.93	13.83	0.00	0.00	0.00	59.00
	12*	Blank edge of filter	0.00	1.19	4.95	19.69	0.00	0.00	1.16	16.52	0.00	0.59	0.00	55.91
C16	13	Small, light particles	3.00	3.30	3.10	7.72	2.91	0.00	1.40	11.02	0.00	3.49	1.89	62.18
	14	Small bonded particles	2.93	1.25	1.02	10.04	6.99	0.00	4.06	29.33	0.00	5.38	2.93	36.08
	15	Large dark particle	10.25	9.68	0.00	1.41	22.60	0.00	3.74	2.16	0.00	0.00	0.00	50.15
	16	Large dark particles	13.40	11.82	0.00	1.30	10.30	0.00	2.28	0.96	0.00	2.17	0.00	57.78
	17	Small bonded particles	4.39	3.56	2.17	10.95	6.88	0.00	2.77	14.02	0.51	2.83	0.00	51.92
	18	Small bonded particles	1.49	2.82	5.86	10.45	4.93	0.00	3.19	26.01	1.19	8.23	0.00	35.84
Average		**Overall areas**	**6.56**	**2.23**	**2.49**	**10.17**	**5.71**	**0.00**	**2.26**	**10.30**	**0.29**	**2.18**	**0.27**	**57.52**
		Light particles	**1.39**	**3.71**	**5.71**	**8.89**	**1.51**	**0.05**	**1.30**	**13.88**	**0.11**	**4.44**	**2.21**	**56.82**
		Dark particles	**10.02**	**10.43**	**0.49**	**4.49**	**13.05**	**0.00**	**3.26**	**3.65**	**0.00**	**1.08**	**0.00**	**53.54**
		Small bonded particles	**2.94**	**2.54**	**3.02**	**10.48**	**6.27**	**0.00**	**3.34**	**23.12**	**0.57**	**5.48**	**0.98**	**41.28**
		Filter edge	**0.00**	**1.06**	**5.03**	**19.94**	**0.00**	**0.00**	**1.04**	**15.18**	**0.00**	**0.30**	**0.00**	**57.46**

* = areas not specifically noted or shown in electron micrograph Figure C15.

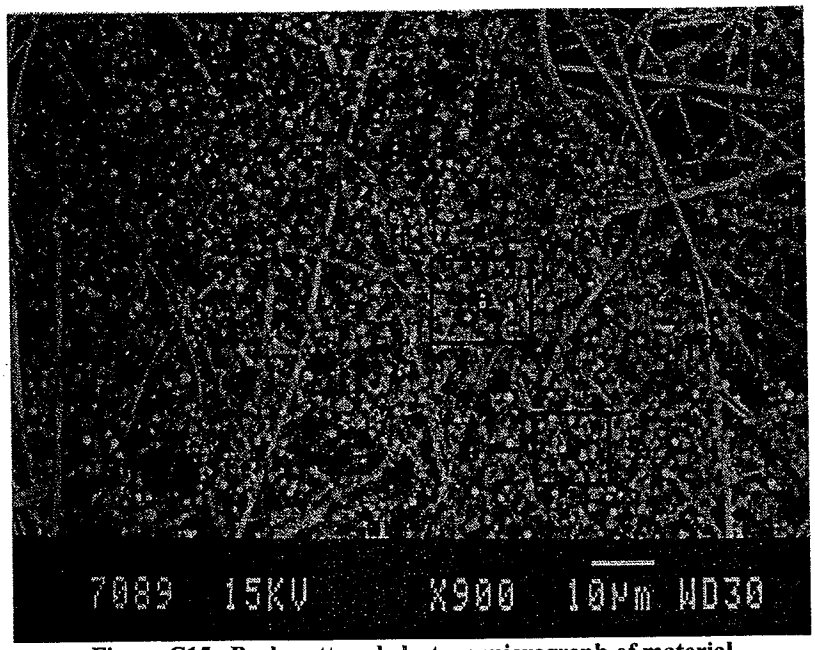


Figure C15. Backscattered electron micrograph of material on filter sample 001, showing analysis areas and points 1 through 10.

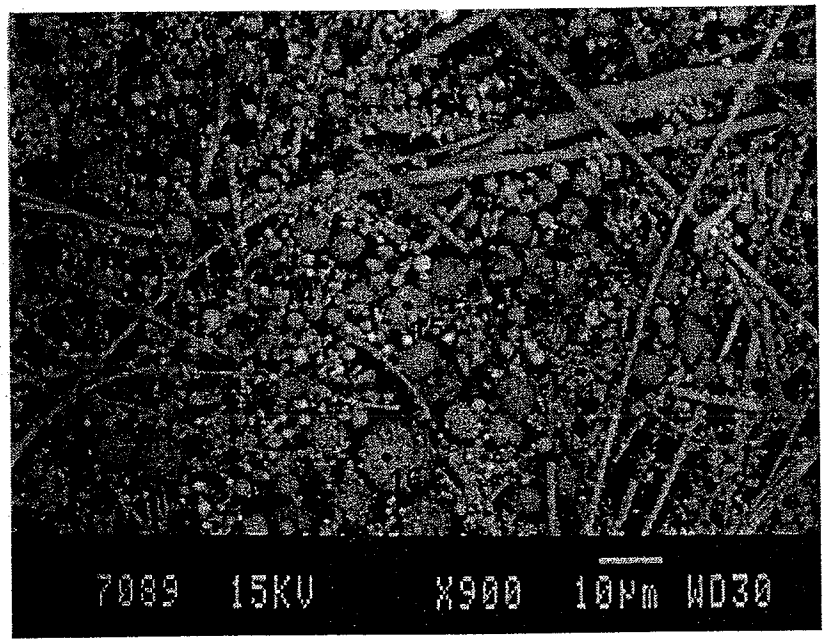


Figure C16. Backscattered electron micrograph of material on filter sample 001, showing analysis areas and points 13 through 18.

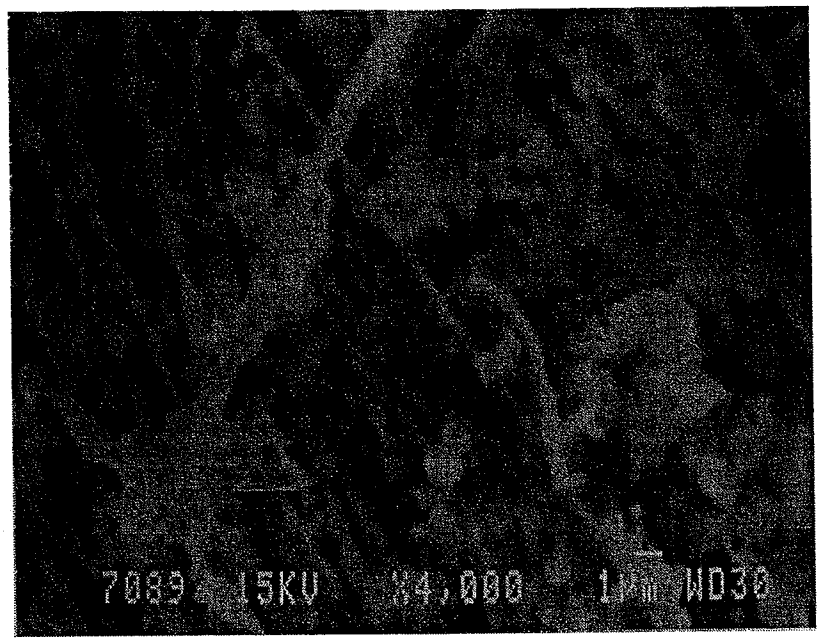


Figure C17. High-magnification secondary electron micrograph of material on filter sample 001, showing fine particles condensed on filter.

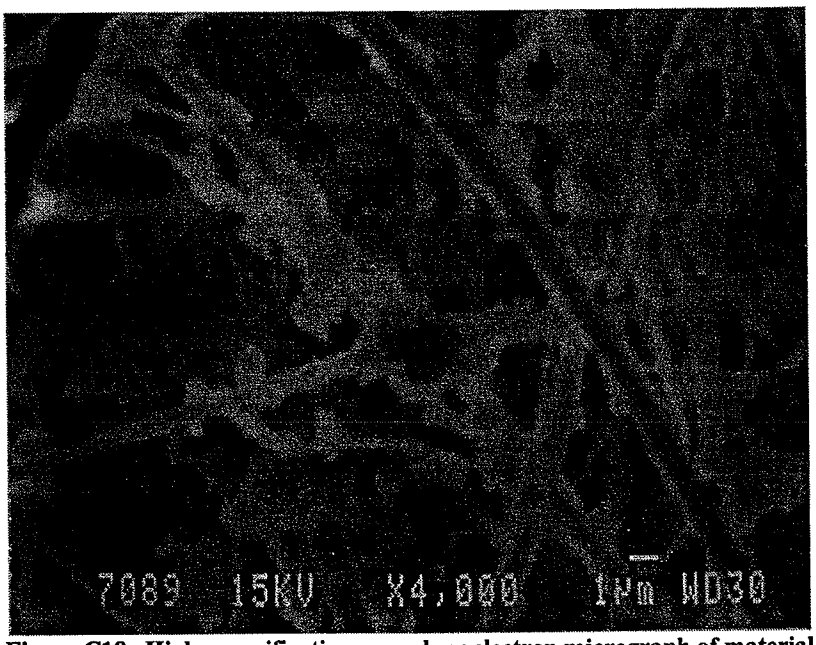


Figure C18. High-magnification secondary electron micrograph of material on filter sample 001 (MTI 07-089), showing fine particles condensed on filter.

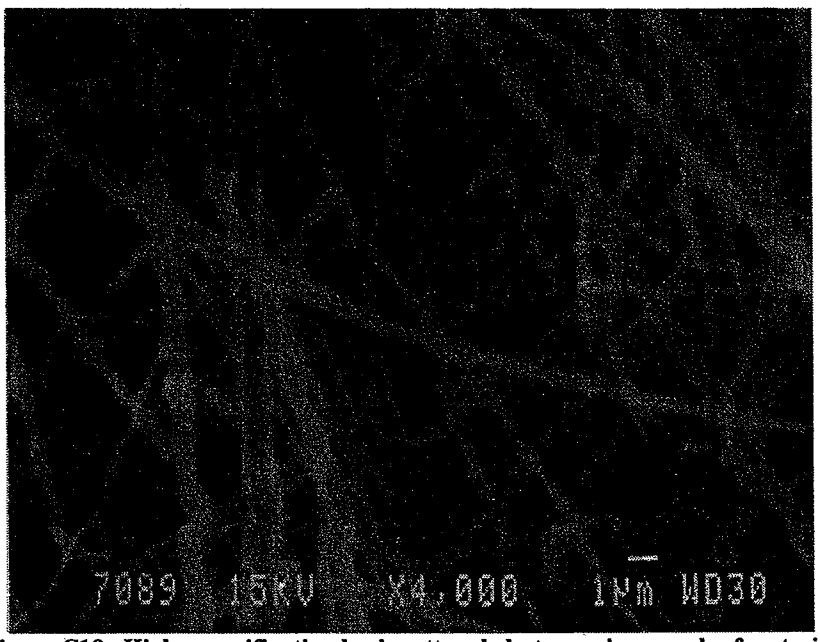


Figure C19. High-magnification backscattered electron micrograph of material on filter sample 001 (MTI 07-089), showing clean region of filter (near filter edge).

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MIL 1019-1

UTILITY BOILER PERFORMANCE SUMMARY

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A. FUEL AS FIRED

SAMPLE		
ANALYSIS	SPECIFIED	
KIND		
COAL — ASTM — CLASS		IV
COAL — ASTM — GROUP		I
COAL — ASTM — MINE		
COAL — SOURCE — SEAM & DISTRICT		
COAL — SOURCE — COUNTY		OLIVER
COAL — SOURCE — STATE		N.D.
SIZE		
GRINDABILITY	22	30
SURFACE MOISTURE, %	3.0-5.0	5.0
ASH SOFT. TEMP., F (REDUCING)		
PROX. ANAL., % — MOISTURE, TOTAL	26-40	36.0
PROX. ANAL., % — VOLATILE MATTER	270-320	29.1
PROX. ANAL., % — FIXED CARBON	270-320	29.1
PROX. ANAL., % — ASH	3.9-8.3	5.8
PROX. ANAL., % — TOTAL		100.0
FUEL	LIGNITE	LIGNITE
ULTIMATE ANALYSIS — % BY WT. — ASH	3.9-8.3	5.80
S		0.74
N_2	2.9-3.5	1.00
C	389-46.1	40.40
CH_4		
C_2H_6		
C_3H_8		
C_4H_{10}		
C_5H_{12}		
C_6H_{14}		
CO_2	001-001	0.01
CO		
SO_2		
H_2O	275-40.3	36.00
H_2	.4-.7	0.65
O_2		13.40
TOTAL		100.00
BTU/LB	6250-7830	6900
BTU/CU FT AT 60F 30 IN. HG		

B. PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR	990	1650	1714
STEAM LEAVING RH1, M LB/HR	876	1460	1534
STEAM LEAVING RH2, M LB/HR			
TYPE OF FUEL	LIGNITE		
GEAR DURATION	CONTINUOUS		
EXCESS AIR ENTERING AIRHEATER	31	28	28
NO. OF BURNERS IN OPERATION	7	7	7
FUEL INPUT, MMB/HR	1565	2422	2510
HEAT AVAIL. MMB/HR (FUEL & HEATED AIR)	1620	2559	2649
QUANTITY, M LB/HR — FUEL (NON-NAT.GAS)	227	352	364
QUANTITY, M LB/HR — FLUE GAS ENTERING AIR HEATER	2250	2817	2919
QUANTITY, M LB/HR — AIR LEAVING SEC. AH & PRI. AH	1520	2312	2396
QUANTITY, M LB/HR — AIR HEATER LEAKAGE			
PRESSURE, PSIG — STEAM AT SH OUTLET	1875	1875	1970
PRESSURE, PSIG — STEAM AT RH1 INLET	258	457	480
PRESSURE, PSIG — STEAM AT RH2 INLET			
PRESSURE, PSIG — PRESSURE DROP — REHEATER 1	15	25	26
PRESSURE, PSIG — PRESSURE DROP — REHEATER 2			
PRESSURE, PSIG — PRESSURE DROP — ECONOMIZER	11	30	33
PRESSURE, PSIG — PRESSURE DROP — DRUM TO SH OUTLET	45	125	135
TEMPERATURE, F — STEAM — LEAVING SUPERHEATER	1010	1010	1010
TEMPERATURE, F — STEAM — LEAVING REHEATER 1	970	1010	1010
TEMPERATURE, F — STEAM — ENTERING REHEATER 1	590	664	663
TEMPERATURE, F — STEAM — LEAVING REHEATER 2			
TEMPERATURE, F — STEAM — ENTERING REHEATER 2			
TEMPERATURE, F — FLUE GAS — LEAVING PRI. SH	810	890	900
TEMPERATURE, F — FLUE GAS — LEAVING AH (EXCL.LKG)	370	325	330
TEMPERATURE, F — FLUE GAS — LEAVING AH (INCL.LKG)			
TEMPERATURE, F — WATER ENTERING ECONOMIZER	408	461	466
TEMPERATURE, F — AIR — ENTERING AIR HEATER	100	100	100
TEMPERATURE, F — AIR — LEAVING AIR HEATER	735	768	777
RESISTANCE, IN. OF WATER — GAS — FURNACE & CONVECTION BANKS	2.4	3.2	4.0
RESISTANCE, IN. OF WATER — GAS — FLUES TO STACK	1.3	1.9	2.0
RESISTANCE, IN. OF WATER — GAS — AIRHEATER & ECON.	4.9	7.6	8.1
RESISTANCE, IN. OF WATER — GAS — DUST COLLECTOR	1.7	2.7	3.0
RESISTANCE, IN. OF WATER — GAS — TOTAL DRAFT LOSS	10.3	15.9	17.1
RESISTANCE, IN. OF WATER — AIR — FUEL BURNERS & WINDBOX	36.5	36.5	36.5
RESISTANCE, IN. OF WATER — AIR — DUCTS & FLOW METER	2.1	3.2	3.3
RESISTANCE, IN. OF WATER — AIR — AIR HEATER	1.5	2.4	2.6
RESISTANCE, IN. OF WATER — AIR — STEAM COIL AH	0.3	0.5	0.5
TOT. AIR RESISTANCE	40.4	42.6	43.1
HEAT LOSS, % — DRY GAS	6.70	5.46	5.58
HEAT LOSS, % — H_2 & H_2O IN FUEL	10.51	10.38	10.40
HEAT LOSS, % — MOISTURE IN AIR	0.17	0.14	0.14
HEAT LOSS, % — UNBURNED COMBUSTIBLE	0.10	0.10	0.10
HEAT LOSS, % — RADIATION	0.32	0.19	0.18
HEAT LOSS, % — UNACC. FOR & MFRS. MARGIN	1.10	1.10	1.10
HEAT LOSS, % — SLAG TANK	0.40	0.40	0.40
HEAT LOSS, % — TOTAL HEAT LOSS	19.30	17.77	17.90
EFFICIENCY OF UNIT, %	80.70	82.23	82.10
NO. IN USE PER BOILER			
TOTAL POWER, KWHR/TON WATER OUTPUT			
% THRU 200 U.S.S. SIEVE			

PREDICTED PERFORMANCE IS BASED ON COMBUSTION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, OR 27.72 IN. HG. BAROMETRIC PRESSURE, ON CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING 11X0

C. EQUIPMENT PER UNIT

TYPE	RADIANT
SIZE	RBC 57/CY.
	DESIGN PRESSURE 2325 PSIG
PRESSURE PART HEATING SURFACE, SQ FT — FURNACE — WATER COOLED SCREEN (CIRCUMFERENTIAL)	
FURNACE — WATER COOLED (PROJECTED)	33760
FURNACE — SUPERHEATER (CIRCUMFERENTIAL)	9229
FURNACE — SUPERHEATER (PROJECTED)	1200
FURNACE — TOTAL FURNACE HEATING SURFACE	44189
CONVECTION — SATURATED (CIRCUMFERENTIAL)	5910
CONVECTION — SUPERHEATER (CIRCUMFERENTIAL)	91607
CONVECTION — REHEATER 1 (CIRCUMFERENTIAL)	36947
CONVECTION — REHEATER 2 (CIRCUMFERENTIAL)	
CONVECTION — ECONOMIZER	44900
CONVECTION — TOTAL CONVECTION HEATING SURFACE	179364
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.	223553
FLAT PROJECTED FURNACE HEATING SURFACE — TO FACE OF PLATENS	37925
FLAT PROJECTED FURNACE HEATING SURFACE — TO FACE OF CONVECTION SURFACE	
FURNACE VOLUME, CU FT	148800
AIR HEATER — TYPE TUBULAR — NO. 1	
AIR HEATER — TOTAL HEATING SURFACE, SQ FT	742,000
FUEL BURNER — TYPE CYCLONE	
FUEL BURNER — NO. 7-10 FT. DIA.	
PULVERIZER — TYPE / SIZE / NO.	
PULVERIZER — CAPACITY OF / PULV. IS M LB STEAM/HR BASED ON GRIND	
PULVERIZER — MW COAL AT % THRU 200 U.S.S. SIEVE	
PULVERIZER — FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE, MIN. GRIND	
PULVERIZER — IS , MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	
STEAM TEMP. CONTROL	STEAM TEMPERATURE CONTROLLED BY GAS RECIRCULATION
UNIT CONSTRUCTION FEATURES	BALANCED DRAFT
	SEMI-OUTDOOR
	MEMBRANE WALL
	SOLIDS IN STEAM 1 PPM

REVISIONS	NO.	DESCRIPTION	BY	DATE

BY [illegible] CATE [illegible]

THE BABCOCK & WILCOX COMPANY

P1-1941-11X0-160

1

MINNKOTA POWER COOPERATIVE
SANDERSON AND PORTER, INC.
ENGINEERS

235MWe UNIT 1 RB-457

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A — FUEL IS FIRED

		DESIGN	PERF.
SAMPLES			
ANALYSES	CUSTOMER SPECIFICATIONS		
COAL SOURCE	KIND		
	CLASS	LIGNITE	LIGNITE
	GROUP		
	MINE		
	SEAM		
	DISTRICT		
	COUNTY		OLIVER
	STATE		N. DAK.
	SIZE		1¼ - 1½
	GRINDABILITY	20 MIN	25
	SURFACE MOISTURE, %		
	H=½W		
	ASH SOFT.TEMP.,F (REDUCING)	2235-2500	2410
PROX. ANALYSIS, %	MOISTURE, TOTAL	38	38.4
	VOLATILE MATTER		25.0
	FIXED CARBON	1	25.0
	ASH	13	11.6
	TOTAL		100.0
ULTIMATE ANALYSIS	FUEL		LIGNITE
	% BY		WT.
	ASH		11.60
	S		0.63
	H_2		2.60
	C		34.70
	CH_4		
	C_2H_4		
	C_2H_6		
	C_3H_8		
	C_4H_{10}		
	C_5H_{12}		
	C_6H_{12}		
	Cl		0.01
	CO_2		
	SO_2		
	H_2O		38.40
	O_2		0.56
	N_2		11.50
	TOTAL		100.00
	BTU/LB	6000	6250
	BTU/CU FT AT 60F 30 IN.HG		

* EXCL. STATIC HEAD AND FEED STOP AND CHECK VALVE.

** INPUT & ALL GENERAL PERFORMANCE INCLUDES ALLOWANCE FOR AVERAGE SOOT BLOWER STEAM CONSUMPTION RATE (40,000 LB/HR).

UTILITY BOILER PERFORMANCE SUMMARY

BY VFH APPD. FJB DATE 3-21-73

THE BABCOCK & WILCOX COMPANY

PS-2783-1Y0-1S-1

B — PREDICTED PERFORMANCE

STEAM LEAVING SH, M LB/HR		1830	2560	3050	3200
STEAM LEAVING RH¹, M LB/HR		1510	2110	2513	2769.6
BLOWDOWN, M LB/HR		18.5	25.9	30.8	32.1
TYPE OF FUEL		LIGNITE	LIGNITE	LIGNITE	LIGNITE
LOAD CONDITION		NORMAL	NORMAL	NORMAL	NORMAL MAX
EXCESS AIR LEAVING ECON., %		38	31	28	25
NO. OF BURNERS IN OPERATION		12	12	12	12
FUEL INPUT, MM/HR **		2849	3883	4505	4686
HEAT AVAIL.,MM/HR (FUEL & HEATED AIR)		2974	4050	4761	4975
QUANTITY, M LB/HR	FUEL	455.8	621.2	720.7	751.4
	FLUE GAS ENTERING AIR HEATER	3410	4439	5050	5264
	AIR TO BURNING EQUIPMENT	2932	3802	4330	4491
	AIR HEATER LEAKAGE				
PRESSURE, PSIG	STEAM AT SH OUTLET	2495	2495	2495	2620
	STEAM AT RH¹ INLET	296	407	518	570
	STEAM AT RH² INLET				
	REHEATER 1	27	23	28	30
	REHEATER 2				
	ECONOMIZER TO DRUM*	17	30	45	50
	DRUM TO SH OUTLET	60	106	165	180
TEMPERATURE, F — STEAM	LEAVING SUPERHEATER	1005	1005	1005	1005
	LEAVING REHEATER 1	980	1005	1005	1005
	ENTERING REHEATER 1	545	582	618	626
	LEAVING REHEATER 2				
	ENTERING REHEATER 2				
FLUE GAS	LEAVING ECONOMIZER TO AH/NOZ	756/550	819/620	863/685	870/695
	LEAVING AH (EXCL.LKG)	284	310	328	330
	LEAVING AH (INCL. LKG)				
	WATER ENTERING ECONOMIZER	421	450	473.7	483.7
AIR	ENTERING UNIT	108	100	100	100
	LEAVING AIR HEATER	661	710	745	750
	FURNACE & CONVECTION BANKS	3.7	5.1	5.0	8.3
GAS	FLUES TO AH OUTLET	1.6	2.2	2.7	2.8
	AIR HEATER	3.0	5.0	6.5	6.9
	TOT. FURN. TO AH OUTLET	8.3	12.5	17.2	18.5
RESISTANCE, IN. OF WATER — AIR	FUEL BURNERS & WINDBOX	43.0	43.0	43.0	44.5
	DUCTS	1.5	2.5	3.2	3.5
	AIR HEATER	2.1	3.6	4.7	5.1
	TOT. FROM FD FAN TO FURN.	46.6	49.1	50.9	53.1
HEAT LOSS, %	DRY GAS	4.79	5.20	5.53	5.58
	H_2 & H_2O IN FUEL	11.08	11.21	11.28	11.30
	MOISTURE IN AIR	0.12	0.13	0.14	0.14
	UNBURNED COMBUSTIBLE	0.10	0.10	0.10	0.10
	RADIATION	0.28	0.21	0.18	0.17
	UNACC. FOR & MFRS. MARGIN & SLAG TANK LOSS	1.83	1.83	1.83	1.83
	TOTAL HEAT LOSS	18.20	18.68	19.06	19.12
EFFICIENCY OF UNIT, %		81.80	81.32	80.94	80.88
PULVERIZER & FEEDER	NO. IN USE PER BOILER				
	TOTAL POWER, KW HR/TON MOTOR OUTPUT				
	% THRU 200 U.S.S. SIEVE				

PREDICTED PERFORMANCE IS BASED ON CONDITION AIR ENTERING UNIT WITH 0.013 LB MOISTURE/LB DRY AIR, ON 27.72 IN. HG. BAROMETRIC PRESSURE, OR CONDITIONS & EQUIPMENT GIVEN ON THIS SUMMARY SHEET & ON ARRANGEMENT SHOWN ON DRAWING PS-2783-1Y0

C — EQUIPMENT PER UNIT

TYPE RADIANT

SIZE RBC 48/CY

DESIGN PRESSURE 2950 PSIG

PRESSURE PART HEATING SURFACE, SQ FT — FURNACE	WATER COOLED SCREEN (CIRCUMFERENTIAL)	
	WATER COOLED (PROJECTED)	43,260
	SUPERHEATER (CIRCUMFERENTIAL)	
	SUPERHEATER (PROJECTED)	15,360
	TOTAL FURNACE HEATING SURFACE	58,620
CONVECTION	SATURATED (CIRCUMFERENTIAL)	7,120
	SUPERHEATER (CIRCUMFERENTIAL)	127,300
	REHEATER 1 (CIRCUMFERENTIAL)	56,060
	REHEATER 2 (CIRCUMFERENTIAL)	
	ECONOMIZER	161,425
	TOTAL CONVECTION HEATING SURFACE	351,905
TOTAL FURN. & CONV. PRESSURE PART. HTG. SURF.		410,525
FLAT PROJECTED FURNACE HEATING SURFACE		
	TO FACE OF PLATENS	45,520
	TO FACE OF CONVECTION SURFACE	60,390
FURNACE VOLUME, CU FT		403,500
AIR HEATER	TYPE TUBULAR NO. 1	
	TOTAL HEATING SURFACE, SQ FT 1,336,400	
FUEL BURNER	TYPE CYCLONE	
	NO. 12	
PULVERIZER	TYPE SIZE NO.	
	CAPACITY OF PULV. IS M LB STEAM/HR BASED ON GRIND	
	BTU COAL AT % THRU 200 U.S.S. SIEVE	
	FOR M LB COAL/PULV.-HR AT % THRU 200 U.S.S. SIEVE MIN. GRIND	
	IS MAXIMUM SURFACE MOISTURE IS % REQUIRING F AIR	

SOLIDS IN STEAM - 0.1 PPM

STEAM TEMP. CONTROL: GAS RECIRCULATION

UNIT CASE STRUCTURE: MEMBRANE WALL, BALANCED DRAFT, INDOOR

REVISIONS	NO.	DESCRIPTION	BY	DATE
	0-1	C59	VFH	4/25/73

SANDERSON & PORTER, INC.

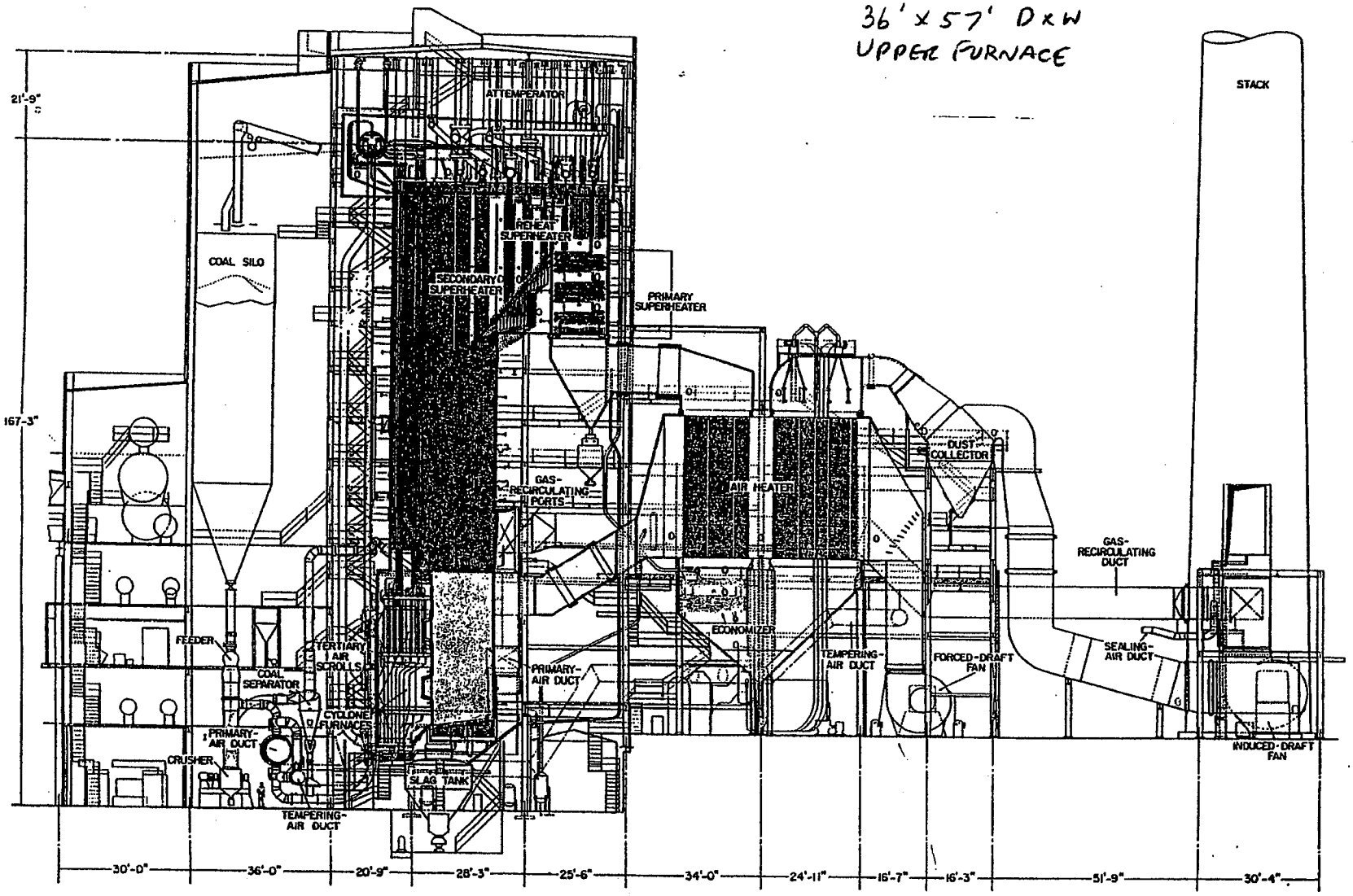
FOR: SQUARE BUTTE ELECTRIC COOPERATIVE, INC.

MILTON R. YOUNG STATION, NORTH DAKOTA

439 MWe RB-525

26' x 57' DxW
LOWER FURNACE

36' x 57' DxW
UPPER FURNACE

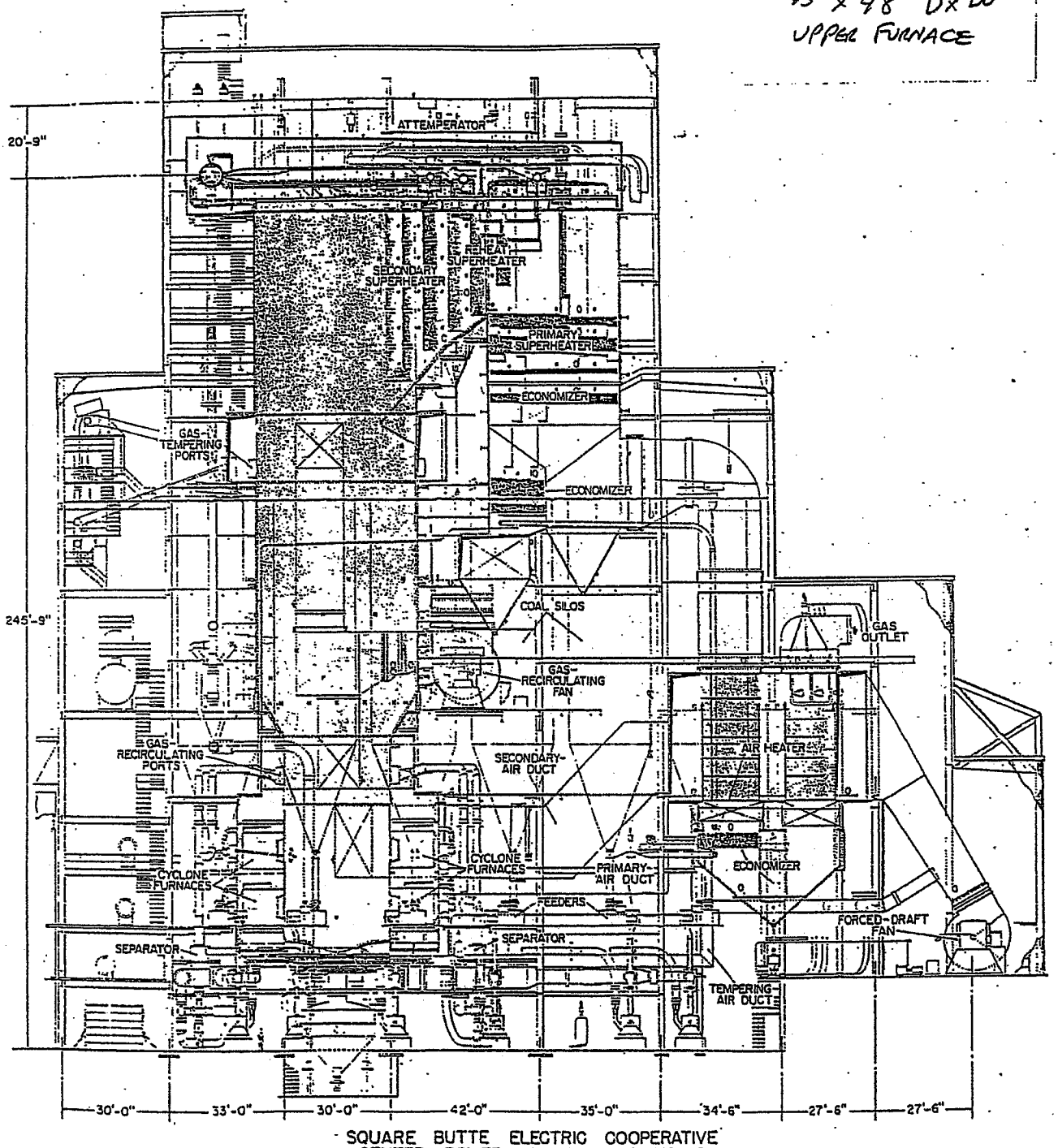


MINNKOTA POWER COOPERATIVE, INC.
CENTER POWER PLANT – UNIT NO. 1
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-457

RB-457-300-2N

30' x 48' D x W
LOWER FURNACE

45' x 48' D x W
UPPER FURNACE



SQUARE BUTTE ELECTRIC COOPERATIVE
CENTER POWER PLANT—UNIT NO. 2
CENTER, NORTH DAKOTA
B & W CONTRACT NO. RB-525

Minnkota MRYS Boiler Cleaning Outages
Milton R. Young Station Unit 1, 1997 - 2006

Start	End	Cause	Description	Eq Hrs	Boiler Cleaning Outages	Comments	Boiler Cleaning Outage Number (from 1-1-97)
09/08/1997 00:00	11/08/1997 09:03	1340	REPLACED SSH & RH TUBING	1474.05	174.05	extensive boiler cleaning time assumed, included in major outage	1
07/10/1998 02:00	07/12/1998 20:55	1305	BOILER CLEANING OUTAGE	66.92	66.92		2
11/19/1998 02:00	11/22/1998 22:32	1305	BOILER CLEANING OUTAGE	92.53	92.53		3
02/15/1999 02:00	02/18/1999 09:42	1305	BOILER CLEANING OUTAGE	79.70	79.70		4
05/20/1999 02:00	05/24/1999 11:31	1305	BOILER CLEANING OUTAGE	105.52	105.52		5
08/21/1999 02:00	08/24/1999 00:10	1305	BOILER CLEANING OUTAGE	70.17	70.17		6
11/18/1999 02:00	11/20/1999 23:59	1305	BOILER CLEANING OUTAGE.	69.98	69.98		7
01/29/2000 02:00	02/01/2000 09:13	1305	BOILER CLEANING OUTAGE	79.22	79.22		8
04/28/2000 02:00	05/01/2000 11:40	1305	BOILER CLEANING OUTAGE	81.67	81.67		9
06/22/2000 02:02	06/24/2000 22:20	1305	BOILER CLEANING OUTAGE	68.30	68.30		10
02/08/2001 02:01	02/10/2001 10:27	1305	BOILER CLEANING OUTAGE	56.43	56.43	shortest boiler cleaning outage duration	11
06/09/2001 01:45	06/12/2001 07:02	1305	BOILER CLEANING OUTAGE	77.28	77.28		12
10/11/2001 02:00	10/14/2001 11:47	1305	BOILER FIRESIDE CLEANING	81.78	81.78		13
02/19/2002 02:00	02/25/2002 19:39	1305	BOILER CLEANING	161.65	161.65	boiler cleaning outage longer than 144 hrs	14
06/13/2002 02:00	06/15/2002 19:13	1305	BOILER CLEANING	65.22	65.22		15
10/12/2002 02:00	10/15/2002 05:38	1305	BOILER CLEANING	75.63	75.63		16
02/20/2003 02:00	02/22/2003 23:20	1305	BOILER CLEANING OUTAGE	69.33	69.33		17
06/12/2003 02:00	06/17/2003 11:24	1305	BOILER CLEANING OUTAGE	129.40	129.40		18
08/30/2003 02:00	10/16/2003 17:18	1800	MAJOR OUTAGE	1143.30	74.00	boiler cleaning time assumed, included in major outage	19
02/21/2004 02:00	02/24/2004 02:35	1305	BOILER CLEANING OUTAGE	72.58	72.58		20
06/18/2004 02:00	06/22/2004 03:54	1305	BOILER CLEANING OUTAGE	97.90	97.90		21
10/30/2004 01:48	11/02/2004 06:06	1305	BOILER CLEANING OUTAGE	77.30	77.30		22
03/04/2005 01:54	03/08/2005 21:39	1305	BOILER CLEANING OUTAGE	67.75	67.75		23
06/19/2005 02:00	06/27/2005 15:43	1305	BOILER CLEANING OUTAGE	205.72	205.72	longest boiler cleaning outage duration; also longer than 144 hrs	24
09/22/2005 01:53	09/25/2005 06:31	1305	BOILER CLEANING OUTAGE	76.63	76.63		25
01/19/2006 02:01	01/22/2006 20:08	1305	BOILER CLEANING OUTAGE	90.12	90.12		26
06/09/2006 02:00	06/12/2006 12:00	1305	BOILER CLEANING OUTAGE	82.00	82.00		27
09/26/2006 06:00	11/08/2006 00:17	4400	HPIP TURBINE RETROFIT	1027.28	90.00	boiler cleaning time assumed, included in major outage	28
			TOTAL		2538.78		
			AVERAGE		90.67		
			Minimum		56.43		
			Maximum		205.72		
			Median		78.26		

Minnkota MRYS Boiler Cleaning Outages
Milton R. Young Station Unit 2, 1997 - 2006

Start	End	Cause	Description	Eq Hrs	Boiler Cleaning Outages	Comments	Boiler Cleaning Outage Number (from 1-1-97)
01/22/1997 00:00	01/25/1997 14:58	1305	BOILER CLEANING-ALL SURFACES	86.97	86.97		1
04/05/1997 00:13	04/07/1997 17:28	1305	BOILER CLEANING-ALL SURFACES	64.25	64.25		2
06/17/1997 23:59	06/20/1997 15:10	1305	BOILER CLEANING-ALL SURFACES	63.18	63.18		3
09/05/1997 01:00	09/09/1997 06:34	1305	BOILER CLEANING-ALL SURFACES	101.57	101.57		4
01/17/1998 00:00	01/19/1998 01:50	1305	BOILER CLEANING OUTAGE	49.83	49.83		5
11/15/1998 02:00	11/18/1998 20:21	1305	BOILER CLEANING	90.35	90.35		6
01/13/1999 00:00	01/14/1999 12:51	1305	BOILER CLEANING OUTAGE	36.85	36.85	shortest boiler cleaning outage duration	7
02/11/1999 02:00	02/13/1999 23:32	1305	BOILER CLEANING OUTAGE	69.53	69.53		8
04/16/1999 02:00	04/19/1999 17:25	1305	BOILER CLEANING	87.42	87.42		9
06/18/1999 02:00	06/20/1999 12:35	1305	BOILER CLEANING OUTAGE	58.58	58.58		10
08/27/1999 02:00	08/29/1999 18:06	1305	BOILER CLEANING OUTAGE	64.10	64.10		11
01/17/1998 00:00	01/19/1998 01:50	1305	BOILER CLEANING OUTAGE	49.83	49.83		12
11/05/1999 01:59	11/08/1999 00:43	1305	BOILER CLEANING OUTAGE	70.73	70.73		13
01/14/2000 02:00	01/16/2000 20:02	1305	BOILER CLEANING OUTAGE	66.03	66.03		14
03/31/2000 02:00	04/03/2000 03:40	1305	BOILER CLEANING OUTAGE	72.67	72.67		15
06/16/2000 01:32	06/18/2000 23:12	1305	BOILER CLEANING OUTAGE	69.67	69.67		16
09/02/2000 01:43	09/05/2000 04:44	1305	BOILER CLEANING OUTAGE	75.02	75.02		17
11/17/2000 00:53	11/20/2000 08:04	1305	BOILER CLEANING OUTAGE	79.18	79.18		18
02/03/2001 02:00	02/06/2001 19:56	1305	BOILER CLEANING OUTAGE	89.93	89.93		19
04/06/2001 02:00	04/11/2001 15:13	1305	BOILER CLEANING OUTAGE	132.22	132.22		20
06/14/2001 02:43	06/18/2001 01:57	1305	BOILER CLEANING OUTAGE	95.23	95.23		21
09/01/2001 02:00	10/03/2001 18:00	1800	MAJOR BOILER OVERHAUL REPAIRS	784.00	132.00	boiler cleaning time assumed, included in major outage	22
02/14/2002 02:00	02/18/2002 18:21	1305	BOILER CLEANING	112.35	112.35		23
06/08/2002 02:01	06/11/2002 04:51	1305	BOILER CLEANING OUTAGE	74.83	74.83		24
10/17/2002 02:00	10/21/2002 05:46	1305	BOILER CLEANING	99.77	99.77		25
02/12/2003 01:02	02/17/2003 13:31	1305	BOILER CLEANING OUTAGE	132.48	132.48		26
06/19/2003 02:01	06/23/2003 15:59	1305	BOILER CLEANING OUTAGE	109.97	109.97		27
09/20/2003 02:00	09/22/2003 04:15	1305	BOILER CLEANING OUTAGE - MINI	50.25	50.25		28
11/01/2003 02:00	11/05/2003 11:10	1305	BOILER CLEANING OUTAGE	105.17	105.17		29
02/27/2004 02:00	03/01/2004 23:31	1305	BOILER CLEANING OUTAGE	93.52	93.52		30
06/16/2004 15:05	06/18/2004 13:43	1305	BOILER CLEANING OUTAGE	46.63	46.63		31
09/04/2004 01:57	10/20/2004 10:40	1800	MAJOR OUTAGE	1112.72	95.00	boiler cleaning time assumed, included in major outage	32
01/22/2005 02:02	01/23/2005 23:23	1305	BOILER CLEANING OUTAGE	45.35	45.35		33
03/10/2005 02:00	03/14/2005 13:24	1305	BOILER CLEANING OUTAGE	107.40	107.40		34
06/09/2005 01:02	06/19/2005 05:30	1305	BOILER CLEANING OUTAGE	244.47	244.47	longest boiler cleaning outage duration; also longer than 144 hrs	35
09/15/2005 02:00	09/20/2005 02:14	1305	BOILER CLEANING OUTAGE	120.23	120.23		36
01/05/2006 02:00	01/08/2006 20:24	1305	BOILER CLEANING OUTAGE	90.40	90.40		37
03/11/2006 02:00	03/16/2006 05:09	1305	BOILER CLEANING OUTAGE	123.15	123.15		38
06/15/2006 02:00	06/19/2006 04:26	1305	BOILER CLEANING OUTAGE	98.43	98.43		39
09/21/2006 02:00	09/25/2006 00:10	1305	BOILER CLEANING OUTAGE	94.17	94.17		40
12/09/2006 02:00	12/13/2006 08:46	1305	BOILER CLEANING OUTAGE	102.77	102.77		41
			TOTAL		3651.48		
			AVERAGE		89.06		
			Minimum		36.85		
			Maximum		244.47		
			Median		89.93		

nmary of Responses to EPA/DOH Questions n Minnkota Power's NO_x BACT Analysis for Milton R. Young Units 1 & 2

Presentation to NDDH and U.S. EPA

Wednesday, May 23, 2007

EERC Energy & Environmental Research Center®

Minnkota Power MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

Burns & McDonnell SINCE 1898

Presentation Agenda

- Burns & McDonnell qualifications
- EERC qualifications
- Responses to comments regarding SCR
  - Statement of key issues related to SCR
  - Basis for technical infeasibility of SCR
  - Research requirements for validation of SCR
  - Results of SCR vendor query
- Responses to comments on non-SCR alternatives
- Control of emissions during startup & shutdown

Presentation Agenda

- **Burns & McDonnell qualifications**
- EERC qualifications
- Responses to comments regarding SCR
  - Statement of key issues related to SCR
  - Basis for technical infeasibility of SCR
  - Research requirements for validation of SCR
  - Results of SCR vendor query
- Responses to comments on non-SCR alternatives
- Control of emissions during startup & shutdown

Burns & McDonnell Qualifications

- Burns & McDonnell Overview
- Relevant Burns & McDonnell Experience
  - Coal-fired boiler NO_x control studies and projects
  - Cyclone Boiler overfire air system projects
  - Coal-fired boiler SCR studies and projects
  - Top-Down BACT Analyses
  - North Dakota lignite boiler studies and projects

Burns & McDonnell Overview

- Business Experience
- Ownership
- Employees and offices
- Areas of practice
- Relevant Experience
- Personnel Qualifications

Burns & McDonnell - More Than a Century of Excellence

Burns & McDonnell Overview

- 109 years in business
- 2000+ employee/owners in Kansas City and 13 U.S. regional offices
- 10 Global Practice business divisions
- "Help Our Clients Be Successful"

Burns & McDonnell Overview

- Full Service Firm with Expertise in:
  - Environmental Studies and Permitting
  - Conceptual Design/Cost Estimating
  - Detailed Design
  - Procurement
  - Construction Management
  - Start-up/Commissioning
  - Training

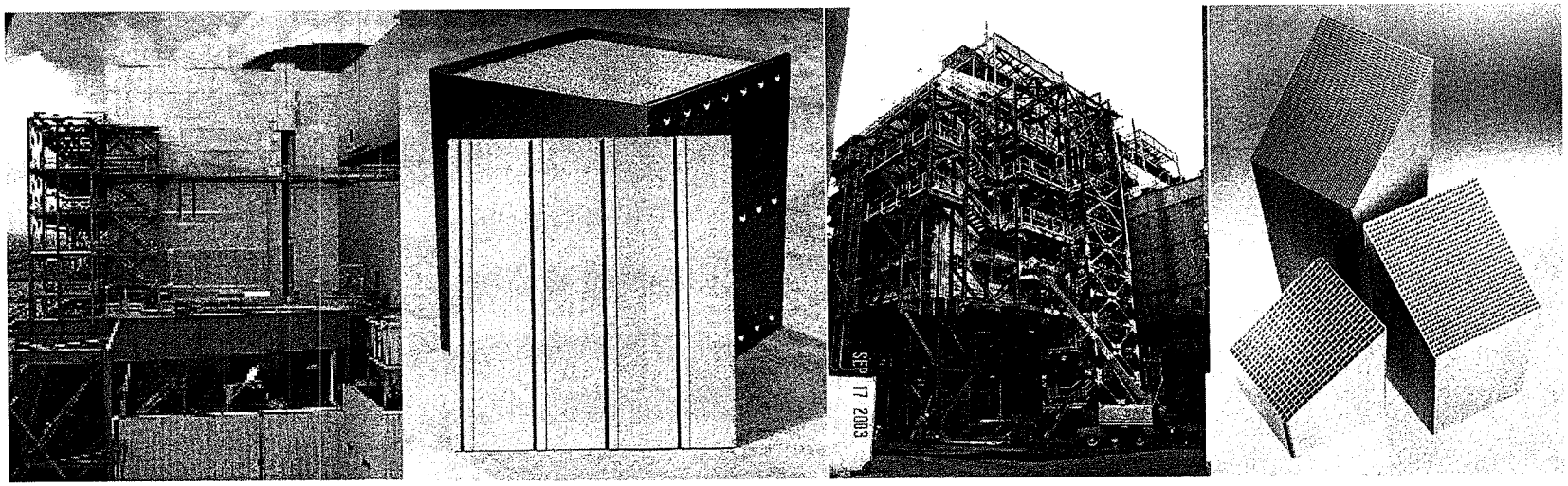
Burns & McDonnell NO_x Control Experience

- Coal-fired boiler NO_x Control studies and projects
  - Numerous pulverized coal and cyclone-fired boilers
  - NO_x reduction and retrofit cost estimates
  - Unit testing (before and after improvements)
  - Detailed Design, Specifications, Bid Reviews
  - Engineer-Procure-Construct (EPC) contracts
- Example: Overfire Air Systems
  - We know the critical combustion design parameters, how to size the system and nozzles, design ductwork and supports, specify hardware procurement, oversee fabrication and installation, test performance and adjust settings, and train clients to operate and maintain them

Burns & McDonnell Cyclone NO_x Control Experience

- Significant cyclone-fired boiler overfire air studies and projects
- Involved in initial concepts and testing to prove it would work
- First commercial cyclone boiler OFA system design and installation
- In-house detailed design for front-wall and opposed wall-fired units
- Engineer-Procure-Construct (EPC) contracts
- Multiple-contract specifications for vendor-designed and Owner-procured / contractor-installed OFA systems

B&McD SCR Experience

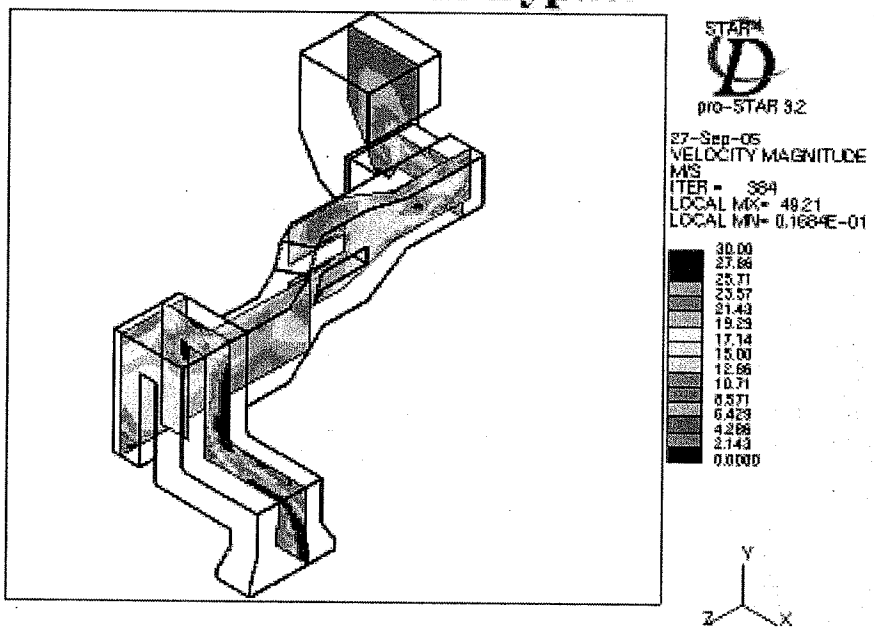


B&McD SCR Experience

Design Studies:

- ***SCR Process Design***
  - ***Coals Analyses***
  - ***Catalyst Selection***
  - ***Initial Modeling***
- ***SCR Arrangement***
- ***Draft Analysis & Implosion***
- ***Foundation***
- ***Geotechnical***
- ***Electrical Integration***
- ***Controls Integration***
- ***Reagent Selection***

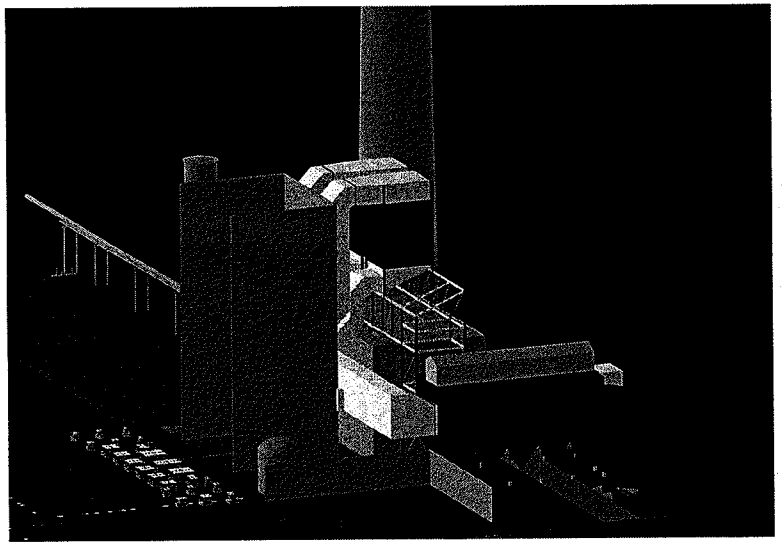
Baseline Bypass



B&McD SCR Experience

Conceptual Design:

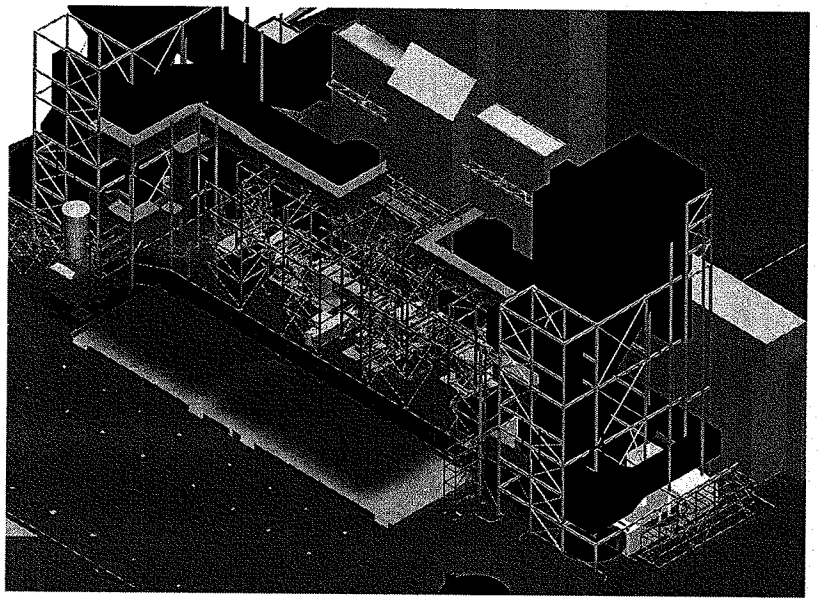
KCPL, LaCygne 1
(PRB –fired cyclone boiler)
Seminole Electric, Seminole 1 & 2
Confidential Client
SMEPA, Morrow 1 & 2
HMPL, Henderson 1 & 2
Hoosier Energy, Merom 1 & 2



B&McD SCR Experience

Detailed Design:

Associated Electric Cooperative, Thomas Hill Units 1, 2 & 3 (*Units 1 & 2 are PRB –fired cyclone boilers)*



Conceptual Design & Studies

Structural Design

Catalyst, Reagent Selection

Balance of Plant Design

Construction Management

B&McD SCR Experience

Owner's Engineer on SCR Retrofit Projects:

KCP&L, LaCygne 1
(PRB –fired cyclone boiler)
KCP&L, Iatan 1
Empire District, Asbury 1
South Mississippi, Morrow 1&2
Seminole Electric, Seminole 1&2
Alabama Electric, Lowman 2&3
Hoosier Energy, Merom 1&2
HMP&L Henderson Station 1 & 2

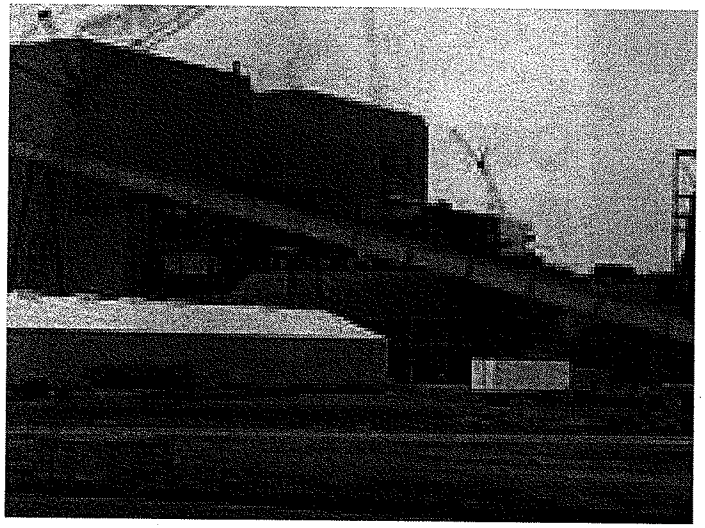
Scope:

- ***Balance-Of-Plant Design including Foundations, Electrical, Controls Integration, Civil; and***
- ***Contract Oversight***

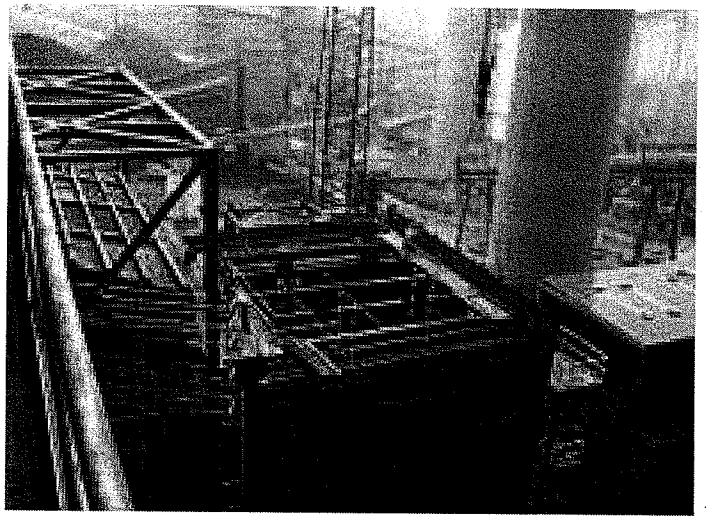
B&McD SCR Experience

Owner's Engineer:
SCR Retrofits

Hoosier Energy, Merom 1&2



HMP&L Station 1 & 2



B&McD SCR Experience

Owner's Engineer - New Coal-Fired Units w/ SCRs

- ***MidAmerican Energy Council Bluffs 4***
- ***CWLP Dallman 4***
- ***CPS Energy JK Spruce 2***
- ***Western Farmers Hugo 2***
- ***Seminole 3***
- ***KCP&L Iatan 2***
- ***Peabody Prairie State 1&2***
- ***TXU Oak Grove 1&2***
- ***ERORA Taylorville IGCC***

B&McD SCR Experience

- Familiarity with Technology Companies:
  - System Suppliers: Alstom, Babcock Power, B&W, Lurgi
  - Catalyst Suppliers: Argillon, Cormetech, Ceram, Hitachi, Topsoe
- Other SCR-Related Experience
  - Technical Specifications for KCPL Hawthorn Unit 5 Rebuild, including conceptual design and detailed requirements for new PRB PC-fired boiler with SCR

Burns & McDonnell
North Dakota Lignite Experience

- Air Pollution Control Technology Assessments
- Boiler Technology Assessments
- Separated overfire air system conceptual designs and cost estimates
- SOFA detailed design and implementation support
- Best Available Retrofit Technology (BART) Determination study reports
- Best Available Control Technology (BACT) Analysis study reports

Burns & McDonnell Top Down BACT Experience

- Performing BACT Analyses for over 30 years associated with PSD permits
- Top-Down BACT since 1988
- Performed over 20 Top-Down BACT analyses for coal-fired utility boilers
  - Recent BACT projects include Big Stone 2, Columbia 3, Nelson Dewey 3, Hugo 2, Holcomb 2, Southwest 2, Dallman 4, Weston 4, Spruce 2, Hawthorn 5
- Authors of two EPRI survey reports on BACT
- Presenters of BACT Workshop at EUEC 2005-2007

Burns & McDonnell Personnel Qualifications

- Carl V. Weilert, P.E.
- Robert D. Blakley, P.E.

Carl V. Weilert, P.E. - Qualifications

- Education:
  - B.S. Engineering Science – Rockhurst University, Kansas City, Missouri
- License & Registration:
  - Professional Engineer, Missouri
- Work Experience:
  - 1974–present – Air pollution control engineer with Burns & McDonnell. Experience includes all aspects of air pollution control for coal-fired electric utility power plants, including regulatory analysis, permitting, evaluation, design, specification, startup, testing and troubleshooting.
- Publications:
  - Author of two EPRI survey reports on BACT.
  - Over 50 technical papers and conference presentations.

Robert D. Blakley, P.E. - Qualifications

- Education:
  - B.S. Mechanical Engineering – University of Colorado (Boulder)
- License & Registration:
  - Originally licensed in New York State (1988); currently licensed and registered in Missouri and North Dakota
- Work Experience:
  - 1977-1981 – Small wind energy conversion systems and large aircraft gas turbine hardware development
  - 1981-1999 – Utility O&M and capital improvements project engineer: waste incineration, steam cogeneration and distribution of steam, water, compressed air and natural gas at Eastman Kodak Company's main manufacturing site in Rochester, New York
  - 2000-present – Plant Services utility combustion and air pollution control project engineer, performing studies and design development for boiler equipment and system condition assessments, BACT analyses and BART determinations involving NOx emissions reductions.

Robert D. Blakley, P.E. Qualifications

- Examples:
  - MRY U2 Overfire Air System conceptual design, combustion calculations, budgetary cost estimate, preliminary performance predictions, detailed system capacity and duct sizing, development of technical specifications for hardware procurement and installation.
  - State Line Energy's 340 MW cyclone boiler firing Decker coal – Combustion engineer and project engineering manager on turnkey project to design and provide an Overfire Air System - included conceptual design, combustion calculations preliminary performance predictions, detailed system capacity and duct sizing, development of technical specifications for hardware procurement and installation, construction and startup/commissioning support
- Publications:
  - Author of "Fireside Tube Corrosion, 20 Years of Kodak Experience" written for, and presented to, the Fourteenth National ASME Waste Processing Conference, Long Beach CA, June 1990

Presentation Agenda

- Burns & McDonnell qualifications
- **EERC qualifications**
- Responses to comments regarding SCR
  - Statement of key issues related to SCR
  - Basis for technical infeasibility of SCR
  - Research requirements for validation of SCR
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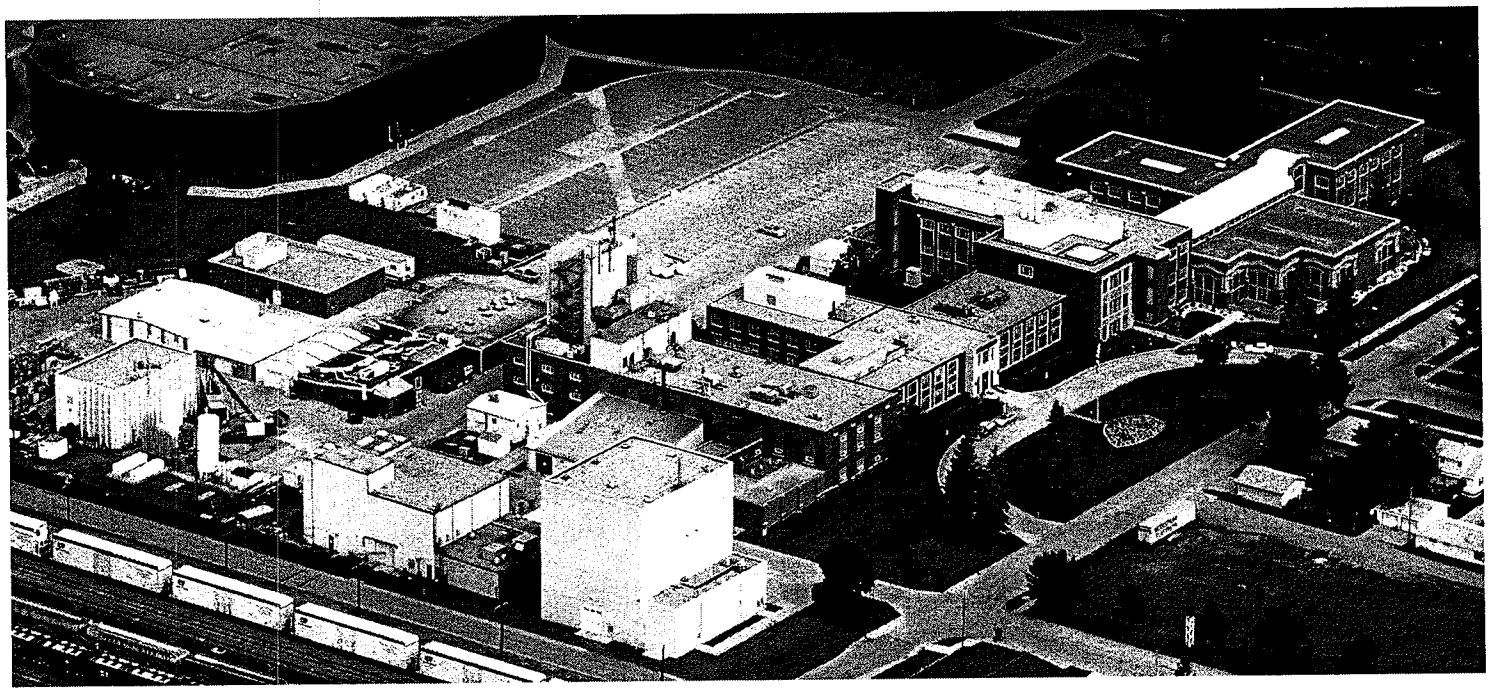
Energy & Environmental Research Center

- EERC Overview
- EERC Expertise
  - Coal-fired boiler studies
  - Cyclone boiler projects
  - Coal-fired boiler SCR studies
  - North Dakota lignite boiler studies and projects
- Personnel Qualifications

EERC
Energy & Environmental Research Center

EERC Overview

- 1949 US Bureau of Mines – Characterize the lignite resource and develop and demonstrate technologies for efficient utilization
- 1979 US Department of Energy – Grand Forks Energy Technology Center Lead laboratory for low rank coals research and development
- 1983 Defederalized – Research arm of the University of North Dakota



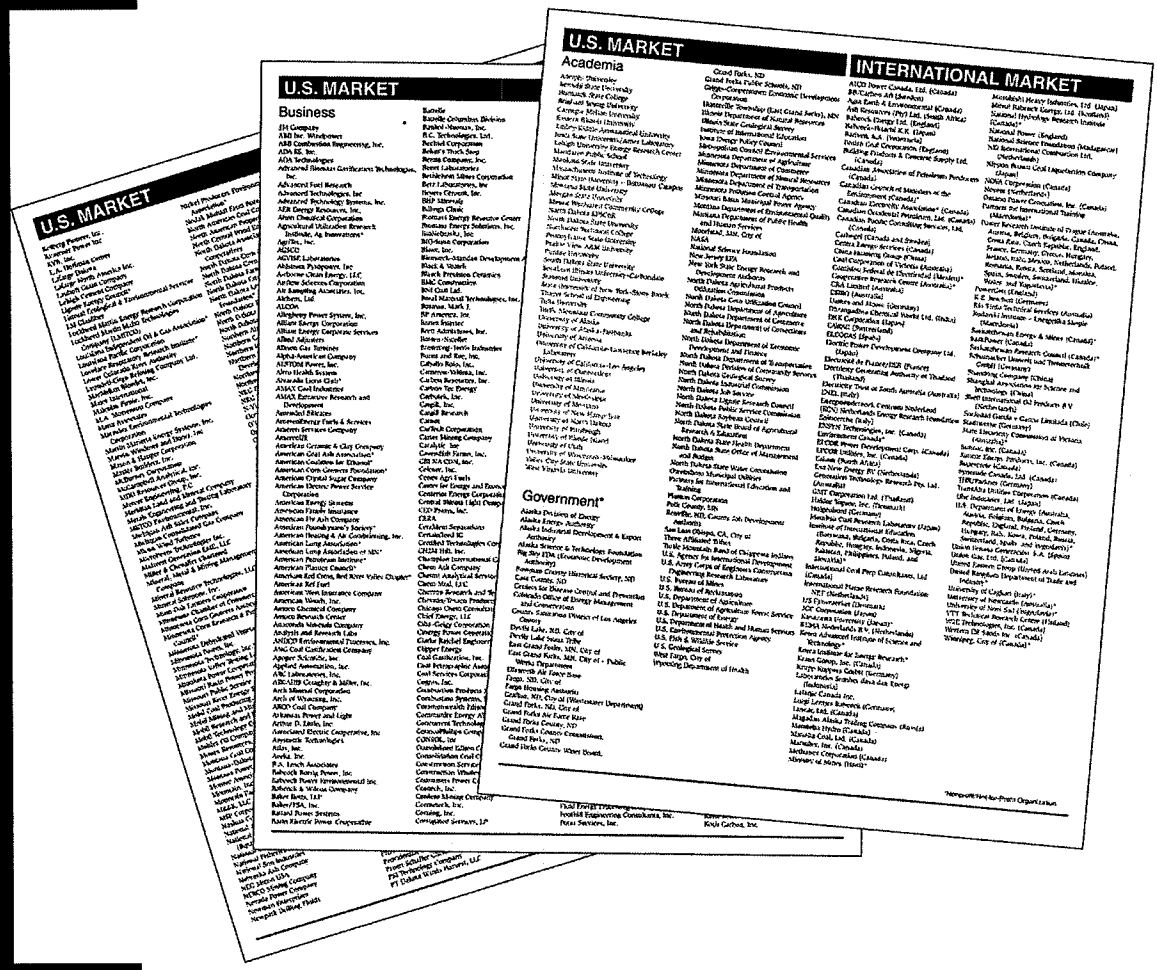
Providing Strategic Solutions to Real-World Problems

The EERC provides practical, cost-effective solutions to today's most critical energy and environmental issues and challenges.

Our research portfolio includes:

- Clean coal technologies
- Coalbed methane
- Underground coal gasification
- Emission control
  - SO_x, NO_x, air toxics, fine particulate, and CO_2
- Mercury measurement and control
- CO_2 sequestration
- Global climate change
- Energy and water sustainability
- Energy-efficient technologies
- Distributed power generation – various fuels
- Hydrogen technologies
- Alternative fuels
  - Ethanol, biodiesel, biojet, and strategic fuels for the military
- Biomass
- Wind energy
- Water management
- Flood prevention
- Waste utilization
- Contaminant cleanup
- Advanced analytical technologies/extraction technologies
- Pesticides and neurological diseases

Worldwide Clients



Since 1987, the EERC has had more than 970 clients in 49 countries and 50 states.

Client Specs:

- Governmental clients: 87
- Academia: 49
- International market: 117
- Private corporations: 721

EERC Today - Quick Facts

- Total value of current EERC contract portfolio is over $122 million.
- The EERC had 438 active contracts in FY06.
- In FY06, 92% of contracts were with nonfederal clients.
- In FY06, over 63% of clients were repeat customers.
- Total employment of more than 290 highly skilled scientists, engineers, and support personnel.
- Current facilities include more than 245,000 square feet of laboratory, demonstration, and office space.
- The EERC sends out an average of nearly one funding proposal per calendar day.
- Total contract awards in FY06 were over $45 million.
- Total expenditures for FY06 were more than $25.7 million, with an estimated regional economic impact of $90 million.
- Fourteen spin-off companies have evolved from EERC programs.

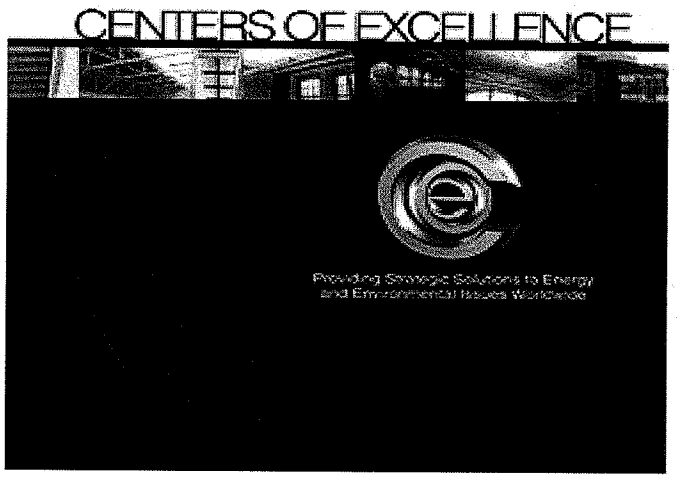
EERC Expertise

- Coal-fired boiler studies
- Cyclone boiler projects
- North Dakota lignite boiler studies and projects
- Coal-fired boiler NOx and SCR studies

EERC Centers of Excellence

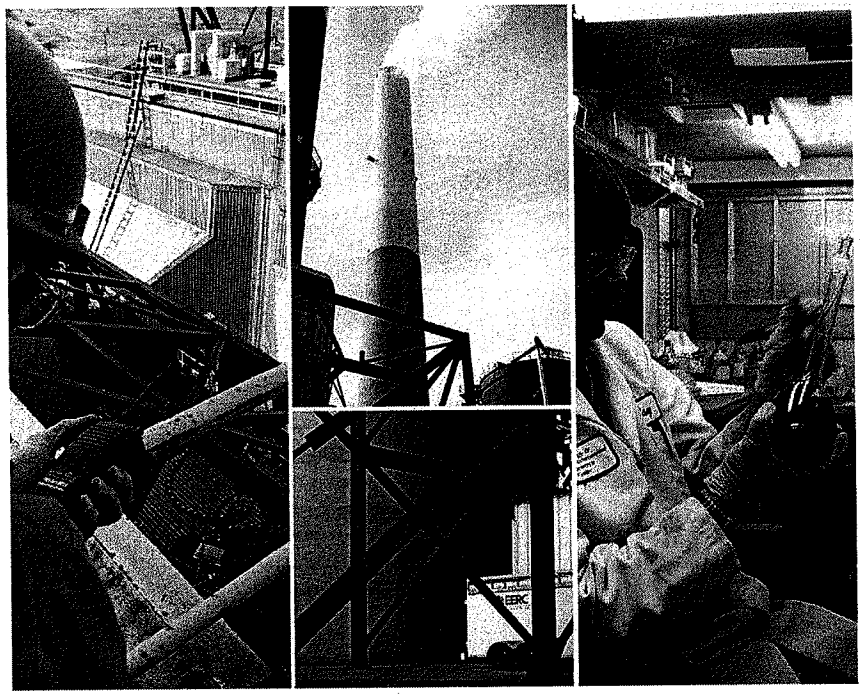
The EERC's Centers of Excellence are leading the world in providing expertise in scientifically advanced energy systems and the prevention and cleanup of air, water, and soil pollution.

- Coal Utilization Technologies Center
- Emission Control Technologies Center
- The National Center for Hydrogen Technology
- Center for Climate Change and CO_2 Sequestration
- Center for Air Toxic Metals® (CATM®)
- Center for Renewable Energy
- Water Management Center
- National Alternative Fuels Laboratory® (NAFL®)
- Supercritical and Subcritical Extraction Technologies Center
- Coal Ash Research Center



Coal Utilization Technologies Center

The EERC, and its federal predecessor organization, has been involved in research and development of clean coal technologies for over 50 years and is the world's leading research, development, demonstration, and commercialization center for cutting-edge coal utilization technologies emphasizing high efficiency and zero emissions.



Emission Control Center

The EERC is internationally recognized for groundbreaking work in understanding the formation of air pollutants and in the development of technologies to control their emission, including:

- Air toxics
- Particulate matter
- SO_2
- SO_3
- NO_x
- CO_2
- H_2O

EERC Coal-fired boiler studies

- Bureau of Mines – lignite properties, application of combustion and environmental control systems, investigations involved bench, pilot, and full scale testing of new and emerging technologies

- Energy Resource Development Agency (ERDA) and U.S. DOE – Subbituminous and lignite coal combustion in cyclone, pc, and fluidized bed. Air pollution control systems for SOx, NOx, particulate, and trace elements.

- EERC – All fuel types – support of existing cyclone, PC, and fluidized bed combustion systems as well as the development of advanced combustion systems (High Temperature Advanced Furnace (HITAF), oxygen blown systems…..)

EERC Cyclone Boiler Projects

- Numerous project on slag flow and ash partitioning for lignite, subbituminous, and bituminous fired systems
- Examples:
  - Project Sodium: consortium based effort to better understand the impacts of sodium on system performance with emphasis on slag flow behavior, partitioning of alkali and alkaline earth elements between silicates and sulfates – 1985-1991
  - Project Calcium: consortium effort focused on partitioning in cyclone fired systems and impacts on equipment downstream of furnace – 1989 - 1992
  - Combustion Inorganic Transformations: Efforts were developing understanding of the chemical and physical transformation of impurities in coal during combustion – 1987- 1992
  - Coal Quality Management System: Effort was on Center lignite and impacts of properties on cyclone performance and develop predictive measures.
  - Coal Quality and Boiler Operations: Effort was on Center lignite to match boiler operations and coal quality.
  - Computer modeling projects predicting partitioning in cyclone fired systems – Coal Quality Expert, Fuel Quality Advisor, AshPro, and others

EERC Coal-fired boiler NOx studies

- Staged combustion and overfired air field testing with lignite – pilot and full scale studies
- Catalytic Bags – Owens-Corning projects
- CarbNOx – carbon based technology for NOx reduction – low temperature gasification process

EERC Coal fired boiler SCR Studies

- SCR catalyst blinding and plugging
  - Various vendors and utilities
  - Consortium to examine mechanisms of sulfate formation
- SCR – SO_3 formation and control
- SCR – mercury oxidation and control

SCR Catalyst Blinding Project – Participants

- Electric utilities
  - Kinectric/Ontario Power Technologies
  - Otter Tail Power Company
  - Alliant Energy
  - AmerenUE
  - Dynegy
- Electric Power Research Institute (EPRI)
- North Dakota Industrial Commission (NDIC)
- U.S. Department of Energy National Energy Technology Laboratory (DOE-NETL)
- Catalyst vendors: Hitachi, Haldor-Topsoe, Cormetech

EERC Personnel Qualifications

- Dr. Steven A. Benson

Dr. Steven A. Benson - Qualifications

- Education:
  - B.S. Chemistry – Minnesota State University
  - Ph.D. Fuel Science, Energy and Geo-Environmental Engineering Department – Pennsylvania State University
- Work Experience:
  - 1977–1983 – Research Chemist, U.S. Department of Energy, Grand Forks Energy Technology Center – Efforts focused on the chemical and physical properties of low-rank lignite and subbituminous coals and their impact on combustion/gasification and environmental control system performance in laboratory, pilot, and field testing.
  - 1983 –1986 – Graduate Research Assistant, Fuel Science Program, Pennsylvania State University – Research topic was on the ash formation and deposition behavior of lignite and subbituminous coals from the western United States.

Dr. Steven A. Benson - Qualifications

- Work Experience (continued):
  - 1986–Present – Associate Director, Senior Research Manager, Energy & Environmental Research Center, University of North Dakota – Responsible for projects involving minimizing the impacts of fuel impurities on power system performance.
- Awards:
  - Graduates of Earth and Mineral Science (GEMS) Award, College of Earth and Mineral Sciences, Pennsylvania State University, 2002. This award is the highest recognition bestowed on an alumnus by GEMS and is given each year to an individual who exemplifies the ideals of the College.
  - Lignite Energy Council, Distinguished Service Award, Research & Development, 1997, 2003, 2005

Dr. Steven A. Benson - Qualifications

- Publications:
  - Editor of 9 special issues and books
  - Over 220 papers

Presentation Agenda

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Key BACT Issues Regarding SCR Infeasibility for MRYS Boilers

- The characteristics of the North Dakota lignite fired at Milton R. Young Station make "technology transfer" of SCR experience from other coal-fired boilers invalid for establishment of SCR as BACT for the cyclone boilers there.
- Substantial research and development would be necessary to confirm that SCR is viable for application at MRYS. This means that SCR cannot be considered to be BACT in this case.

EPA Guidance on Technical Infeasibility

"Within the context of the top-down procedure, an applicant addresses the issue of technical feasibility in asserting that a control option identified in Step 1 is technically infeasible. In this instance, the applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or *unusual circumstances which exist with application of the control to the applicant's emission units*. Generally, such a demonstration would involve *an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology*. 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)."

EPA New Source Review Workshop Manual, pg B.19 (emphasis added)

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Basis for Technical Infeasibility of SCR as BACT for MRYS Boilers

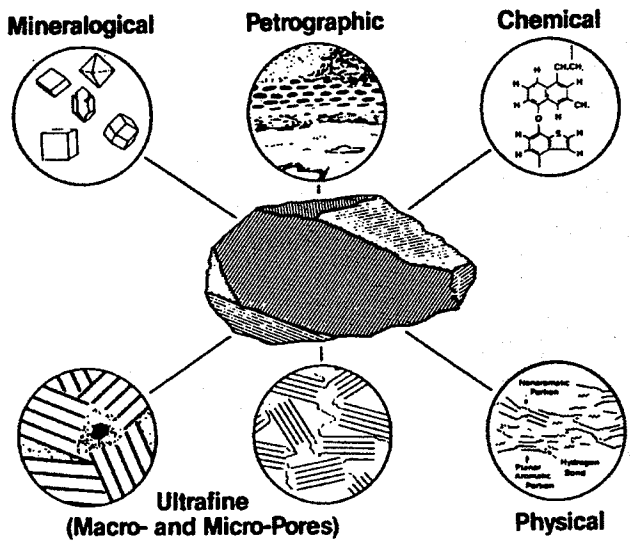
- Effect of cyclone firing of North Dakota lignite on ash characteristics entering SCR
- Effect of high sodium on potential for SCR catalyst deactivation
- Effect of high flue gas temperatures at SCR location in gas path at M R Young Station
- Effect of small particles downstream of ESP on feasibility of "low-dust" SCR

Key MRY SCR Feasibility Issues – blinding, plugging, and deactivating catalysts

- Lignite properties
  - Organically associated elements (sodium, calcium)
  - Highly variable
- Cyclone combustion
  - Partitioning of the ash
  - Concentrates bonding materials
- Sodium calcium sulfates – bonding phase
  - Small particle formation and transport
  - Reaction with SO_2/SO_3

Fort Union Lignites – complex chemical and physical characteristics

- Organically associated impurities -- organic structure has bonding sites for alkali and alkaline earth elements (Na, Ca, and Mg)
- Mineral impurities -- Highly variable quartz, clays, sulfides, and others
- Water associated impurities – sodium sulfate other species



Importance? Impacts the fate in cyclone, furnace, convecti pass, and air pollution control devices

me Chemical and Physical Properties of Coals in the Various nk Classes of the ASTM System

anic Geochemistry of Coal, Given (1984))

			High-Volatile Bituminous			Bituminous		
	Lignite	Subbit.	C	B	A	Med. Vol.	Low Vol.	Anthracite
% C, mmf	65–72	72–76	76–78	78–80	80–87	89	90	93
% H	4.5	5	5.5	5.5	5.5	4.5	3.5	2.5
% O	30	18	13	10	10–4	4–3	3	2
% O as COOH	13–10	5–2	0	0	0	0	0	0
% as OH	15–10	12–10	9	?	7–3	2–1	1–0	0
Aromatic C atoms, % of total C	50	65	?	?	75	80–85	85–90	90–95
Av. no. benz. rings, layer	1–2	?		2–3			5?	>25?
Volatile matter, %	40–50	35–50	35–45	?	31–40	31–20	20–10	<10
Reflectance, % of vitrinite	0.2–0.3	0.3–0.4	0.5	0.6	0.6–1.0	1.4	1.8	4
Density, in helium					minimum			
Total surface area					minimum			
Plasticity and coke formation					only			
Calorific value, moist. mmf, Btu/lb	7000	10,000	12,000	13,500	14,500	15,000	15,800	15,200

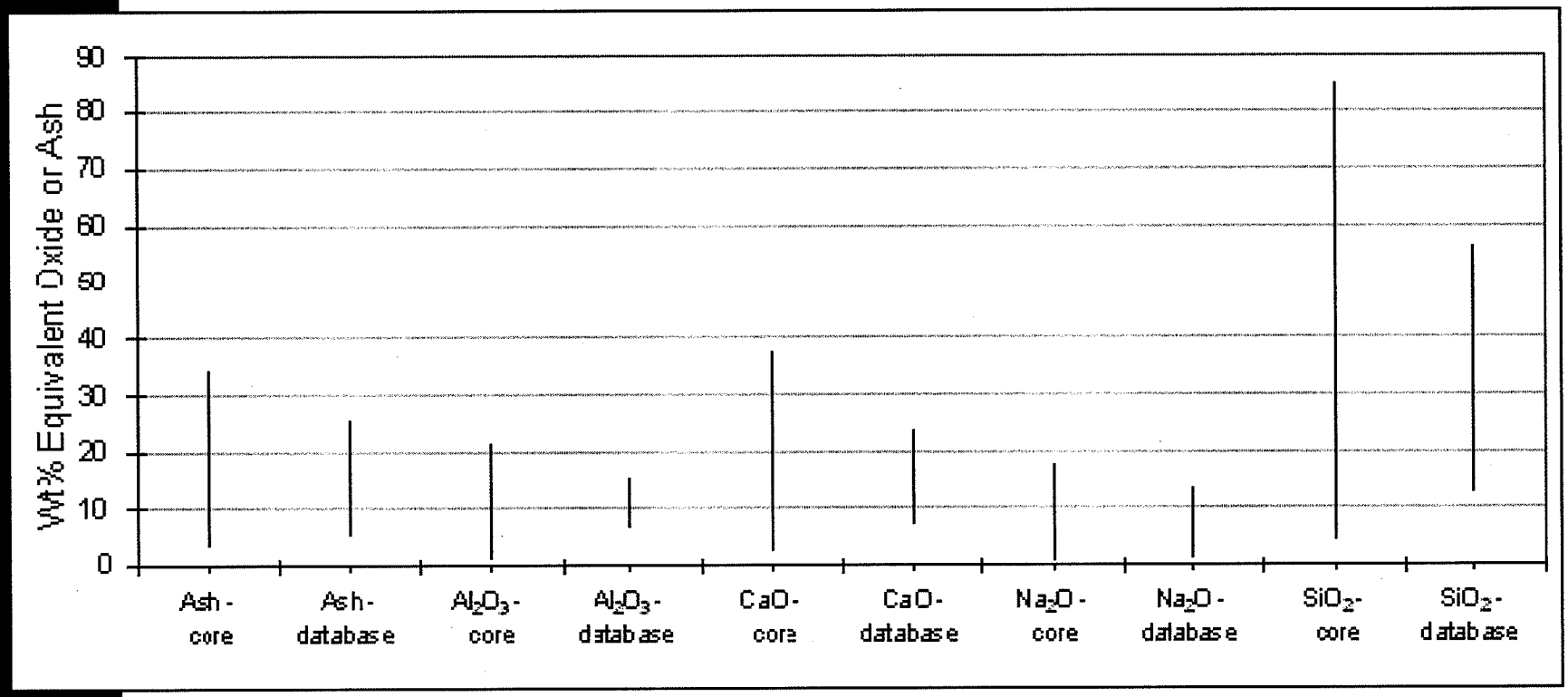
Lignite Properties

North Dakota lignite properties and variability

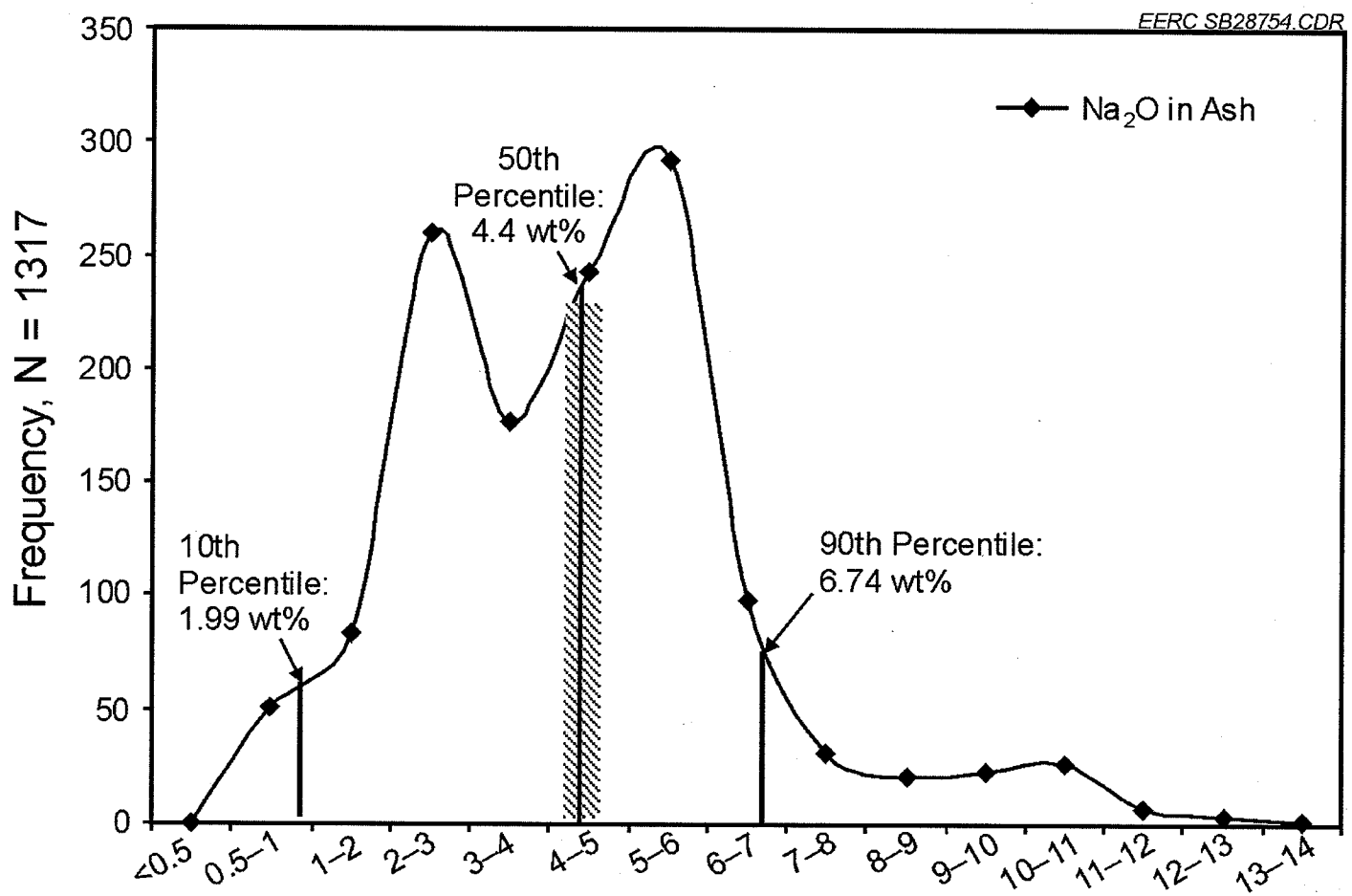
- High moisture content
- High reactivity
- Moderate heating value (Btu/lb)
- Ash content 2x PRB coal
  - High in sodium, magnesium and calcium – primarily organically associated
  - Highly variable clay mineral content – wide range of quartz, kaolinite, illite
  - Wide range in levels of pyrite minerals

Ash Composition Variations –Center Lignite

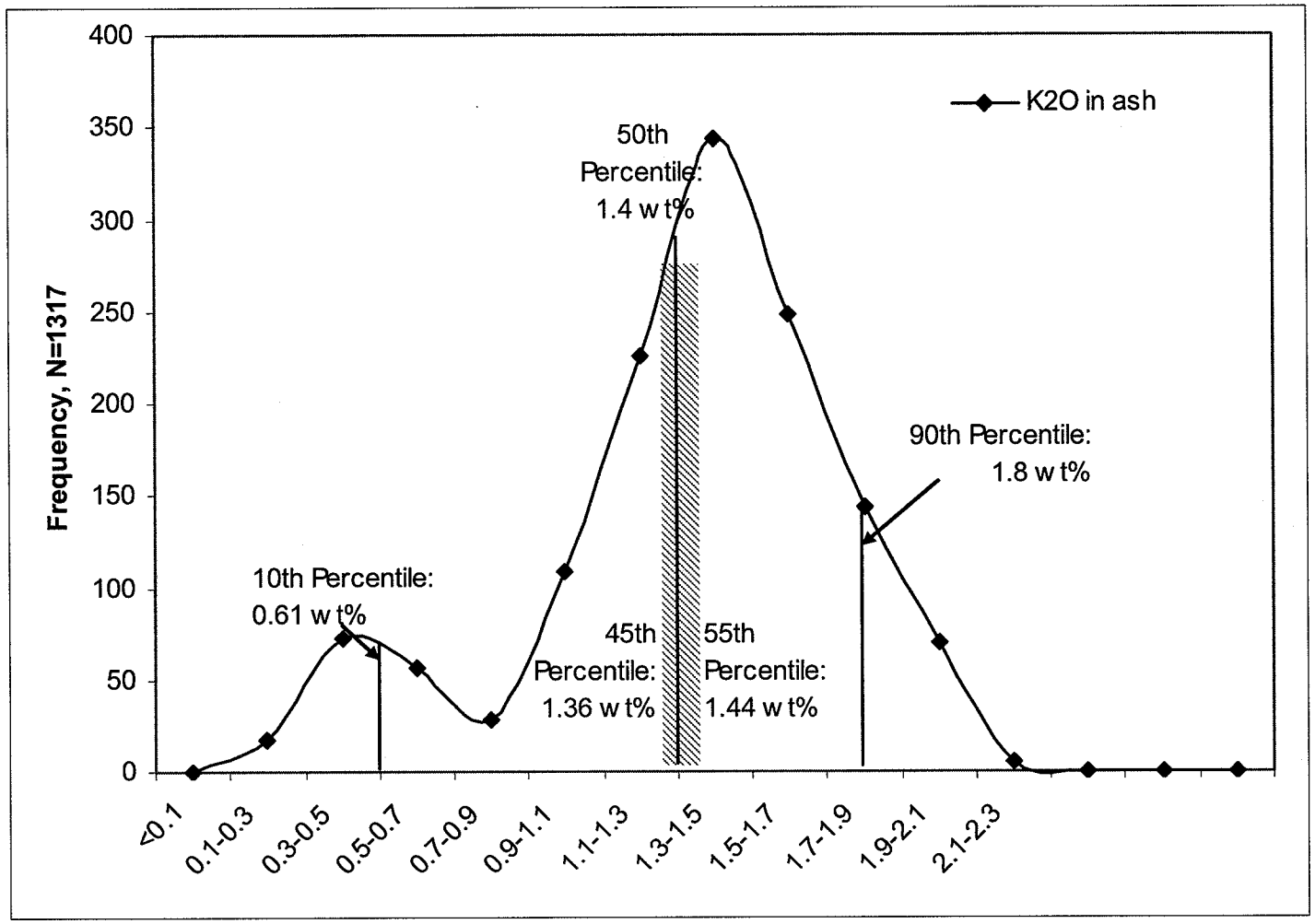
(Ash Content (as received), Ash composition wt. % oxides)



Sodium Content of as-fired Center lignite

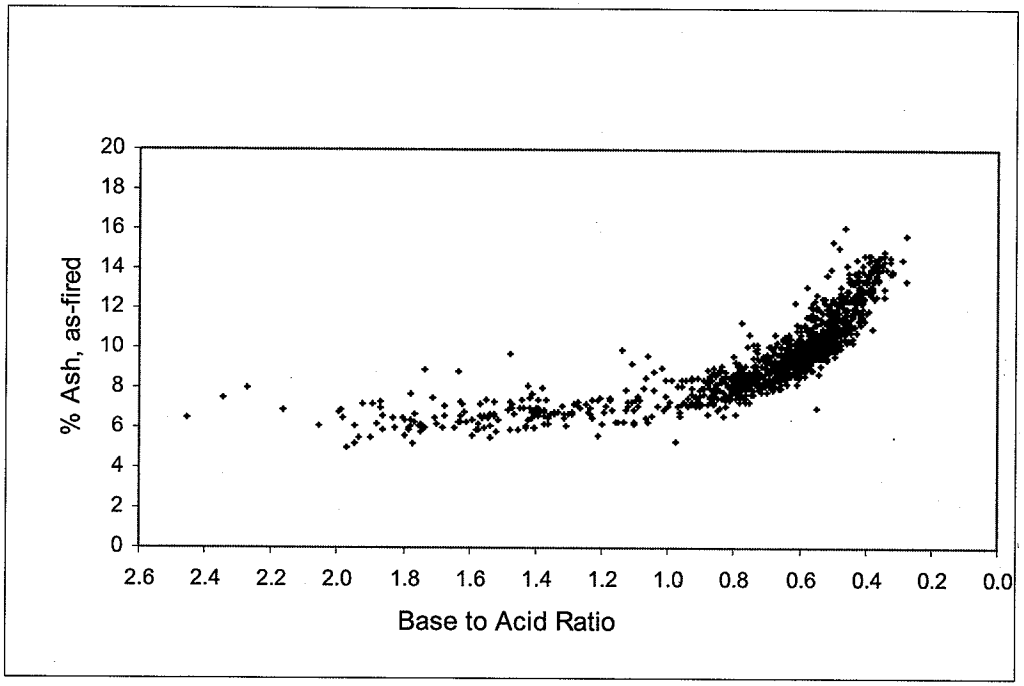


Potassium Content of as-fired Center lignite



Center lignite ash composition trends

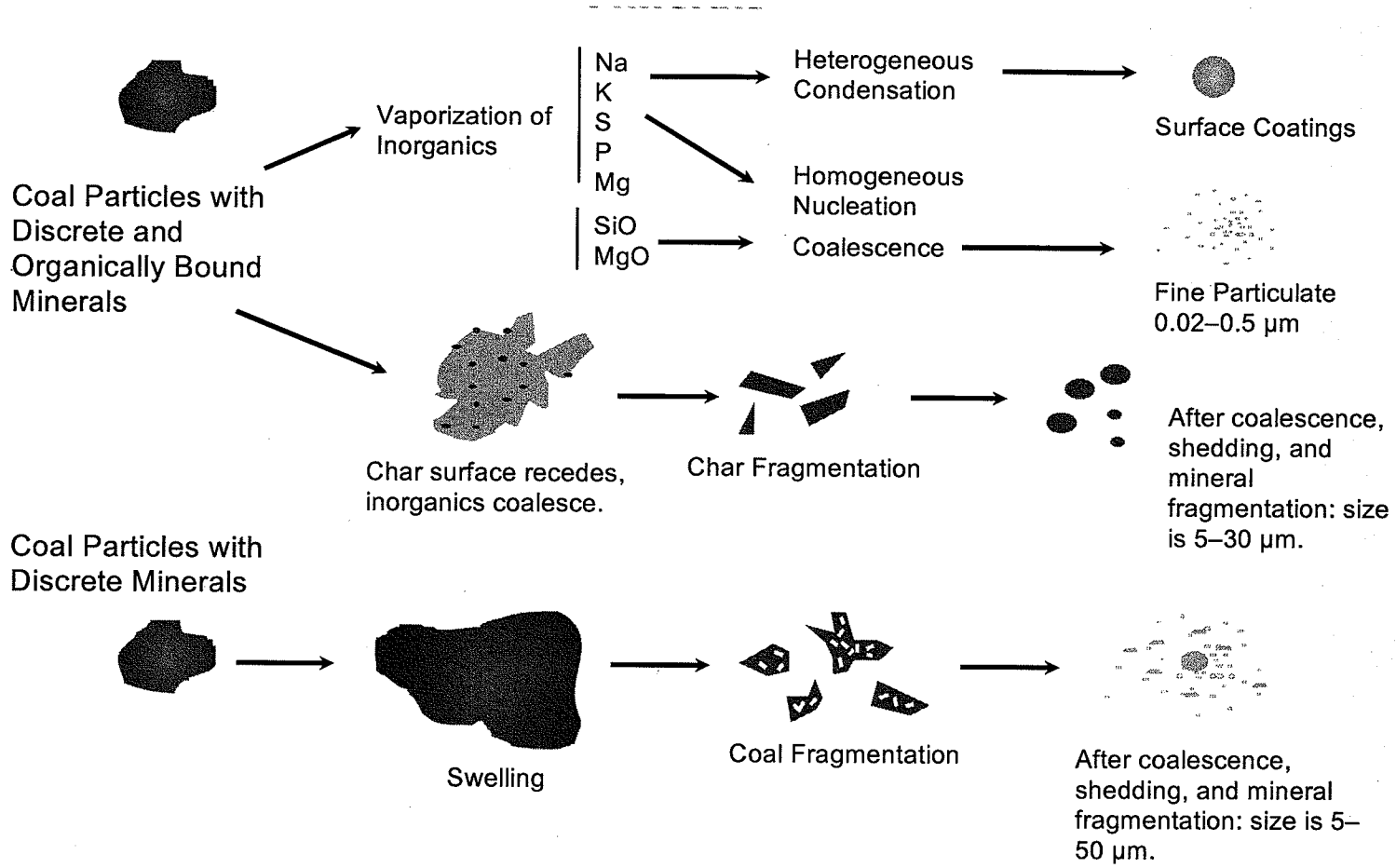
- Low ash content- high sodium and calcium
- High ash – high silicon and aluminum
- Impacts of organically associated elements
- High Base-to-Acid ratios are problematic in MRYS boilers



Effect of high sodium from Ft. Union lignite on potential for SCR catalyst deactivation

- Soluble forms cause faster and greater catalyst deactivation

Mechanisms for Fly Ash Formation During Combustion



Effect of cyclone firing of North Dakota lignite on ash characteristics entering SCR

- Cyclone boilers are designed to melt the fuel ash during combustion
- Vapor phase species and fine ash particles are emitted from cyclones
- Constituents in northern lignite ash are partitioned in the cyclone, furnace and convection zones of the boiler
- Fireside fouling from flyash is severe
- High sodium and other condensed species are found in very small particles

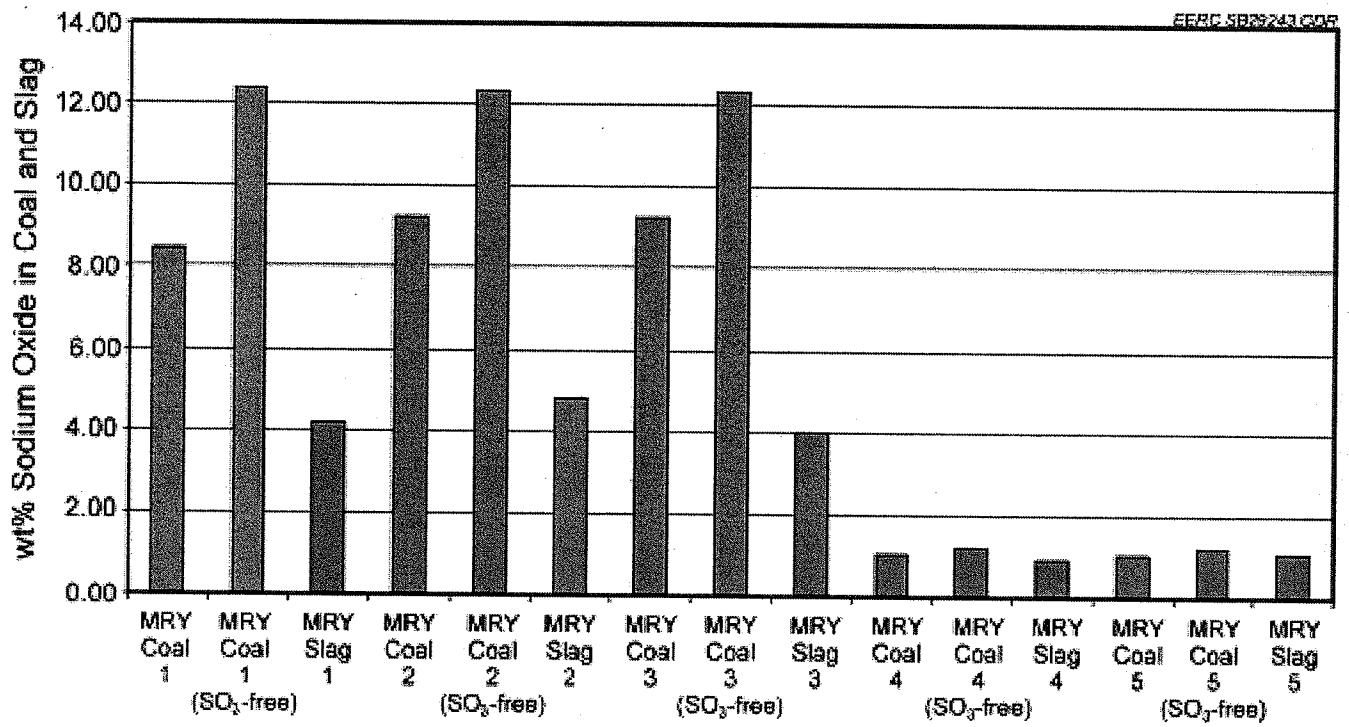
Cyclone Boilers for Northern Lignite

- Only 5 cyclone-fired boilers designed and built specifically to burn northern lignite fuel:
  - MRY1 (250MW, 1970, RB-457, 7 cyc.)
  - LOS2 (450MW, 1974, RB-489, 12 cyc.)
  - Big Stone (450MW, 1974, RB-490, 12 cyc.)
  - MRY2 (450MW, 1977, RB-525, 12 cyc.)
  - Coyote (450MW, 1981, RB-563, 12 cyc.)

Cyclone firing – impacts ash composition approaching SCR

- High temperature cyclonic process partitions the impurities – organically associated elements vaporize and/or form small particles
- Enrichment of sodium and calcium in the smaller size fractions of the fly ash
- Mineral components depleted from fly ash results in less surface for heterogeneous condensation and dilution of bonding materials (sulfates)

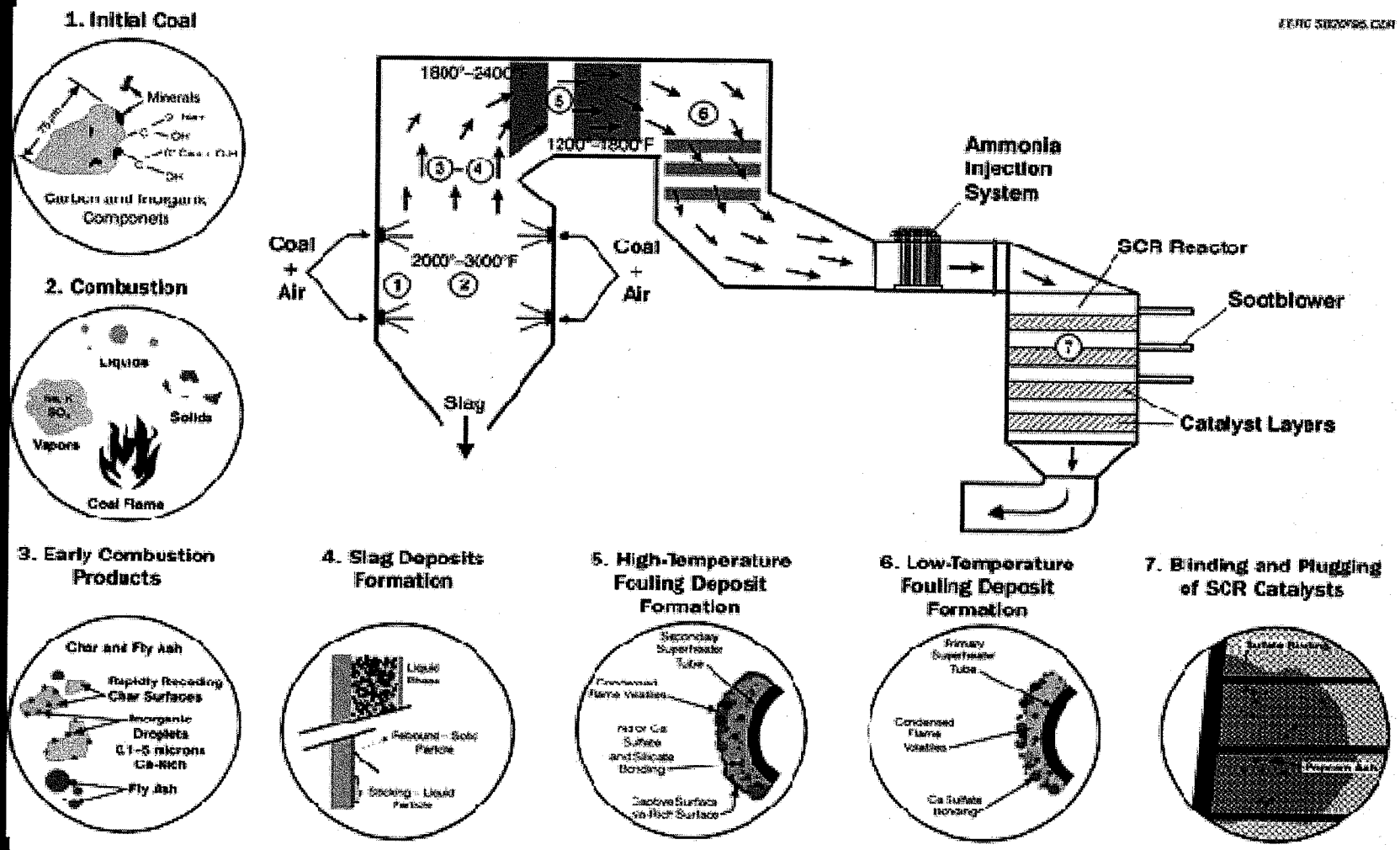
Sodium Partitioning in Cyclones



Impacts of Lignite Variability

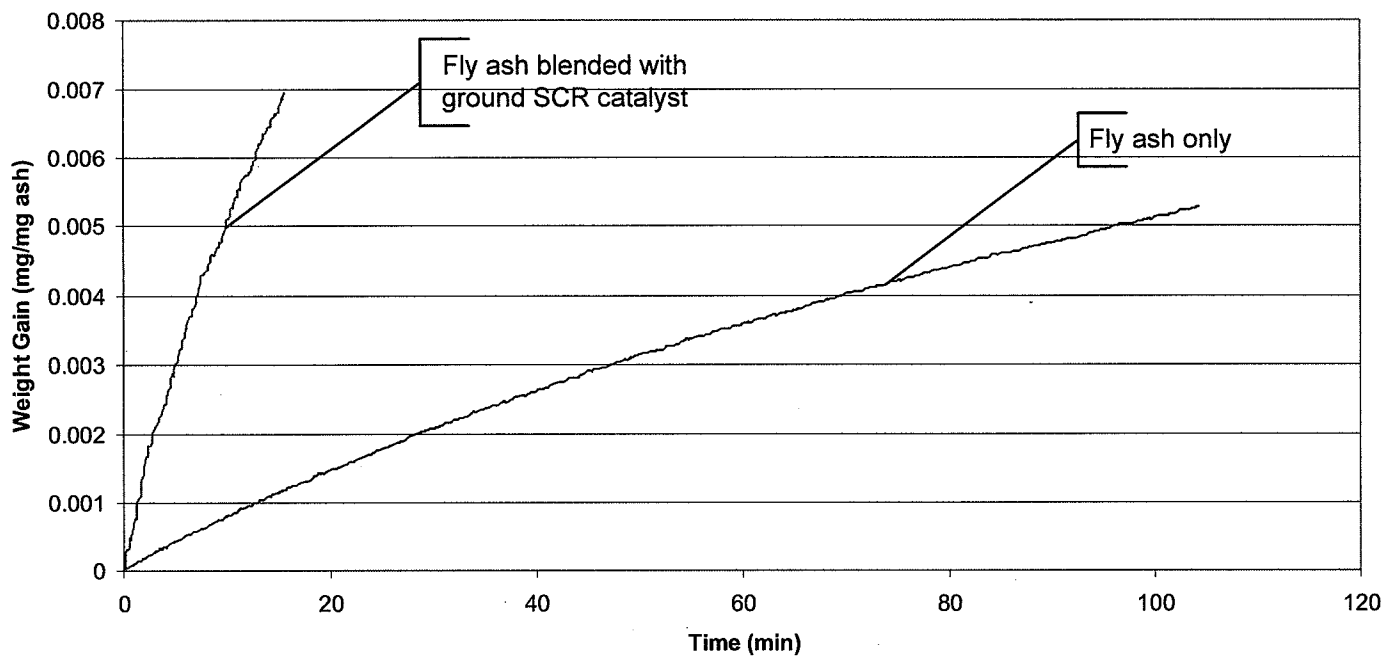
- Fireside performance
  - Cyclone – slag flow
  - Water walls – Ash deposit accumulation --slagging
  - Convective pass – Ash deposit accumulation -- fouling
- Air pollution control devices – ash particle size and composition
  - ESP – particle capture -- ash resistivity, cohesivity
  - Baghouse – particle capture (dust cake formation) pressure drop and cleanability -- ash cohesivity

Ash-Related Problems in Utility Boilers



Sulfate formation

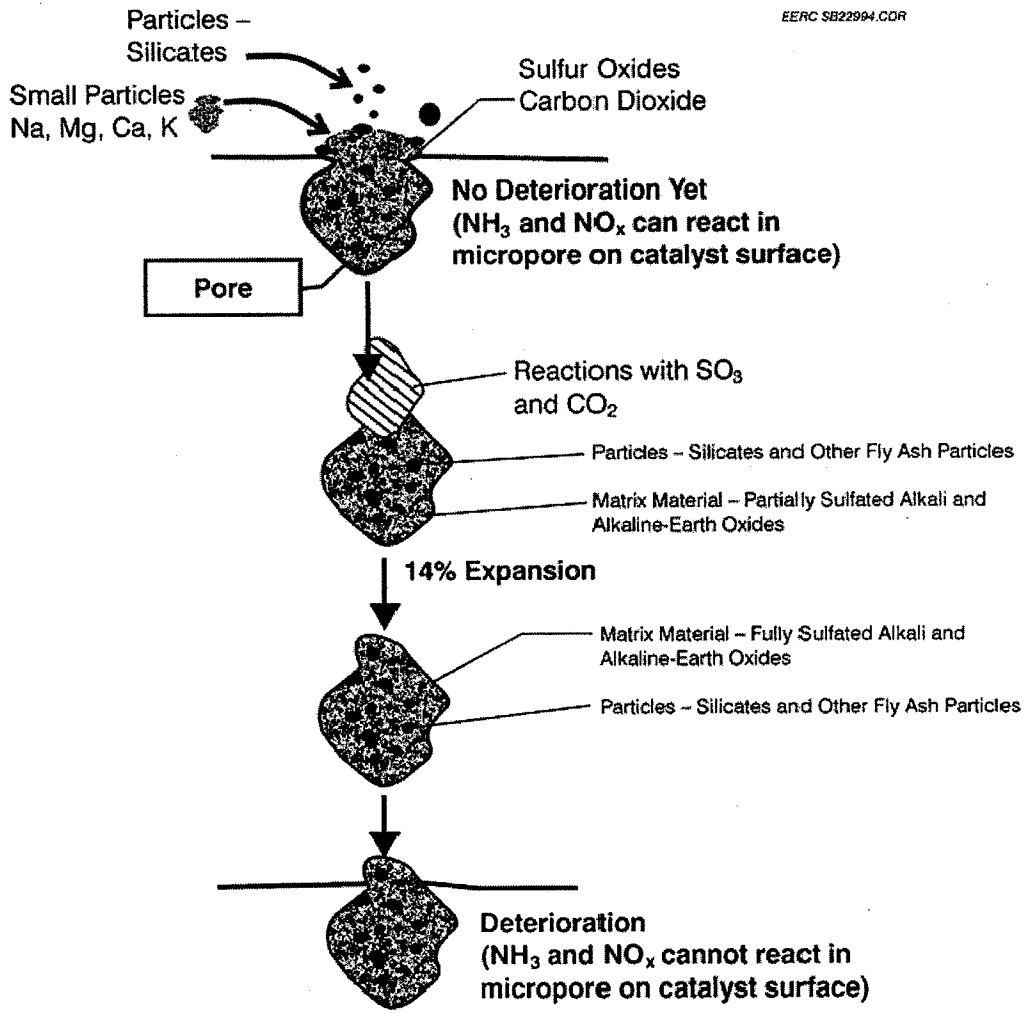
- Catalyzed by the SCR processes
- SO_3 readily reacts with sodium, calcium, magnesium
- Bonding forms low melting point liquids – sulfates and pyrosulfates
- Reaction product increase in size fill pores and plug catalysts
- TGA analysis show higher SO_2 uptake with catalyst present



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

SCR Catalyst Blinding Mechanism



Project: Evaluation of Potential SCR Catalyst Blinding During Coal Combustion

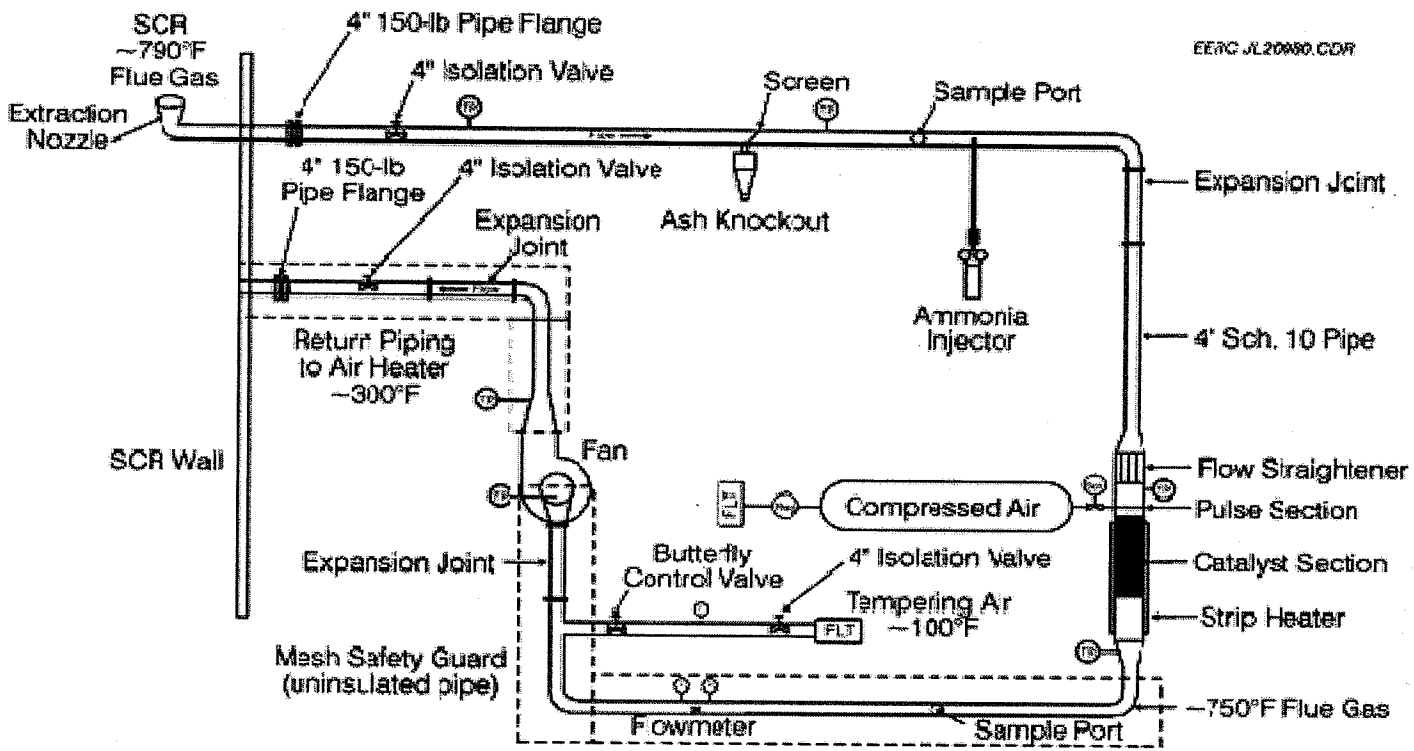
- Objectives
  - Determine potential for low-rank coal ash to cause blinding of selective catalytic reduction (SCR) catalysts
  - Determine mechanisms of SCR blinding
  - Determine the degree of elemental mercury conversion across SCR catalyst material

SCR Catalyst Blinding Project – Participants

- Electric utilities
  - Kinectric/Ontario Power Technologies
  - Otter Tail Power Company
  - Alliant Energy
  - AmerenUE
  - Dynegy
- Electric Power Research Institute
- North Dakota Industrial Commission
- U.S. Department of Energy National Energy Technology Laboratory
- Catalyst vendors: Hitachi, Haldor-Topsoe, Cormetech

Slipstream SCR Catalyst Test System

- Design and operation protocols of the slip stream system were develop with detailed input and approval by Hitachi, Cormetech, and Haldor Topsoe.
- All test plans and procedures were approved by consortium team.



Plants Tested – 6-month tests

	Baldwin	Columbia	Coyote
Unit No.	1	2	1
Utility	Dynegy	Alliant	Otter Tail
Boiler Type	Cyclone	T-fired	Cyclone
Fuel type	Antelope – subbituminous	Caballo – subbituminous	Beulah – Zap lignite
Load	Base	Base	Base
Location	Baldwin, IL	Portage, WI	Beulah, ND
MW	600	520	425

Coals Fired During Slip Stream Testing

Ultimate Analysis Results (dry basis), wt%

	Antelope (Balwin)	Caballo (Columbia)	Beulah (Coyote)
Ash Content	7.28	6.59	11.62
Total Sulfur	0.33	0.51	1.49
Carbon	69.97	67.88	61.50
Hydrogen	4.77	4.83	3.96
Nitrogen	1.05	1.24	1.08
Oxygen (by difference)	16.61	18.96	20.35

Ash Composition (wt% equivalent oxide)

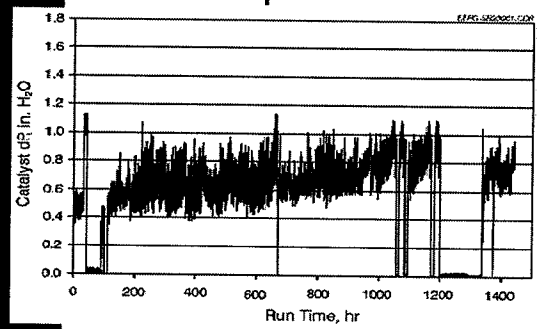
Oxide	Antelope	Caballo	Beulah
SiO_2	24.82	26.70	16.50
Al_2O_3	13.55	16.60	13.30
TiO_2	1.39	1.10	0.80
Fe_2O_3	7.52	5.10	16.60
CaO	26.68	25.10	19.50
MgO	7.14	8.00	7.40
K_2O	0.17	0.30	0.20
Na_2O	1.47	1.00	5.20
P_2O_5	0.90	1.70	0.00
SO_3	16.33	14.40	19.80

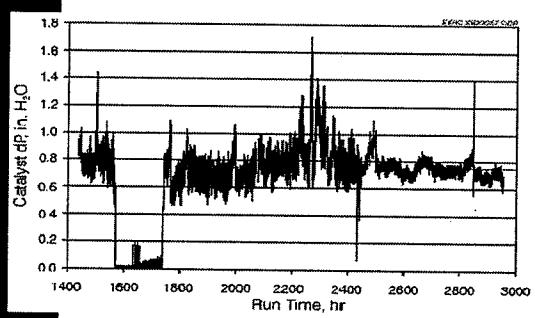
Selected Operating Conditions of the SCR Slip-Stream Test Catalysts

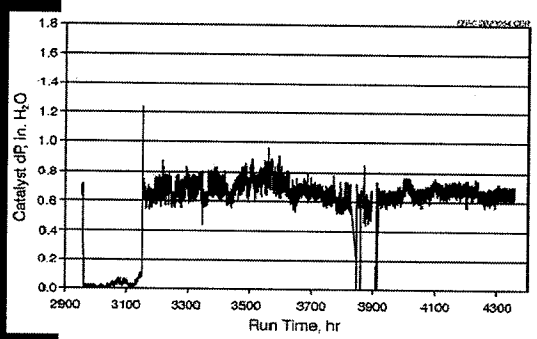
Plant Name	Average SCR Inlet Temp., °F	Average SCR Outlet Temp., °F	Air Pulse Frequency	Flue Gas Flow Rate, acfm
Baldwin	645	549	Once a day and on demand	393
Columbia	672	662	Once a day and on demand	385
Coyote	675	667	Once a day and on demand	385

Pressure Drop Across SCR Catalyst

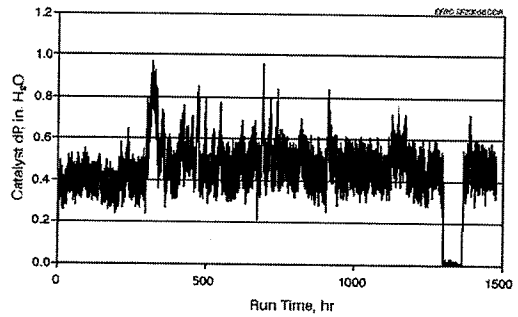
Baldwin, PRB, Cyclone
Haldor-Topsoe

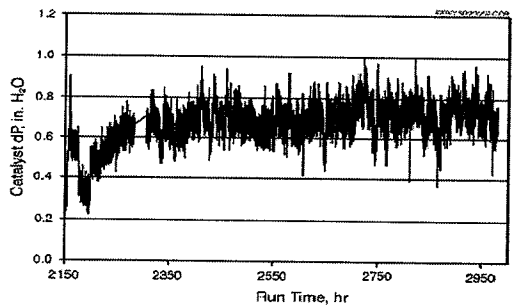


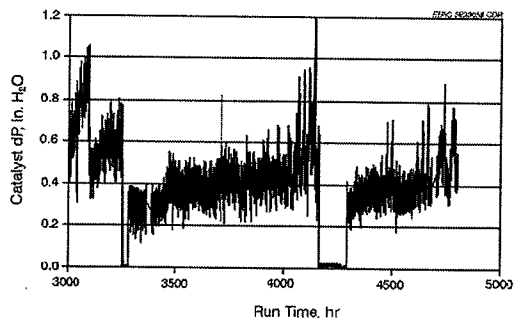




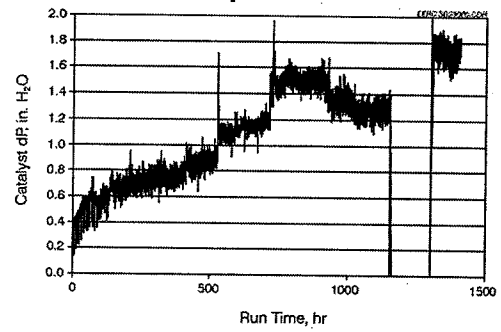
Columbia, PRB, T-Fired
Hitachi

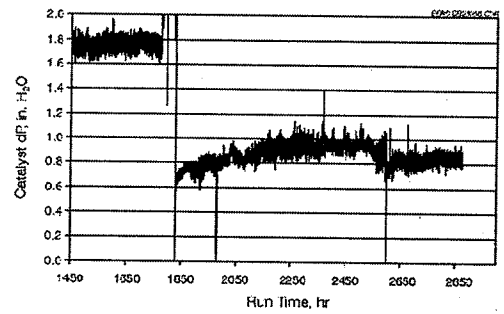


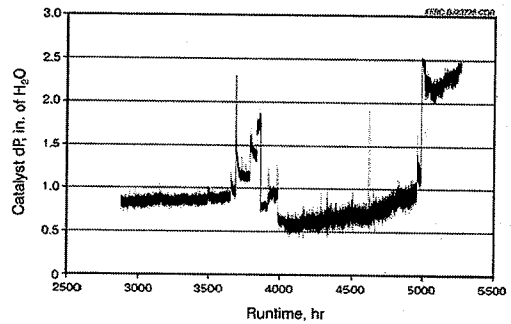




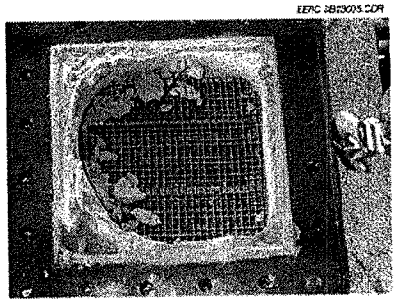
Coyote, Lignite, Cyclone
Haldor-Topsoe



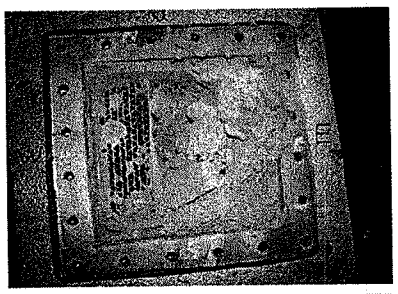




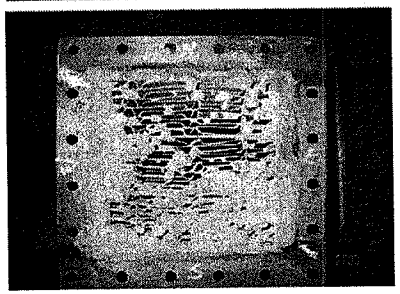
Plugging of Catalyst Inlet



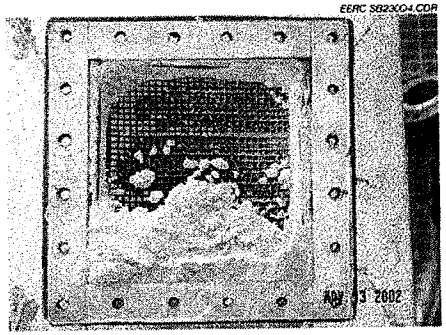
Baldwin Station after 2 months
PRB Coal



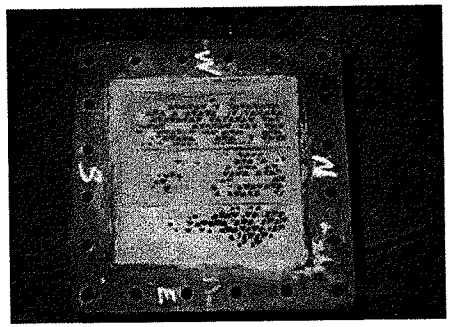
Coyote Station after 2 months
Lignite Coal



Columbia Station after 2 months
PRB Coal

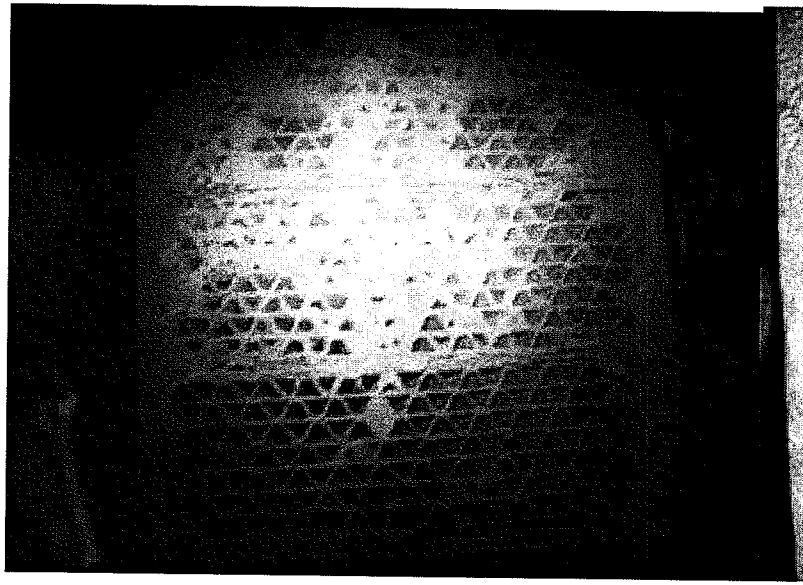


Baldwin Station after 4 months
PRB Coal

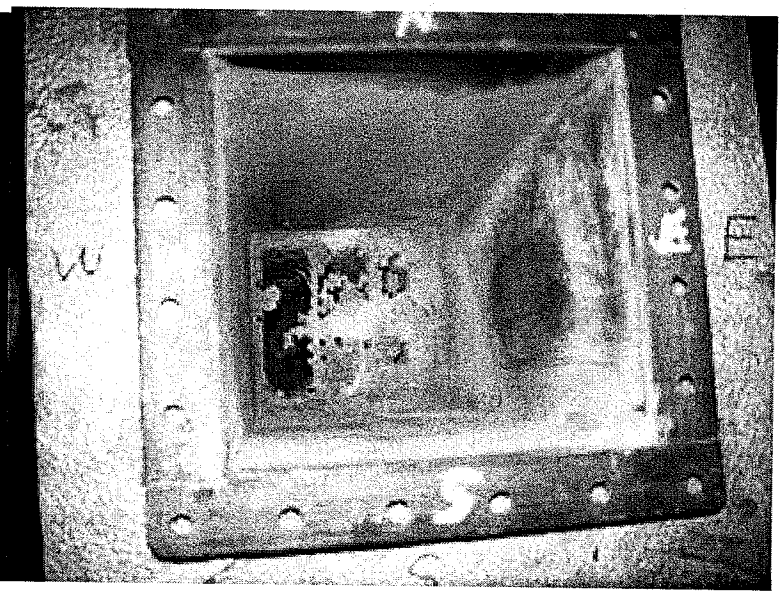


Coyote Station after 4 months
Lignite Coal

Plugging of SCR catalyst outlet



Outlet of catalyst section

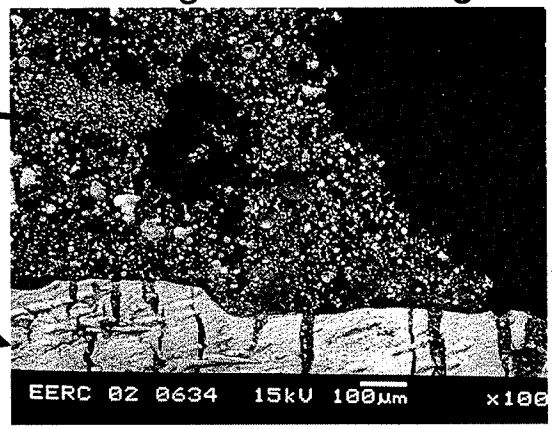


Deposit remaining after catalyst section was removed

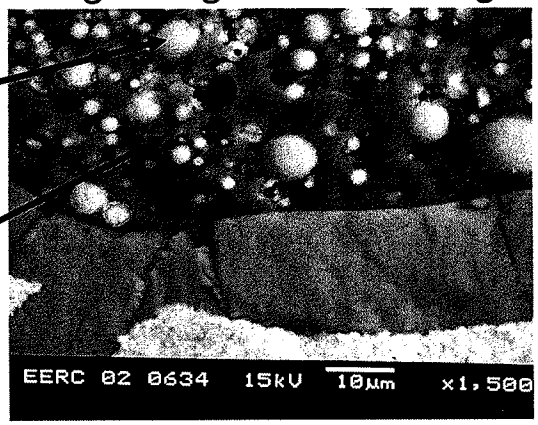
Formation of Sulfate Bonded Deposits

- Key processes
  - Small particle and vapor phase diffusion
  - Inertial impaction and incorporation of larger particles
  - Vapor-phase SO_2 and SO_3 reaction, possibly CO_2
  - Pore filling and densification
  - Surface tension forces
  - Reactivity of deposited material

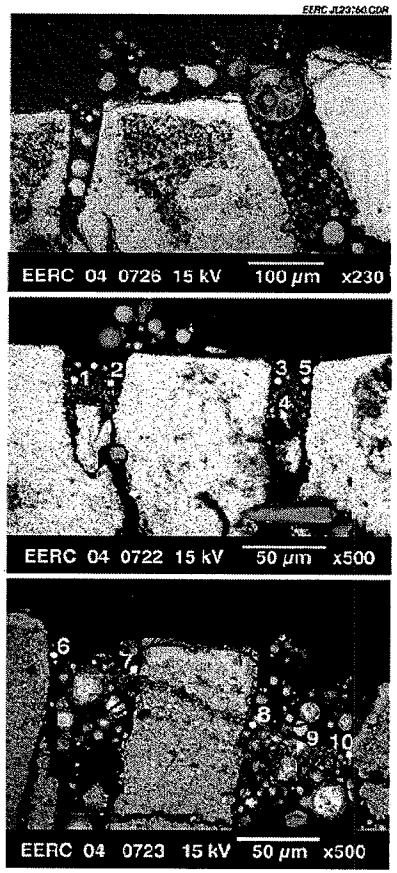
Low Magnification Image



High Magnification Image



Blinding Pores of Catalyst – Coyote – 6 months



A

B

C

Analysis of selected points

	Element, wt%				
	Point 1	Point 2	Point 3	Point 4	Point 5
Oxide					
Na_2O	5.0	3.2	6.6	5.8	4.1
MgO	1.6	0.0	0.0	7.6	1.4
Al_2O_3	2.1	3.3	0.6	0.8	1.7
SiO_2	10.7	12.8	3.6	2.6	14.4
P_2O_5	0.0	0.0	0.0	0.0	0.0
SO_3	57.9	40.7	67.0	71.0	52.7
K_2O	0.5	0.8	0.8	1.3	0.4
CaO	13.7	6.2	12.7	7.7	16.3
TiO_2	2.0	33.0	0.0	1.7	2.1
Fe_2O_3	6.5	0.0	8.8	1.4	7.0
BaO	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100
	Point 6	Point 7	Point 8	Point 9	Point 10
Oxide					
Na_2O	6.5	4.1	5.7	8.1	6.7
MgO	4.6	3.1	4.4	7.5	3.7
Al_2O_3	3.3	10.2	1.6	5.4	2.4
SiO_2	11.5	2.3	4.1	10.1	9.6
P_2O_5	2.2	0.5	0.0	0.9	7.2
SO_3	52.5	48.2	61.4	53.1	56.7
K_2O	1.9	1.0	10.0	3.0	0.9
CaO	13.6	23.9	2.6	8.6	10.5
TiO_2	2.7	3.7	0.7	0.0	0.0
Fe_2O_3	1.2	3.0	9.5	3.3	2.3
BaO	0.0	0.0	0.0	0.0	0.0
Total	100	100	100	100	100

Deactivation due to sodium

- Haldor Topsoe indicated deactivation of catalytic site due to reactions with sodium. Their data suggest sodium or potassium resembles the ammonium ion and blocks access to the active sites in the catalyst.
- Beck and others (2004) established that sodium correlates with catalyst deactivation activity and that pore condensation of sodium is the major deactivation mechanism.
- Mr. Christman did identify potassium, sodium, and magnesium as causing deactivation of catalysts .

Topsoe's Corrugated-type DeNOx Catalysts – Characteristics and Operating Experience, T. Slabiak and S. Enevoldsen, accessed in Haldor Topsoe's website February 13, 2007.

Beck, J.; Brandenstein, J.; Unterberger, S.; Hein, K. *App. Catal. B: Environ.* **2004**, *49*, 15–25.

ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NOX BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

Conclusions – SCRs in Lignite-Fired Boilers – Blinding – I

- High alkali and alkaline-earth elements present in the coal fired at ND plants form sulfates that blind the catalyst.
  - During combustion of ND lignite, sodium and calcium are enriched in the finer fly ash size fraction and as a result increase SCR catalyst blinding. Cyclone-firing increases the level of sodium in the fines.
  - Sulfate formation is also enhanced by the presence of an SCR catalyst (convert SO_2 to SO_3); 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.

Conclusions – SCRs in Lignite Fired Boilers – Blinding – II

- Impact SCR performance in Japan and Europe
  - Alkali (Na, K) and alkaline-earth (Mg, Ca) elements that result in sulfate formation blinding catalysts.
  - The levels of calcium in ND lignite are 2 to 4 times higher than the problematic coals in Japan and Europe.

Conclusions – SCRs in Lignite- Fired Boilers – Plugging

- Higher pressure drops were observed for testing with ND lignite indicating significant plugging evident.
- Deposit carryover, or popcorn ash, plugging the top of the SCR catalyst with deposit fragments. 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.
  - Sootblowing of the SCR catalyst, the entrainment of deposit fragments along with the sootblowing media will result in significant erosion of the catalyst surfaces.

Conclusions

- The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world and result in the formation of sodium calcium sulfates in the pores of the catalyst.
- Based on this information, the installation of SCR catalyst at plants firing high-sodium coals is technically infeasible for NO_x control.

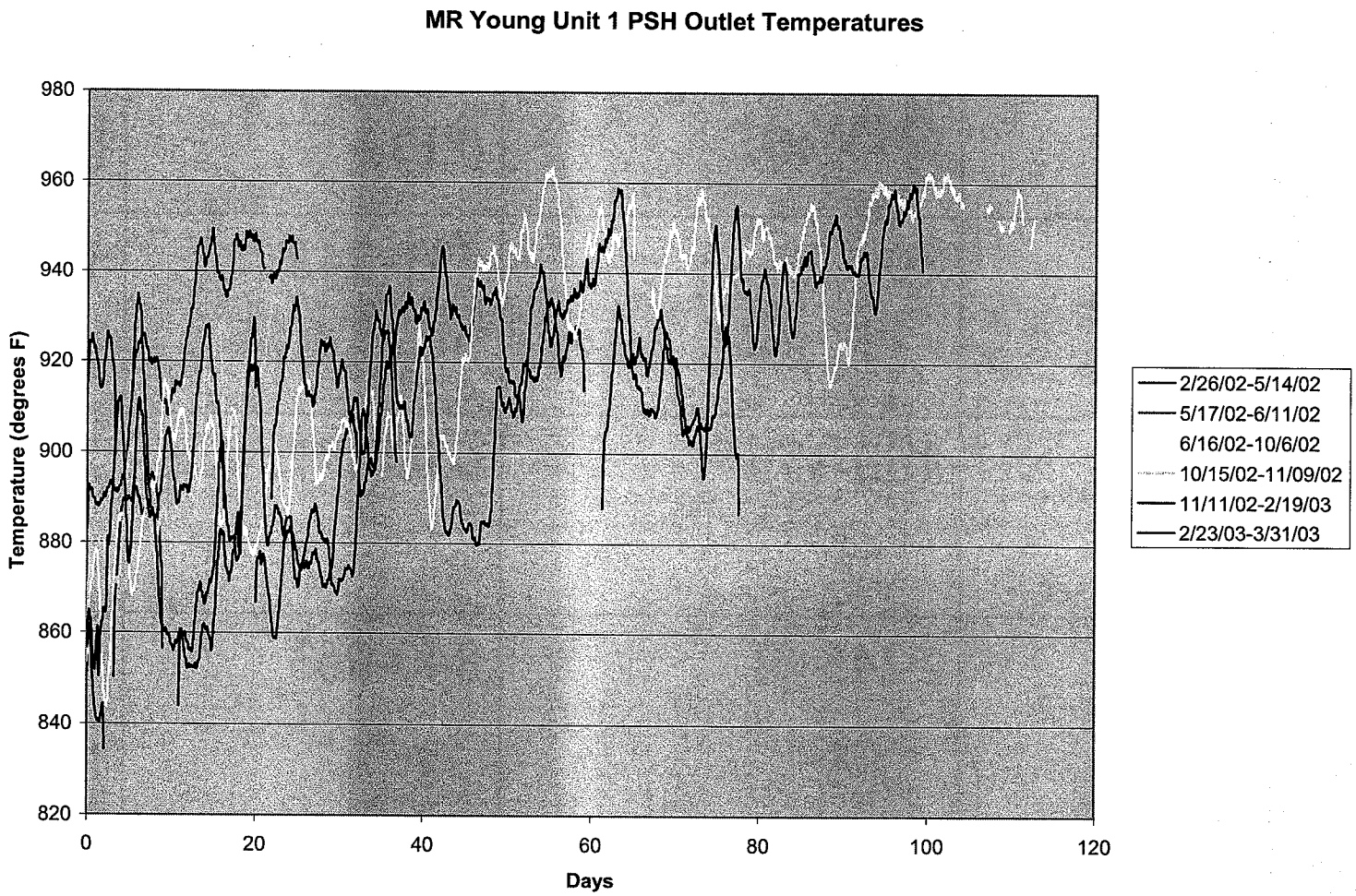
Effect of high flue gas temperatures at SCR location in gas path at M R Young Station

- Lignite drying for ND cyclone boilers requires hot air (primary) around 700°F
- Design for hot air temperatures requires high boiler exit flue gas temperatures (BEGT) at high load
- Severe fireside surface fouling raises BEGT as furnace get dirty between cleanings

High Flue Gas Temperatures of MRYS Unit 1 Boiler

Load	**Load Range (MWg)**	**PSH Outlet** (°F)	**ESP Exit** (°F)
Low	80-120	431-742	177-269
Mid	150-175	656-877	236-320
High	>245	840-963	303-355

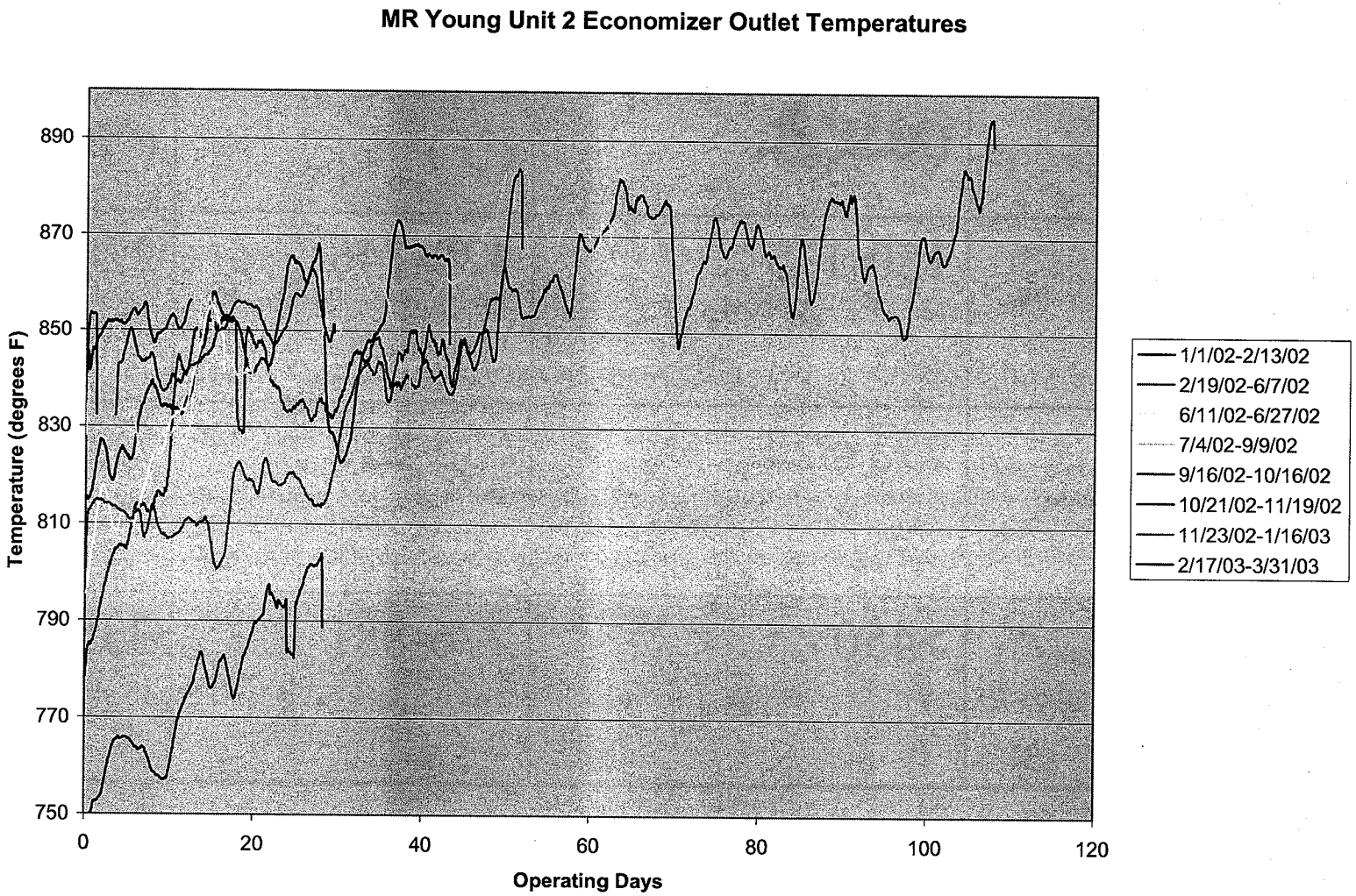
Flue Gas Temperatures of MRYS Unit 1 Boiler



High Flue Gas Temperatures of MRYS Unit 2 Boiler

Load	**Load Range (MWg)**	**PSH Outlet** (°F)	**ESP Exit** (°F)
Low	150-175	429-746	228-282
Mid	295-320	675-812	286-334
High	>450	776-881	335-354

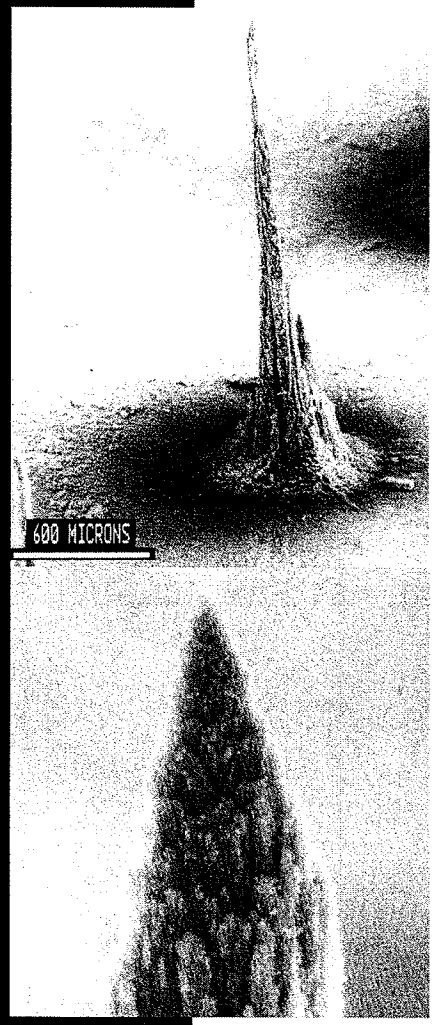
Flue Gas Temperatures of MRYS Unit 2 Boiler



Effect of small particles downstream of ESP on feasibility of "low-dust" SCR -- Low-Temperature Pyrosulfates

- The presence of sodium sulfate and other sulfates 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
  - The fine particles on the SCR will form pyrosulfates that have melting points as low as 535°F that will blind the catalyst.

m-rich Fine Particulate Collected Downstream of a Scrubber when g High-Na-Coal



Chemical Composition of the Spike Shown in SEM Image at the left and the Filter (weight percent expressed as equivalent oxide).

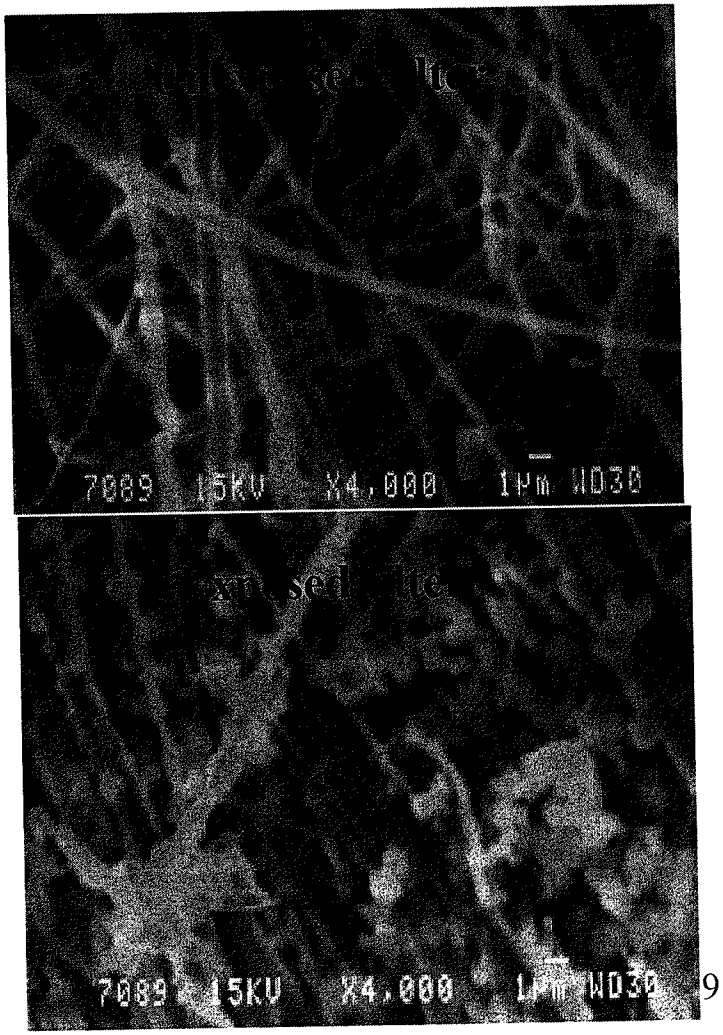
Oxide	100% Coal A	
	Spike	Filter
Na_2O	35.1	17.3
MgO	1.4	7.8
Al_2O_3	2.0	9.8
SiO_2	9.1	10.6
P_2O_5	0.4	0.2
SO_3	39.7	28.0
K_2O	2.6	1.5
CaO	6.2	15.7
TiO_2	0.2	1.8
Cr_2O_3	1.4	0.1
Fe_2O_3	0.9	2.9
BaO	0.5	2.6

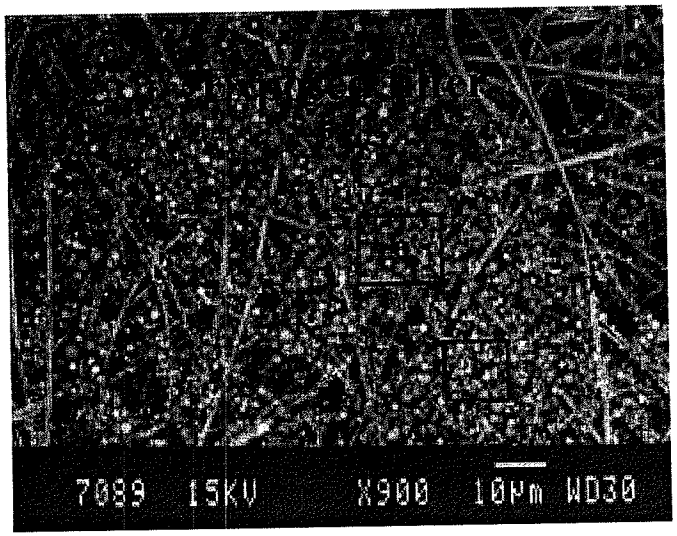
Condensed sodium sulfate aerosols collected on an impactor plate

Hurley, J.P.; Katrinak, K.A. *Determination of Ash Formation and Deposition Mechanisms at Minnesota Power Clay Boswell Station*; DOE/MC/10637-3365, July 1992.

Fine Particle Downstream of ESP

- Sample of particulate was conducted downstream of ESP/Wet FGD at MRY
- SEM and x-ray microanalysis indicate sodium, sulfur, and calcium present in small particles





Presentation Agenda

- Burns & McDonnell qualifications
- EERC qualifications
- **Responses to comments regarding SCR**
  - Statement of key issues related to SCR
  - Basis for technical infeasibility of SCR
  - **Research requirements for validation of SCR**
  - Results of SCR vendor query
- Responses to comments on non-SCR alternatives
- Control of emissions during startup & shutdown

R & D Required for SCR at MRYS

- High sodium content of the fuel indicates that pilot testing should be done to establish deactivation rates
- High flue gas temperatures

SCR Applicability for Northern Lignite

"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."

EPA New Source Review Workshop Manual, pg B.18

Research needed to establish viability of SCR for North Dakota lignite

- Establish SCR catalyst deactivation rate from northern lignite-fired cyclone boilers via pilot-scale testing
- Full-scale catalyst with slip-stream reactor
  - Exposure to high flue gas temperatures, sulfur and soluble alkali ash compounds

Research to Apply SCR Must

- Identify and investigate potential solutions for resolving low and high boiler exit flue gas temperatures:
  - Boiler modifications for high-dust SCR
  - Flue gas reheat energy sources for low-dust/tail-gas SCR
  - Capital and O&M cost estimates

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Results of SCR Vendor Query

- Alstom, Babcock & Wilcox, Babcock Power, and Hitachi were asked about high-dust SCR catalyst and performance guarantees on North Dakota lignite fired at MRYS
  - Alstom has not responded
  - All respondents noted "lack of data" available for guiding the application of SCR technology to ND lignite firing
  - Babcock & Wilcox did not answer the issues of high boiler exit gas temperature and lignite firing (flue gas constituents), agrees these are *"significant challenges"*, but did not offer guarantee.

SCR Vendor Responses to Query

- Babcock Power acknowledged that MRY1 and MRY2 boilers are "very difficult" for applying high dust SCR but did not offer guarantee.
- Hitachi noted:
  - "it is quite difficult to install and operate the SCR at temperature over 850F",
  - Na content in ash is "very high [and] it may cause serious deactivation of the catalyst",
  - "SO3 content in ash is very high" and "may also cause faster catalyst deactivation", and
  - "there is also a concern over how sticky the ash is and if this will cause a pluggage problem"
  - Hitachi did not offer guarantee

SCR Catalyst Vendor Responses

- Argillon, Ceram, Cormetech, and Haldor Topsoe were asked about high-dust SCR catalyst and performance guarantees on North Dakota lignite fired at MRYS:
  - Argillon and Cormetech have not provided written responses
  - Haldor Topsoe noted "extremely high flue gas exit temperatures and lack of flue gas temperature control" but did not address these issues. HT expects high catalyst deactivation rate before 4000 operating hours and will guarantee performance based on "the fuel analysis provided to HT and *assuming the high FGET can be controlled*". Level of performance to be guaranteed was not specified, not described as "make good", and catalyst is not specifically warranted as "evergreen"

SCR Catalyst Vendor Responses

- Ceram provided a preliminary catalyst design with expected performance and life guarantee, based upon an assumed maximum continuous SCR operating temperature of 850°F .
  (no example of actual life or performance achieved by full-scale coal-fired SCR catalyst operating continuously above 800°F was cited)
- 7.4 mm pitch catalyst w/ full SCR bypass recommended
- 16,000 hour guaranteed catalyst life w/ 2 ppm NH3 slip
  (Life guarantee not specified as "make good" or "evergreen")
- Designed for 85% NO_x reduction (from 0.53 to 0.08 lb/mmBtu when operated with ASOFA)
- Only one high-dust PRB coal-fired cyclone boiler SCR catalyst installation designed for flue gas temperature of 800°F (NIPSCO Michigan City Unit 12 500 MW SC)
  (believe 800°F is an excursion temperature condition, not expected to be operated continuously at this high T)

SCR Vendor Query Responses

- High Boiler Outlet F.G. Temperature and Lignite fuel and ash constituents are issues:
  - Boiler OEMs B&W and BPE recommend further investigation (presumably on a compensated basis) to develop design concepts to reduce temperature.
  - Slip-stream catalyst testing (Hitachi) or catalyst coupons (BPE) were recommended.
- NO Boiler OEMs or catalyst vendors offered definitive solutions to high temperature issues or cited specific examples where difficult conditions such as those experienced at MRYS were resolved satisfactorily
- Ceram's expected SCR catalyst design performance not specified as "make good" guarantee, catalyst life not guaranteed with "evergreen" warranty
- Topsoe's performance to be guaranteed was not specified, nor described as "make good", and expected catalyst life was not given or guaranteed nor warranted as "evergreen"

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Combustion NO_x Reduction Options

Need to recognize specialized features for combustion of lignite in cyclone boilers :

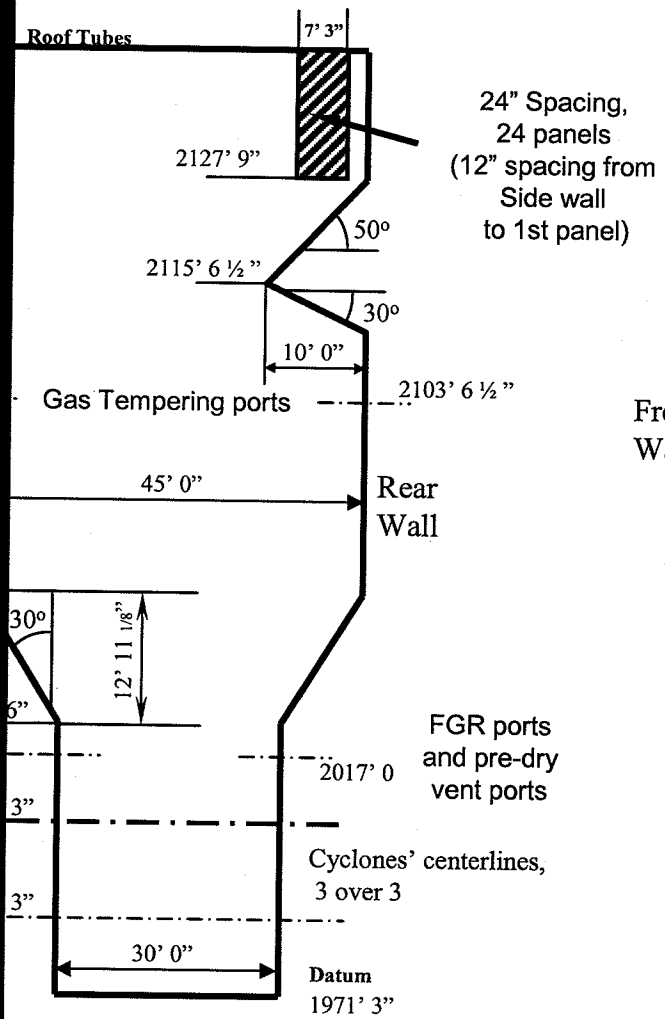
- Pneumatic conveying of crushed fuel to scroll-type burners (tangential inlet of primary air with fuel)
- fuel conditioning system for crushing and pre-drying with hot primary air (700F)
- pre-dry air/crushed coal separation
- pre-dry air vented to furnace is cool (150F) and saturated with water, entrained coal and ash fines
- high overall furnace excess air (4% O2) due to amount of pre-dry vent air input (20% of total combustion air)

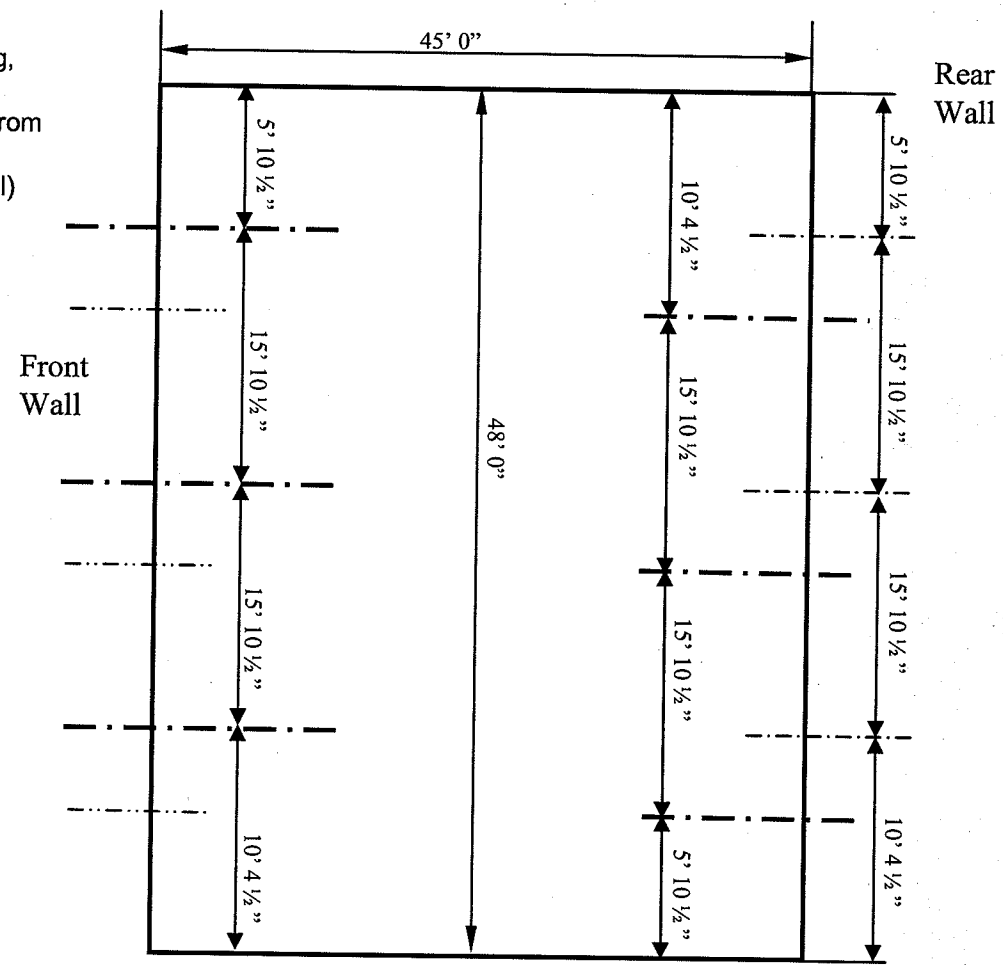
Non-SCR NO_x Reduction Options

Combustion-based controls for NO_x Reduction in Lignite-fired Cyclone Boilers have challenges:

- MRY lignite variability due to mine operation and handling methods
- No direct measure or control of fuel BTU input on an individual cyclone basis in real time
- Cyclone barrel slag blanket formation and slag tap operation depends on lignite ash character and temperature
- NO_x reduction from cyclone "starved air" combustion and additional in-furnace reduction due to carbon monoxide formation

MRY U2 Furnace Elevation and Plan

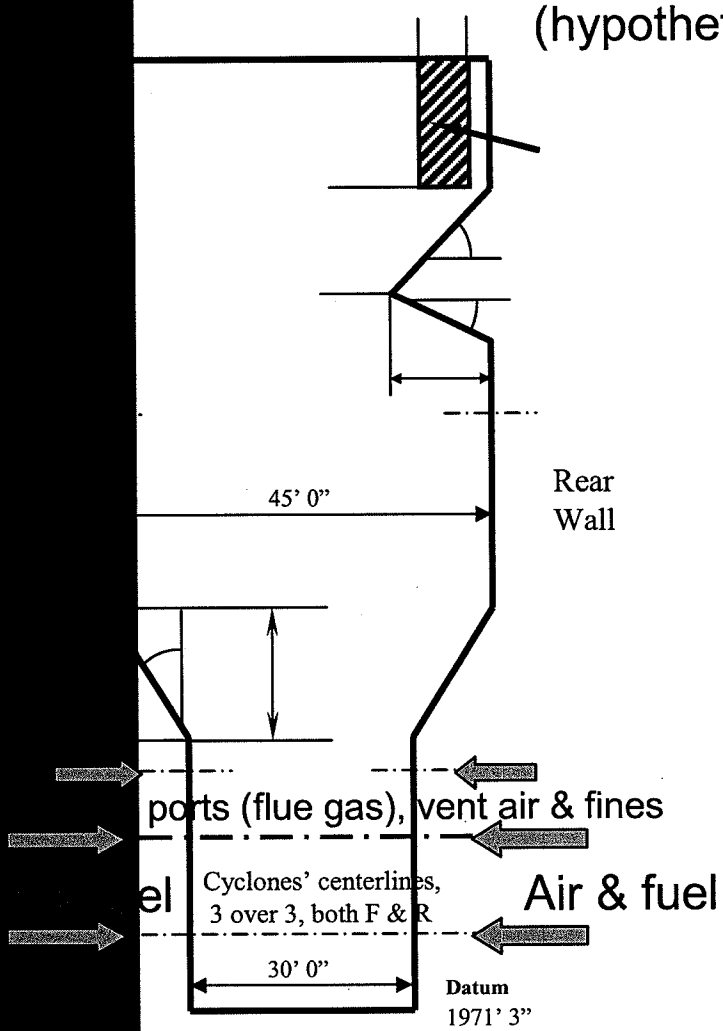


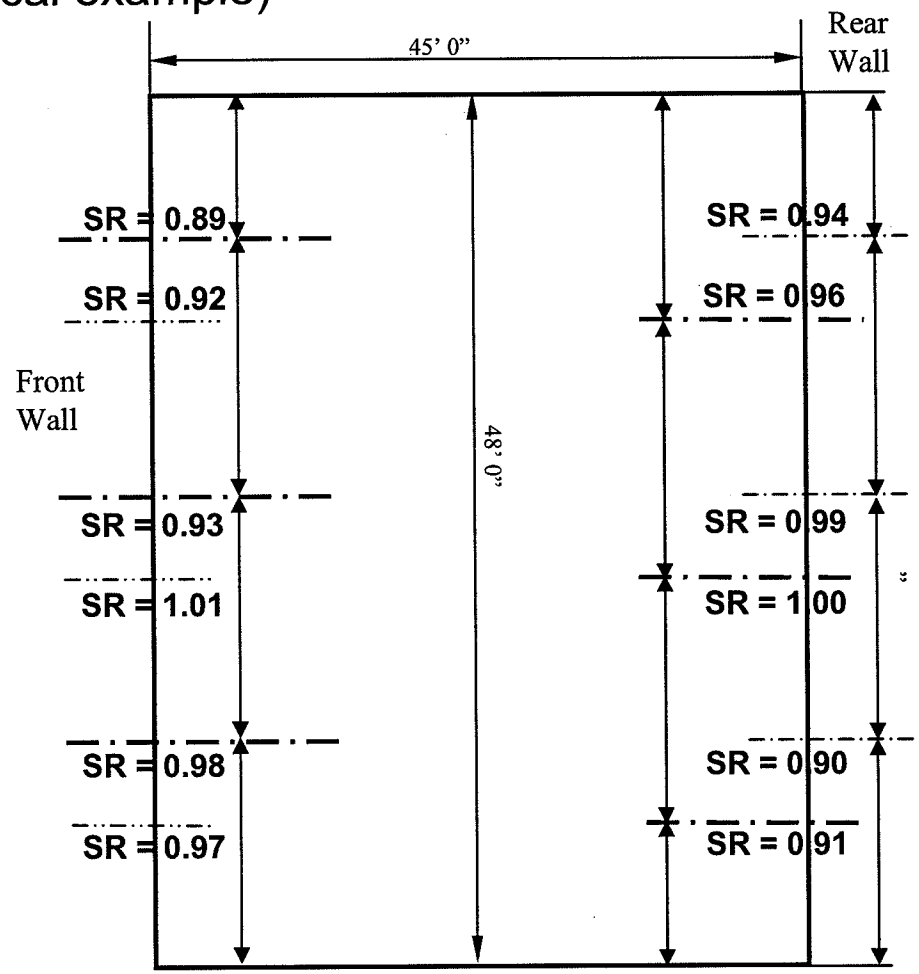


- MRY U2 Original Furnace Design

MRY U2 Cyclone Air-Fuel Ratio Variability w/ SOFA

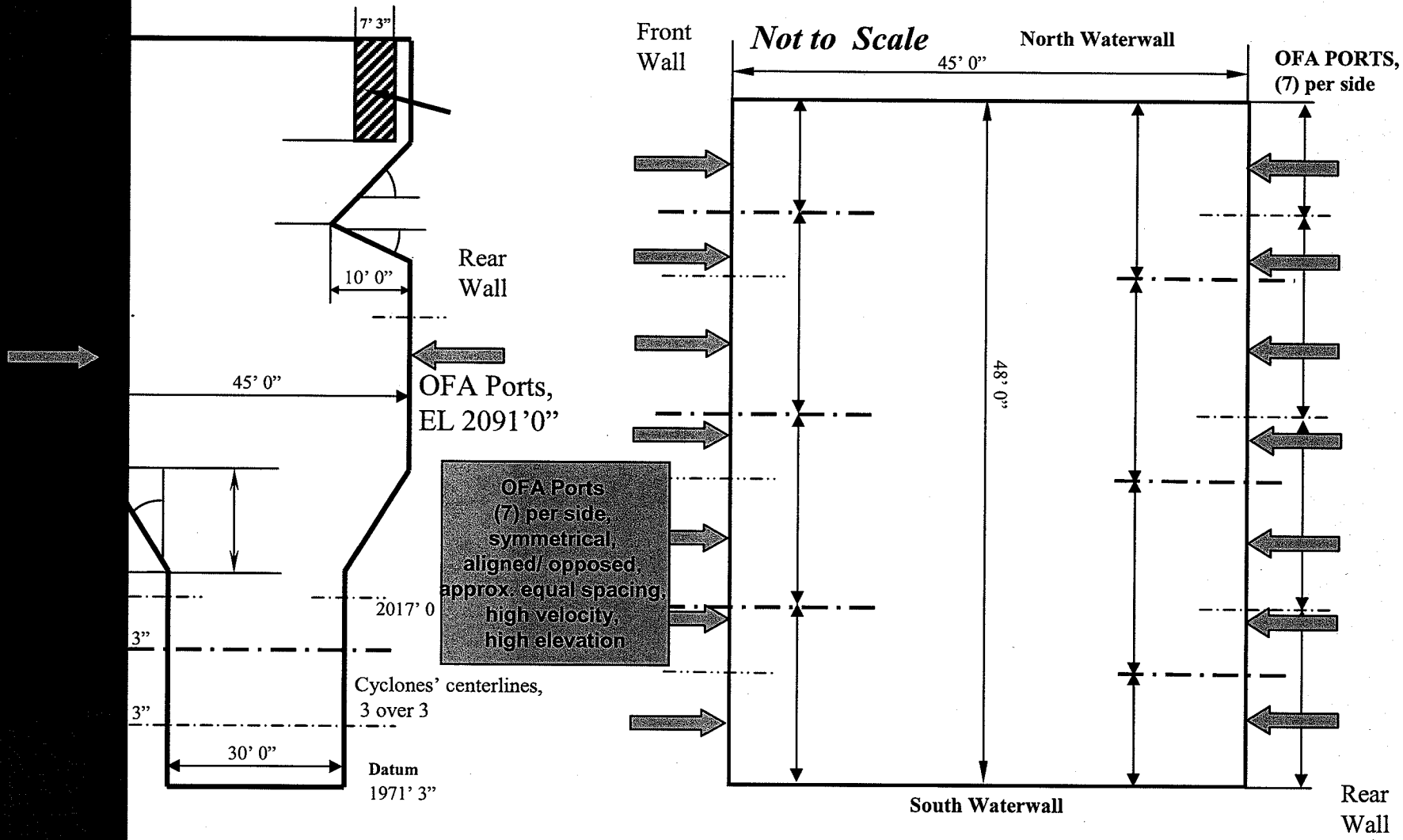
(hypothetical example)



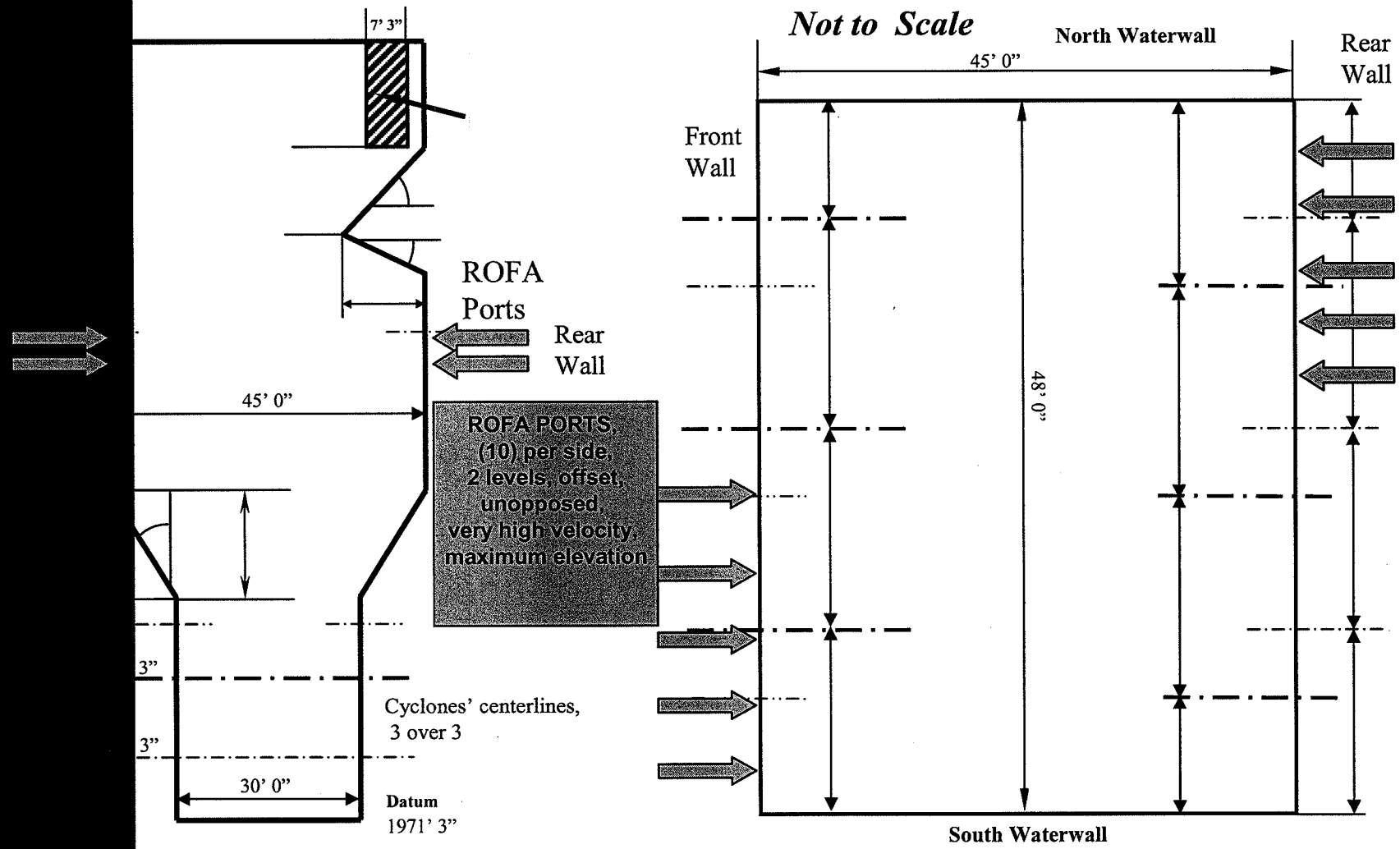


verall average cyclone air/fuel stoichiometric ratio = 0.95 with variation up to + or - 0.06 is not the same as all cyclones operating at 0.95 S.R.

MRY U2 SOFA Conceptual Design



MRY U2 ROFA Conceptual Design



SOFA vs ROFA Conceptual Designs

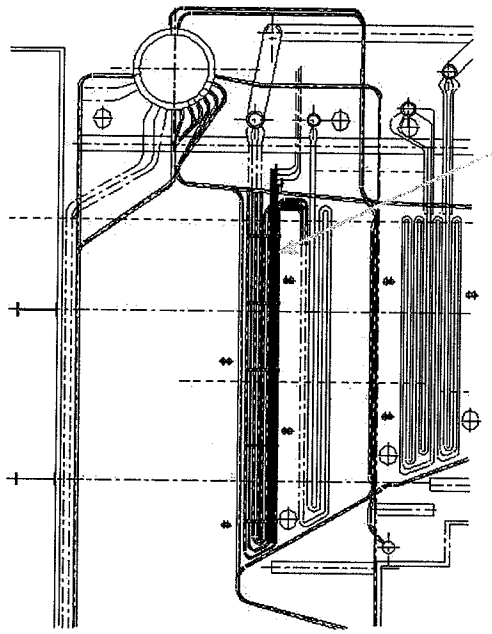
- Constructability Issues Dominate
  - Boiler wall ports must be located where nozzles can be supplied air from ducts and there are no obstructions above, below, and sideways
  - Many obstructions at MRY preclude potential ROFA advantages
- Success still depends on degree of cyclone air-staging, slag flow & tapping, furnace fouling
- ROFA will not change lignite drying, combustion fundamentals and operability limitations
- Hot combustion air booster fan not needed for cyclone OFA to get high injection velocity

SOFA NO_x Reduction Efficiency

- Slag blanket formation and tapping issues are practical limits as cyclones are air-starved below stoichiometric unity
- Variability of lignite fuel and ash quality and feed heat input vs combustion air limits ability to maintain constant air/fuel ratio needed for reliable boiler operation and consistent NO_x reduction
- Modest cyclone air-staged combustion for MRYS boilers limits NO_x control effectiveness
- Relocating lignite drying vent ports from lower to upper furnace will further reduce NO_x emissions

Other Potential Combustion and Post-Combustion Non-SCR NO_x Reduction Options Not Evaluated

- Hydrocarbon-enhanced SNCR (NOxStar™)



NOxStar™ ammonia/hydrocarbon/steam injection lances (vertical lances behind secondary superheater inlet tubes require high temperature steam source, must be located in proper furnace temperature zone

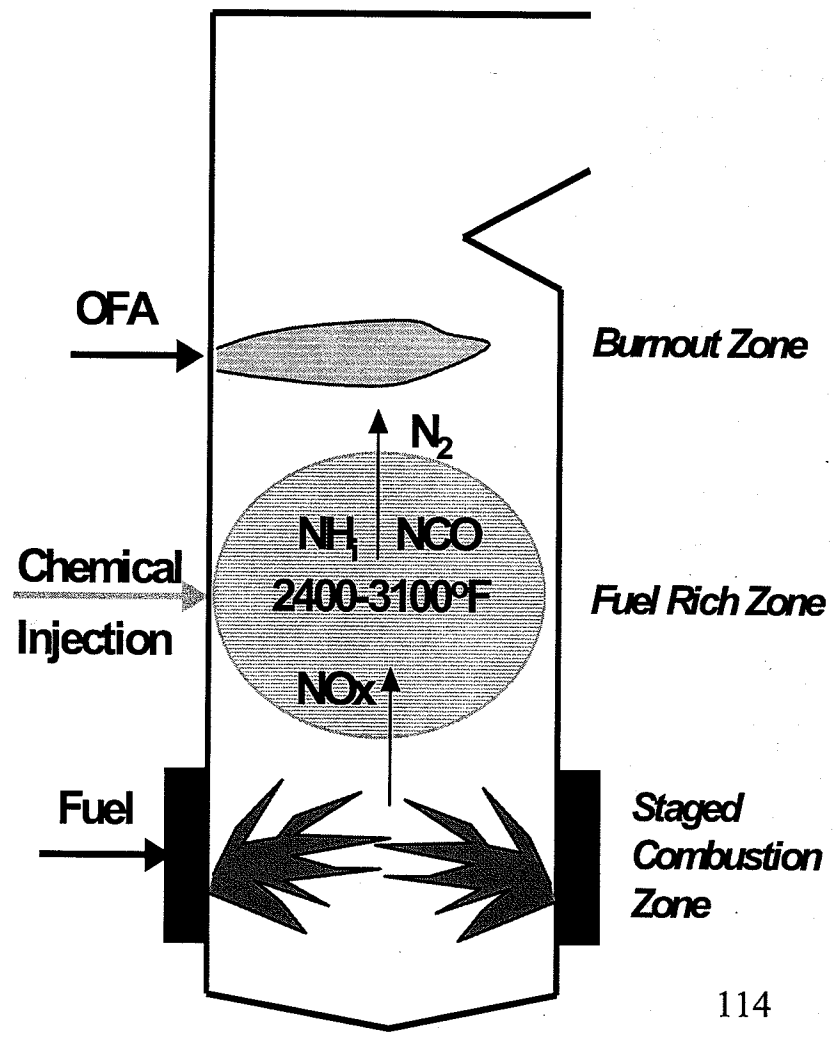
- NOxStar™ lances are exposed to hot furnace gas conditions, susceptible to flyash deposition distorting reagent distribution, can't be retracted or maintained during boiler operation, with no experience on severe slagging coals

Other Potential Combustion and Post-Combustion Non-SCR NO_x Reduction Options Not Evaluated

- Reburn with SNCR
  - Gas reburn alternatives not on dominant controls cost curve (least-cost envelope)
  - Coal reburn has high coal preparation and feed equipment requirements, capital cost and O&M costs with moderate NO_x reduction expected
  - Only one Gas Reburn+SNCR PC installation
  - Adding SNCR would have lower incremental NO_x reduction with significantly higher costs

Other Potential Combustion and Post-Combustion Non-SCR NO_x Reduction Options Not Evaluated

- Rich Reagent Injection
  - Specifically designed for cyclone boilers
  - Requires hot, fuel-rich furnace zone for reagent injection
  - Can create NO_x
  - Does not perform consistently with modest air-staged combustion with SOFA
  - First two permanent RRI installations in late 2006
  - High reagent usage



SNCR NO_x Reduction Efficiency

- SNCR NO_x control depends on inlet NO_x, furnace temperature (1700-2100°F), ability to disburse the reagent where the NO_x is, and NH3 slip levels
- Firing rates and clean vs dirty furnace conditions affect gas temperatures
- NO_x concentration dependent on cyclone air staging with SOFA
- Reagent injection lances are exposed to hot furnace gas conditions, susceptible to flyash deposition distorting reagent distribution (can be retracted and maintained during boiler operation)
- 30% NO_x reduction expected with modest SOFA; 60% control not realistic nor achievable at MRYS

Presentation Agenda

- Burns & McDonnell qualifications
- EERC qualifications
- Responses to comments regarding SCR
  - Statement of key issues related to SCR
  - Basis for technical infeasibility of SCR
  - Research requirements for validation of SCR
  - Results of SCR vendor query
- Responses to comments on non-SCR alternatives
- **Control of emissions during startup & shutdown**

Control of Emissions During Boiler Startups

- Certain boiler operating conditions needed before NO_x control can commence:
  - Cyclones need sufficient time and heat to form "slag blanket", keep ash molten; air-staging w/ SOFA can lower cyclone temperature and cause slag to "freeze".
  - Gas temperatures vary with furnace height, drum pressure, fuel firing rates and fireside cleanliness; must be hot enough at SOFA injection ports to oxidize CO to CO2; CO competes with SNCR reagent in NO_x reduction reactions.
  - Furnace gas temperatures must be between 1700°F and 2100°F at SNCR reagent injection ports for effective NO_x reduction.

Control of Emissions During Boiler Startups

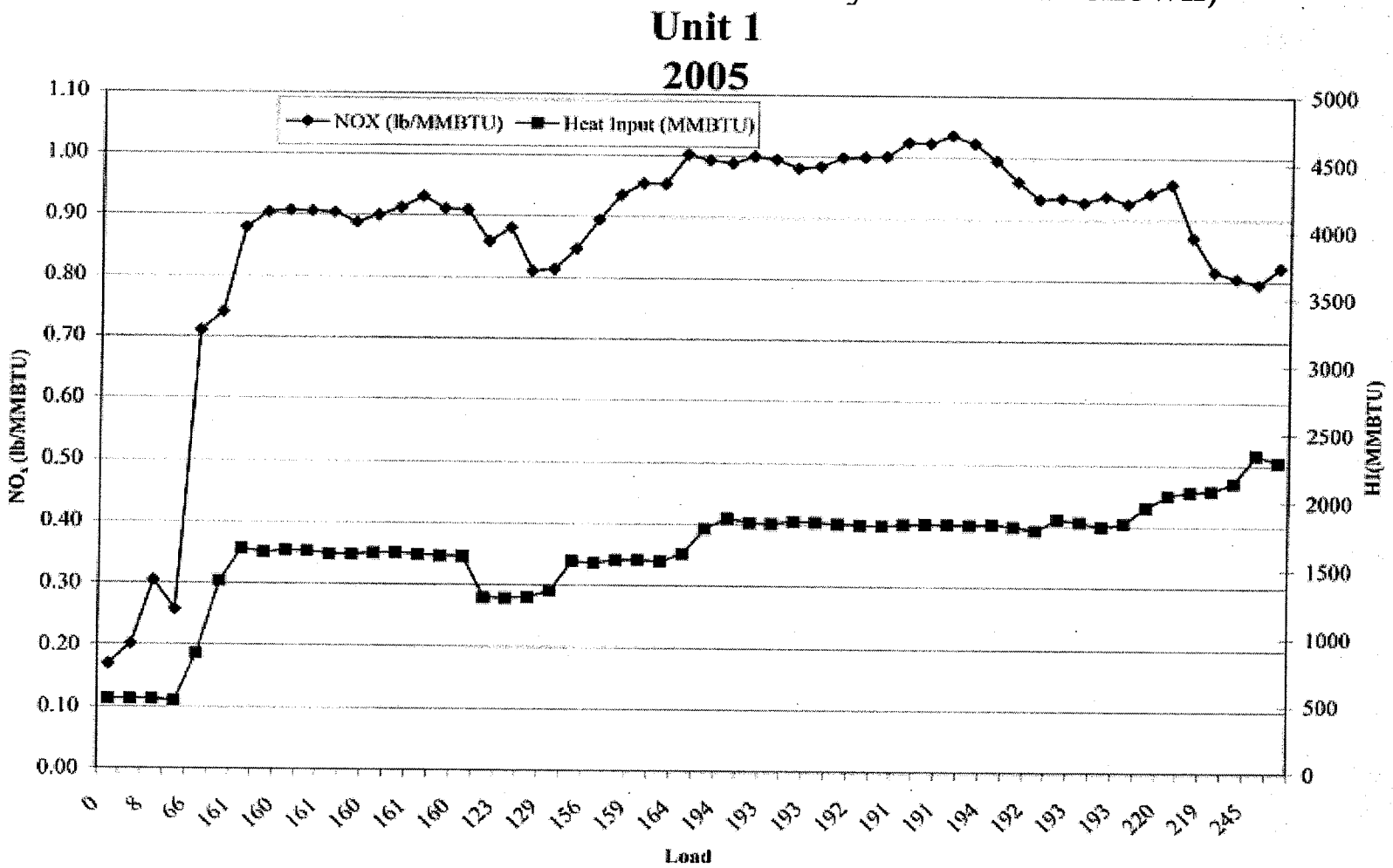
- MRYS boiler startup events are typically lengthy (average > 24 hours from cold condition)
- Can have 3 cold startups in 30 days
- Expected 12-month BACT emission rates include boiler startup emissions
- 30-day emission permit limits need to recognize frequency and duration of startup events having higher than steady-state NO_x emissions with little or no ability to control

MRYS Unit 1 Startup Events Defined

- From initial fuel combustion until:
  - 6-hr rolling average heat input ≥ 2500 Btu/hr; or
  - Duration of longest 2001-2005 U1 startup elapses; or
  - Fuel firing is discontinued prior to either criteria being satisfied
- "Cold" startup if ≥ 72 hours elapse since firing
- "Warm" startup if ≥ 8 hrs < 72 hrs since firing
- "Hot" startup if < 8 hrs since firing
- 71 startups from 2001-2005 (avg 5 every 4 months) (includes 18 hot startups less than 1 hour duration each)

Longest Unit 1 Startup - June 2005

(HOURLY CEMS REPORTED DATA - every other hour shown)



Longest Unit 1 Startup 2001-2005

- Began June 27, 2005 0500 hrs
- Ended June 29, 1700 hours
- Overall duration 61 hours
- Overall average NOx 0.766 lb/mmBtu
- Highest 24-hour avg NOx 0.980 lb/mmBtu
- Impact on 30-day rolling avg NOx rate excluding startups +0.041 lb/mmBtu = [{(0.766*(3)+(0.36)*27}/30]-0.36
- 30-day rolling average assumes 30 equal-weighted consecutive daily operating day average emission periods (partial days count equally as full days)
- U1 had (4) startups in one 30-day period (7/14-8/14/2001) and (14) in another 30-day period (10/16-11/08/2003) between 1/1/01 and 12/21/05

MRYS Unit 1 Recommended 30-Day and 24-hour Startup Emission Limits

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	0.360	+0.041 per startup

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

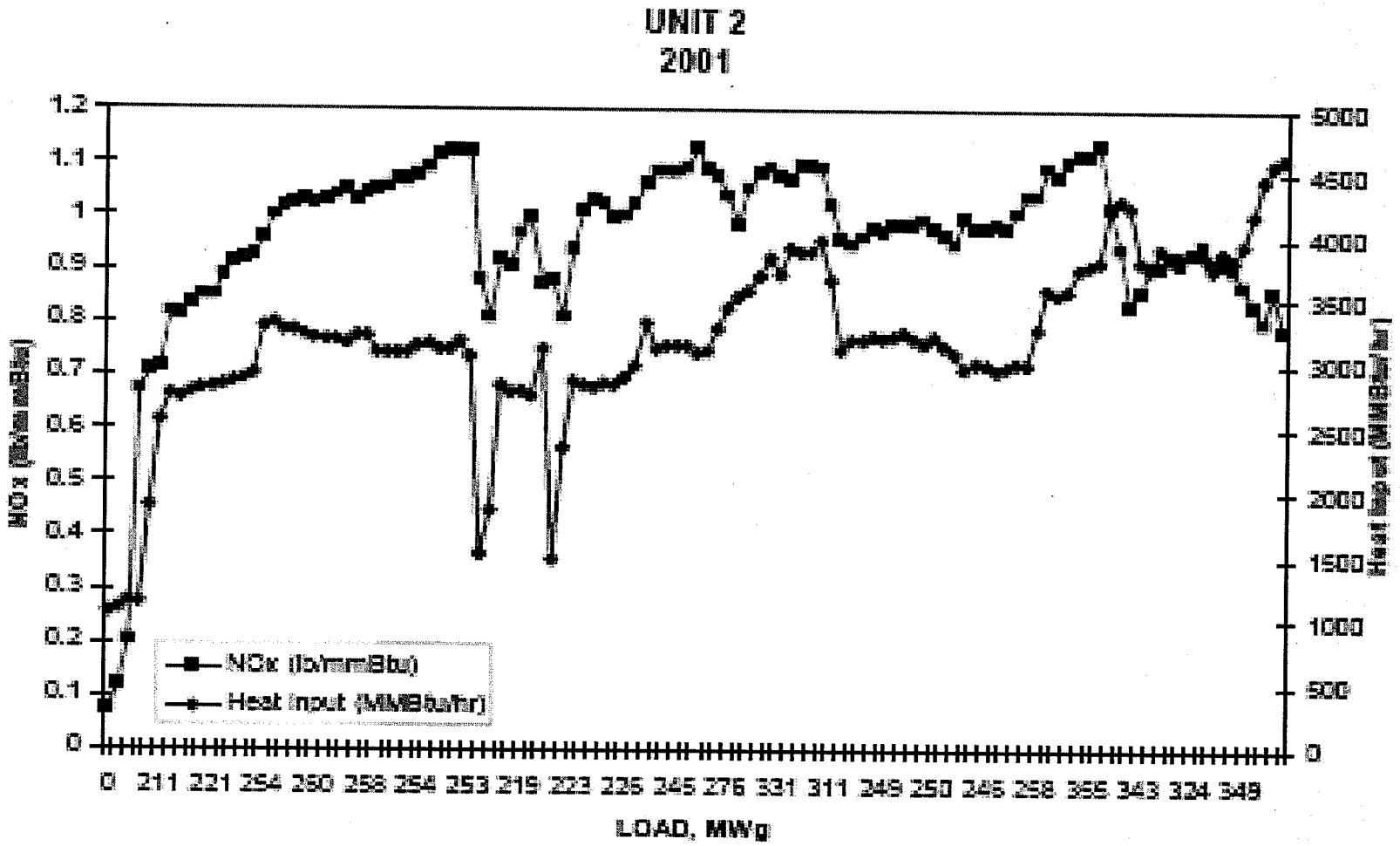
Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
1	0.980

MRYS Unit 2 Startup Events Defined

- From initial fuel combustion until:
  - 6-hr rolling average heat input ≥ 4800 Btu/hr; or
  - Duration of longest 2001-2005 U2 startup elapses; or
  - Fuel firing is discontinued prior to either criteria being satisfied
- Same "cold", "warm", and "hot" startup criteria
- 63 startups from 2001-2005 (avg 5 every 4 months) (includes 3 hot startups less than 1 hour duration each)

Longest Unit 2 Startup – Oct 2001

(HOURLY CEMS REPORTED DATA - every other hour shown)



Longest Unit 2 Startup 2001-2005

- Began October 25, 2001 2000 hrs
- Ended October 30, 1400 hours
- Overall duration 115 hours
- Overall average NOx 0.959 lb/mmBtu
- Highest 24-hour avg NOx 1.064 lb/mmBtu
- Impact on 30-day rolling avg NOx rate excluding startups +0.102 lb/mmBtu = [{(0.959*(5)+(0.35)*25}/30]-0.35
- 30-day rolling average assumes 30 equal-weighted consecutive daily operating day average emission periods (partial days count equally as full days)
- U2 had (4) startups in one 30-day period (10/20-11/06/2004) and (3) startups in (8) 30-day periods between 1/1/01 and 12/21/05

MRYS Unit 2 Recommended 30-Day and 24-hour Startup Emission Limits

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	0.350	+0.102 per startup

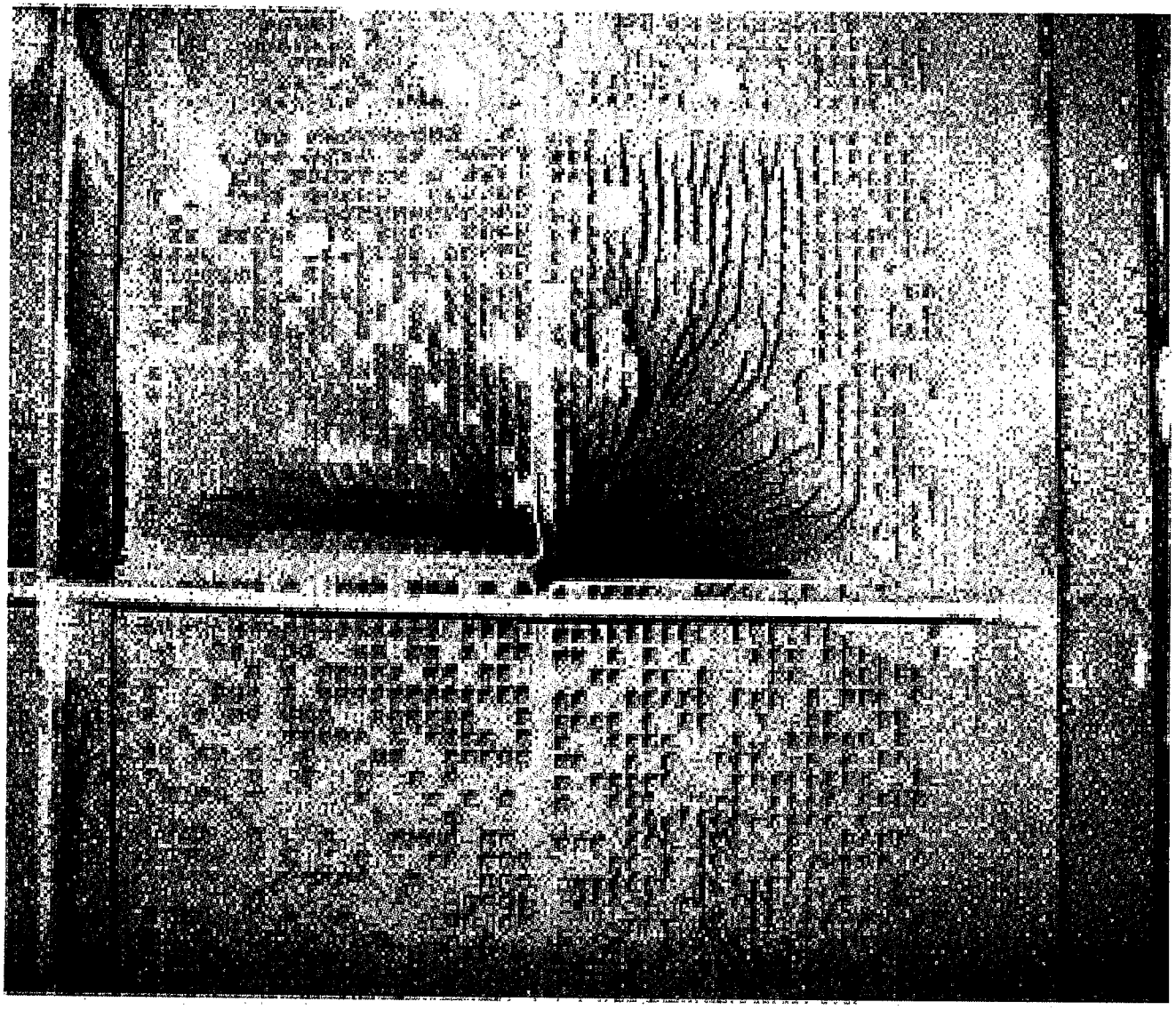
Recommended 24-Hour Rolling Average NO_x Emission Rate Limit During Startups

Unit	24-hour Rolling Average NOx Emission Rate Limit During Startups (lb/million Btu)
2	1.064

Discussion

Application of SCR Technology

Example of Catalyst Erosion



Physical: Catalyst Erosion

- Potential Solutions
  - Erosion is related to velocity (exponentially)
    - reduce superficial velocity
    - larger reactor (risk of ash deposition)
  - Achieve best possible gas flow and angular profiles
  - Solution(s) for lignites unclear
- Pilot testing ongoing on Texas Lignite
  - Sponsored by TXU (S&L) and EPRI

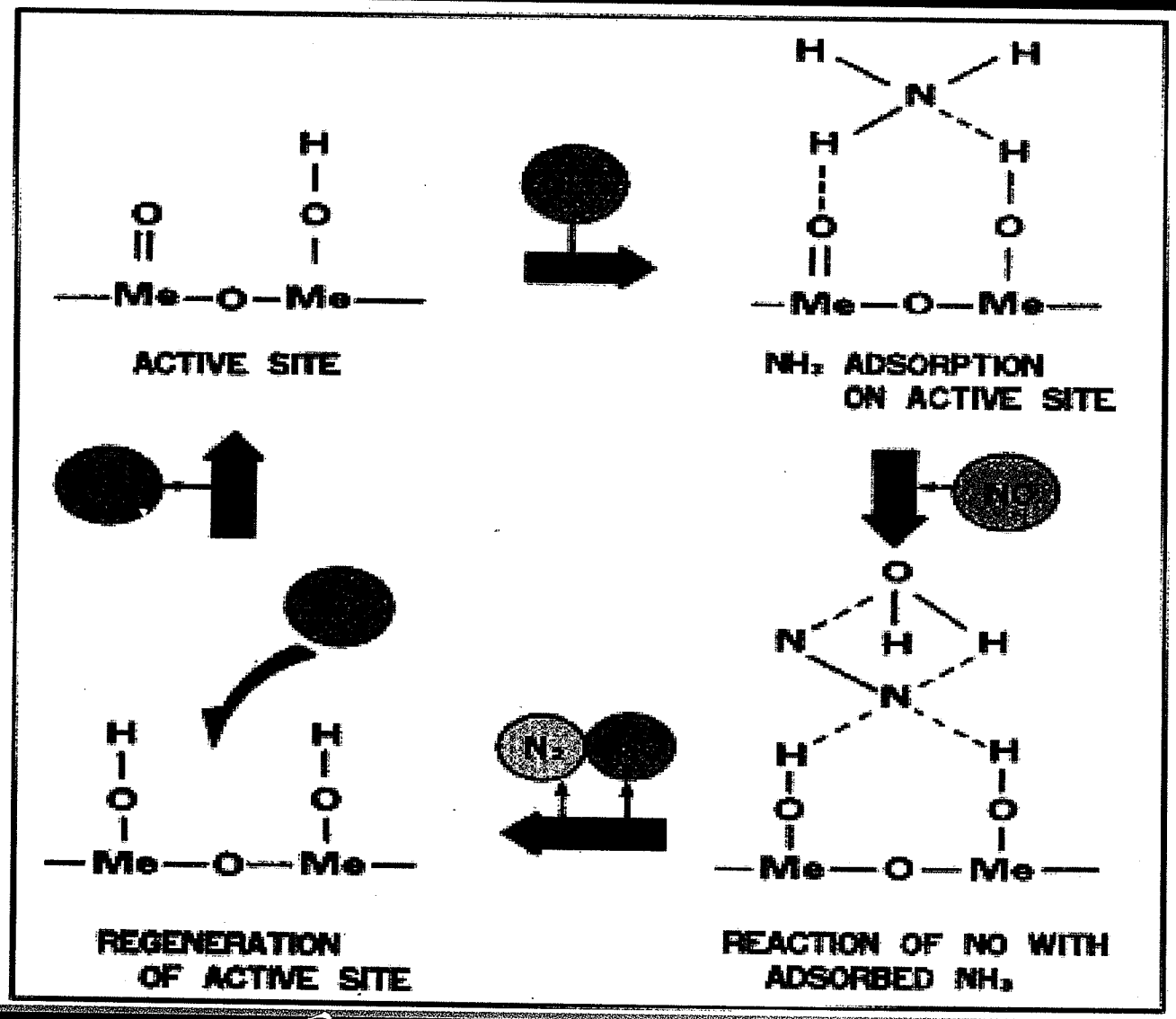
Chemical Catalyst Degradation Mechanisms

- Surface Masking
- Deactivation of catalytic sites

Generally driven by:

- fuel/ash chemistry
- combustion process

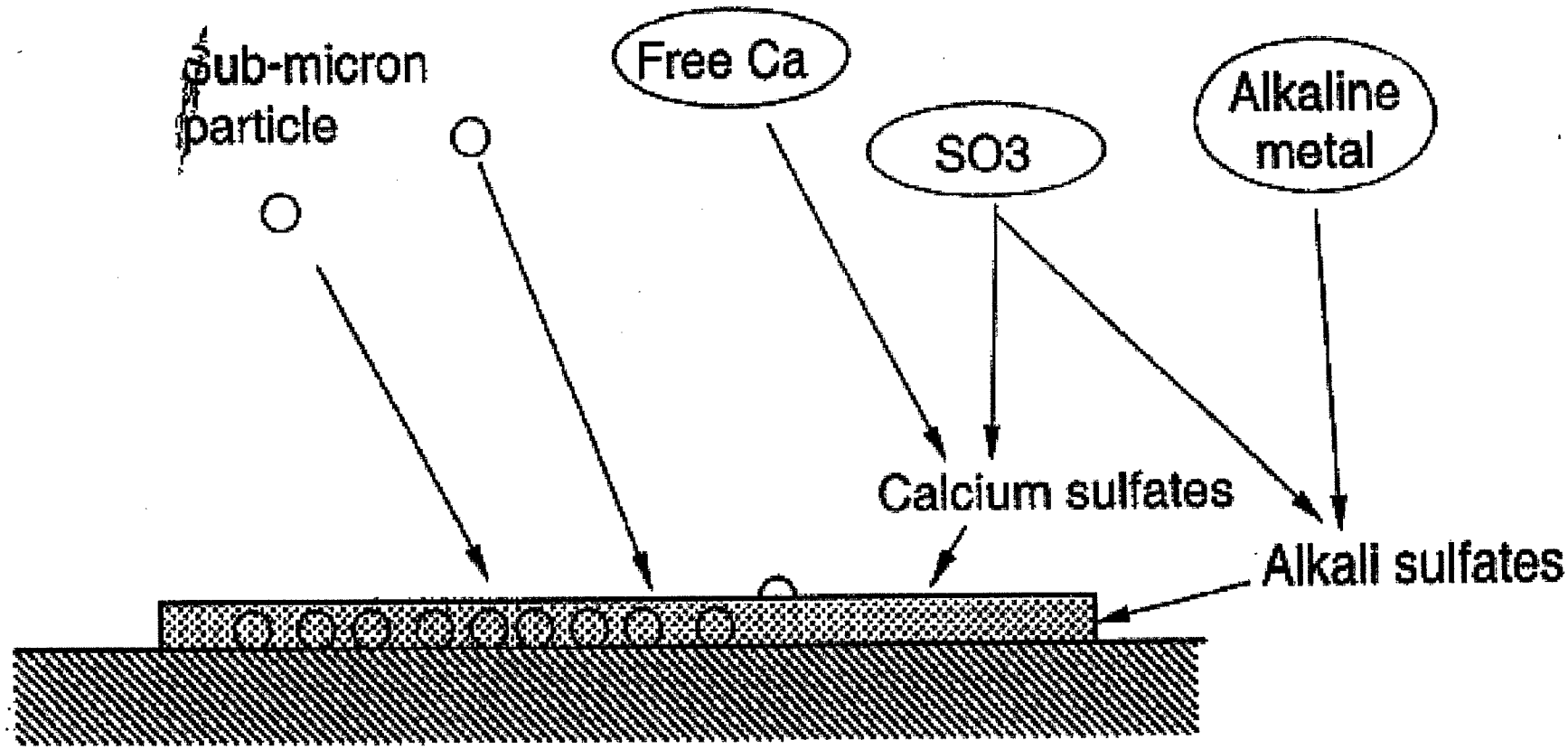
NOx Reduction Mechanisms



Chemical: Catalyst Surface Masking

- Sulfate formation and deposition on the catalyst surface
  - Alkalis in ash react with SO_3 generated in the catalyst
  - Can also plug macro pores in catalyst
  - Serious phenomenon on high alkaline fuels
- Possibly reversible with out of reactor cleaning
  - PRB (high calcium) showing encouraging results
  - Soluble alkali less likely due to deeper pore penetration

Catalyst Masking due to Calcium Sulfate



Chemical: Catalyst Surface Masking

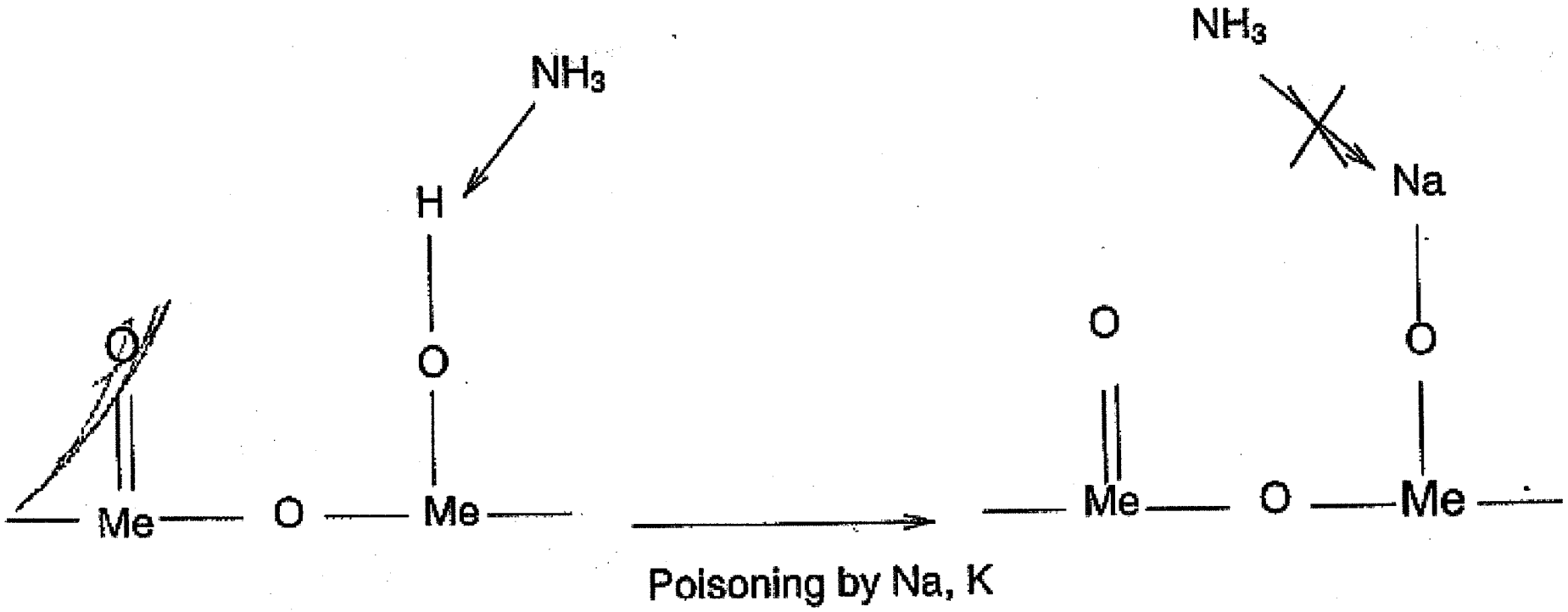
- Solutions
  - Increase volume of catalyst (more surface)
  - Increase size of reactor
  - Facilitate catalyst mgmt to ease catalyst cleaning requirements
    - Reactor access (doors, platforms, hoists, etc.)
- "Solutions" for soluble alkalis (Na and K) unknown
  - Ongoing pilot on Texas lignite will not provide help

Chemical: Catalyst Deactivation

- Deactivation of actual catalytic sites in the catalyst
  - most serious form of catalyst degradation
    - irreversible in many instances
  - Penetration of poisons into the micro pores
    - gaseous arsenic
    - gaseous alkalis (e.g. sodium and potassium)
    - soluble alkalis (e.g. sodium and potassium)

Catalyst Deactivation due to Soluble Alkali

Active site occupied by catalyst poisons and NH3 can not absorb the active site.



Chemical: Catalyst Deactivation

- Possible solutions
  - Arsenic
    - Not a problem with high calcium fuels
    - Add calcium (limestone) to low calcium fuels
    - Arsenic "resistant" catalyst
  - Soluble alkalis
    - no known "solution"
    - TXU pilot testing will not help
    - More catalyst and larger reactors? How much?

Agenda

- Keys to a Successful SCR System Design
- Catalyst Degradation Mechanisms
- SCR Fuel Experience
- Combustion Process
- Degradation Mitigation Alternatives
- Conclusions
- Recommendations

SCR Technology Fuel Experience

Relatively new to Utility Industry

- less than 30 years worldwide
- less than 10 years in the US

Fuel Diversity

- Bituminous
- Sub-bituminous (PRB)
- Natural gas
- Fuel oil
- Biomass co-firing with coal (limited)
- European lignites (limited)

SCR technology Fuel Experience

Beginning to understand impacts of fuel chemistry

- Some limits have been established (* in ash)

• Ash	>20%
• Arsenic	>50ppm* (and < 2% CaO)
• Chlorine	>2000ppm*
• Fluorine	>300ppm*
• CaO	>20%* and <2%
• MgO	>6%*

SCR technology Fuel Experience

Beginning to understand impacts of fuel chemistry

- Some thresholds or limits are yet to be defined (* in ash)
  - Na_2O >2%*
  - K_2O >1%*
  - P_2O_5 >1%*
  - Abrasion index unknown

Various Fuel's Ash Alkali Content

el Subset	Various PRB Coals				Texas Lignites		North Dakota Lignites		
ne Name	Buck-skin	Eagle Butte	Jacobs Ranch	Caballo	Wilcox	Jackson	Leland Olds	Center Mine High	Center Mine Averag
lcium (CaO)	24.60	25.00	23.80	23.10	10.90	6.84	21.10	21.00	17.09
tassium (K_2O)	0.25	0.20	0.31	0.30	0.29	0.93	**1.20**	**1.50**	**0.83**
dium (Na_2O)	1.31	1.70	1.50	1.60	0.04	0.72			
osphorus (P_2O_5)	0.67	0.60	0.57	0.70	0.08	0.06	0.21	0.42	0.21
gnesium (MgO)	6.03	6.10	4.12	4.30	2.89	1.23	7.39	6.10	4.84

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Combustion Process:

Cyclone Furnace with ND Lignite Fuel

- NOx Production
- Ash Distribution (bottom vs fly)
- Ash Characteristics

NOx Production: Cyclone Furnace

- High Furnace Temperature necessary to melt ash
  - Typical fuel bound Nitrogen NOx production
  - Significantly higher thermal NOx production
- Range: 0.7 to 2.0 lbs/mmBtu
- Typical NOx rate for PC boiler is <0.6 lbs/mmBtu
- Lignite fired cyclone 0.7 to 1.0 lbs/mmBtu
  - due to high moisture content of lignite

Ash Distribution

- Bottom ash / Fly ash split:
  - Cyclone Furnace:
    - 60-80% bottom ash
    - 20-40% fly ash
  - Pulverized Coal Furnace:
    - 20% bottom ash
    - 80% fly ash
- SCR on cyclone will have 50-75% lower ash loading
  - could help erosion loss

Ash Characteristics

- Characteristics of cyclone combustion
  - High and unpredictable LPA (popcorn) ash production
  - High unburned carbon in the ash
  - High level of alkali vaporization
- Fuel/Air balancing key to control LPA and carbon only
  - problematic in practice
- Results are:
  - LPA must be removed before the SCR reactor
  - Unburned carbon causes "sticky" ash
  - Possibly higher levels of alkali vapor in reactor?

Agenda

- Keys to a Successful SCR System Design
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Lessons Learned From PRB Experience

- Relevant pilot testing on PRB
- Design lessons learned from PRB testing
- Design lessons learned from full scale PRB applications

But.....

- Design issues for North Dakota Lignite not addressed by PRB experience

Relevant Pilot Testing on PRB

- Associated Electric: New Madrid Station
  - 2x600 MW
  - Cyclone Fired
  - 100% PRB
  - Catalyst coupons placed in economizer outlet
  - multiple catalyst suppliers

Relevant Pilot Testing on PRB

- Reliant Energy (now NRG): Parish Station
  - 2x650MW and 2x765MW
  - PC fired (2 wall and 2 corner)
  - 100% PRB
  - Full scale catalyst elements
  - multiple catalysts suppliers

Relevant Pilot Testing on PRB

- Dynegy: Baldwin Station
  - 2x600MW
  - Cyclone fired
  - Range: 100% bituminous to 100% PRB
  - Full scale catalyst elements
  - multiple catalyst suppliers

Relevant Pilot Testing on PRB

- We Energies: Pleasant Prairie Station
  - 2x600MW
  - Turbo Furnace
  - 100% PRB
  - 4'x4' reactor
  - multiple catalyst suppliers

Relevant Pilot Testing on Lignite (Texas)

- TXU: Sandow Station.....Ongoing
  - 640 MW
  - PC fired
  - 100% Texas Lignite
  - 2'x2' reactor
  - Hitachi catalyst

Design Lessons Learned From PRB Testing

- Catalyst deactivation impacts
  - Ca and Mg sulfate masking resulted in:
    - 10-20% more catalyst
    - 10-20% larger reactor
- Physical catalyst limitations
  - Ash characteristics required:
    - larger catalyst pitch
    - larger open area
    - larger reactor
- Helped us focus on potential problems in full scale

Design Lesson Learned From Full Scale PRB Application

- LPA (popcorn ash) removal system design
  - location at economizer outlet hopper area
  - baffle design in hopper to prevent re-entrainment
  - Screen sizing and velocity limitations
    - maximize collection
    - minimize erosion

Design Lesson Learned From Full Scale PRB Application

- Reactor Design
  - Importance of flow modeling (precision guidelines)
    - physical plastic models
    - CFD (computational fluid dynamics) modeling
  - Design details to prevent ash accumulation
  - Ash cleaning equipment design
    - Ducts
    - Catalyst
    - Reactor

Design Issues for North Dakota Lignite Not Addressed by PRB Experience

Wealth of knowledge obtained from PRB Pilot Tests

- Reactors would have been too small
- Catalyst would not have performed
- Operation would have been problematic

Some very important questions left unanswered:

- High level of soluble alkali in ND lignite
- Particle size & sticky nature of high alkaline ND lignite ash
- Potential abrasive qualities of ND lignite ash

Various Fuel's Ash Alkali Content

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agnesium (MgO)	6.03	6.10	4.12	4.30	2.89	1.23	7.39	6.10	4.84

Application of SCR Technology

Example Industry Experience with Fuels Having High Soluble Alkali in the Ash

	Utility	Station	Fuel	Notes
1.	Preussen Elektra: Germany	Staudinger	German & African Coals	• 5% K_2O • 2.2% NaO • Accelerated catalyst poisoning
2.	Energi E2: Denmark	Avedore	Biomass co-firing w/coal	• High Potassium • 50% deactivation in 1000 hrs • 25-30 times faster than bit.coal • 15-20 times faster than sub-bit.
3.	Energi E2: Denmark	Studstrip	Biomass co-firing w/coal	• Similar to Avedore
4.	Mirant: Mass. US	Canal	Heavy oil	• Sodium • Potassium • Accelerated catalyst poisoning and frequent catalyst management

Unanswered Questions

Unlike Calcium and Magnesium, Sodium and Potassium are:

- Smaller sized particles when in the solid phase
- Highly soluble
- Partially in the vapor phase

These phenomena make the catalyst more vulnerable

- to chemical deactivation (both gas and liquid phase)
- to physical pluggage of even the catalyst micro pores

Unanswered Questions

Catalyst erosion potential

- Unknown at the typical velocities of an SCR reactor
- Could drive reactor size to control erosion rate in balanc with ash deposition rate

TXU pilot testing at Sandow may answer this question

- Began in early March
- Will operate for 1 year

Agenda

- Keys to a Successful SCR System Design
- Catalyst Degradation Mechanisms
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Conclusions Summary

The Industry has learned a great deal from:

- Foreign SCR experience from the 1970s and 1980s
- Early US experience with bituminous coals
- PRB pilot testing and early full scale projects

Much of this knowledge is directly applicable to North Dakota lignite

Conclusions Summary

Some important unanswered questions pose significant risks for an SCR design engineer:

- An unknown catalyst deactivation rate will prevent:
  - optimum selection of a catalyst design
  - selection of an appropriate reactor size
- This could burden the operator with a long term costly maintenance requirements and unscheduled outages

Conclusions Summary

Premature catalyst failure will:

- Require more frequent catalyst replacement
  - including unscheduled outages
- Ammonia slip and subsequent airheater pluggage
  - ammonium bi-sulfate formation
  - unscheduled outages for cleaning
  - ammonia discharge to atmosphere
- Higher auxiliary power requirements

Application of SCR Technology

Fundamental Question:

Is it possible to design an SCR today for Basin Electric's LOS Unit 2 North Dakota Lignite fired cyclone boiler with confidence in it's performance?

Answer:

There are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict it's performance.

Recommendations

Parametric pilot test program to:

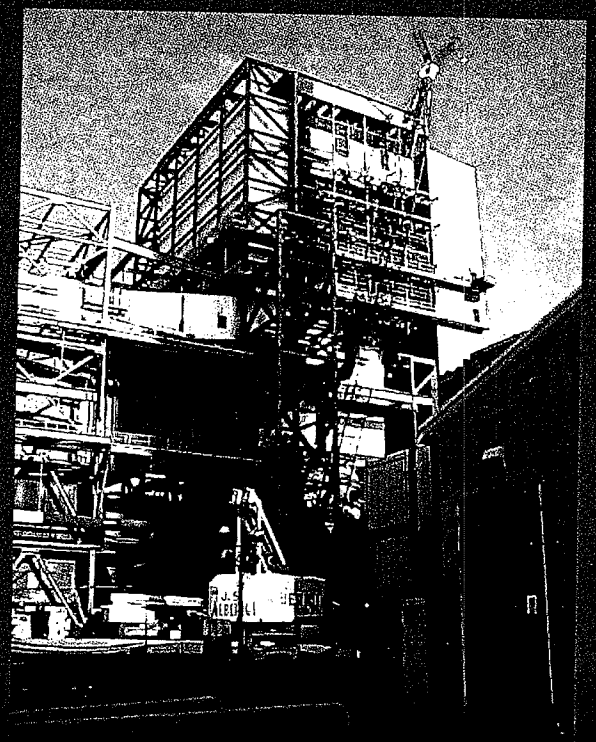
- Answer questions on:
  - soluble alkalis
  - ash characteristics
    - size
    - stickiness
    - abrasive qualities
- Compare findings with PRB experience

Recommended Pilot Test Features

- Reactor size of a minimum 2' x 2'
- Location: high and low dust configuration
- Use of full size catalyst elements
- At least one year of operation
- Encourage participation of catalyst suppliers
  - Develop unique formulations
  - Create unique pore size and volume designs
  - Develop abrasion resistant designs
- Overall Pilot Test Program duration: 18 to 24 months

Application of SCR Technology to North Dakota Lignite Fuels

Sargent & Lundy, LLC
May 2007



Application of SCR Technology

Sargent & Lundy Overview

- 116 Years of Experience
- Independent Engineering & CM Services Only
- 100% Dedicated to the Power Industry

Sargent & Lundy L.L.C.

- Privately Held Limited Liability Company
- 25 Owners Involved in Day-to-Day Operations
- Current Staff: 2000+
- Consistently ranked by Engineering News-Record as a top global power industry consultant

Application of SCR Technology
Sargent & Lundy LLC Organization

Chairman, President and Chief Executive Officer

Alan Wendorf

Quality Assurance

Nuclear Power Technologies

Brian Renwick

Fossil Power Technologies

Greg Anderson

Power Delivery Services

Tom Murray

Information Technology Services

Jim Anderson

Global Energy Consulting Group

Rich Knoebel

Engineering

W. Paschal

Finance & Administration

Jim Anderson
Dennis Chaplin

Application of SCR Technology

People and Resources

Director
William DePriest

- SO_2 Program
  - Technologies Unit
    - Steve Katzberger
    - Dave Sloat
    - George Dusatko
    - Kevin Hopkins
    - Ted Kurtides
    - W. Patel
  - Process Control Unit
    - Will Boward
    - Bill Siegfriedt
    - Raj Gaikwad
    - Wally Rymarczak
    - Paul Farber
    - Ben Williams
    - Dave Stopek
    - Ajay Jayaprakash
    - Kevin Fauzze
- NO_x Program
  - Materials Selection Unit
    - Eldon Dille
    - Shu-Jin Fang
  - Materials Handling
    - Sam Madan
    - Bob Shah
    - Ed Wollington
- Particulate, Air Toxics & IGCC
  - Environmental Permitting
    - Tim Krause
    - Ken Snell
    - Paul Derezotes
    - Dan Marmer
    - Ron Cook
    - Dan Kocunik
    - Bernie Mount
    - Russ Light
    - Dave Helm
  - Water Treatment Unit
    - Mike Rosen
    - Jeri Penrose
    - Gopal Komandini

Application of SCR Technology

Bill DePriest
Senior VP and Director of Environmental Services

- B. S. in Chemical Engineering from Michigan Tech.
- Employment History:
  - Babcock and Wilcox: 1972 to 1985
  - Sargent and Lundy: 1985 to present
- Professional Engineer
- Published Extensively on Power Plant Emission Controls

Application of SCR Technology

Raj Gaikwad
Technical Advisor in the Environmental Services

- Ph.D. in Chemical Engineering – McGill Univ. 1985
- M.Tech. in Chem. Eng. – I.I.T. Bombay 1979
- Employment History:
  - SNC, Inc: 1985 to 1987
  - Ontario Hydro: 1987 to 1989
  - Sargent and Lundy: 1989 to present
- Professional Engineer
- >50 Publications on Power Plant Emission Controls, Coal Liquefaction, Coal Chemistry, Combustion

Sargent & Lundy LLC

Air Quality Control

Qualifications

Application of SCR Technology

Sargent & Lund

Air Quality Control Experienc

Recent Experience
(Since 1990)

	Units	MW
Particulate Control		
Fabric Filters	47	14,300
ESPs	27	7,800
FGD Systems		
Wet	**45**	**24,000**
Dry (w/ESP)	15	6,000
NOx Controls		
LNB Systems	40	8,000
SCR Systems	**53**	**27,000**
SNCR Systems	17	4,800
Multi Pollutant Studies	22 (Utilities)	System Wide

Application of SCR Technology
S&L Market Participation

SCR Projects (53 of 113)	46%
FGD Projects (58 of 117)	
Owner's Engineer (30)	26%
Design (28)	24%
Total	50%

Application of SCR Technology

SCR Project Summary

- **53 Utility SCR Projects**
  - 39 coal-fired units
  - 14 gas-fired units
- **34 Full S&L Design**
  - 26 coal-fired units
  - 8 gas-fired units
- **10 Designed for PRB Coal**
  - Most in industry
- **The 7 Lowest NOx Emitting Plants in the USA in 2006**

Recent SCR Projects

Utility	Station/Unit	MW (Total)	Status	Contracting
Ameren (CIPS)	Coffeen 1, 2	1,006	Operating	MLS
Ameren (UE)	Sioux 1, 2	1,000	On Hold	MLS
Associated Electric	New Madrid 1, 2	600	Operating	EPC (O-E)
Cinergy Services	9 units	6,500	Operating	MLS
Dynegy	Baldwin 1, 2	1,200	Operating	MLS
	Havana 6	450	Operating	MLS
Exelon Power	Mountain Creek 8	550	Operating	EPC (O-E)
	Hardley 3	400	Operating	EPC (O-E)
	Hardley 4-5	916	Operating	EPC (O-E)
Gainsville Regional Utilities	Deerhaven 2	200	Design	EPC (O-E)
Mirant	Morgantown 1, 2	1,252	Design	EPC/MLS
Owensboro Municipal	Reuter Smith 1	150	Operating	MLS
PSEG	Mercer 1, 2	640	Operating	EPC (O-E)
Reliant Energy	Laussat 5-8	2,500	Operating	MLS
	8 Gas Units	5,150	Operating/Lay-up	MLS
Santee Cooper	Cross 1, 2	1,200	Operating	MLS with Supplier
	Winyah 1-4	1,360	Operating	MLS with Supplier
Southern Illinois Power	Marion 4	174	Operating	MLS
Tampa Electric	Big Bend 1-4	1,400	Design	MLS
TNU	Lake Hubbard 2	525	Operating	EPC (O-E)
	[illegible]	[illegible]	[illegible]	[illegible]
TOTALS	**53 units**	**27,051**		

MLS: Multiple Lump Sum
EPC: Engineer, Procure, Construct

Sargent & Lundy

Basin/ Sargent and Lundy Relationship

- Engineer of Record for Leland Olds Scrubber 1&2
- Engineer of Record for Leland Olds 2 Combustion Mods.
- SCR Technology Consultant

Agenda

- Keys to a Successful SCR System Design
- Catalyst Degradation Mechanisms
- SCR Fuel Experience
- Combustion Process
- Degradation Mitigation Alternatives
- Conclusions
- Recommendations

Application of SCR Technology

Fundamental Question:

Is it possible to design an SCR today for Basin Electric's LOS Unit 2 North Dakota Lignite fired cyclone boiler with confidence in it's performance?

Agenda

- Keys to a Successful SCR System Design
- Catalyst Degradation Mechanisms
- SCR Fuel Experience
- Combustion Process
- Degradation Mitigation Alternatives
- Conclusions
- Recommendations

Keys to Good Reactor Design

- Proper Catalyst Specification & Application
- Reactor Sized to meet Catalyst Mgmt Program
- Efficient & Thorough Mixing of Ammonia with NOx
- Extremely Uniform Distribution of Gas and Ash in the Reactor

Keys to Achieving Success

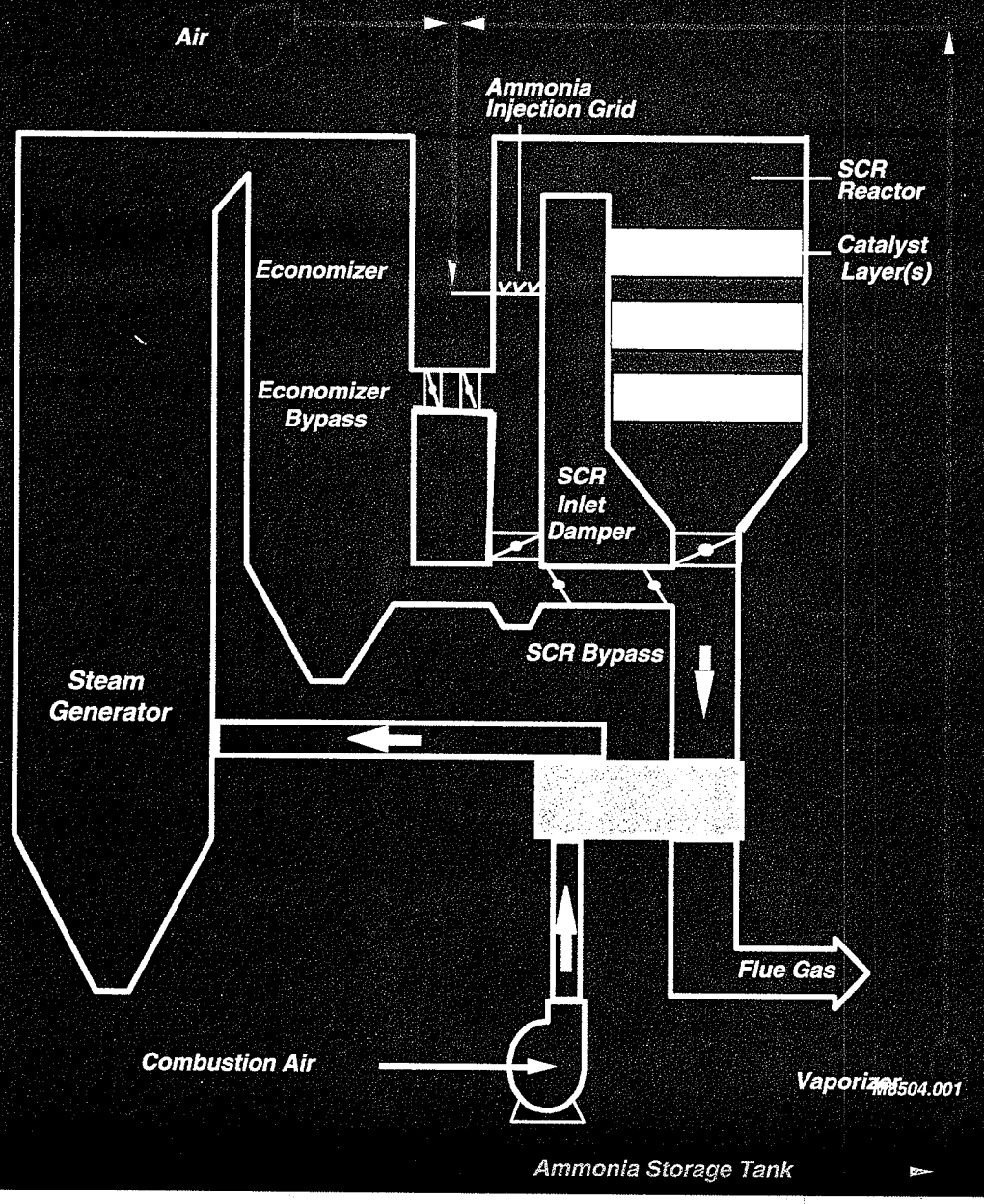
- Understand deactivation mechanisms
- Understand ash behavior
- This "Understanding" establishes:
  - Catalyst formulation
  - Catalyst pitch
  - Reactor velocity
  - Catalyst surface and volume
- Results in Reactor size and shape to match cat. Mgmt. plan

Keys to Achieving Success

- Physical Modeling for:
  - NH_3 and NOx mixing
    - Minimize NH_3 slip
    - Maximize catalyst life
  - Gas distribution and velocity profile
    - Turning vanes
    - Gas velocity rectifiers
- CFD modeling for:
  - identify and mitigate areas of potential ash deposits
    - In reactor and ductwork
  - Mixing gases of different temperatures

Application of SCR Technology

High Dust Selective Catalytic Reduction System



M8504.001

SCR TECHNOLOGY
Chemistry

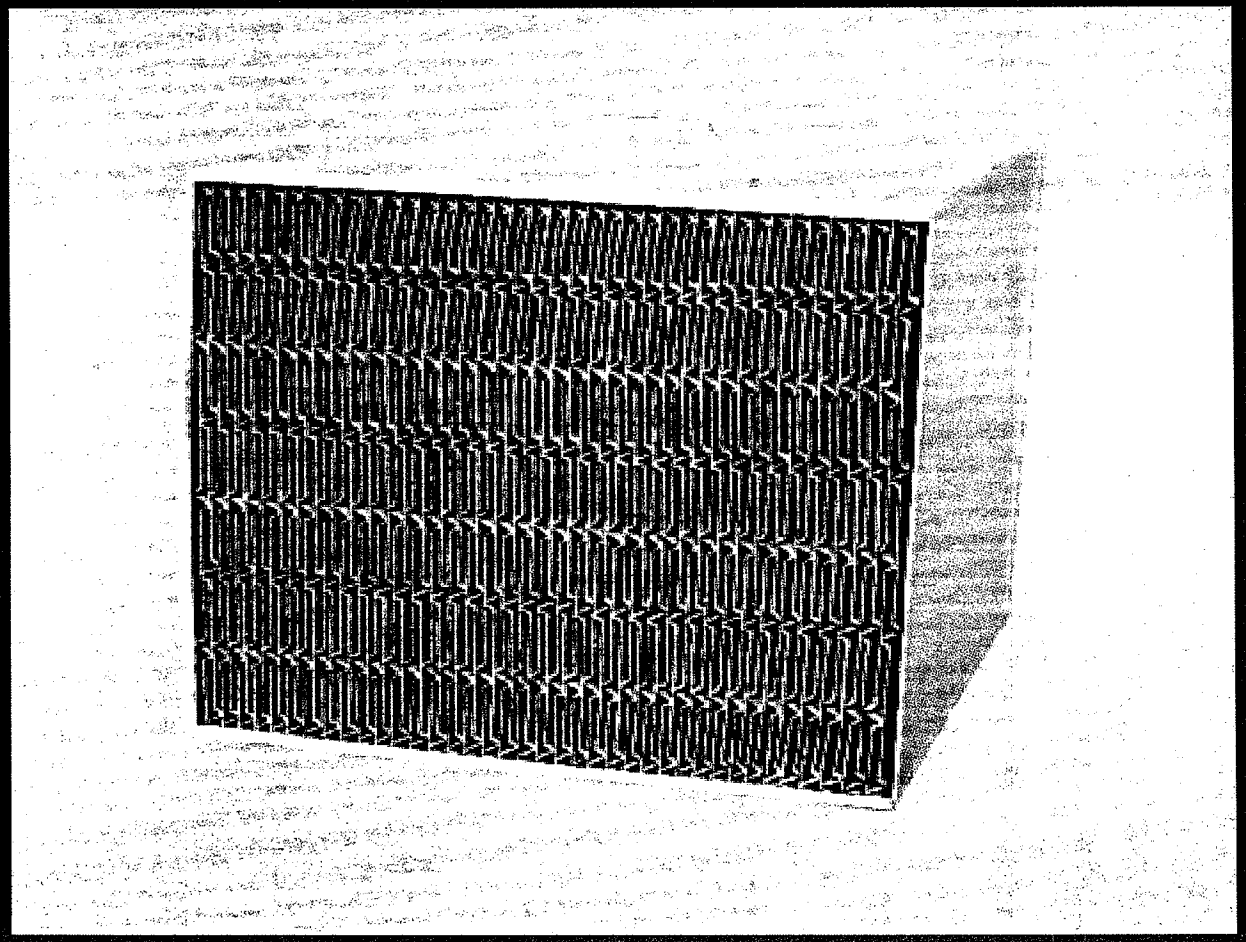
Two Desirable Reactions

Ammonia is adsorbed into the catalyst pore structure and then reacts as follows:

$$4\ NH_3 + 4\ NO + O_2 \xrightarrow{CAT} 4\ N_2 + 6\ H_2O$$

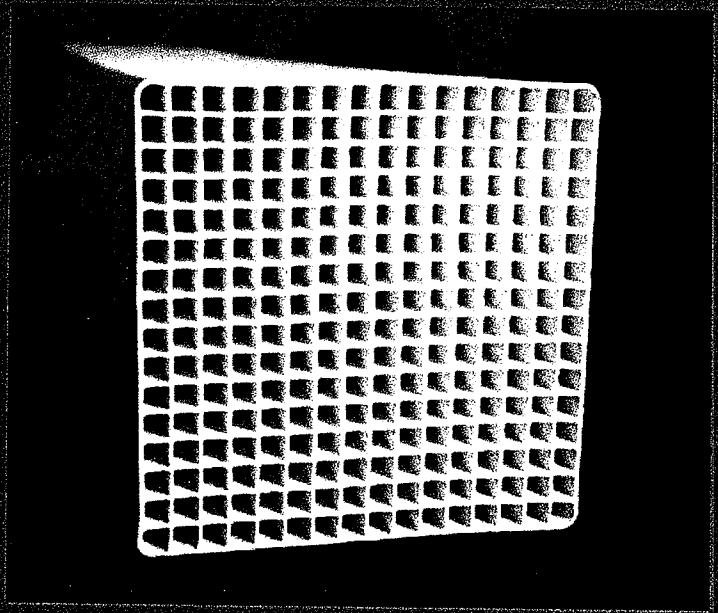
$$4\ NH_3 + 2\ NO_2 + O_2 \xrightarrow{CAT} 3\ N_2 + 6\ H_2O$$

End view of Plate Catalyst Module



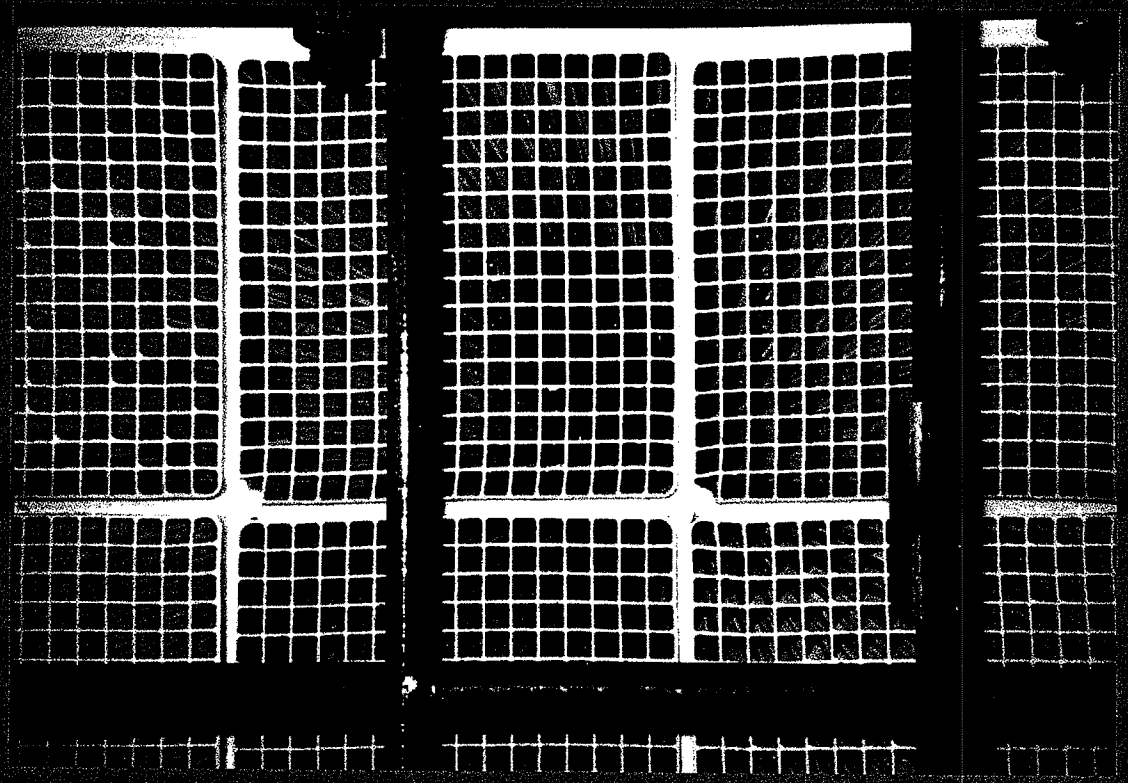
Honeycomb Catalyst

- Catalytic material is dispersed throughout a homogeneous, ceramic extruded structure



Application of SCR Technology

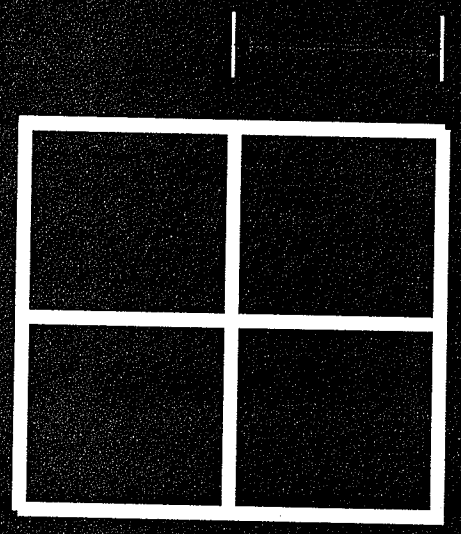
Honeycomb Catalyst Module



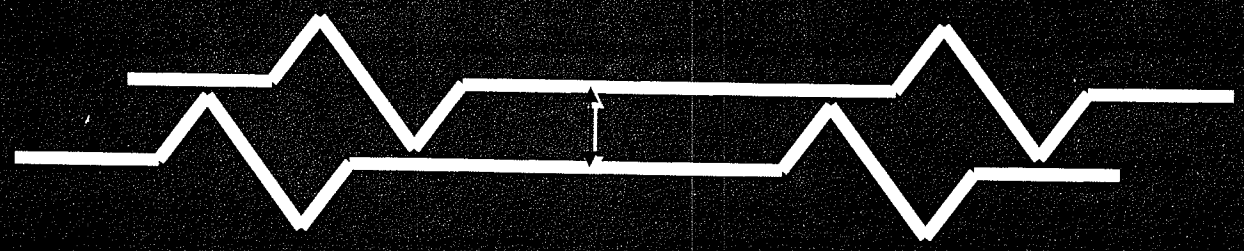
Application of SCR Technology

Catalyst Pitch

Honeycomb

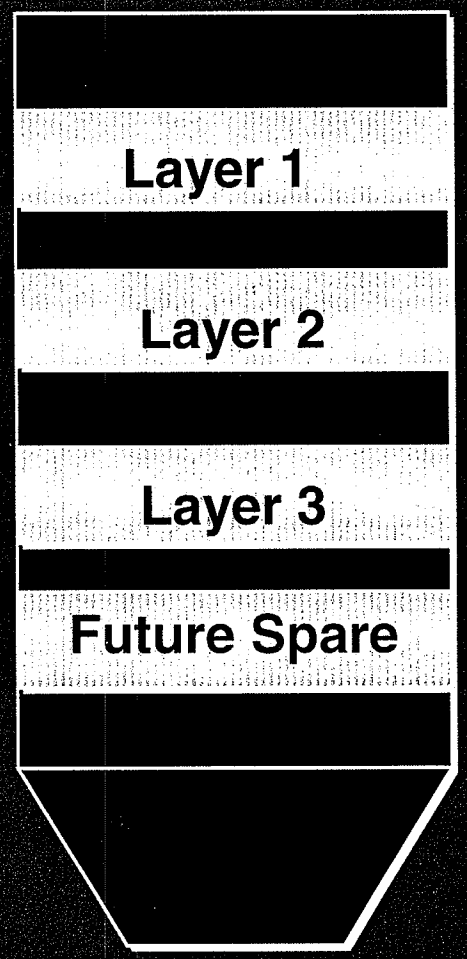


Plate



Catalyst Layers & Future Spare

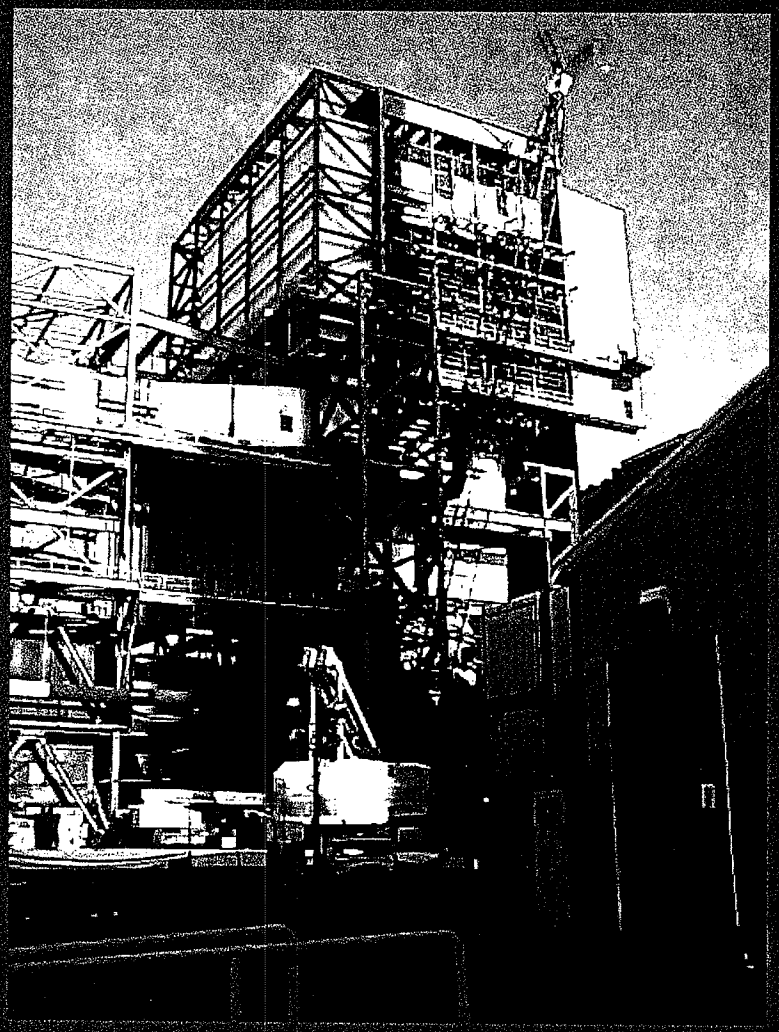
- 2 + 1 Arrangement
- 3 + 1 Arrangement
- Catalyst Deactivation
- Catalyst Management
  - Add spare layer first
  - Next replace first stage
- 16,000 to 20,000 hour guarantees



Application of SCR Technology

Catalyst Reactor

- Structures may be as high as boiler house
- Design Issue of Expansion from ambient to 800 °F
- Significant Loads
  - Module 3,000 to 4,000 lbs
  - Each level may have 150+



Summary: Keys to Achieving Success

- Understand deactivation mechanisms
- Understand ash behavior

Agenda

- Keys to a Successful SCR System Design
- Catalyst Degradation Mechanisms
- SCR Fuel Experience
- Combustion Process
- Degradation Mitigation Alternatives
- Conclusions
- Recommendations

Catalyst Deactivation Mechanisms:

Two Major Categories

- Physical
- Chemical

Catalyst Degradation Mechanisms

- Physical
  - Gas Channel Blockage
  - Pore Pluggage
  - Sintering
  - Erosion

Generally driven by:

- size, shape, and "stickiness" of the ash
- physical design of the catalyst (pitch, height, etc.)
- flow conditions in the reactor

Catalyst Degradation Mechanisms

- Physical
  - Gas Channel Blockage
  - Pore Pluggage
  - Sintering
  - Erosion

Generally driven by:

- size, shape, and "stickiness" of the ash
- physical design of the catalyst (pitch, height, etc.)
- flow conditions in the reactor

Catalyst Degradation Mechanisms

- Chemical
  - Surface Masking
  - Deactivation of catalytic sites

Generally driven by:

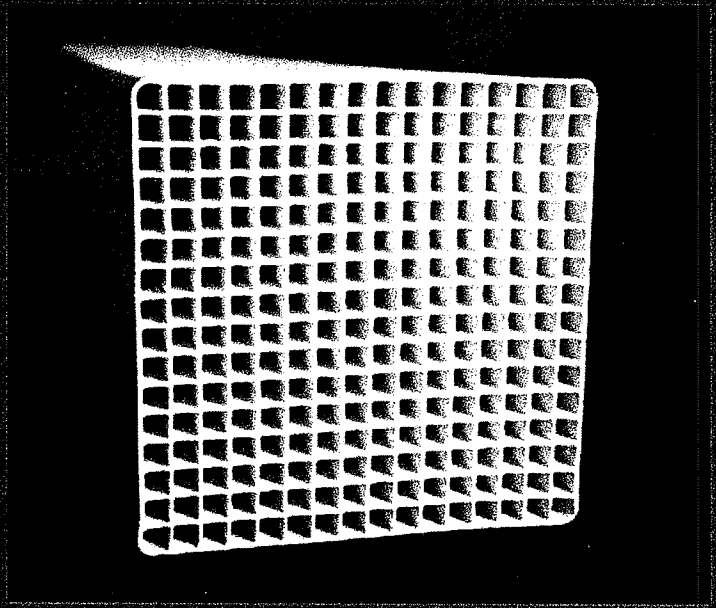
- fuel/ash chemistry
- combustion process
- gaseous trace elements

Physical: Gas Channel Blockage

- Two Major Mechanisms
  - Large Particle Ash (LPA)
    - Also known as "popcorn" ash
    - Forms in combustion zone of furnace
    - Prevalent in cyclone boilers
    - Typically intermittent
    - Not well understood
  - "Sticky" Ash
    - Sensitive to alkali and unburned carbon levels in ash
    - Particularly severe on PRBs and Lignites

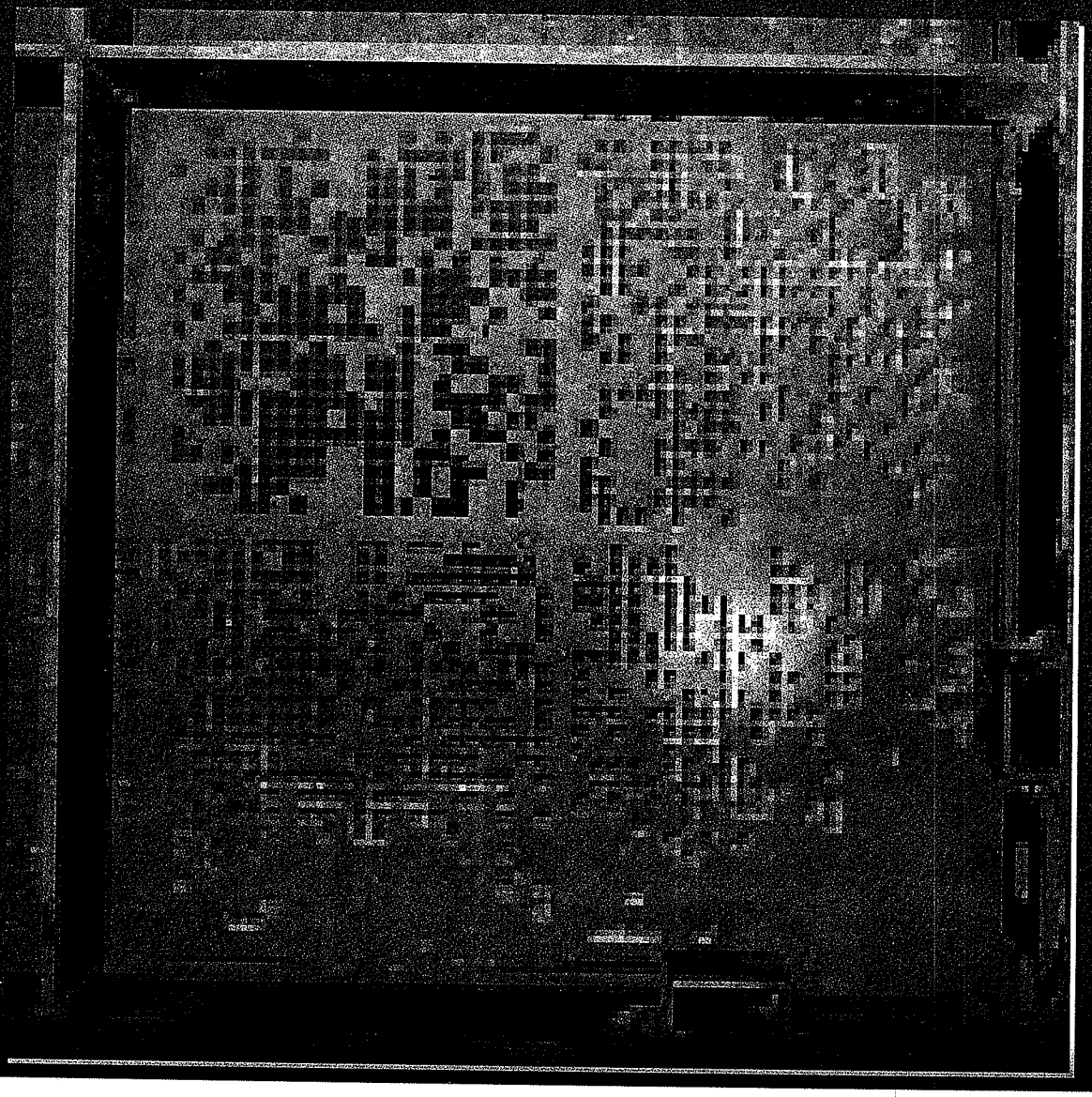
Honeycomb Catalyst

- Catalytic material is dispersed throughout a homogeneous, ceramic extruded structure



Application of SCR Technology

Example of Plugged Catalyst



Physical: Gas Channel Blockage

- Solutions
  - Screen and baffle system for LPA (popcorn)
    - usually at Economizer outlet
  - Ash distribution devices in ducts and reactor
  - Proper catalyst selection
  - Reactor cleaning systems
    - soot blowers
    - acoustic horns

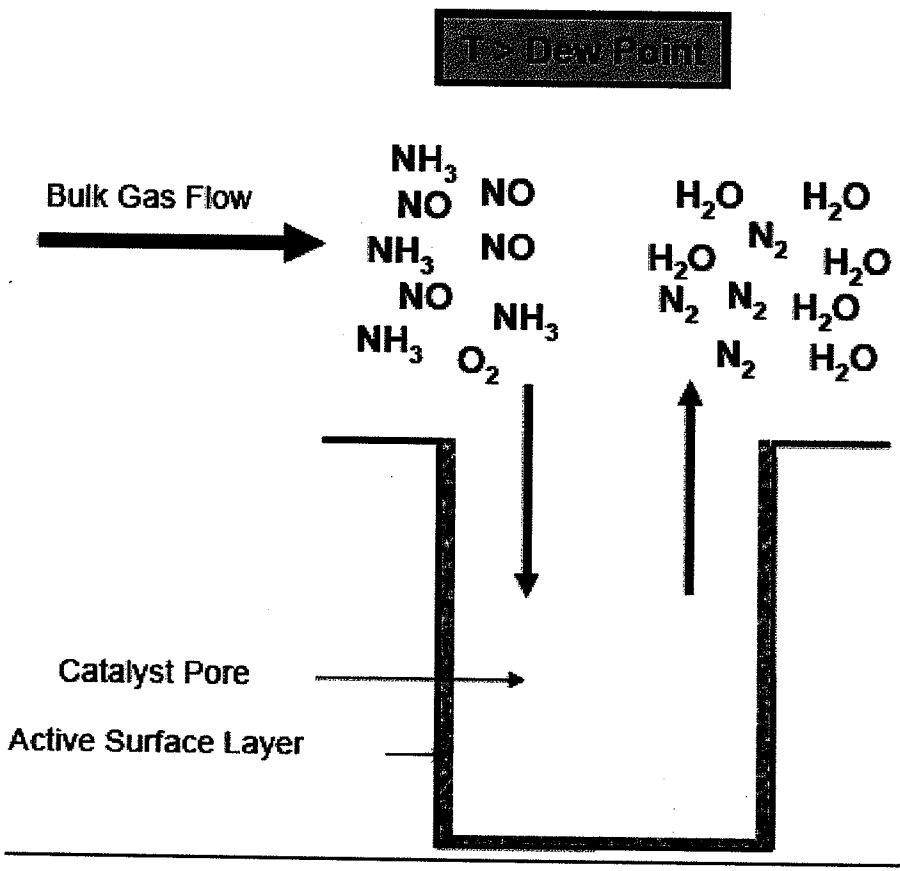
Physical: Pore Pluggage

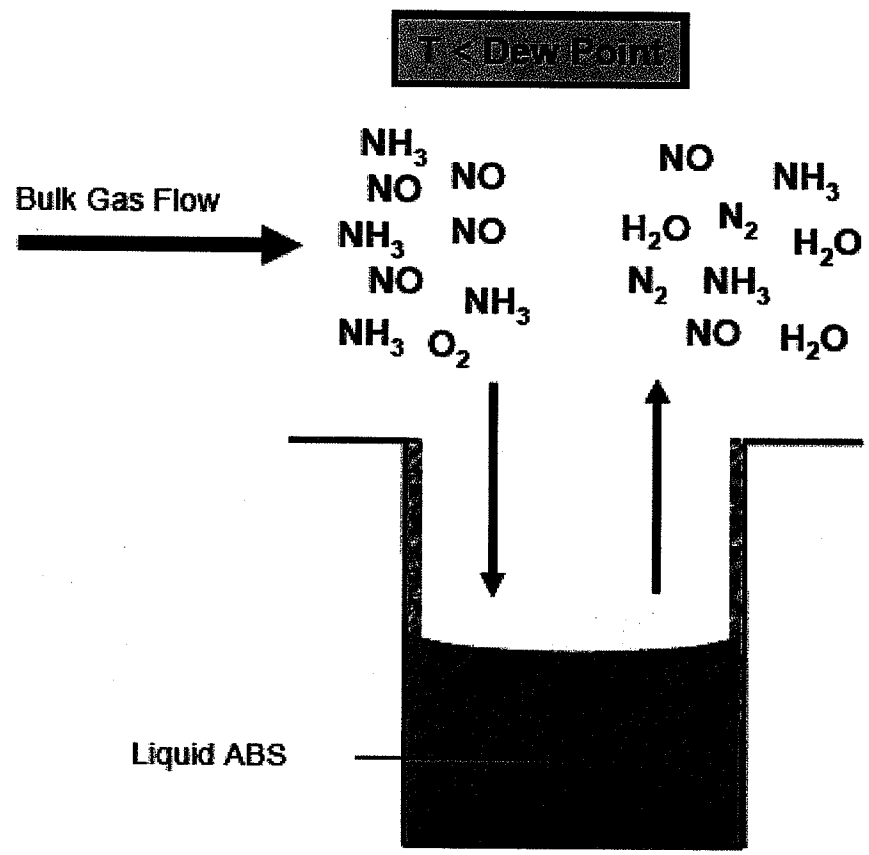
- Two Major Mechanisms
  - Bi-modal ash size distribution
    - typical of high alkaline ashes
    - sub-micron and micron size ash can penetrate deep in catalyst pores
  - Ammonium sulfate/bi-sulfate formation
    - function of SO_3 conc. and temp.
    - ammonium sulfate (solid)/bi-sulfate (liquid) plugs all pores

ABS Plugs SCR Catalyst Pores at Low T

$$[NH_3(g) + SO_3(g) + H_2O(g) \leftrightarrow NH_4HSO_4(l)]^{(ABS)}$$

$$P_{ABS} = P_{NH3}\, P_{SO3}\, P_{H2O} = 1/K$$





Physical: Pore Pluggage

- Solutions
  - Bi-modal ash size distribution
    - Add more catalyst
    - Use larger reactor
  - Ammonium sulfate/bi-sulfate
    - Reduce oxidation of SO_2 to SO_3 in boiler
      - deactivate catalyst: increases catalyst volume
    - Do not inject ammonia below ~560-590 °F while burning PRB or lignite

Physical: Sintering

- Typically at temps above 750F
  - Vanadium dependent and therefore SO_2 to SO_3 oxidation dependent
    - Closer to 850 °F for low oxidation catalyst (medium to high sulfur bituminous)
    - Closer to 750 °F for high oxidation catalyst (PRB, Lignites, natural gas)
  - Important consideration but typically not an issue for solid fuel application
    - May require modifications to economizer to control temperature

Physical: Catalyst Erosion

- Influenced by:
  - Abrasive characteristics of the ash
    - Lignites known abrasive qualities
  - Magnitude of ash loading
    - Cyclone furnaces produce less fly ash
  - Gas velocity profile at face of catalyst
    - superficial
    - angular

Minnkota Power
MPC COOPERATIVE, INC.

Your Touchstone Energy® Partner

1822 Mill Road • P.O. Box 13200 • Grand Forks, ND 58208-3200 • Phone (701) 795-4000

August 16, 2007

AUG 2007
Received
Air Quality

Terry O'Clair, Director
Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Subject: SCR Pilot Testing

Dear Mr. O'Clair:

Enclosed, please find a report entitled "APPROPRIATENESS OF CONDUCTING PILOT TESTING OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY AT MILTON R. YOUNG STATION UNITS 1 AND 2, FOR USE IN A NO_X BACT ANALYSIS". This report is submitted response to the Department's request that Minnkota consider a pilot test of SCR catalysts, at Milton R. Young Station, to gather additional data for use in Minnkota's previously submitted NOx BACT analysis. This report addresses three aspects that must be considered when making a decision to pursue SCR catalyst pilot test. The aspects are: 1) the legal basis for the testing; 2) is there a reasonable expectation that the results would be different than the results of previous testing; 3) could the testing be accomplished in the required amount of time.

Based upon the information presented in the enclosed report, Minnkota has decided not to pursue SCR pilot testing at Milton R. Young Station, as elaborated in the document.

Should you have any questions concerning the above, or the enclosed document, please contact me by telephone at 701-795-4221 or by email at jgraves@minnkota.com.

Yours truly,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard
Luther Kvernen
Craig Bleth
Kevin Thomas
Stu Libby
Tom Anseth
Young Station File

APPROPRIATENESS OF CONDUCTING PILOT TESTING OF SELECTIVE CATALYTIC REDUCTION (SCR) TECHNOLOGY AT MILTON R. YOUNG STATION UNITS 1 AND 2, FOR USE IN A NO_X BACT ANALYSIS

Prepared For
MINNKOTA POWER COOPERATIVE, INC

By

Dennis L. Arfmann
Hogan & Hartson

Steven A. Benson
Energy & Environmental Research Center

Carl V. Weilert
Burns & McDonnell

August 14, 2007

BACKGROUND

The North Dakota Department of Health (NDDH) has requested that Minnkota Power Cooperative (Minnkota) consider performing a pilot test at the Milton R. Young Station (MRYS) to investigate the technical feasibility of Selective Catalytic Reduction (SCR) technology for control of emissions of nitrogen oxides (NO_x) from the North Dakota lignite-fired cyclone boilers at that power plant. The results of the pilot test would be used in the NOx BACT analysis for MRYS. Technical feasibility of SCR application to utility boilers firing this fuel is a principal issue in the determination of best available control technology (BACT) for NO_x emission control at MRYS. The determination of BACT for NO_x emission control at MRYS is a requirement of the Consent Decree (CD) filed in the case *United States of America and State of North Dakota v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative.*

Minnkota has evaluated NDDH's request and has decided not to pursue SCR pilot testing at MRYS for three reasons as elaborated in this document, below. The reasons for not conducting further pilot testing prior to the BACT determination are:

1. Pilot testing is specifically not required by the BACT determination procedures established by the U.S. Environmental Protection Agency (EPA).
2. Previous research, including previous SCR pilot testing conducted at the Coyote Station, indicates that there is not sufficient reason to believe that the pilot testing suggested by NDDH will produce results any different from those obtained from the prior pilot test.
3. The compliance schedule for installation of NO_x BACT technology at MRYS as established by the CD cannot be met if pilot testing of SCR, followed by installation of SCR, is selected as the basis for BACT.

Each of these points is explained further in the text that follows.

REGULATORY BASIS FOR MINNKOTA'S DECISION NOT TO CONDUCT PILOT SCR TESTING

Minnkota's decision not to conduct pilot testing of SCR technology is supported on a regulatory basis for the following reasons:

1. EPA Guidance Specifically Describes When an Emission Control Technology is "Technically Feasible"

EPA has prepared a New Source Review Workshop Manual (Draft, October 1990) that explains, in detail, the evidence and analysis necessary to support a BACT determination. This process of defending a particular BACT recommendation is summarized in the Workshop Manual as follows:

> The applicant's role is primarily to provide information on the various control options and, when it proposes a less stringent control option, provide a detailed

> rationale and supporting documentation for eliminating the more stringent options. It is the responsibility of the permit agency to review the documentation and rationale presented and: (1) ensure that the applicant has addressed all of the most effective control options that could be applied; and (2) determine that the applicant has adequately demonstrated that energy, environmental, or economic impacts justify any proposal to eliminate the more effective control options. Where the permit agency does not accept the basis for the proposed elimination of a control option, the agency may inform the applicant of the need for more information regarding the control option. However, the BACT selection essentially should default to the highest level of control for which the applicant could not adequately justify its elimination based on energy, environmental and economic impacts. If the applicant is unable to provide to the permit agency's satisfaction an adequate demonstration for one or more control alternatives, the permit agency should proceed to establish BACT and prepare a draft permit based on the most effective control option for which an adequate justification for rejection was not provided. [Workshop Manual at B.53.]

The Workshop Manual requires an applicant to "make a good faith effort to compile appropriate information from available information sources, including any sources specified as necessary by the permit agency." [*Id.* at B.11]. This analysis should at least identify technologies that may be potentially transferable to the particular source, though later those technologies may prove technically infeasible or economically cost-ineffective.

For each alternative emission control technique, the applicant should analyze whether the control technique is feasible. EPA defines a *technically feasible alternative as one that is available* (i.e., commercially available for the application in question) *and applicable* (i.e., whether the available controls may reasonably be deployed on the source in question). The Workshop Manual provides a detailed analysis of the availability and applicability of a control technology, which bears quoting at length:

> In step 2, the technical feasibility of the control options identified in step 1 is evaluated. This step should be straightforward for control technologies that are demonstrated—if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and technically feasible. For control technologies that are not demonstrated in the sense indicated above, the analysis is somewhat more involved.
>
> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, 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. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.

Availability in this context is further explained using the following process commonly used for bringing a control technology concept to reality as a commercial product:

- Concept stage;
- Research and patenting;
- Bench scale or laboratory testing;
- Pilot scale testing;
- Licensing and commercial demonstration; and
- Commercial sales.

A control technology is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. 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.* An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provision of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.

Commercial availability by itself, however, is not necessarily 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 construction.

Technical judgment on the part of the applicant and the review authority is to be exercised in determining whether a control alternative is applicable to the source type under consideration. In general, a commercially available control option will be presumed applicable if it has been or is soon to be deployed (e.g., is specified in a permit) on the same or a similar source type. Absent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously. Deployment of the control technology on any existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary. [*Id.* at B.17–B.18] (emphasis added).

The *proper method for showing technical infeasibility* is identified by the Workshop Manual as follows:

> [T]he applicant should make a factual demonstration of infeasibility based on commercial unavailability and/or unusual circumstances which exist with application of the control to the applicant's emission units. Generally, such a demonstration would involve an evaluation of the pollutant-bearing gas stream characteristics and the capabilities of the technology. 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). Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process.
>
> A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that the technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts which, in turn, may form the basis for eliminating a control technology (see later discussion at V.D.2). [*Id.* at B.19–B.20.]

Each of the elements of demonstrating technical infeasibility, along with background and supporting information as necessary, must be decisively documented.

2. Following the Guidance from the Workshop Manual, Minnkota has Decisively Documented that SCR is Technically Infeasible at Milton R. Young Station

SCR has not been demonstrated on any North Dakota lignite-fired cyclone unit. In light of this lack of demonstration, NDDH has asked Minnkota to consider conducting pilot testing of SCR to determine the life expectancy of a particular SCR catalyst. However, the 1990 Workshop Manual concludes that pilot testing of an undemonstrated technology cannot be required as a part of a BACT analysis.

The Workshop Manual addresses technical feasibility in the context of both demonstrated technologies (not applicable to Minnkota here) and undemonstrated technologies (Minnkota's situation). As set forth in detail above, the key questions in determining whether the undemonstrated technology is feasible are whether the technology is "available" and "applicable." Most importantly, the Workshop Manual 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." [*Id.* at B.18].

As Minnkota has demonstrated in its previous filings, EERC and Burns & McDonnell have demonstrated SCR cannot be reasonably installed and operated on the Milton R. Young Station. SCR is therefore unavailable and inapplicable, and NDDH may not require Minnkota to conduct extensive pilot testing as a part of a BACT analysis to experiment with the availability or applicability of SCR to North Dakota lignite-fired cyclone boilers.

In conclusion, Minnkota has demonstrated that SCR is not technically feasible, that that SCR is not "available" under the EPA guidance, that SCR is not "applicable" under the EPA guidance, and that a pilot test is not allowed under the EPA guidance for BACT.

TECHNICAL BASIS FOR MINNKOTA'S DECISION NOT TO CONDUCT PILOT SCR TESTING

In order to determine if additional pilot testing of SCR catalysts on lignite fueled cyclone-fired boiler would produce similar or potentially different results from previous testing, the fouling and poisoning mechanisms must be examined. This is necessary in order to evaluate design changes that could be made to reduce or eliminate the fouling and poisoning of the SCR catalysts.

Fouling and poisoning of SCR catalysts are affected by the following:

- Lignite properties
- Combustion processes
- Partitioning of sodium and other elements during combustion
- SCR catalyst characteristics and properties
- Chemical and physical mechanisms of pore plugging

The primary concern for lignite coals from the Northern Great Plains of North America is blinding and poisoning of SCR catalysts because of the presence of alkali and alkaline elements in the coal and their fate upon combustion. Mussatti (2002) indicated in the "EPA Air Pollution Control Cost Manual – Sixth Edition" the following primary mechanisms for catalyst deactivation:

> "Poisoning - Certain fuel constituents which are released during combustion act as catalyst poisons. Catalyst poisons include **calcium oxide and magnesium oxide**, potassium, **sodium**, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them irreversibly. Catalyst poisoning represents the main cause of catalyst deactivation."
>
> "Blinding/Plugging/Fouling - Ammonia-sulfur salts, fly ash, and other particulate matter in the flue gas cause blinding, plugging or fouling of the catalyst. The particulate matter deposits on the surface and in the active pore sites of the catalyst. This results in a decrease

of the number of sites available for NO_x reduction and an increase in flue gas pressure loss across the catalyst."

Based on research, development, and demonstration testing to date these challenges have not been overcome. Significant fundamental research is required to further develop NO_x reduction technologies for lignite coals.

Lignite Properties

Lignite from the Center Mine in North Dakota is part of the Fort Union region. The Fort Union region represents the lignite bearing reserves in North America. The age of lignite in the Fort Union ranges from late Cretaceous through Eocene. The younger lignite coals have higher levels of oxygen as compared to higher ranked coals. Lignites can contain as high as 20% oxygen on a moisture and ash free basis. The most important oxygen containing group in lignite is the carboxylic acid group accounting for up to 65% of the oxygen (Schobert, 1995). The carboxylic acid groups act as bonding sites for various elements such as Ba, Ca, Mg, Na, and Sr and are enriched in lignite coals as compared to bituminous coals (Schobert, 1995). As coal rank increases the oxygen functional groups are lost due to the coalification process. The carboxylic acids act as ion exchange sites for sodium and other elements such as Mg, Ca, Sr, and Ba that are accumulated from ground water. The abundance of sodium and other elements that are associated with the carboxylic acid groups in the coal are determined using chemical fractionation (Benson and Holm, 1985). The chemical fractionation results for Center lignite indicates that 76% of the total sodium is ion-exchangeable indicating an organic association in the coal with the remaining in a water soluble form (Schobert, 1995). In addition to the organic and water associated impurities, lignites contain significant levels of mineral grains. The types of minerals present in lignite consist of pyrite, quartz, clay minerals, sulfates, carbonates, and others (Benson and others, 1993).

Lignite fired at the Milton R. Young (MRY) plant is mined from three seams at the Center mine of the Fort Union Region, the Kinneman Creek (KC), Hagel A (HA), and Hagel B (HB). The coal fired in the Units 1 and 2 represent some blending of the coal through handling and delivery. The variability selected coal quality components for the as-fired Center lignite is shown in Table 1. The average, maximum, and minimum as well as the percentiles were derived from analysis of the as-fired coal database. The database consists of 1316 samples of coal collected using sampling systems on Unit 2. The elements that are largely organically associated as described above are highlighted. These elements are largely organically associated and can contribute to the formation of reactive fine particulate during combustion and gas cooling.

Table 1. Center lignite composition (moisture, ash, sulfur, and heating value expressed on an as-received basis; and ash composition expressed as weight percent equivalent oxide of the ash produced at 750 °C).

	Moisture, %	Ash, %	Sulfur %	Btu/lb	Al_2O_3	BaO	CaO	Fe2O3	MgO	P_2O_5	K_2O	SiO_2	Na_2O	SO_3
Average	37.13	9.64	0.98	6578	11.68	0.52	13.15	8.90	3.99	0.12	1.33	36.04	4.40	18.39
Max	39.37	25.46*	2.55	7101	15.62	1.22	23.96	24.72	7.09	1.00	2.30	55.98	13.03	34.50
Min	33.56	4.97	0.47	5852	6.31	0.20	6.80	5.38	2.30	0.01	0.16	12.30	0.55	8.12
90th Perc.	38.10	12.51	1.29	6820	14.23	0.84	19.92	12.20	5.68	0.41	1.92	45.98	8.71	26.25
10th Perc.	35.95	7.06	0.72	6359	9.58	0.37	9.73	7.08	3.00	0.04	0.61	22.70	1.99	14.35
45th Perc.	37.17	9.33	0.90	6552	11.62	0.47	12.15	8.34	3.81	0.09	1.36	36.99	4.09	17.30
55th Perc.	37.37	9.75	0.94	6592	11.97	0.50	12.74	8.68	3.97	0.10	1.44	38.36	4.61	18.02

* High value may be an analysis or reporting error. Sample could not be reanalyzed to verify.

Figures 1 - 3 show the frequency distributions with the 10th, 50th, and 90th percentile values for sodium, base-to-acid ratio, and ash content in the as-fired database. In addition, the future Center lignite characteristics in ten-year averages for % sodium oxide in ash, base/acid ratio, and % ash are plotted on the frequency distribution diagrams in Figures 1-3. The future Center lignite characteristics are based on weighted averages of analysis conducted for drill cores. This information was used to calculate the weighted averages for 10-year spans. The frequency distribution of the sodium content of the ash is shown in Figure 1. The projections for the future have similar sodium levels to the upper mode of sodium contents. The sodium content of the future coals appears to be decreasing initially from the upper mode and then increasing from 2036–2064. The base-to-acid ratio shown in Figure 2 indicates coals typical of lower ash contents and high levels of sodium, calcium, potassium, and iron relative to silicon, aluminum, and titanium. This information indicates that the future coals will have a higher propensity on average to cause low-temperature fouling than coals fired over the past several years. Lower ash content and higher base-to-acid ratio coals produce more low temperature fouling due to sulfate formation. Figure 3 shows the projected ash values compared to the as-fired database. The data from 2006–2015 show similar data to the as-fired database with decreasing levels of ash in the latter years.

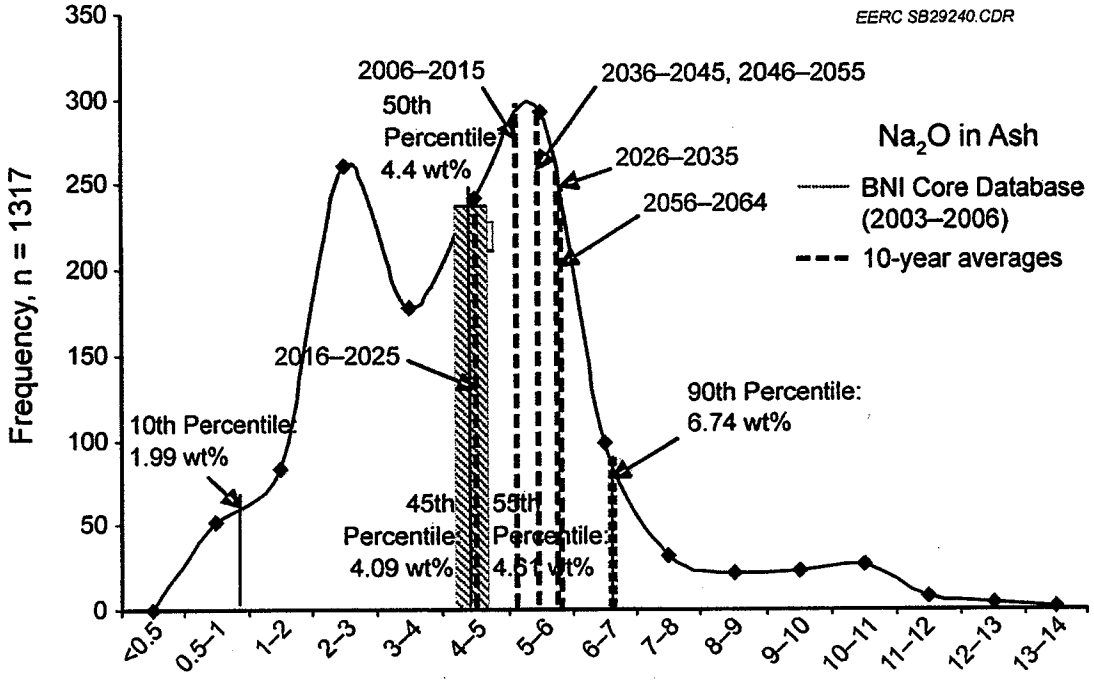


Figure 1. Sodium oxide in ash frequency distribution for as-fired database compared to 10-year averages and weighted Core Database values.

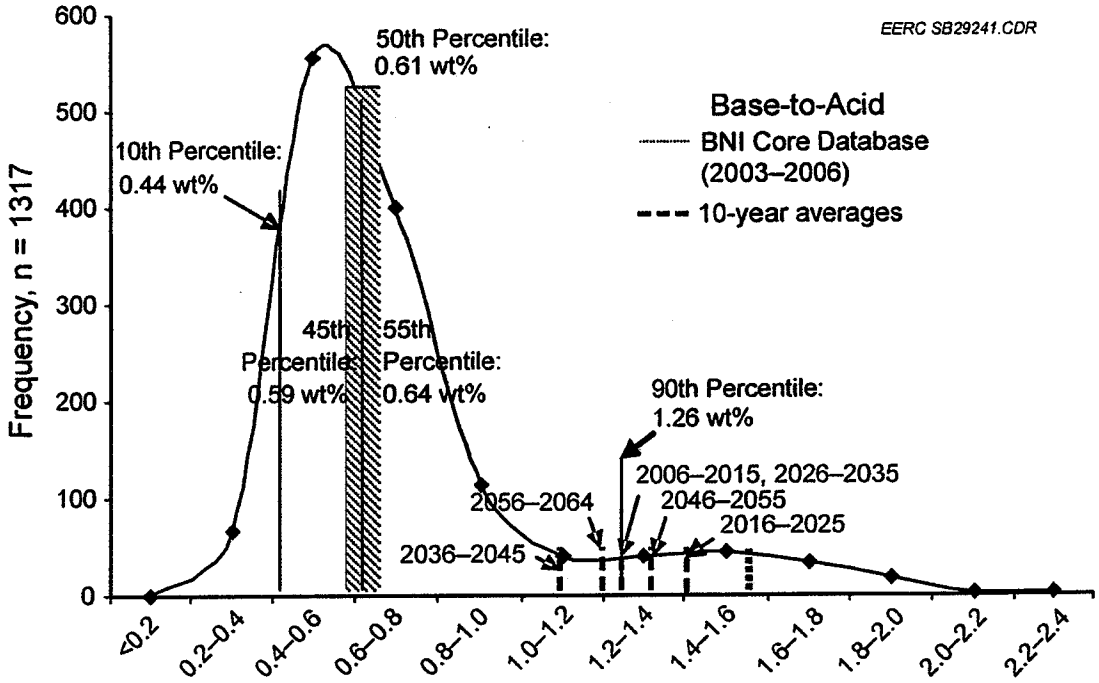


Figure 2. Base-to-acid ratio of ash frequency distribution for as-fired database compared to10-year averages and weighted Core Database values.

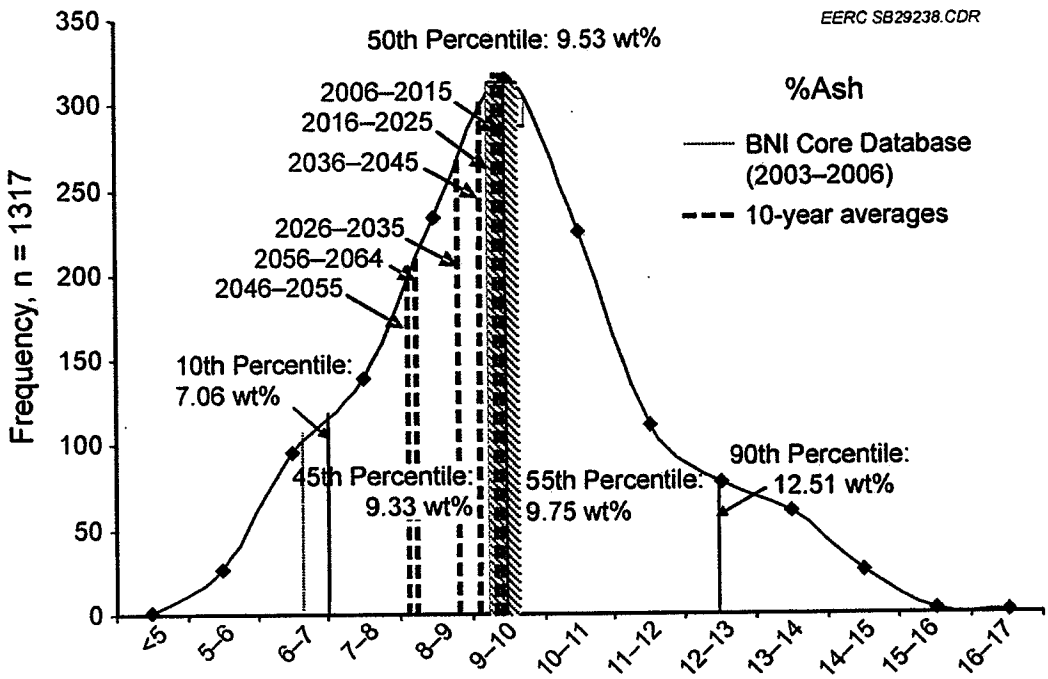


Figure 3. Ash frequency distribution for as-fired database compared to 10-year averages and weighted Core Database values.

Combustion Processes and Partitioning

The inorganic coal components undergo complex chemical and physical transformations during combustion to produce intermediate ash species in the form of inorganic 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 transformations involved in fly ash formation illustrated in Figure 4 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 resulting ash composition and mass distribution as a function of size is also shown in Figure 4. Typical ash derived from coal combustion has a bimodal to multimodal size distribution that consists of a submicron and supermicron size fraction as shown in Figure 5. The submicron component is largely a result of the condensation of flame-volatilized inorganic components such as sodium. The intermediate size mode at about 2 micrometers is derived from the more refractory organically associated elements such as calcium and magnesium. The larger particles at approximately 12 to 15 μm are derived from the mineral grains present in the coal. The larger-size particles have been called the residual ash by some

investigators (Sarofim and others, 1977) because these ash particles resemble, to a limited degree, the original minerals in the coal. 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.

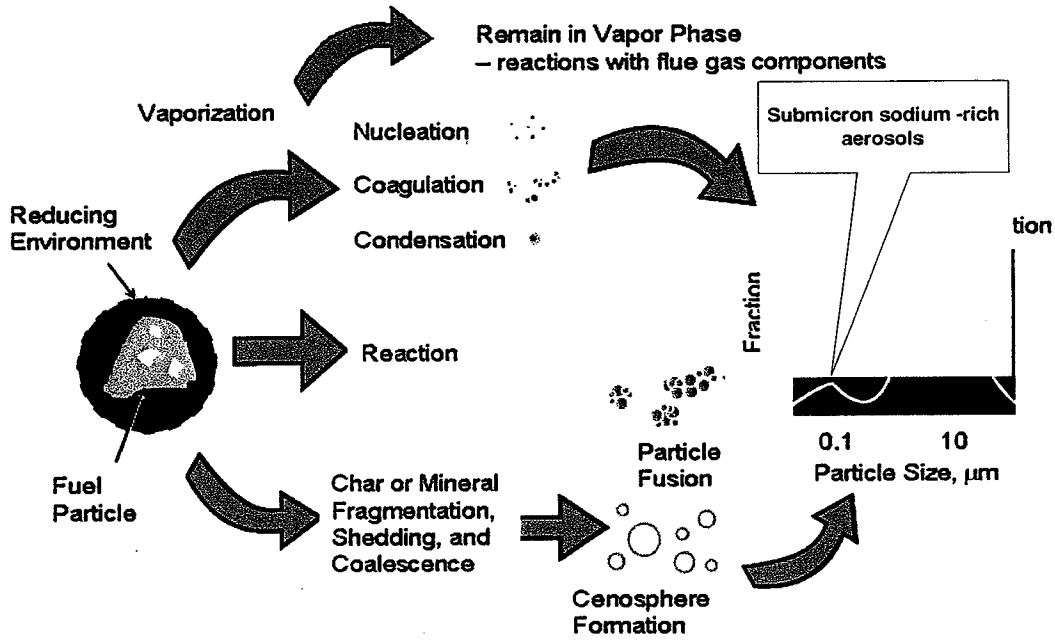


Figure 4. Transformation of inorganic components present in coal during combustion.

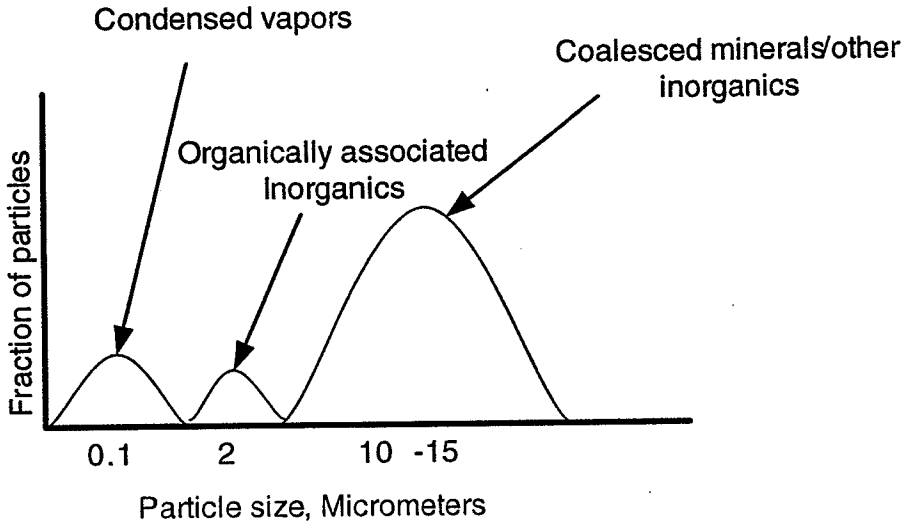


Figure 5. Final size distribution of ash particles produced upon combustion of lignitic coals (Benson and Laumb, 2007).

Cyclone fired systems enhance the partitioning of the inorganic components both by high temperatures and cyclonic action. The partitioning of sodium between the slag and coal is shown in Figure 6. The results show the sodium present in the as-fired coal ash presented with and without SO_3. The retention of sulfur in the ash is an artifact of the ashing procedure. In comparing the level of sodium in the slag to the coal fired for the high-sodium cases, only about half of the sodium is retained in the slag. The slag samples were recovered from the slag tap for the boiler. These slag samples include deposits that fall from the walls and the high-temperature convective pass.

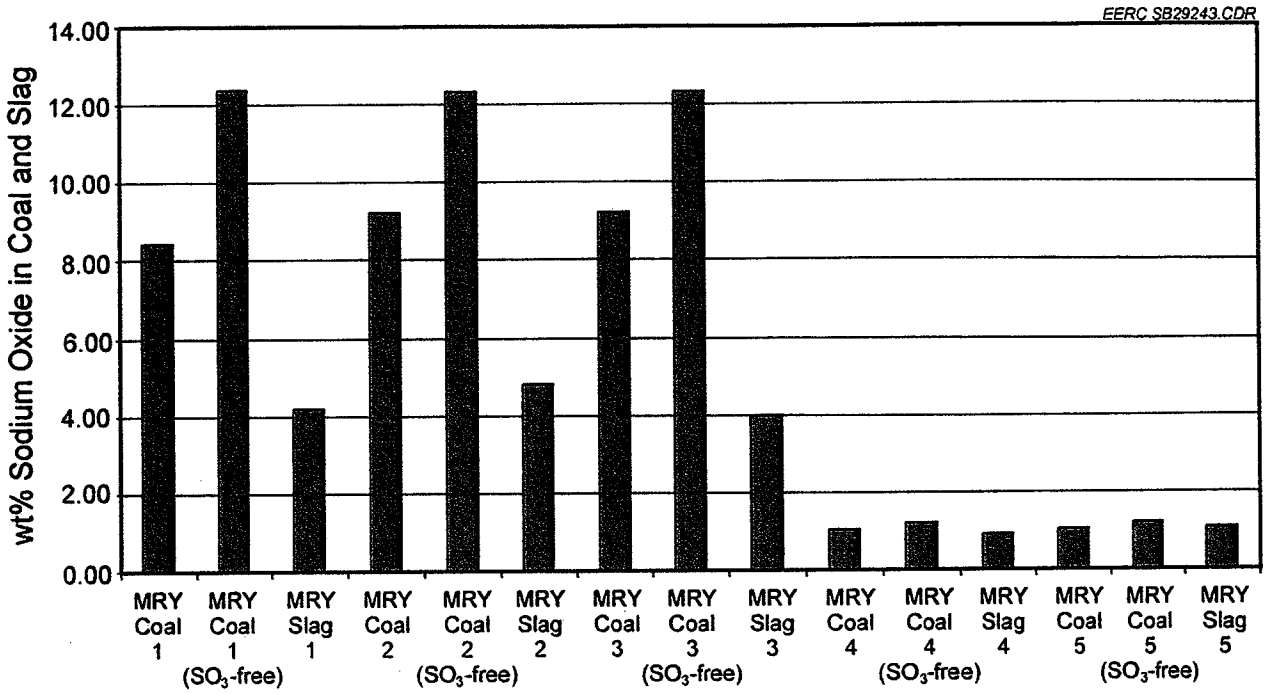


Figure 6. Comparison of sodium levels in Center lignite coal and slag samples.

The transport of intermediate ash species (i.e., inorganic vapors, liquids, and solids) to surfaces within a combustion system (combustion and air pollution control system) is a function of the state and size of the ash species and system conditions such as gas flow patterns, gas velocity, and temperature. Several processes are involved in the transport of ash particles to surfaces in the combustion system. These processes have been described in detail by Raask (1985) and Rosner (1986). The primary transport mechanisms are illustrated in Figure 7. For larger particles inertial impaction and eddy impaction in turbulent regions are the dominant mechanisms. The small particles (<1 μm) and vapor-phase species are transported by the vapor phase and small particle diffusion. The inorganic materials are transported to heat-transfer and catalyst surfaces by diffusion, electrophoresis, and inertial impaction. Thermophoresis is not a significant contributor to the transport of particles as it related to SCR materials. However, thermophoresis is a contributor to particle transport on heat transfer surfaces because of the temperature gradient.

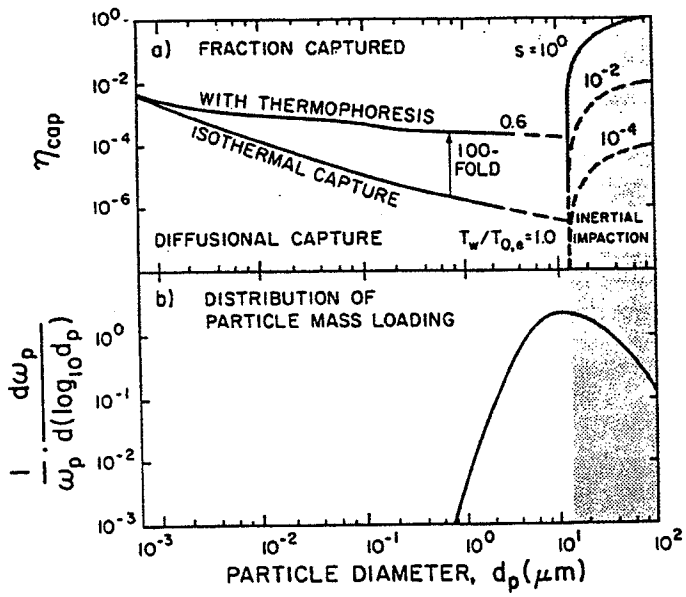


Figure 7. Overview of ash transport mechanisms (Rosner, 1986); (a) particle size dependence of captured fraction n_{cap}; (b) size distribution of the mainstream particle mass loading. The accumulation rate will involve a combination of a and b.

The vapor phase and small particles are characteristically rich in flame-volatilized species that condense upon gas cooling in the bulk gas or in the gas boundary layer next to the surface. The diffusion mechanisms important with respect to the transport of vapor species and small particles to the surface of SCR catalysts include:

1. Fick diffusion – molecular level.
2. Brownian diffusion – particles suspended by a host liquid.
3. Eddy diffusion – turbulent systems.

SCR Catalyst Characteristics and Properties

SCR catalysts for coal combustion applications consist of ceramic material with high porosity that contains imbedded active catalytic sites. The NO_x reduction occurs on the active surface of the catalyst. The active surface of the catalyst consists of flat surfaces and pores within the flat surface of the catalyst. The flat surfaces and pores in the catalyst are designed to provide gas contact with the active surface of the catalyst. The pores consist of open macropores and micropores that occur on the surface of the catalyst structures.

The size of the openings in honey comb catalyst impacts the velocity of the gases flowing through the catalyst. Pitch is the term used to describe the openings between the flat surfaces of the catalyst. Figure 8 illustrates the pitch, p and the wall thickness, a. Lower gas velocities will result for higher pitch numbers while small numbers will result in higher gas velocities through the catalyst. Catalyst vendors have methods to identify the proper pitch for specific fuel types and ash characteristics to minimize bridging or plugging where the dominant transport mechanism is inertial impaction and eddy impaction for the large particles. Selecting a pitch that

will minimize the transport of small particles and vapor phase species is not as straightforward. High pitch catalysts will result in lower velocity gas flow through the catalyst and will create a thicker boundary layer resulting in an increased potential for small particle transport. Catalyst geometry plays a significant impact on gas flow patterns through the catalyst. Evaluation of the literature and information provided by catalyst vendors indicate that the geometries of catalysts have not been improved to minimize small particle and vapor phase deposition on the surface and within the pores of catalyst (Hansen, 2007).

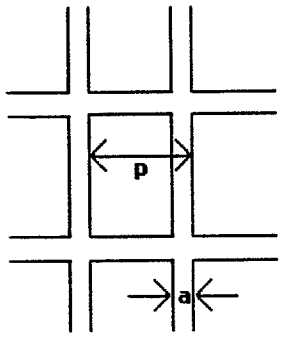


Figure 8. Catalyst pitch (Mussatti, 2002).

An example of the macropore structure is shown in Figure 9 for an actual surface for a honeycomb type catalyst. The openings in the catalysts create porosity and surface area to expose the reactive components of the catalyst to gas phase components. These openings are prone to filling with small particles and large particles through the transport processes of diffusion and impaction, respectively. Once these particles are transported to the surfaces they will be held in place by weak electrostatic and van der Waals forces and they will react with vapor phase sulfur oxide species.

Chemical and physical mechanisms of pore plugging

The most significant problems that limit the successful application of SCR catalysts to lignite coal is the formation of low-temperature sodium–calcium–magnesium sulfates 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. Studies conducted at Coyote station (Benson and others, 2005) found significant blinding and filling of the pores with small particles as shown in Figure 9. Rapid filling of the pores occurred with the catalyst pitch of 6 mm. These materials were subjected to air pulsing that did not remove the materials from the catalyst. The characteristics of the materials filling the pore were rich in sodium and calcium sulfates. A high magnification image of the materials coating the catalyst and filling the pore is shown in Figure 10. This image shows the importance of the very small particles less than 1 micrometer and their impact on the bonding of the deposited materials. These small particles readily interact with gas phase SO_2 and SO_3 expanding to create a bonded matrix as shown in Figure 11 that completely fills the pores of the catalyst with a continuous bonded phase. A high magnification cross-section is shown in Figure 12 of a highly sulfated bonded matrix.

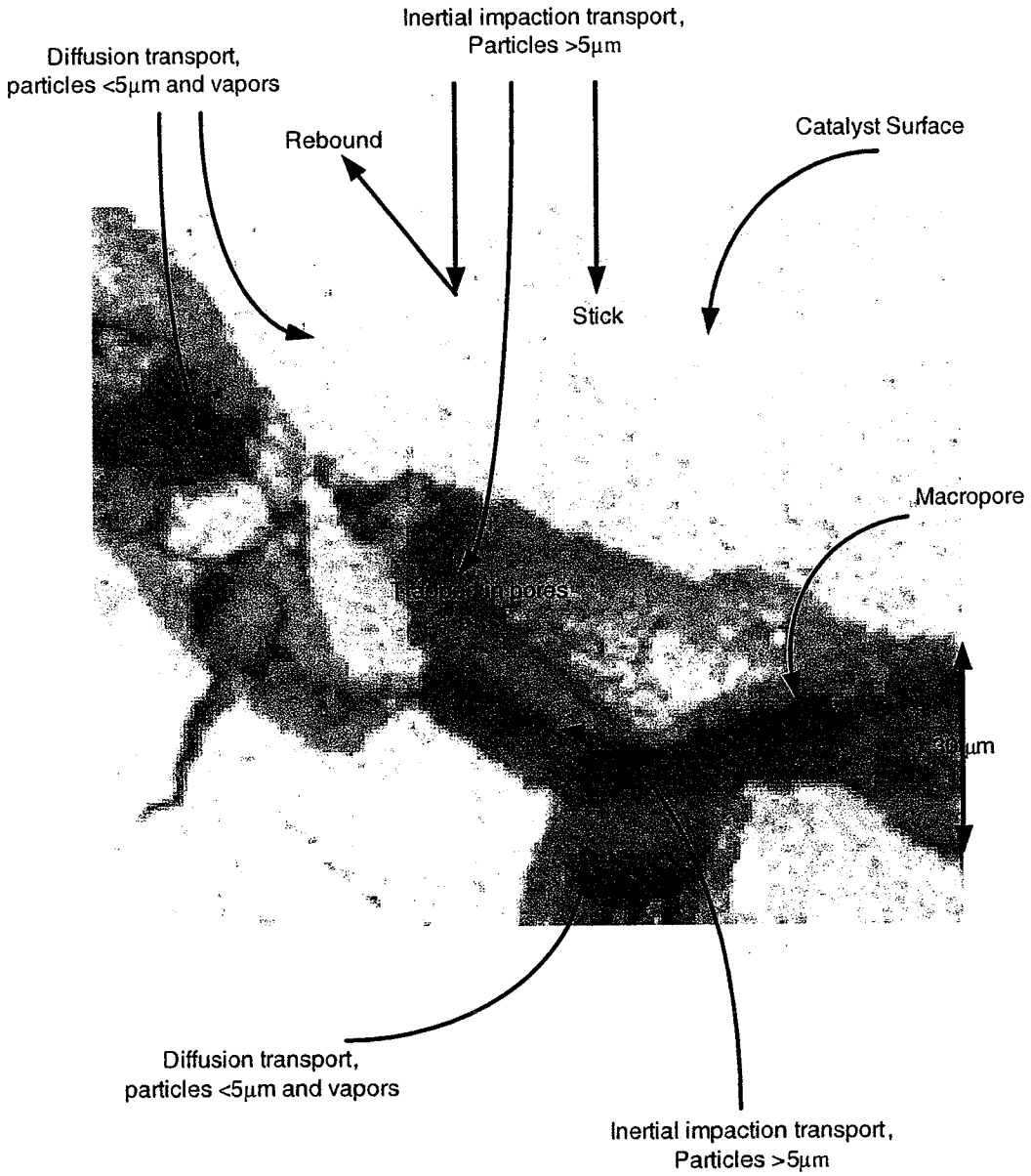


Figure 9. Scanning electron microscope secondary electron image of the macropore structure of an SCR catalyst with transport process descriptions.

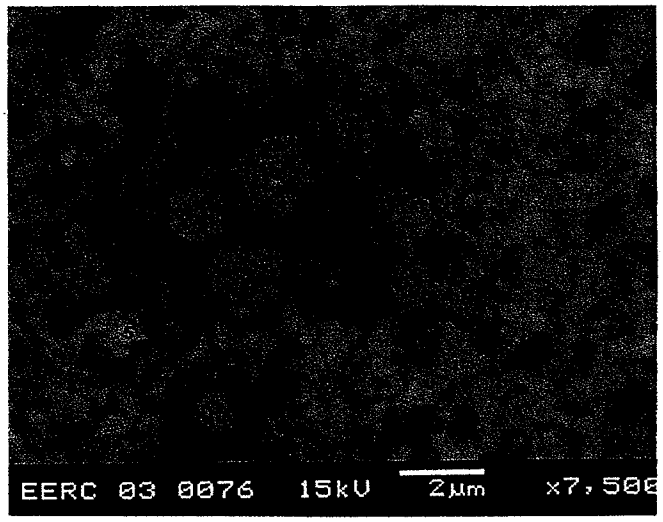


Figure 10. High magnification secondary electron image of ash filling pores and covering catalysts.

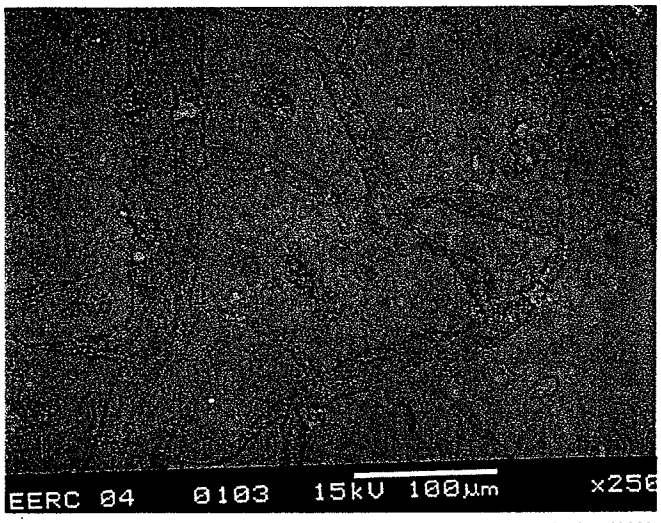


Figure 11. Scanning electron microscopy image of ash materials filling the pores of catalyst exposed to flue gases derived from the firing of Beulah lignite at Coyote Stations (Benson and others, 2005).

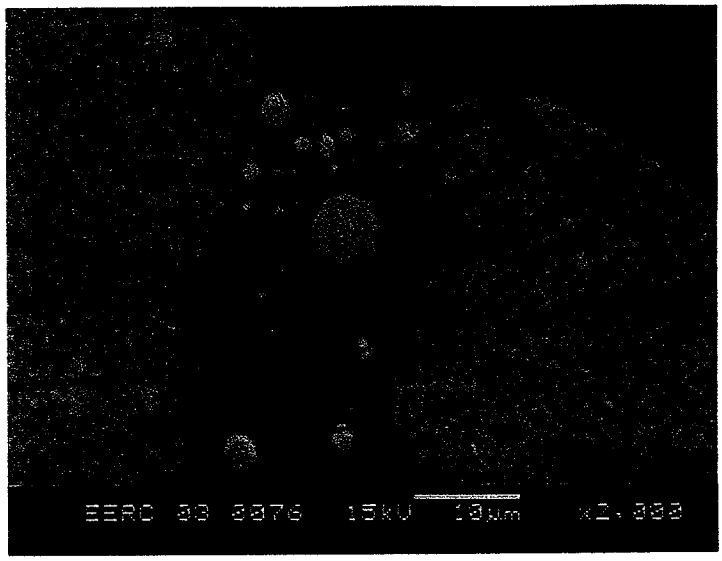


Figure 12. High magnification image of materials typical of ash filling pores that has sulfated and bonded.

Pyrosulfates are present in ash deposits and will likely form in SCR catalysts. Melting points for pyrosulfates between 535° and 770°F have been reported in the literature (Singer, 1981). 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. The melting points of selected pyrosulfate phases are shown in Table 2.

The formation of pyrosulfates involves the following processes

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 – $Na_2SO_4 + SO_3 \rightarrow Na_2S_2O_7$

A diagram depicting the physical and chemical reactions involved in the filling and plugging of catalyst pores is shown in Figure 13 (Benson and others, 2005).

Table 2. Melting Points of Selected Pyrosulfate Compounds

A. 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

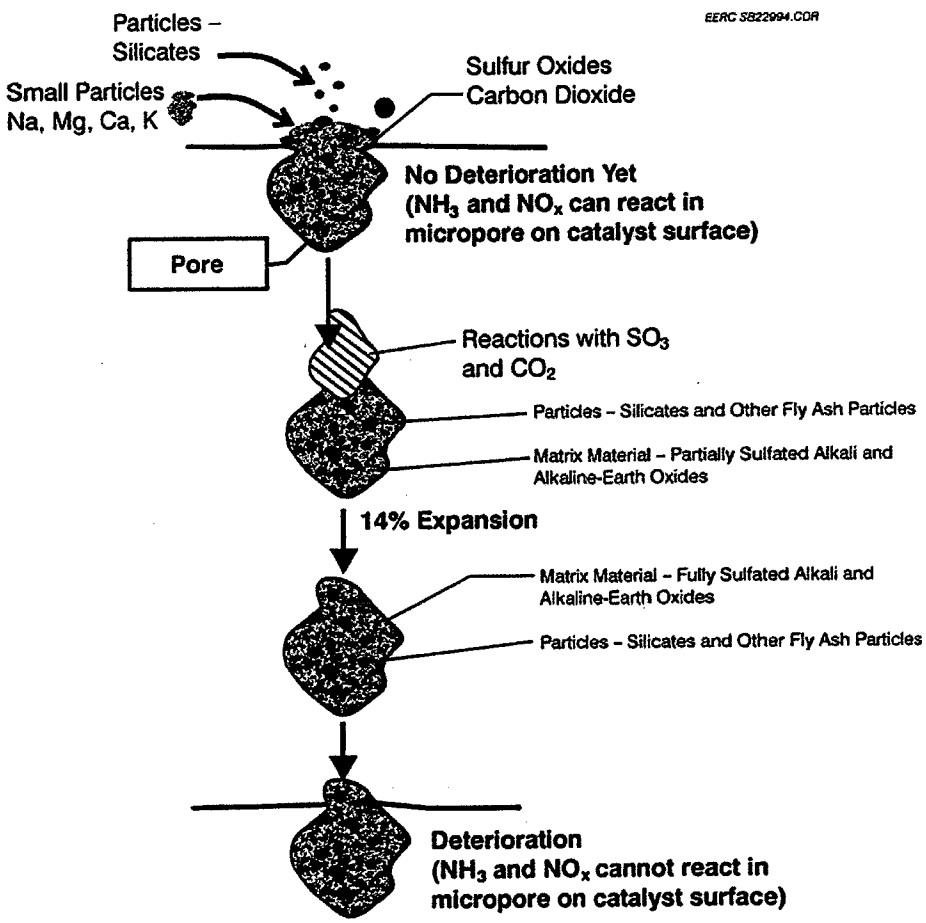


Figure 13. Overall mechanism of SCR Catalyst blinding (modified after Pritchard and others (1995)).

Sodium-related catalyst deactivation mechanisms

Alkali elements such as sodium and potassium are known to cause catalyst deactivation. Prichard and others (1995) indicate that the alkali elements can interact with the catalyst active sites and cause them to lose their activity as shown in Figure 14. They indicate that the degree of deactivation is dependent upon the concentration of alkali elements and the form of the alkali. Based on the evaluations conducted and/or reported by Cormetech (Prichard and others, 1995), Topsoe (1999), EPRI (Broske, 2005), and EPA (Mussatti, 2002) the water soluble form of the alkali is the problematic form since these alkali species are highly mobile allowing them to migrate into the catalyst. Cormetech (Prichard and others, 1995) incorrectly indicate the following:

> *"For the subject catalyst in coal-fired applications, it is our experience that this type of poisoning has a small impact, since most of the alkaline metals in the coal ash are not water soluble."*

This comment is very surprising and is likely indicative of catalyst vendor's level of understanding of lignite coals. Much work has been conducted for decades on the solubility of alkali and alkaline earth elements in coal ash. Sodium in Center lignite is associated in the groundwater and with the organic matrix of the coal (Benson and Holm, 1985; Schobert, 1995). Very little of the sodium is associated with the mineral fraction of the coal such as clays. During combustion, the sodium in the water soluble and organic association will vaporize and become dispersed in the gas stream and react with sulfur oxides to form soluble sodium sulfates species. Combustion Engineering conducted an analysis of the impact of soluble and organically associated sodium with fouling potential (Singer, 1981). The results of the analysis are summarized in Table 3. The soluble alkali shown for lignite and subbituminous coals is very high, with North Dakota lignite and Montana high-sodium subbituminous coals having the highest available sodium for low-temperature fouling processes.

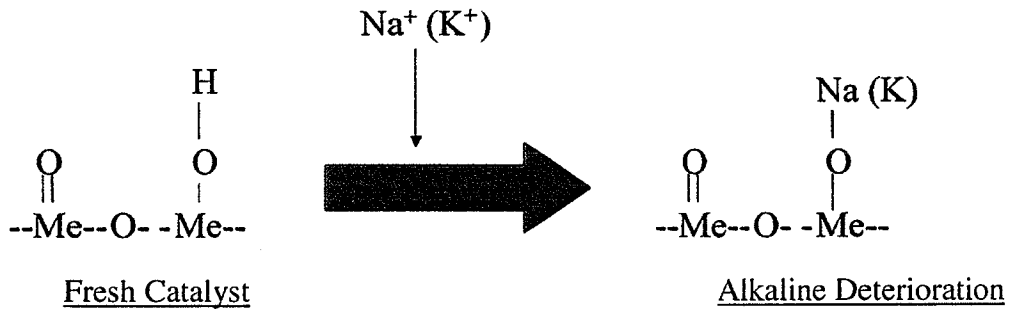


Figure 14. Alkaline (alkali) SCR catalyst deterioration mechanism (Prichard and others, 1995).

Table 3. Comparative Alkali Content Analysis for U.S. Coals (Singer, 1981)

Rank Region	Lignite ND	Sub B MT	Lignite TX (Yegua)	Lignite TX (Wilcox)	hvBb UT	hvAb PA	Lignite TX (Wilcox)
HHV, Btu/lb, Dry Basis	10640	12130	7750	9710	12870	13200	8420
Ash Composition (%)							
SiO_2	20.0	33.9	62.1	52.3	52.5	51.1	57.9
Al_2O_3	9.1	11.4	15.1	17.4	18.9	30.7	21.8
Fe_2O_3	10.3	10.8	3.5	5.3	1.1	10.0	3.9
CaO	22.4	21.0	6.2	9.4	13.2	1.6	7.1
MgO	6.4	2.7	0.7	3.2	1.3	0.9	2.1
Na_2O	5.0	5.8	3.6	0.9	3.8	0.4	0.7
K_2O	0.5	1.6	1.9	1.2	0.9	1.7	0.8
TiO	0.4	0.7	0.9	1.2	1.2	2.0	1.1
SO_3	21.9	12.0	6.1	9.6	6.2	1.4	4.4
Fouling Potential	Severe	High	High	Moderate	Moderate	Low	Low
Lb Ash/10^6 Btu, Dry Basis	9.0	4.6	43.3	20.1	7.9	10.2	34.4
Acetic-Acid-Soluble							
Sodium (Na, ppm)	3980	2680	9650	1030	1120	250	340
Potassium (K, ppm)	. . .	. . .	1230	85	85	. . .	110
Alkali in Ash, % Wt.							
Na_2O	5.0	5.8	3.6	0.9	3.8	0.4	0.7
K_2O	0.5	1.6	1.9	1.2	0.9	1.7	0.8
Equiv. Sol. Alkali in Ash, % Wt. of Ash							
Na_2O	5.58	6.45	3.88	0.71	1.49	0.15	0.16
K_2O	. . .	. . .	0.44	0.04	0.08	. . .	0.05
% Sol. Alkali of Total (Equiv. Sol. Na_2O)/ (Na_2O in Ash)	112	111	108	79	39	38	23
(Lbs Sol. Na)/ (10^6 Btu Fired)	0.374	0.221	1.245	0.106	0.087	0.018	.040
(Lbs Sol. Na)/(lb Ash/ 10^6 Btu Fired)	0.044	0.048	0.223	0.005	0.014	0.002	0.001

The following summarizes the state-of-the-art relative to the application of SCR for use in high sodium lignite combustion systems such as at the MRY plant.

- Coal properties
  - Center lignite coal contains organically associated sodium, magnesium and calcium
  - The levels of sodium in the Center lignite will remain constant and will likely increase in the future years
- Ash formation
  - Sodium vaporizes during combustion to form very small particles
  - Sodium is in a soluble form

- Catalyst properties
    - Catalysts have high porosity in the form of macropores and micropores that have active components dispersed within them allowing for NOx reduction reaction
    - Pitch of the catalyst appears to be the only change in geometry available to minimize deposition
    - Catalyst are prone to deactivation because of the presence of soluble sodium
- Ash transport in SCR catalyst
    - Ash particle transport mechanisms are dependent upon gas velocity
    - Particles greater than approximately 10 micrometers are transported to the surfaces of catalysts by inertial impaction mechanisms
    - Vapor phase and small particles are transported through diffusion processes into the pores of the catalyst across the stagnant gas boundary layer next to the surface
    - Small ash particles rich in sodium, calcium, and sulfur infiltrate deep into the catalyst pores causing blinding and plugging and possibly deactivation

The following are changes that could be made in future pilot testing and, based on the previously presented information, the impacts of those changes that could reasonably be anticipated to occur.

- Test catalysts with larger openings (greater Pitch)

  Impacts: The current recommendation (for the coal-fired industry in general) by catalyst vendors is to use catalysts that have a larger pitch. Using catalysts with a larger pitch will likely decrease the velocity through the catalyst and decrease the impaction rates of the larger particles. However, this does not address the key problem of vapor phase and small particle diffusion into the pores of the catalysts that is associated with the combustion of high sodium Center lignite. By decreasing the velocity, the gas boundary layer may be larger resulting in an increase in the diffusion processes resulting in increased deposition of the smaller particles into the pores. In addition, decreasing gas velocity will decrease the scrubbing action of impacting particles that aids in removing deposited ash particles.

- Test catalyst with modified pore structure that does not accumulate small particles

  Impacts: The use of these catalysts should have a positive impact on reducing catalyst poisoning and pore plugging. However, discussions with catalyst vendors and literature searches indicate that little or no work has been conducted on such formulations. Most of the work being conducted by catalyst vendors is focused on reducing SO_3 production and enhancements for mercury oxidation. As a result, these catalysts are not available.

- Enhanced cleaning technologies for removal of particles in the pores of catalysts

  Impacts: The use of acoustic horns appears to clean the surfaces as well as sootblowers on subbituminous and bituminous fueled boilers. However, this

technology has not been demonstrated on lignite fueled boilers. There is significant uncertainty in the ability of acoustic horns to clean the ash particles from the pores of the catalyst.

There does not appear to be a catalyst material that has shown significantly improvement over the past catalyst relative to the performance in high sodium containing system. The specific question was asked to Flemming Hansen (Hansen, 2007) as to whether improvements have been made in catalysts over the ones tested at Coyote station that warrant further testing. He indicated that no formulation or design changes have been made to improve their performance in high sodium containing flue gases.

The testing at Coyote station indicated that the macropores and the catalyst openings were plugged. The blinding of the catalyst from the Coyote station testing was so severe that the catalyst vendor could not make deactivation measurements. Cleaning the catalyst and measuring deactivation was not performed based on recommendation of the catalyst vendor. The reason for not cleaning and conducting the measurements were based on concerns expressed by the vendor that the results of such deactivation testing after cleaning would not provide meaningful data on deactivation rates.

At the present time, there is not sufficient evidence to indicate that further pilot testing, even though it could be significantly reconfigured from previous testing, would yield significantly different results from that of testing already conducted at the Coyote station. Additionally, there is nothing to suggest that further testing would necessarily result in catalyst samples being made available that would allow for the measurement of deactivation rates.

SCHEDULE BASIS FOR MINNKOTA'S DECISION NOT TO CONDUCT PILOT SCR TESTING

The CD requires that compliance with the "30-day Rolling Average NO_x Emission Rate" established as BACT in accordance with the CD be achieved for Unit 2 at MRYS not later than December 31, 2010. For the hypothetical case in which an SCR pilot test were conducted to potentially establish the technical basis for SCR application to the Units at MRYS, the following tasks would need to be completed prior to this date:

1. Design the SCR pilot test protocol and obtain concurrence of NDDH and EPA
2. Design, procure and install the pilot SCR
3. Conduct the SCR pilot testing and evaluate the results
4. Conduct a technical feasibility analysis of the boiler modifications that would be necessary for Units 1 and 2 to allow reduction of flue gas temperatures (which are currently well above the required range for SCR operation, as previously documented in Minnkota's submittals to NDDH) while maintaining the ability to dry the lignite as required for combustion.
5. Revise the BACT analysis based on the results of Steps 3 and 4 (hypothetically assuming that they concluded it was technically possible to install SCR) to establish the revised "30-day Rolling Average NO_x Emission Rate" based on the hypothetical use of SCR.

6. Receive the final determination from NDDH regarding the "30-day Rolling Average NO_x Emission Rate" representing BACT in accordance with the CD.
7. Incorporate the results of steps 3 through 6 (hypothetically assuming that they concluded it was technically possible to install SCR and established an SCR-based value for the "30-day Rolling Average NO_x Emission Rate") into a procurement specification for the SCR system in accordance with RUS requirements.
8. Procure the SCR system on a "furnish and erect" basis, obtaining a vendor guarantee that assured compliance with the BACT emission limit as set forth in Step 6.
9. Design, fabricate, and erect the SCR systems and the necessary boiler modifications, using the Contractor selected in Step 8.
10. Start-up and commission the SCR system for Unit 2 and achieve stable performance to allow continuous compliance with the BACT emission limit as set forth in Step 6.

Based on Burns & McDonnell's evaluation, the time required to complete these tasks would be approximately 65 months from initiation of Task 1. Thus it would not be possible to comply with the CD date certain of December 31, 2010 for compliance with the "30-day Rolling Average NO_x Emission Rate" established as BACT in accordance with the CD.

The estimate of 65 months duration to complete this process is based on the following assumptions for the duration of the individual steps:

Step 1 is assumed to require two months. It should be noted that the EPA and its consultants have claimed that the previous SCR pilot testing at Coyote was fundamentally flawed. Thus it is essential that this step be thoroughly and carefully conducted and documented in order to assure the "buy in" of the interested parties.

Step 2 is estimated to require six months.

Step 3 is estimated to require 24 months. It is believed that the collection of 18 months of data will be necessary to properly evaluate the technical feasibility of SCR at MRYS. Due to the operating characteristics of the Units and based on prior experience with pilot testing, it is believed that the duration of pilot testing needed to acquire 18 months of data will be 24 months.

Step 4 is estimated to require six months, based on consultation with the boiler OEM. It should be noted that although Step 4 is assumed to be performed concurrently with Steps 1 through 3, all other steps must be conducted sequentially. Also, it should be noted that the subsequent sequence is based on the hypothetical assumption that the results of Steps 3 and 4 are favorable to the technical feasibility of SCR.

Steps 5 and 6 are estimated to require two months each. Because no SCR vendor has experience with SCR operation on North Dakota lignite, the determination of an emission rate corresponding to the hypothetical use of SCR will require the dissemination of the pilot test results from the catalyst vendors (which are assumed to be active participants in the pilot SCR program) to the SCR system suppliers. This is because the establishment of a NO_x emission rate representing BACT will require at least a preliminary indication from the system suppliers that such a level can be guaranteed. It is assumed that the system suppliers will guarantee the

emission rate established in Step 6, and will otherwise respond favorably to the procurement process in Step 8.

The development of the technical specifications for the SCR procurement contract (Step 7) is estimated to require two months. The specifications must incorporate not only the results of the pilot SCR testing from Step 3 but the boiler modifications identified in the study conducted in Step 4. Again, the sequence assumes that it will be possible to find a feasible way of modifying the boilers to simultaneously achieve the flue gas temperature range required for SCR operation while continuing to achieve proper pre-drying of the lignite.

The period for bidding and award of the SCR contract (Step 8) is estimated to be four months. Typical bid period for a complex "furnish and erect" SCR retrofit contract such as this will be three months. One month is assumed for evaluation and negotiation.

For Step 9 it has been assumed that the period from award of the SCR contract to the completion of erection and tie-in will be 20 months. It is anticipated that the duration of construction of an SCR system in North Dakota will require somewhat longer than would be expected for other parts of the country due to the severity of the winter. Also, depending upon the complexity of the required boiler modifications, the construction period can be expected to be extended compared to a "typical" SCR project schedule which does not include the need for extensive boiler modifications.

The startup, commissioning and tuning of the SCR system (Step 10) has been estimated to require three months. It should be noted that concerns with the characteristics of the fly ash are anticipated to extend the time that would routinely be required for this step. Also, unlike most retrofit SCR projects completed to date in the U.S., this installation would be subject to a "not to exceed" emission limitation on a 30-day rolling average. Assurance that the limit could be continuously met would require more than the usual extent of operational tuning.

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OCT 2007
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Air Quality

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Re: Transmittal of EPA's Response to Minnkota's Letters Dated March 19, 2007 and April 23, 2007, Regarding the October 2006 NO_x BACT Analysis Study Report for Milton R. Young Station

Dear Terry, David and John:

The United States Environmental Protection Agency, Region 8 (EPA) submits this letter and the Enclosure to respond to letters dated March 19, 2007 and April 23, 2007 authored by Minnkota Power Cooperative, Incorporated (Minnkota) regarding the Burns & McDonnell (B&McD) Best Available Control Technology (BACT) Analysis for Nitrogen Oxides (NO_x) at Milton R. Young Station (MRYS), Units 1 and 2, prepared by B&McD for Minnkota (Minnkota BACT Analysis). The above identified two letters were submitted by Minnkota in response to letters sent by EPA to North Dakota Department of Health (NDDH), dated January 8 and 26, 2007, and were also in response to a letter from the NDDH dated February 1, 2007.

EPA appreciates the ongoing dialogue and exchange of information with NDDH and Minnkota on these very complex and important issues related to the appropriate NO_x control technology to be installed at MRYS Units 1 and 2. The meeting in Bismarck on May 23, 2007 with representatives of Minnkota was very useful. EPA also appreciates the efforts by you and your staff to seek a well-informed decision on this matter. The Enclosure contains a response from EPA's consultant, Roger Christman of Eastern Research Group, on technical issues related to Selective Catalytic Reduction (SCR) (Christman August 20, 2007 Memo). The Enclosure also contains EPA's detailed response to Minnkota's letters dated March 19, 2007 and April 23,

2007.

To briefly summarize the Enclosure, the Minnkota BACT Analysis is incomplete, and the determinations of technical infeasibility for the High–dust SCR, Low-dust SCR, Hydrocarbon Enhanced Selective Non-Catalytic Reduction (HE SNCR), Reburn with SNCR and Rich Reagent Injection NOx control technologies are incorrect. Minnkota has incorrectly interpreted and misapplied Chapter B of EPA's "New Source Review Workshop Manual – Prevention of Significant Deterioration and Non-attainment Area Permitting" (Draft October 1990) (NSR Workshop Manual) in its determination that these control technologies are technically infeasible. Furthermore, Minnkota has incorrectly utilized the results of the pilot testing conducted at the Coyote Station by the Energy & Environmental Research Center to find that SCR is inapplicable. Minnkota must evaluate these control technologies beyond step 2 of the process outlined in the NSR Workshop Manual.

The operational problems associated with the Coyote Station pilot test and the lack of catalyst deactivation data greatly diminish the usefulness of the test results in analyzing the technical feasibility of SCR at MRYS. EPA maintains that the results of the Coyote Station pilot test do not demonstrate technical infeasibility of SCR for utility boilers firing North Dakota lignite. Minnkota has not provided information and/or data in the original Minnkota BACT Analysis or in any of the subsequently delivered letter responses demonstrating that the differences between North Dakota lignite and other solid fuels would prevent the successful application of SCR at MRYS. EPA finds that the wealth of experience in the utility industry applying SCR to solid fuel utility boilers creates a presumption of technical feasibility at MRYS. Minnkota has not overcome this presumption. As such, EPA presently finds that the Minnkota BACT Analysis is incomplete, has not been carried out in accordance with Chapter B of EPA's NSR Workshop Manual, does not provide all of the information necessary for NDDH to make a BACT determination and does not contain all of the information requested by EPA.

EPA has received NDDH's letter dated September 21, 2007 transmitting Minnkota's paper entitled "Appropriateness of Conducting Pilot Testing of Selective Catalytic Reduction (SCR) Technology at Milton R. Young Station Units 1 and 2, for use in a NOx BACT Analysis" and is planning to review it. EPA remains committed to moving the BACT process forward so that Minnkota can meet the deadlines specified in the Consent Decree. For the BACT process to proceed, EPA believes NDDH should move past the question of technical feasibility for SCR and the other incorrectly determined technically infeasible control technologies and require Minnkota to complete the Top-Down BACT analysis for SCR and the other control technologies in accordance with paragraphs 24 and 65 of the Consent Decree. If you would like to discuss any of these matters, please call me at (303) 312-6776.

Sincerely,

Martin Hestmark

Martin Hestmark, Director, Air and Toxics
Technical Enforcement Program, ECEJ

Enclosure

cc: Eddie Sierra, Deputy Assistant Regional Administrator, ECEJ
Jeff Kodish, OECA
Ron Rutherford, OECA
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ERG

MEMORANDUM

TO: Hans Buenning, Albion Carlson, Doug Latimer, Martin Hestmark, Brenda Morris, EPA Region 8
Sounjay Gairola, Ron Rutherford, EPA/ORE HQ

FROM: Roger Christman, Eastern Research Group, Inc.

DATE: August 20, 2007

SUBJECT: Summary Discussion in Response to the Burns & McDonnell and EERC Reports (Minnkota, March 19, 2007 and Minnkota, April 23, 2007) and the Subsequent Meeting on May 23, 2007, at the Offices of the Division of Air Quality, North Dakota Department of Health (NDDH).

INTRODUCTION

ERG has been tasked by the U.S. EPA Office of Regulatory Enforcement to provide technical assistance to EPA Region 8 in evaluating a series of documents prepared by Burns & McDonnell (B&McD), and the Energy & Environmental Research Center (EERC) at the University of North Dakota, on behalf of Minnkota Power Cooperative, Inc. In response to the submission, in October of 2006, of a BACT Analysis for Milton R. Young Station (MRYS) and the appended *Ash Impacts on SCR Catalyst Performance* (Benson, October 2005), I prepared a memo (Christman, January 2007) addressing issues raised in the BACT Analysis and the Benson paper that were cited by Minnkota as rendering SCR technically infeasible at MRYS. My memo, along with EPA Region 8 and NDDH questions and requests for additional information were forwarded to Minnkota.

Minnkota provided a response to the ERG memo (Minnkota, March 19, 2007) and additional responses and information about a month later (Minnkota, April 23, 2007). These materials were reviewed by Region 8 personnel and ERG in preparation for a meeting with Minnkota at NDDH on May 23, 2007. A list of nine unresolved "core " issues were identified and were subsequently discussed at the May meeting. They are addressed below. Also, some of the discussion during a meeting on May 24, 2007, that included an SCR/North Dakota Lignite presentation by Sargent & Lundy (S&L), corroborated much of the EPA and ERG positions and will also be noted in the discussion here. Issues that appear to have been resolved prior to, or at the May 23 meeting are not discussed (e.g., popcorn ash).

The nine "core" issues include:

1. Center Mine ash content variability
2. Catalyst deactivation by sodium and regeneration difficulties.
3. Downtime for catalyst cleaning and change out.
4. Sticky ash.
5. EERC pilot test procedures/design.
6. Split air preheater.
7. B&McD low dust SCR assessment.
8. Texas Lignite comparison.
9. SCR vendor quote request.

DISCUSSION

1. Center Mine ash content variability.

At the May meeting, B&McD representatives and Dr. Benson continued to refer to the extreme **coal variability**, both in proximate analysis and ash constituent concentrations and continued to refer to ash contents as high as 25.5%. An examination of the actual data (analyses of more than 700 as-fired coal samples provided by Minnkota in 2003) shows that the coal ash content is not particularly variable, with more than 95% of the samples having an ash content between 7% and 15%. Well over 50% of the samples fall between 8% and 11%. The actual maximum content is just under 16%, not 25.5% as stated by B&McD. The higher figure is based on a single sample with none of the more than 700 other samples exhibiting an ash content greater than 16%. Examination of other data associated with the sample confirms that the ash figure is in error. Despite having a roughly average moisture content, the heat content of the sample in question is also roughly average. If the 25.5% ash figure was correct, the sample would have the lowest heat content of the total data set. It does not. In conclusion, the Center Mine coal does not have unusual variability in ash content and in no case has an ash content five times higher than PRB coal as B&McD has contended.

Along with the general discussion of ash variability, Dr. Benson introduced the concept of variability in the "acid-to-base ratio" of the ash (pages 7-9, Minnkota, March 2007) as having relevance to the technical feasibility of SCR as applied to North Dakota Lignite. He included two figures that display moisture and Base/Acid and an undefined "Cyclone Performance". The accompanying text refers to slag freezing events and the need to provide supplemental fuel. Although the ash fusion temperature and the ash viscosity at cyclone barrel temperatures (>2,500 F) are functions of ash composition and thus are sensitive to variations in that composition with time, there should be no impact on that ash behavior downstream at SCR temperatures. Dr. Benson does not, in fact, make a direct connection between his discussion of base-to-acid ratio and the functioning of an SCR system. B&McD also only mentions impact on "operation of the boilers at MRYS" (page 9) and makes no connection specifically to an SCR system. As a final note, I have been involved in one way or another with SCR since the early 1970's and I have

never heard or read anything about acid-to-base ratio of ash in any SCR document or discussion, prior to Dr. Benson's introduction of the subject.

2. Catalyst deactivation by sodium and regeneration difficulties.

Dr. Benson cited a paper by Khodayari as evidence that catalyst poisoned by potassium could not be regenerated and that the same would be true of sodium-poisoned catalyst (reference 12, Minnkota, March 2007). A careful reading of the paper shows that Khodayari achieved 90% to 110% recovery of the original reactivity of the catalyst. Further, Khodayari's PhD dissertation states that potassium, not total alkali, is the problem for SCR application to biofuel combustion. A paper authored by engineers involved in the application of SCR to biomass fuels cites Khodayari's work as evidence that catalyst activity can be recovered by washing and will result in reduced cost for biomass applications (Alstom, undated, ~2006).

Dr. Benson further states that work by Beck (reference 16, Minnkota, March 2007) established a deactivation correlation with sodium in ash. Again, a careful reading of the paper shows that sodium is only mentioned when the discussion addresses total alkali and Beck actually cites potassium and phosphorus as the primary poisons associated with a range of bio-materials that are burned for energy recovery. He concludes that additional research is needed to determine the relative contributions of phosphorus, potassium and sodium. His subsequent work focused entirely on phosphorus and did not address sodium at all.

A 2006 presentation covering work conducted by the University of Utah and REI on the application of SCR to low-rank coals concluded that "chemical poisoning is not important" for low-rank coals, but masking by fly ash is a problem. The study further concluded that the poisoning potential of the alkali materials ranked as: K>Na>Ca.

While Dr. Benson concludes that the sodium levels in North Dakota Lignite ash are so high as to render SCR technically infeasible, apparently others at EERC do not share that opinion and have researched the co-firing of biofuels with low-rank coals (EERC, Folkedahl, 2006). The intent of the study was to determine if the higher levels of alkali materials in the biofuel would accelerate the deactivation rate (which Dr. Benson concludes is already intolerably high). The final report states: "However, little is known of biomass firing with low-ranked coals, such as North Dakota Lignites and Powder River Basin coals." The report concludes that, although they experienced operating difficulties, the deactivation rate appears to be 1.7% to 2.6% every 1000 hours.

In summary, Dr. Benson misread the work of Khodayari regarding regeneration of alkali-poisoned catalysts. Both a careful reading of the cited Khodayari paper and some of his other publications confirm this, as does the Alstom paper and several recent papers by the catalyst regeneration vendors (Full-Scale Catalyst Regeneration Experience at the Coal-fired Indiantown Generation Plant, Bullock and Hartenstein, October 2003 and Regeneration Advances, McMahon, May 2006) and a comprehensive SCR technology survey (The First 100 GW of SCR in the U.S.- What Have We Learned?, Cichanowicz, Muzio and Hein, 2006). He also misread the Beck paper which, upon careful reading, does not shed much light on sodium poisoning, but rather, has a major focus on phosphorus and potassium. Work by the University of Utah and REI

further implicates potassium as having a greater poisoning potential than sodium. Although the high sodium content of Center Mine coal ash is an economic issue (it will contribute to catalyst deactivation), Dr. Benson provides no evidence that it will render SCR technically infeasible at MRYS.

As a final note, since catalyst deactivation due to alkaline materials is a "chronic," rather than "acute" phenomenon, deactivation depends on the total time and mass exposure. This dependency is probably not linear, since the overwhelming amount of ash in any installation does not deposit on the catalyst (it passes through the catalyst channels and ends up in the ESP hoppers or is emitted), but it is most appropriate to consider average values of chemical poisons. This is because the total exposure will be less than the average for about half the time and more than the average about half the time. The overall deactivation rate "averages out".

3. Downtime for catalyst cleaning and change out.

Although the downtime durations for boiler cleaning cited by Minnkota are not long enough to permit a complete catalyst change out, they do in some cases approach the 3 day turnaround that Flemming Hansen cited in the April 16, 2007 phone conversation with Region 8 personnel. Additionally, the boiler cleaning outages would afford the opportunity for some cleaning of the catalyst four times a year; a luxury not available at most year-round SCR installations. This would contribute to both catalyst life and lower pressure drop. Also, during discussions with S&L, their engineers pointed out that the system can be designed to facilitate faster catalyst change out by providing wider than normal platforms at each catalyst layer level, thereby allowing replacement modules to be pre-positioned as the spent modules are removed. If one assumes a rather extreme short catalyst life of one year and if the change out is coordinated with a boiler cleaning outage, the SCR unit would only contribute one or two days of downtime per year.

4. Sticky ash.

Much light was shed on the topic of sticky ash during the S&L presentation and discussion. Sticky ash (in PRB applications) was described as having a steeper angle of repose (less slump) and thus tended to accumulate in large amounts on structural members and subsequently falling onto the tops of the catalyst layers in piles. These piles can not be readily broken down by sootblowing (steam or horns) and eventually require shutdown for manual cleaning. S&L's engineering response has been to eliminate flat, horizontal surfaces (weld an inverted vee on the tops of I-beams and angle-iron members that are above the catalyst layers) and aim sonic horns at areas prone to ash accumulation. When asked directly if sootblowing (steam or horns) would effectively prevent plugging from the ash that is normally entrained in the flue gas (not falling accumulations) the answer given was "yes".

5. EERC pilot test procedures/design.

Page 7 of my previous memo (Christman, January 2007) contains a detailed discussion of the EERC test at the Coyote Station, all of which remains valid. In summary, the catalyst should

have been cleaned with some frequency so that it could be continuously exposed to flue gas. Tests of the scale at Coyote are not useful in determining plugging potential and the attempt at simulating sootblowing was not effective. By EERC's own admission (and confirmed by Hansen during the April 16, 2007 call) the plugging was a result of ash accumulations falling onto the catalyst (see "sticky ash", above). Mr. Hansen also confirmed that the catalyst pitch at Coyote (6 mm) was too small. S&L presenters suggested that a 10 mm pitch might be required for North Dakota Lignite applications.

In my January memo and at the May 23rd meeting, I stated that the Coyote test was so flawed that it did not provide any meaningful data bearing on the issue of technical feasibility. During the S&L discussion on May 24th, Bill DePriest was asked, by an NDDH participant, what he thought of the EERC test at Coyote. Even though he was clearly uncomfortable criticizing the work of another organization, he stated that the test produced no useful information.

6. Split air preheater.

The discussion of the split air preheater approach contained in the Minnkota March 19th document seems a bit ambivalent, implying first that it couldn't be done and later stating that conceptually, it could be done (page 15, Minnkota, March 2007). Further evidence that it is not infeasible is found in the fact that the SCR retrofits a New Madrid (two large, PRB-fired cyclone boilers) included replacement of the tubular air preheaters with new regenerative air preheaters with enamel-coated baskets. I do not believe that B&McD indicated infeasibility during the meeting on May 23rd, but they did insist that BACT would not require substantial rebuild of the source (boiler).

7. B&McD low dust SCR assessment.

I am not qualified to comment on the B&McD discussion of the steam extraction for flue gas reheat for the low dust application. I do not believe that resort to the low dust approach is warranted, since ash issues should be manageable.

8. Texas Lignite comparison.

George Offen's letter (EPRI, September 7, 2006) provides some useful insights, particularly with regard to erosion. S&L personnel confirmed that Texas Lignite ash is more erosive that North Dakota Lignite ash. This means that the TXU pilot test currently underway should resolve any concerns regarding erosion at a future MRYS SCR installation.

9. SCR vendor quote request.

The volume of information provided in the B&McD vendor quote request will be troubling to the vendor's sales staff since they are not likely to invest a great deal of time in something that is clearly not meant to generate a sale in the foreseeable future. Also, by including a discussion on the enforcement situation, it is clear that the requestor is looking for support for the technical infeasibility argument. The ability to provide flue gas at the appropriate temperature is not

discussed and the startup/shutdown requirements may be unreasonable. I do not expect the exercise to produce any meaningful results.

ENCLOSURE

RESPONSE TO EERC AND C AND B&McD's MARCH 17, 2007 LETTER RESPONDING TO EPA REGION VIII COMMENTS – JANUARY 8, 2007

I. Introduction and Summary of EPA's Preliminary Analysis

EPA's January 8, 2007 Comment:

EPA's preliminary analysis is that the B&M study lacks sufficient information within the BACT analysis. Specifically, the study excludes Selective Catalytic Reduction (SCR) as a technically feasible control option at step 2 of the five-step Top-Down analysis, while not presenting NO_x control effectiveness or catalyst activity data. As a result, B&M fails to rank SCR against other control options in terms of control effectiveness at step 3, and fails to analyze costs of SCR versus other control options at step 4. EPA questions the reasons cited by B&M for technical infeasibility of SCR. Furthermore, based on a survey of SCR vendors described later in this report, EPA found there are vendors that will offer performance guarantees for this type of application. Further information should be requested, to support the analysis with respect to SCR.

B&McD's March 13, 2007 Response:

.....The EPA's NSR Manual does not specifically define the operating parameter or performance measure that a particular NO_x control technique or technology would have to achieve to satisfy "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 order for said alternative to be excluded from further consideration.

The severe accumulation of ash and blinding in the Coyote station slipstream SCR catalyst field test after 2 months was documented in Dr. Benson's referenced technical paper. The evident failure of the Coyote slipstream SCR catalyst field test to avoid severe catalyst fouling and ash accumulation led Burns & McDonnell to believe that if such results were routinely encountered at a full-scale high-dust SCR catalyst installation during operation on a North Dakota lignite-fired cyclone boiler, aggressive on-line cleaning and/or frequent extended forced outages would be needed to remove ash accumulation or remove the catalyst for cleaning in order to restore full unit output and catalyst NO_x reduction effectiveness. Either or both of these maintenance activities could damage the catalyst and/or require it to be frequently replaced.

Two months between SCR catalyst maintenance activities would be an extremely short operating cycle time compared to 36 months typically experienced at other SCR installations. Burns & McDonnell interpreted these field test results as "empirical data showing the technology would not work on the emissions unit under review" for technical infeasibility purposes. Eliminating technically-infeasible alternatives prior to ranking the feasible controls based upon control effectiveness, and then evaluating the impacts of implementing only feasible control techniques and technologies follows the BACT process.....

EPA Response:

As articulated in the January 26, 2007 letter related to other widely-used NO_x control options that were eliminated in Minnkota's BACT analysis based on technical infeasibility, EPA believes the Minnkota BACT analysis for SCR should begin with the presumption that SCR is technically feasible, since the technology has been widely demonstrated on utility boilers. This presumption is based on the "technology transfer" discussion in the NSR Workshop Manual,[1] other EPA guidance documents,[2] and the fact that hundreds of SCR systems have been successfully installed on utility boilers worldwide. The NSR Workshop Manual and other EPA guidance clearly places a substantial burden of proof on the applicant to show that, based on a comparison of the physical and chemical characteristics of the exhaust gas stream under review and the sources to which the technology had been previously applied, the technology would be technically infeasible. EPA agrees that the NSR Workshop Manual does not specifically define the operating parameter or performance measure that a particular NO_x control technology or technique would have to meet in order to satisfy the criterion. However, given the sheer number of successful SCR systems in operation at utility boilers today, EPA believes this burden of proof is considerable on the part of Minnkota and should include quantitative evidence that such unresolvable differences do exist that would render the technology unsuccessful at controlling NO_x.

The qualitative evidence provided to date by B&McD and EERC demonstrates that there are certain factors relevant to MRYS that will require engineering design considerations to make an SCR installation workable; however, considering each SCR system design for a specific facility has to be customized to some extent, this situation is hardly unique. Additionally, nothing has been provided that would demonstrate that SCR would be an ineffective means of NO_x control at MRYS. B&McD's belief is that the pilot test results from Coyote Station show that a full-scale SCR installation at MRYS would require "aggressive on-line cleaning and/or

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1 See NSR Workshop Manual page B.19: "Unless significant differences between source types exist that are pertinent to the successful operation of the control device, **the control option is presumed to be technically feasible unless the source can present information to the contrary.**" (Emphasis added)

2 See June 15, 1989 letter from Gary McCutchen (EPA Office of Air Quality Planning and Standards, New Source Review Section Chief) to John Daniel (Department of Air Pollution Control, Commonwealth of Virginia): "Another point worth mentioning is the area of technology transfer. We have heard that some applicants are attempting to define gas streams and source types far more narrowly than common sense would dictate in an effort to avoid certain controls. For example, an applicant might say that NOx controls have been applied to a 30 and 70 MW coal boiler, but not a 45 MW coal boiler; that the control technology has been applied to pulverized and fluidized bed units, but not to spreader stokers; or that the technology has never been applied to the particular mix of, say wood and coal planned for that unit. Such arguments should be closely scrutinized and the applicant should explain fully not only what is different about the gas stream (if the control technology being analyzed is an add-on control), but also why that difference precludes transfer of that control technology to the proposed source. The burden of proof should be relatively high in order to prevent circumvention of reasonable technology transfer by the selection of some slightly different unit." http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/finlbact.pdf

frequent extended forced outages." While this may or may not be the case, such conditions do not undermine the conclusion that SCR should still be considered technically feasible.[3] EPA did acknowledge that such real costs associated with operational realities of the boiler and fuel type in an SCR application at MRYS can be accounted for through the cost evaluation under step 4 of the BACT analysis.[4] EPA does not view additional maintenance and operational measures that would be required at MRYS compared to other facilities to be justification of technical infeasibility. Again, the burden of proof is considerable in the case of demonstrating infeasibility of SCR for a utility boiler due to the large number of systems currently in operation at utility boilers.

B&McD has apparently interpreted the pilot testing experience at Coyote Station to mean that an SCR installation at MRYS would require "SCR catalyst maintenance activities" every two months and that this constitutes "empirical data showing the technology would not work on the emissions unit under review."[5] B&McD states that this time period "would be an extremely short operating cycle time compared to 36 months typically experienced at other SCR installations." EPA does not believe B&McD's use of the Coyote Station pilot testing maintenance requirements is an accurate means of predicting full-scale maintenance requirements. The EERC report indicates that aggressive catalyst cleaning and maintenance measures were also taken at the Baldwin and Columbia Stations during the initial months of the pilot testing and that significant ash accumulation, catalyst plugging, and pressure drop increases occurred during the course of the six-month test at both facilities. Baldwin and Columbia Stations both burn PRB coal, which is also burned at many full-scale utility boilers currently operating SCR systems with typical maintenance cycles. EPA believes B&McD's conclusions regarding the use of the "empirical data" from the Coyote Station pilot-scale testing is not relevant for an analysis of technical feasibility, and fails to consider the observations on catalyst maintenance frequency and pressure drop trends from the Baldwin and Columbia Station pilot tests. A comparison of these findings for all three facilities is presented below.

During the testing at the Baldwin Station, "(a)t 2-month intervals, a section of catalyst was removed and replaced with a new one."[6] The narrative indicates that catalyst plugging at Baldwin had also occurred during the first two months, as the "pressure drop steadily increased."[7] The report describes that during the remainder of the test (months 2-6), pressure drop was highly variably but maintained within a range of 0.6 and 0.8 inches of water "due to the installation of fresh catalyst section and leaving two thirds of the catalysts in place that were

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3 See pages B.19 and B.20 of the NSR Workshop Manual: "Where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible."

4 See page 6 of EPA Region 8 Preliminary Analysis of Burns and McDonnell BACT Analysis for Nitrogen Oxide at Milton R. Young Station, Units 1 and 2, January 8, 2006.

5 See page B.20 of the NSR Workshop Manual which indicates empirical data can be used in making determinations of technical feasibility.

6 See Appendix B, Page 19 of October 2006 Minnkota BACT Analysis Study for MRYS.

7 See Appendix B, Page 19 of October 2006 Minnkota BACT Analysis Study for MRYS.

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."[8] Hence, based on B&McD's reasoning, the SCR pilot testing at Baldwin would provide empirical evidence demonstrating that a full-scale SCR installation on PRB facilities would be infeasible, especially at the typical 36-month operating cycles for major maintenance. In fact, the EERC report suggests that when a section of catalyst at Baldwin was changed out every two months to deal with the increase in pressure drop caused by plugging, low NO_x conversion for the SCR would be likely. Based on the catalyst maintenance requirements and pressure drop data, B&McD would presumably conclude that the pilot testing at Baldwin Station showed that a SCR system operating on PRB coal would require significant and frequent catalyst maintenance and replacement and that the NO_x reduction would be limited, much like the results of the Coyote Station testing.

The final test report describes the catalyst reactivity test results for catalyst samples at 2, 4, and 6 months of operation at Baldwin Station.[9] The two month sample "had no noticeable loss of reactivity compared to the reference catalyst. After four months, the reactivity was 96% of the reference, and after six months, the reactivity had dropped to 84% of the reference catalyst." It does not appear there is any real correlation between the pressure drops observed at Baldwin Station and the measured activity of the catalyst. The pressure drop did not steadily increase as the reactivity decreased during the 4 and 6 month intervals. While there were some temporary variations, the pressure drop throughout the test was in the range of 0.6-0.8 inches of water. The most prolonged period during which the pressure drop was higher than 0.8 inches of water was during the first two months, when no deactivation occurred.

For the Columbia Station, there was also aggressive reactor cleaning and catalyst replacement within the six-month period of the test. The EERC report in Appendix B of the Minnkota BACT Analysis does not provide as much information as is contained in the *Fuel Processing Technology* article describing the same pilot testing. The *Fuel Processing Technology* article includes a graph of pressure drop for the entire six months of testing, whereas the Appendix B EERC report only shows the pressure drop graph for the first two months of testing. It is unclear why this additional data was not part of the Appendix B report, but the entire data set does show there were significant increases in pressure drop after the first two months of the test. According to the *Fuel Processing Technology* article, there was "a rapid increase in pressure drop across the catalyst at about 3000 h of operation, and aggressive pulsing brought it down to 0.4 in. of water until the catalyst section was changed out at about 3200 h. After cleaning the reactor and replacing one catalyst section, the pressure drop was about 0.3 but

8 See Appendix B, Page 19 of October 2006 Minnkota BACT Analysis Study for MRYS.
9 Final Report for JV Task 31 – Evaluation of Potential SCR Catalyst Blinding During Coal Combustion and Add-On: Impact of SCR Catalyst on Mercury Oxidation in Lignite-Fired Combustions Systems, November 29, 2004, page 41.

increased to over 0.6 in of water up to about 4100 h. 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 in. of water within 500 h."[10] Most of this paragraph describing the entire 6 months of the test does appear in Appendix B of the EERC report, with the exception of the first sentence. In any case, it appears as though significant plugging also occurred during the Columbia Station pilot test that required aggressive on-line cleaning and catalyst replacement. The problems first appeared at about four months and then reoccurred in much shorter time intervals. These time frames, while longer than that observed at Coyote Station, are obviously much shorter than the 36-month operating cycle described by B&McD for normal SCR maintenance.

Additionally, Columbia Station catalyst reactivity testing showed 93% reactivity at two months, 90% at four months and 90% at six months.[11] Again, there does not seem to be a clear correlation between pressure drop readings through the six months of pilot testing at Columbia Station and the catalyst reactivity testing. During the first two months, pressure drop readings were generally between 0.4 and 0.6 inches of water. During months two through four, pressure drop was generally higher, between 0.6 and 0.8 inches of water. During the final two months, pressure drop was more varied, but generally between 0.4 and 0.6 inches of water. It does not appear that there was any clear relationship between degree of pressure drop and the level of reactivity retained by the catalyst. Furthermore, while the "Columbia Station showed more significant accumulation and plugging than the Baldwin Station,"[12] the catalyst reactivity for Baldwin Station decreased more than at Columbia Station over the course of the six months of pilot testing (84% vs.90%). Again, it does not appear that the qualitative observations from the pilot study for Baldwin and Columbia Stations correlate well with the catalyst reactivity testing results, which were not included in Appendix B of the Minnkota BACT analysis.

For the Coyote Station, EPA agrees that the plugging and pressure drop observed during the pilot test were more pronounced and occurred quicker than what was observed at the two facilities burning PRB coal. Additionally, based on the deposition sampling, EPA agrees there is evidence that sodium was a factor in the plugging at Coyote, where it did not appear at the other two facilities. However, EPA disagrees that these test results can lead to a conclusion that extended forced outages would be needed at two month intervals as stated by B&McD in Minnkota's March 19, 2007 letter.[13] The results of the catalyst deactivation testing at Baldwin

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10 See Page 594, *Fuel Processing Technology 86 (2005) 577-613*, "SCR Catalyst Performance in Flue Gases Derived from Subbituminous and Lignite Coals" (Accepted July 2004)

11 Babcock-Hitachi K.K "Test Results of Catalyst Samples for Energy & Environmental Research Center", April, 2005, Table 3.

12 Final Report for JV Task 31 – Evaluation of Potential SCR Catalyst Blinding During Coal Combustion and Add-On: Impact of SCR Catalyst on Mercury Oxidation in Lignite-Fired Combustions Systems, November 29, 2004, page 29.

13 Page A1-30 of October 2006 Minnkota BACT Analysis Study for MRYS indicates that the anticipated catalyst life for SCR at MRYS would be 2-12 months, "requiring extended, frequent outages for replacement."

and Columbia Stations showed no clear correlation between magnitude of pressure drop and the degree of catalyst deactivation at each plant. Also, the qualitative observations on catalyst plugging did not correlate to the degree of catalyst deactivation for Baldwin and Columbia Stations relative to one another. Furthermore, given that the two facilities burning PRB coal required similar maintenance measures and schedules to Coyote Station, EPA questions how the maintenance activities (and their timeframes) required during the pilot testing at Coyote Station can be significantly distinguished from the Baldwin and Columbia Stations burning PRB coal. EPA does not agree that it is correct to define catalyst replacement requirements associated with full-scale SCR at MRYS based on the pilot testing experience at Coyote Station.

Additionally, based on a July 2, 2004 conversation between Jim Standt of Andover Technology Partners and Flemming Hansen of Haldor Topose, the sudden build up of flyash on the catalyst face that occurred during the pilot testing at Coyote Station was determined to be caused by the accumulation of ash upstream of the catalyst and sudden dropping of that accumulated ash onto the catalyst face.[14] Thus, the initial pressure drop experienced during the pilot test at Coyote Station might have been largely due to conditions that would not exist, and/or could be avoided through design, on a full-scale application of a SCR system. This further calls into question the applicability of the pressure drop trends experienced during the pilot testing to full-scale SCR applications and their catalyst maintenance requirements.

Based on the above comparison of the pilot testing results presented by EERC, it is unclear to EPA that any definitive conclusions can be extrapolated from the results about SCR technical feasibility and/or the timing or extent of SCR maintenance requirements and boiler outages for these three facilities, as was done by B&McD for MRYS. Clearly, the two facilities operating on PRB coal experienced catalyst plugging that required extensive and aggressive cleaning measures within timeframes that, if applied directly to anticipated maintenance at full-scale operation, would not be consistent with real full scale experience at numerous boilers burning PRB coal. EPA knows that there are successful applications of SCR systems to utility boilers burning PRB coal. **Hence, EPA does not believe it is reasonable to directly apply the catalyst maintenance and replacement experience from the pilot test to a full-scale application at MRYS.**

Based on B&McD's assertions about expected maintenance requirements and schedules for MRYS based on the Coyote results, a facility burning PRB would also be expected to encounter significant plugging, which would require aggressive on-line cleaning, catalyst replacement, and forced boiler outage periods within the initial months of installation. EPA knows from experience that the issues facing facilities burning PRB coal, while real and significant, have been dealt with successfully. Therefore, EPA believes the pilot testing was either designed in a way that does not accurately reflect full-scale SCR catalyst plugging and/or mitigation measures

14 August 20, 2004 Memorandum from Jim Staudt (Andover Technology Partners) to Sikander Khan (EPA), "SCR catalyst testing on ND Lignite"

currently known to exist, or that additional measures could have been taken beyond what was attempted during the pilot testing to keep the catalyst face clean and mitigate the effects of catalyst plugging. To that end, although it was mentioned in the preliminary EPA comments, B&McD has not provided a response to EPA's statements regarding the normally observed pronounced ash deposition during pilot testing, the small catalyst pitch used at Coyote Station and how a larger pitch might have affected the test results, and how the air pulsing did not properly represent sootblowing capabilities on a full-scale SCR application. In summary, EPA does not agree with conclusions drawn from the pilot testing presented in Minnkota's March 17, 2007 letter related to catalyst maintenance and replacement requirements and the related forced boiler outages to accommodate these activities. As an alternative to relying on these pilot test results, it would be preferable for Minnkota to work with catalyst and SCR design companies to analyze how the sodium deposition at MRYS would affect catalyst maintenance and replacement requirements and schedules.

EERC March 19, 2007 Response:

We spoke to Flemming Hansen of Haldor Topsoe, an SCR catalyst vendor, regarding providing performance guarantees. After describing the characteristics of Center lignite, specifically issues related to sodium, they were very concerned regarding guaranteeing performance. Based on the conversation, it became evident that EPA representatives may have not indicated the levels of sodium and the form of sodium in the coal. Haldor Topsoe indicated that the sodium was a major concern and that it causes deactivation, especially the organically associated form. They indicated that they had some experience and found significant deactivation of coupon samples after 6000 to 7000 hours of operation with a coal having elevated levels of sodium.

EPA Response:

EPA also spoke with Flemming Hansen regarding the feasibility of an SCR installation at MRYS and the nature of the SCR pilot testing at the Coyote Station conducted by EERC. EPA asked Mr. Hansen about the effects of sodium on SCR catalyst performance. Mr. Hansen said the sodium ion can poison catalyst because it prevents the ammonia from interacting with it. He also estimated that sodium catalyst poisoning limits the life of the catalyst to roughly one year. At that point, the catalyst would need to be replaced or washed/rejuvenated.

Mr. Hansen indicated that the only experience Haldor-Topsoe has had with lignite coal was the pilot testing performed at the Coyote Station conducted by EERC. However, they did run some catalyst "test coupons" at the Wisconsin Electric Power (WE Energies) Presque Isle Station, which burns Powder River Basin coal with sodium levels similar to North Dakota lignite. Mr. Hansen recollected that there was a significant difference in the deactivation of the test coupons upstream of the particulate control device (ESP) compared to downstream of the ESP at Presque Isle.

Mr. Hansen said he recalled there were problems during the Coyote Station pilot test because the reactor became quickly plugged with flyash causing rapid increases in pressure drop. Mr. Hansen said that the pressure drop was mainly caused by duct-wall ash accumulations dropping on the catalyst face. Mr. Hansen recalled that problems with the sodium poisoning were secondary compared to the ash plugging problems. He stated that ash plugging is a problem of pilot-scale testing and would not be a real full-scale application issue. He said that he was aware that actual operations at plants burning PRB coal perform much better than the pilot tests would indicate.

Mr. Hansen said that, in hindsight, the pilot test should have been performed differently. Mr. Hansen stated that changes to the pilot test at Coyote Station, such as the use of a higher pitch catalyst, could have helped reduce, but not entirely eliminate, the impacts of ash plugging. Additionally, he said the pilot test did not have good simulation of full-scale sootblowing. If the test were to be redone, a better effort could also be made to keep the catalyst face clean.

Mr. Hansen said the pilot testing at Coyote Station was inconclusive in terms of determining whether SCR would be technically feasible on North Dakota lignite. Mr. Hansen said that pilot tests often have problems that can be overcome at the full scale. Mr. Hansen said that Haldor Topsoe would not rule out bidding on a project that involved North Dakota lignite and that they would primarily look at the computer flow modeling for the specific coal analysis and boiler and evaluate whether there are available mitigation options to address any significant technical issues indicated by the analysis. Mr. Hansen said that there "are many tools in the toolkit" to address SCR technical issues. For North Dakota lignite, with its high ash and sodium content, Mr. Hansen said that Haldor Topsoe would likely consider such options as screens, very good soot blowing (steam assisted) and a high catalyst pitch. Mr. Hansen said and/or implied that an SCR could be designed to work with the specific characteristics of North Dakota lignite through proper reactor sizing, pitch sizing, steam soot blowing, and proper regeneration schedule. He gave a rough estimate that the SCR system could be designed (larger) to accommodate a catalyst replacement schedule of about every year.

EPA asked Mr. Hansen how he would weigh the results of the pilot testing at Coyote Station. Mr. Hansen said that he would have to go back and look at the Coyote Station test results and see if there was any useful information to consider. Mr. Hansen said and/or implied that the coal profile information and the results of computer flow modeling would be more critical than the Coyote Station pilot test results in any evaluation of bidding a project with North Dakota lignite.

Mr. Hansen was unaware that Haldor Topsoe sent emails to EPA Headquarters stating that Haldor Topsoe (and two other catalyst vendors) could provide guarantees for the MRYS coal. However, he sent an email to a consultant to EPA in 2004 stating in general they could propose SCR catalysts for North Dakota lignite assuming certain criteria are met. He had also talked with that consultant at that time about the fact that pilot plants have problems that full-scale SCR systems do not.

II. EPA Case-Specific Review of Burns & McDonnell & EERC Technical Feasibility Analysis for Selective Catalytic Reduction

A. High-Dust SCR

B&M has eliminated High-Dust SCR as technically infeasible due to issues described below. B&M's analysis utilizes a report by the Energy & Environmental Research Center (EERC). EPA's response on each issue is also presented below

1. Ash Deposition Issue Raised by Burns & McDonnell:

EPA's January8, 2007 Comment:

The concern about high amounts of ash material causing blinding of macro-pores in the catalyst is real but solvable. Strides in catalyst formulations, catalyst management systems, and recently, catalyst regeneration processes, have all combined to lower the overall cost contribution of both initial and replacement catalyst in modern SCR systems.

EERC March 19, 2007 Response:

EPA states that the high amount of ash materials causing blinding of macropores in the catalyst is real but solvable. We spoke to Flemming Hansen of Haldor Topsoe, a catalyst vendor, regarding what has been done to deal with the problems of high-sodium coals with regard to advanced formulations and catalyst regeneration, and he was not aware of any work that had advanced SCR systems for high-sodium applications.

Regeneration has been attempted in Europe with SCR catalysts exposed to biomass with high K (similar in chemistry to Na), and they had some significant problem in recovering reactivity.

EPA Response:

EPA is also not aware that any catalyst formulations have been developed to deal specifically with the issue of sodium. However, the reference cited by EERC (Khodayari and Odenbrand, 2001) does not indicate that the biomass plants had significant problems in reactivity recovery. As indicated in the August 2007 Christman Memo, the Khodayari paper actually indicates that 90-110% of the original catalyst activity was recovered.

B&McD March 19, 2007 Response:

It is unclear whether EPA's claimed SCR catalyst improvements cited would translate into preventing the catalyst layers from being susceptible to macro-pore blinding and plugging by calcium-based compounds and the impact on the individual catalyst reaction sites from sodium-based compounds discussed in Dr. Benson's referenced technical paper. The EPA cites no published technical literature that describes the results of testing that definitively documents how long currently available SCR catalysts can survive and provide effective NOx reduction when exposed to the flue gas and flyash constituents exhausted from combustion and operation of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application such as would be the case at Milton R. Young Station.

EPA Response:

As described earlier, the burden of proof is on Minnkota to demonstrate SCR would be technically infeasible at MRYS. The BACT process does not require that the reviewing agency demonstrate that a technology would work for the exact type of installation under review, especially when the technology has been well documented to be technically feasible for the source category under review.

EPA had asked Minnkota to look further into the engineering solutions currently available and determine whether or not the macro-pore plugging issues described in the EERC report could be effectively managed. It does not appear that these engineering solutions were given much consideration. Without addressing the available engineering solutions to deal with macro-pore blinding and plugging, Minnkota has not met the significant burden of proof demonstration EPA believes is required for showing SCR is not a technically feasible control option for NO_x at MRYS.

a. Comparison of MRYS to SCR Systems Operating on Powder River Basin Coal

EPA's January 9, 2007 Comment:

Even though the chemical compositions of PRB ash and Center Mine coal ash are very similar, particularly for the specific constituents of concern for catalyst deactivation, the quantity of ash in the Center Mine coal is more than twice as high on a per MMBtu basis. However, for a cyclone boiler, only

about 30-50% of the ash ends up as fly ash at full load (less at lower loads) and for a wall or corner-fired pulverized coal boiler (PC boiler), about 80% of the ash ends up as fly ash. The result is that SCR catalyst in a PC boiler PRB application is exposed to similar quantities of the major constituents of concern (alkaline material) as a catalyst would be exposed to at MRYS. The B&M analysis also suggests that a linear comparison of theoretical total ash or ash constituent rates to SCR catalyst deactivation rates can be made. Although EPA does not believe this to be the case and B&M has not presented any evidence of a quantitative relationship between ash loading and SCR catalyst deactivation rates, EPA has nevertheless examined B&M's arguments related to ash loading.

Table 1 below shows a comparison of the total ash loading for different boiler designs for North Dakota lignite, assuming a reference unit of 1.0 lb/MMBtu for lignite, lignite will have twice the ash content on a per Btu basis, and the conversion to flyash will be 30-50% for cyclone boilers and 80% for PC boilers. As can be seen from this comparison, the theoretical flyash loading for a PC boiler firing PRB boiler (0.4 lb/MMBtu) will be in the same range as what would be expected for a cyclone boiler firing North Dakota lignite (0.3-0.5 lb/MMBtu)……Deactivation depends on the total time and mass exposure, and the PRB PC boiler data are extremely relevant to evaluating SCR feasibility for North Dakota lignite……Table 1 shows that, on a lb/MMBtu basis, total theoretical flyash loading at the economizer exit of a cyclone boiler firing lignite would be very similar to that of a PC boiler firing PRB coal.

Another alkaline constituent that has been a concern is calcium, which can react with SO_3 to plug pores as $CaSO_4$. This has been a much-studied problem and the mechanism involves the calcium-containing particle getting "caught" in a macro-pore of the catalyst and subsequently reacting with SO_3 in the flue gas. The resulting $CaSO_4$ particle is larger in volume than the CaO particle and, in essence, swells to fill the pore……PRB coal has been shown to have approximately 30% more calcium in its ash compared to North Dakota lignite……Other alkaline materials (potassium, sodium and magnesium) deactivate catalysts by deactivating individual reaction sites rather than the blinding by macro-pore plugging that was described for calcium. The average Center Mine coal ash content for these alkaline constituents is about 9%…… This percentage is somewhat lower than most PRB coals and within the envelope of experience of European installations. One of the references cited in the Appendix B EERC report, Cichanowicz & Muzio (2001), places the range of European SCR experience with these alkaline constituents at 8% to 15% of ash. Thus, the coal used at MRYS has similar poisoning potential compared to other coals in use at SCR-equipped boilers in Europe and the U.S……..

The concern about high amounts of alkaline materials in Center Mine coal expressed in B&M's BACT analysis and described in the Appendix B EERC report is real, though not necessarily unlike operating SCR systems on PC boilers burning PRB coal. As explained above, we believe there is value in successful operating experience realized at current SCR installation at PRB-fired power plants. The problems cited in the BACT analysis are being dealt with at several NO_x SIP Call SCR installations today. In addition, the analysis presents no quantitative analytical information derived from the firing of lignite coal on SCR catalyst deactivation to justify the finding that SCR is infeasible.

EERC's March 19, 2007 Response:

The sodium and ash contents of Center lignite are significantly different from PRB coals. EPA indicates that the problems of deposition will decrease because the cyclones take out some of the ash as slag but for lignite, cyclones create additional deposition problems downstream. The cyclones partition the more refractory ash components into the slag and the more volatile components into the fly ash. The fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components that cause bonding.

EPA discusses ash loadings and the potential impacts on SCR performance. They also discuss the formation of calcium sulfates that can plug pores in catalysts as well as the impacts of other alkaline materials (potassium, sodium, and magnesium) and their potential to deactivate individual sites rather than blinding pores. They fail to recognize the formation of combined phases such as sodium calcium sulfates with low melting points that are very reactive and can both block pores and deactivate individual sites in catalysts. They also fail to recognize that cyclones partition the ash, increasing the proportion of sodium in the smaller particles, resulting in increased propensity for the formation of the complex sulfate phases.

Topsoe presented a paper at the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL) meeting on SCR-selective non-catalytic reduction (SNCR) on testing conducted with biomass fuels that contain high potassium and sodium found rapid deactivation in the SCR catalyst. Their data suggest sodium or potassium resembles the ammonium ion and blocks access to the active sites in the catalyst. They indicate that this occurs most readily where the alkali elements are in a soluble form. Topsoe incorrectly assumes that all alkali in coal is not soluble because of work they did on potassium. Potassium is associated in the coal with clay minerals and is not soluble. Sodium in North Dakota lignite is organically associated (soluble form) and is readily available for reactions with catalysts and flue gas species. More recent work conducted by Beck and others (2004) established that sodium correlates with catalyst deactivation activity and that pore condensation of sodium is the major deactivation mechanism.

Sodium levels at MRYS have a multimodal distribution, and assuming the average sodium level in the ash is not realistic……

EPA Response:

EPA does not dispute EERC's description of the chemical and physical fate of sodium in a cyclone boiler. Please refer to the August 20, 2007 Christman Memo Item #2 for the response on the effects of sodium on a SCR system and the appropriateness of using average coal constituent values when evaluating their effect on an SCR system.

EPA's original analysis was in response to B&McD's quantitative comparison of sodium ash loading presented in the original BACT analysis.[15] This comparison uses average fuel ash and sodium values to calculate a sodium ash loading rate of 7.3 lb/MW-hr for North Dakota lignite compared to 0.9 lb/MW-hr for a PRB-fired cyclone boiler.[16] One reason EPA provided a comparison is that B&McD's analysis did not look at PC-fired PRB units, which would have a higher ash loading rate than a cyclone unit. This information is relevant considering SCR systems have been installed on PRB-fired PC units. B&McD's analysis assumes 35% conversion of fuel-ash to flyash for PRB-fired cyclone units and 50% for lignite-fired cyclone units. Using the 80% conversion of fuel ash to flyash for a PRB-fired PC unit increases the sodium loading presented by B&McD to 2.1 lb/MW-hr. [(0.9 lb/MW-hr / 0.35) = 2.57 lb/MW-hr (sodium in the fuel ash for PRB coal) * 0.8 conversion of fuel ash to flyash in a PC boiler = 2.1 lb/MW-hr (0.9 lb/MW-hr is the sodium loading for PRB coal calculated by B&McD on a cyclone boiler assuming 35% conversion of fuel ash to flyash)] The other reason EPA provided this analysis was to include the entire set of ash constituents for the quantitative comparison.

EPA presented this comparison with some reservations, since, as stated in the comments, EPA does not believe that a linear comparison can be made between theoretical ash constituent loading rates to SCR catalyst deactivation rates. Nevertheless, EPA wanted to demonstrate that B&McD's comparison of only the sodium ash loading from lignite-fired cyclone units to PRB-fired cyclone units ignores the PRB-fired PC units which have the higher fuel ash to flyash conversion and other ash constituents that do effect SCR operations. On its surface, B&McD's analysis portrays a sodium loading difference between North Dakota lignite and PRB coal that is greater than a factor of seven. This difference becomes less when including PRB-fired PC units (about a factor of three difference) and other ash constituents (virtually zero). Again, EPA does not believe there is a linear relationship between this ash loading and SCR deactivation rate. However, since B&McD presented a theoretical sodium loading comparison between North Dakota lignite and PRB coal fired cyclone units, with the apparent implication that the difference was significant in the discussion of technical feasibility of SCR at MRYS, EPA wanted to include a more complete comparison.

15 See page A1-29 of October 2006 Minnkota BACT Analysis Study for MRYS.
16 In the March 19, 2007 response (page 28), EERC dismisses EPA's analysis. "Sodium levels at MRYS have a multimodal distribution, and assuming the average sodium level in the ash in not realistic." Note that the analysis presented by B&McD uses average fuel characteristics for North Dakota lignite and PRB coal.

EPA acknowledges that the sodium content of the Center Mine lignite is generally higher than PRB coals. EPA also recognizes that ash partitioning in a cyclone boiler and resulting sodium deposition presents certain problems that could pose engineering challenges to the design and operation of an SCR system at MRYS. However, Minnkota has not provided any quantitative data that shows that the plugging and deactivation of the SCR system would be an unresolvable technical barrier and/or the ability of the SCR to control NO_x would be so limited that SCR would be an ineffective control option. Again, EPA thinks that both of these issues would be more appropriately addressed at step 4 of the Top-Down BACT analysis.

The Topsoe 1999 paper referenced by EERC does observe that biomass having a high percentage of soluble sodium or potassium that was burned in an incinerator caused "rapid deactivation in the SCR catalyst." It is unclear how these soluble sodium or potassium percentages compare to the alkaline makeup of Center Mine lignite. Furthermore, it is unclear what Topsoe meant by "rapid deactivation." The paper does not appear to indicate that the SCR was inoperable or ineffective for this test. It is inappropriate to draw any meaningful conclusions on technical feasibility based on these qualitative statements in Topsoe's paper.

B&McD's March 19, 2007 Response:

The discussion in the EPA's preliminary analysis of Minnkota's NOx BACT Analysis at MRYS ignores the BACT reports' statements that the firing of lignite coal in a cyclone boiler specifically designed and built to pre-dry and burn North Dakota lignite produces fine flyash particles which will enter the pores of the SCR catalyst, react with SO3 in the flue gas, and form sulfates which bind other ash particles into the matrix.

When considering the much higher sodium content of Center lignite coal ash (lb/mmBtu) compared to PRB coal, the impact on the individual catalyst reaction sites from sodium-based compounds discussed in Dr. Benson's referenced technical paper has largely been ignored by the EPA's commenters……..

The problems associated with sodium combined with calcium, sulfur, and other alkaline elements at any cyclone boiler firing North Dakota lignite appear to be unpreventable for successful application of SCR catalysts. There is no full-scale long-term documented and published demonstrated experience at commercial SCR installations on large coal-fired boilers with similarly high sodium levels. The tendency of small sodium vapor particles to be generated during the combustion and slagging processes of a North Dakota lignite-fired cyclone boiler has not been adequately addressed by the EPA commenter's discussion.

The lack of published NOx control effectiveness and catalyst activity data for the Coyote slipstream SCR catalyst field test precluded Burns & McDonnell from evaluating or including it in the NOx BACT Analysis Study reports for the Milton R. Young boilers.....Electric Power Research Institute, Inc. (EPRI) produced a recent study on the impact of coal type on SCR catalyst life and performance..... This study found that the Sioux plant's 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.

Burns & McDonnell believes that the flue gas and flyash conditions produced during the combustion and slagging processes of a North Dakota lignite-fired cyclone boiler will be significantly more problematic than the tests at Sioux Station demonstrated.....

EPA Response:

Please refer to the August 20, 2007 Christman Memo Item #2 for the response on the effects of sodium on SCR. EPA's original comment does not largely ignore the statements in the Minnkota BACT analysis about higher sodium content and its impact on catalyst deactivation. EPA's analysis looked at the combined percentages of other alkaline materials (potassium, sodium, and magnesium) that would contribute to catalyst deactivation, instead of just focusing on sodium. These other constituents are of importance. See the expanded analysis and discussion above.

B&McD states that EPA has not adequately addressed the high Center Mine lignite sodium issue and has provided no documented long-term experience at commercial SCR installations on large coal-fired boilers with similarly high sodium levels. As discussed earlier, EPA believes that the burden of proof in this case is on Minnkota to provide definitive quantitative evidence that SCR would be technically infeasible at MRYS due to the high number of SCR systems currently in operation at utility boilers. Furthermore, a lack of a full-scale long-term commercial SCR installation at a facility with similar sodium levels in the fuel is not evidence that SCR is technically infeasible at MRYS. While EPA agrees that the sodium levels in North Dakota lignite are higher and will require aggressive mitigation measures, SCR systems have obviously been applied to new fuel types with unique characteristics over the history of SCR installations.

EPA has mentioned a number of engineering solutions that could help manage the high sodium issue from a technical standpoint. EPA does not believe that the qualitative information presented thus far is sufficient to outweigh the vast amount of SCR operating experience for utility boilers to say that SCR would be technically infeasible at MRYS. Due to the lack of NO_x emission and catalyst deactivation data, the Coyote Station study does not support utilizing any definitive conclusion, other than there was significant plugging, which also appeared at both the Baldwin and Columbia Stations.

EPA believes that the experience the utility industry has gained from the installations at PRB facilities would be useful in designing an SCR system for a cyclone unit burning North

Dakota lignite. According to the presentation given in Bismark on May 23, 2007 to NDDH and EPA by the utility design firm, Sargent & Lundy, the successes and failures of the PRB installations would provide valuable information for designing an SCR system on a plant burning North Dakota lignite. While Sargent & Lundy indicated that getting further data from a well-designed pilot study would enhance their ability to optimally design a more cost-effective SCR system, they indicated that they would certainly draw upon the experience gained through the PRB installations.

EPA does not have access to the EPRI study referenced that produced field data from an "In-Situ Mini SCR Reactor" and showed that the fastest rate of deactivation was from the AmerenUE Sioux Station, which is a cyclone boiler burning a PRB/bituminous blend. B&McD appears to imply that this result demonstrates that an SCR installation on a cyclone boiler will experience faster deactivation than an installation on a PC-fired boiler because of the higher economizer flue gas exit temperatures. Since EPA does not have access to this data, EPA does not know how large of a difference there was between the cyclone unit and the PC-fired units. Without access to this data, it would in appropriate for EPA to place any reliance on assumptions or conclusions from this study. Furthermore, EPA is unsure how this relates exactly to the issue of SCR technical feasibility at MRYS. This data might be useful in trying to predict catalyst cleaning / replacement requirements, but it is not relevant to demonstrating the technical feasibility of SCR at MRYS.

b. Engineering Solutions for SCR Applications at High-Ash Facilities

EPA's January 9, 2007 Comment:

Plugging of SCR catalysts by fly ash accumulation and bridging of passages in honeycomb catalysts and between plates in plate-type catalysts has been a problem for designers and catalyst vendors since the first coal-fired installations in the 1970s. The primary response has been more sootblowing, on-line cleaning equipment, and larger catalyst pitch for honeycomb configurations and wider plate spacing for plate-type configurations. These measures, combined with periodic cleaning during boiler outages have, by-and-large, reduced catalyst plugging to a manageable SCR problem..... Also, the fact that the MRYS units are brought down for planned boiler deposit cleaning at 120-day intervals provides more opportunity for catalyst cleaning maintenance than is available at the typical power plant.

Further demonstrating the ability of SCR designers to use existing knowledge and experience with SCR installations for high ash fuels, the Electric Power Research Institute (EPRI) has advised clients that based on industry experience on a wide range of SCR installations over the years, SCR designs can accommodate fuel types never before used in practice on a full scale. In a September 7, 2006 letter addressed to TXU Power, EPRI stated, "While experience specifically with Texas lignite is limited, this should not prevent suppliers from providing an SCR system that meets these objectives; dealing with a new fuel is similar to the challenge faced by U.S. utilities and their SCR suppliers when first installing SCR systems on plants firing high sulfur bituminous or PRB coals. Neither suppliers nor utilities had

prior experience with these fuels, which produce flue gas properties that are very different from those in the Japanese and European plants where SCR has been installed before. Therefore, SCR designers had to rely upon their knowledge, engineering judgment, and experience with these other coals to design SCR systems suitable for these new applications. While some of the first U.S. SCR installations experienced problems (e.g., accelerated catalyst activity decay due to arsenic poisoning in the absence of sufficient calcium in the coal, and catalyst pluggage due to large particle ash), none of these problems prevented the systems from achieving their NOx goals initially and, eventually, maintaining them over the expected life of the catalysts."

EERC's March 19, 2007 Response:

The issue is not strictly the high ash content of North Dakota lignite, it is the high sodium content of this lignite's ash. The issue for the application of SCR on North Dakota lignite-fired cyclone boilers is a high potential for ash deposition in lower-temperature convective pass surfaces such as the economizer and primary superheater. The high ash deposition rates require continuous cleaning with sootblowers, and the resulting liberated deposit fragments will cause catalyst plugging. The deposit fragments, along with the formation of sulfated sodium- and calcium-rich fine particulate plugging pores of the catalyst, causes plugging of gas paths.

EPA Response:

The response from EERC simply restates their position regarding the high sodium content of the Center Mine lignite and how this will cause both catalyst pore plugging and gas path plugging. EERC fails to consider the use of available engineering solutions to address these problems with operation of an SCR at MRYS.

B&McD's March 19, 2007 Response:

For a North Dakota lignite-fired cyclone boiler, aggressive on-line cleaning and/or frequent extended forced outages would be needed to remove the ash accumulation or remove the catalyst for cleaning in order to restore full unit output and catalyst NOx reduction effectiveness. Either or both of these maintenance activities could damage the catalyst and/or require it to be frequently replaced……the estimated amount of time and difficulty for MRYS boilers' SCR maintenance appears to be insufficient to use boiler deposit cleaning outages to perform significant catalyst cleaning or replacement work without delaying startup.

EPRI's statements do not conclusively support the technical feasibility of applying SCR with specific technical evidence that shows proof of the hypotheses that it will be successful on Texas lignite-fired boilers. It also does not suggest or imply that North Dakota lignites are similar to Texas lignites and therefore SCR should also be successful on such applications. The high ash and moisture content of a Texas lignite-fired unit would result in a different set of challenges for application of high-dust SCR technology. Possible solutions to deal with Texas lignite are not relevant to compare to North Dakota cyclone boilers in this NOx BACT analysis for MRYS. Already-installed boiler and backend equipment designs on units firing TX vs ND lignites are significantly different, reflective of the approaches the

original design engineers took to attach these situations as separate problems. A comparison of the differences between Texas and North Dakota lignites is included in EERC's subsequent response to the EPA's comments regarding the NSPS revisions later in this response document.

EPA Response:

This response states that aggressive on-line cleaning and/or frequent extended outages would be required to remove ash accumulation or remove the catalyst for cleaning. The response seems to acknowledge that the SCR could be used at MRYS, albeit with potentially higher than normal maintenance requirements. This is not inconsistent with EPA's position, which is that the problems cited in the Minnkota BACT analysis appear to be more a matter of cost than technical feasibility. If indeed necessary, the extended outage times could be accounted for as additional operational cost (if more frequent catalyst cleaning is necessary and/or cannot be performed online) or accounted for by adding additional catalyst layers to the SCR system.

The intent of referencing the EPRI letter on Texas lignite was not to imply that North Dakota lignites are exactly the same as Texas lignites. The intent of referencing this letter was to show that a major utility research organization is of the opinion that the existing experience of the SCR designers would greatly help in designing SCR systems for accommodating fuel types never before used in practice on a full scale. This underscores EPA's position that, although the specific fuel and boiler characteristics at MRYS may present challenges to an SCR installation, the significant industry experience with SCR for new fuel types in the past would serve useful to overcome the technical challenges described by Minnkota. This again was reiterated by the design firm Sargent and Lundy in the presentation described above.

c. Other Ash Deposition Problems on Downstream Components

EPA's January 9, 2007 Comment:

B&M's discussion of these "other" potential accumulation problems does not reach any definitive conclusions related to the technical feasibility of SCR, so EPA does not see this as a technical barrier to installing SCR at the MRYS units.

EERC March 19, 2007 Response:

Note that it is not the ash loadings, it is the sodium in the lignite ash that causes the deposition. The sodium-related deposition on SCR catalyst will shorten the time between outages for off-line cleaning.

EPA's Response:

EPA acknowledges that the sodium content in North Dakota lignite presents engineering challenges. EPA also thinks it is possible that the "sodium-related deposition on SCR catalyst will shorten the time between outages for off-line cleaning." As stated previously, the requirement for increased catalyst maintenance does not render the technology technically infeasible. Any increased maintenance and unit downtime would result in added cost, which should be quantified at step 4 of the Top-down BACT analysis. Unfortunately, the pilot testing conducted at Coyote Station did not provide any quantitative results that could be used to predict the time periods between catalyst cleaning/replacement on a full-scale application.

B&McD's March 19, 2007 Response:

The higher amount of ash, sodium, and sulfur in North Dakota lignite combined with calcium and other alkaline elements along with ammonia and SO3 emitted from a high-dust SCR will exaggerate tubular air preheater and economizer tube exterior surface fouling and plugging problems at any cyclone boiler firing this fuel compared to bituminous or PRB coals. The tubular air preheaters and the built-in economizers at MRYS are not equipped with sootblowers for on-line gas-side surface deposit cleaning. Noting that MRYS boilers' air preheater and economizers would be downstream of the boiler backpass outlets and a high-dust SCR, isolating these components during off-line boiler deposit cleaning or SCR cleaning outages from negative impacts of "dirty air would be challenging and expensive. Similar estimated amounts of time and difficulty for such off-line downstream deposit removals will also delay unit startups following such outages……

EPA's Response:

It is unclear how the tubular air preheater and economizer tube exterior surface fouling and plugging problems would become exaggerated from the use of an SCR system. As noted, in the August 20, 2007 Christman Memo, "the SCR retrofits at New Madrid (two large, PRB-fired cyclone boilers) included replacement of the tubular air preheaters with new regenerative air preheaters with enamel-coated baskets." This and other alternatives should have been considered in Minnkota's BACT analysis. The additional expense to clean these components and isolating the SCR system are described as "challenging and expensive." As discussed previously, these costs should be addressed under step 4 of the Top-Down BACT analysis, not at the technical feasibility stage.

d. *Accounting for Catalyst Life & Performance in Top-Down BACT Analysis*

EPA's January 9, 2007 Comment:

Finally, the conclusion reached in the B&M BACT analysis that ash deposition and catalyst pluggage will adversely affect SCR performance (we assume this means control efficiency) and catalyst life does not necessarily support a conclusion that the technology is technically infeasible and that SCR

should be eliminated at step 2 of the Top-Down BACT analysis. Furthermore, the B&M analysis presents no quantitative data related to SCR performance and catalyst life to support such a conclusion...
...However, SCR performance and any real construction and operational costs are factors that would be accounted for under the economic impact stage related to cost effectiveness of SCR (step 4) under the Top-Down BACT analysis.

B&McD March 19, 2007 Response:

The reasons for the assertion of technical infeasibility of SCR for lignite-fired cyclone boilers were presented in the MRY Station Unit 1 and Unit 2 NOx BACT analysis reports, with further explanation provided herein. The EPA's preliminary analysis comments minimize the difficulties posed by the higher amount of ash, sodium, and sulfur in North Dakota lignite combined with calcium and other alkaline elements along with ammonia and SO3 emitted from a high-dust SCR on the two existing North Dakota lignite-fired cyclone boiler at MRYS.

The EPA cites no published technical literature that describes.....as would be the case at Milton R. Young Station.

The evident failure of the Coyote slipstream SCR catalyst field test to .....led Burns & McDonnell to believe these field test results indicate .....for technical infeasibility purposes.

EPA Response:

The majority of this comment is addressed under EPA's response to the preliminary summary. EPA does not discount the challenges that Center Mine lignite might pose for an SCR installation at MRYS. However, EPA cannot concur that the qualitative pilot testing results at Coyote Station cited in the EERC report demonstrate that a full-scale SCR installation at MRYS, that included the currently available engineering design measures, would not be technically feasible and offer substantial NO_x reductions. EPA has pointed out some of the inherent limitations in the pilot testing that might have contributed to the "failure" of that test. B&McD and EERC's responses do not provide much insight on whether these tests were designed to reasonably represent full-scale conditions, other than to say that EERC was not alone responsible for the testing's design. EPA questions the design and operation of the Coyote Station pilot test in light of the lack of critical data obtained.

EPA has also not found any definitive quantitative results, taking into account the ash deposition and catalyst plugging counter measures, that show the expected rate of catalyst deactivation and off-line cleaning frequency that would be necessary for operation of an SCR system at MRYS. As described in detail previously, EPA does not believe the pilot testing presented by EERC provides an accurate estimate of what type of catalyst maintenance and replacement would be required. Without such quantitative information, EPA continues to believe that Minnkota has not provided sufficient evidence of technical infeasibility for SCR at MRYS. EPA believes SCR is in fact technically feasible at MRYS. EPA believes under the

Top-Down BACT analysis, any additional costs should be accounted for under step 4. Furthermore, as explained previously, EPA believes the burden of proof for technical infeasibility for SCR at MRYS is considerable given the large number of SCR systems currently in operation at utility boilers worldwide with vastly different fuel types and characteristics. Quite simply, the record does not support Minnkota's conclusions.

2. **EPA Analysis of the "Popcorn Ash" Issue:**

No response given to EPA's comment by EERC or B&McD. The topic was similarly addressed in the January 2007 Christman Memo.

3. **EPA Analysis of the Temperature Issue:**

No response given to EPA's comment by EERC or B&McD. The topic was similarly addressed in the January 2007 Christman Memo.

4. **EPA Analysis of the Erosion Issue:**

No response given to EPA's comment by EERC or B&McD. The topic was similarly addressed in the January 2007 Christman Memo.

5. **EPA Analysis of the Energy & Environmental Research Center Report (Appendix B):**

EPA's January 9, 2007 Comment:

.....However, the conclusions reached in the Appendix B report do not address some of the engineering solutions previously cited and explained below that are available for full-scale SCR applications. Furthermore, EPA Region 8 believes that there may be inherent limitations with the pilot study (that was the basis for both EERC reports) that draws into question the validity of directly applying those conclusions to the range of possible SCR designs of a full-scale application at MRYS. Statements from three major SCR catalyst manufacturers (including Haldor Topsoe, the catalyst manufacturer involved in the pilot testing for North Dakota lignite) suggest that the catalyst deposition and plugging problems experienced during the pilot testing may be exaggerating on a pilot scale and can be solved in a full-scale design and application.....

Other inherent problems associated with directly applying the results of the EERC pilot testing at Coyote Station on North Dakota lignite include:

1) The air pulse used to clear deposits during the pilot test is a poor simulation of sootblowing and is much less effective.....

2) The 6mm pitch catalyst used for the pilot testing at Coyote Station is much smaller than currently being specified for coal-fired installations. Vendors are now supplying 9mm, 10mm or even

11mm pitch catalysts……

3) The one meter depth of the catalyst used in the pilot test is equivalent to one layer of catalyst in a commercial installation. Commercial systems aimed at high removals have three layers, each about three feet thick, and, at various times in the catalyst management cycle, incorporate four layers. EERC's test, then, only simulated the top layer of a multi-layer system……This is why the first step in most catalyst management schemes usually involves adding a fourth layer and leaving the badly degraded top layer in place for the second operating period. EERC's project provides no real insight into the effectiveness and survivability of a second or third layer.

4) The scale of testing carried out in this project is usually associated with observing catalyst life prospects (or said another way, the rate of loss in catalyst activity) rather than physical processes of deposition or plugging. This is because the deactivation mechanisms operate on a micro-scale and can be accurately simulated at this small scale, but the plugging and deposition are influenced by larger processes, such as flow imbalance and countermeasures (sootblowing, horns, screens, baffles, etc.) and are not duplicated on the small scale.

For these reasons, EPA Region 8 questions the direct application of the results of the EERC pilot testing at Coyote Station and the accompanying Appendix B EERC report for purposes of the BACT technical feasibility analysis of SCR at MRYS. The experience and opinions of the SCR supplier that participated in the EERC pilot test indicate that the problems encountered during the pilot test are not determinate of whether SCR plugging experienced during the pilot test would be unresolvable by vendors. To the contrary, statements from Haldor Topsoe offering their SCR catalyst for installation on lignite-fired boilers indicates that the full-scale differences and engineering solutions available today provide evidence that the EERC pilot testing results should not alone be the deciding consideration when evaluating SCR technical feasibility at MRYS.

EERC March 19, 2007 Response:

……The catalyst vendors, Haldor Topsoe, Cormetech, and Hitachi, were all involved in the design of the pilot-scale slip stream test system and testing conditions..The pulsing system was designed with the assistance of the catalyst vendors. They provided suggestions on the sootblowing pressures and felt it would be sufficient to remove the deposits. The 6mm pitch was recommended by the vendors. If the first layer plugs, the gases cannot get to the subsequent layers; significant deposition was noted downstream of the SCR catalyst section installed. Deposition and plugging are significant problems that impact the reliability of the MRY facility. Haldor Topsoe was the only catalyst vendor willing to provide catalyst for the lignite testing.

The EERC pilot-scale testing was a collaborative effort involving coal-fired utilities, EPRI, DOE, and catalyst vendors. All decisions on system design, plants for testing, and testing conditions were reviewed and agreed upon by vendors. The EERC comparisons of catalyst blinding for lignite and subbituminous coal testing as well as the sodium deactivation work conducted by other research organizations and catalyst vendors should be used in evaluating technical feasibility of SCR for MRYS.

EPA Response:

The results of the pilot testing were examined in more detail. EPA's observations on the test as it relates to expected catalyst maintenance and replacement requirements at MRYS are described in detail under the EPA response to the preliminary summary.

EERC indicates that the catalyst vendors assisted in the design of the air pulsing system for the Coyote Station pilot testing and recommended the 6 mm catalyst pitch. Flemming Hansen of Haldor Topsoe, the catalyst vendor for the Coyote Station pilot test, informed EPA Region 8 that, in hindsight, the pilot testing should have been conducted differently. Specifically, Mr. Hansen said that changes to the test such as increased catalyst pitch could have helped reduce the impacts of ash plugging. Additionally, Mr. Hansen said that pilot test's air pulsing system did not accurately simulate full-scale sootblowing and that if the test could be redone, a better effort could be made to keep the catalyst face clean. Mr. Hansen recalled that the Coyote Station test reactor became quickly plugged with flyash causing rapid increases in pressure loss caused mainly by wall-duct ash accumulations dropping on the catalyst face. Mr. Hansen stated that this type of ash deposition would not be a problem on a full-scale application.

Mr. Hansen's statements support EPA's original comments that there were inherent problems with the pilot testing that contributed to the degree of catalyst plugging during the Coyote Station pilot testing. In addition, experts from Sargent & Lundy indicated that they were disappointed in how the Coyote Station pilot test was carried out and found the results to be of very little value for evaluating an SCR system for a facility burning North Dakota lignite.

Based on the EERC response, the degree of catalyst plugging observed at Coyote Station was the reason no deactivation testing on the catalyst was conducted. If the testing were designed and conducted in a way that could have greatly reduced the effects of ash deposition on the catalyst face, presumably catalyst deactivation data would have been obtained. As stated previously, EPA questions Minnkota's heavy reliance on the questionable results from the Coyote Station pilot testing and cannot support using this data to draw definitive conclusions on the feasibility of SCR at MRYS. Furthermore, whether the design issues were originally attributable to the catalyst vendor or not, EPA does not believe that a pilot test designed and conducted under conditions unrepresentative of full-scale engineering capabilities is a fair measure of whether the technology is technically feasible or not. Input from both Haldor Topsoe and Sargent and Lundy support this position.

6. EPA Analysis of the Burns & McDonnell's Conclusion:

EPA's January 9, 2007 Comment:

EPA notes that there is considerable experience in the industry to show that use of SCR on North Dakota lignite is technically feasible. EPA has previously articulated this belief in a number of national rulemakings, including the Clean Air Interstate Rule (CAIR), the Best Available Retrofit Technology (BART) Guidelines, and revisions to the New Source Performance Standards (NSPS) for Electric Utility Steam Generating Units (finalized on February 27, 2006)……..

EPA understands from the EERC pilot study at Coyote Station using North Dakota lignite, there was noticeable ash build up on the catalyst and concerns with catalyst plugging during the test. While EERC notes that ash deposition problems were most pronounced at Coyote Station, compared to the two test facilities burning PRB coal, it also states generally that all of the coals in the pilot study "produced ash that had significant accumulations of ash on the catalyst on both macroscopic and microscopic levels." Thus, the conclusions of the study appear to be that deposition issues might be somewhat greater for North Dakota lignite than for PRB coal. Since significant accumulations of ash on the catalyst was also observed during pilot testing at those facilities burning PRB coal and there are numerous examples of PRB coal-fired power plants successfully operating SCR systems, the qualitative results of the pilot testing described by B&M and EERC would not appear to preclude successful operation of SCR on a power plant burning North Dakota lignite. The EERC study does not appear to quantify the effect that the ash accumulation had on microscopic catalyst deactivation rates or overall catalyst performance. Absent such information that reflects the use of currently available full-scale ash loading mitigation designs, pilot testing results may not be evidence that successful implementation of SCR on North Dakota fired units "is going to be impossible," as stated in the Appendix B EERC report……..

The October 1990 EPA draft New Source Review Manual (NSR Manual) states that a "demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles, and/or empirical data showing that the technology would not work on the emissions unit under review, or that ***unresolvable*** *technical difficulties would preclude the successful deployment of the technique. Physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts, which, in turn, may form the basis for eliminating a control technology." (Page B.20) (Emphasis added) Based on the available information, the problems cited by B&M for application of SCR at MRYS (ash deposition, "popcorn ash", temperature, and erosion) are resolvable through the engineering solutions discussed above. While such engineering solutions may be a cost burden to Minnkota, as noted above, step 2 is not the proper stage of the Top-Down BACT analysis to account for these costs. As described in the NSR Manual, "where the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible. The economic feasibility of a control alternative is reviewed in the economic impacts portion of the BACT selection process." (Pages B.19-B.20) Many of the technical feasibility arguments presented in the BACT analysis are centered on decreased catalyst life and performance, increased maintenance and outage time, and plant differences unique to MRYS that preclude SCR feasibility at MRYS. Consistent with the NSR Manual, these concerns are incorrectly incorporated into the Top-Down BACT analysis at step 2 and really should be accounted*

for as additional costs per ton of pollutant removed at step 4 of the analysis.....So, while EPA does not consider vendor guarantees by themselves to be determinate in making technical feasibility decisions, they are a contributing factor in making these decisions. EPA is aware of three catalyst vendors (Haldor-Topsoe, Cormetech, and Argillion) who would be willing to provide performance guarantees for lignite-fired boilers applications.

Based on the criteria discussed above, Minnkota and B&D should have further explored both the full-scale engineering solutions used to address the problems cited in their analysis in conjunction with information from SCR/catalyst vendors to offer performance guarantees to design and install an SCR unit at MRYS. The BACT analysis for MRYS that was submitted relies heavily on the technical problems experienced during the EERC pilot testing at Coyote Station in conjunction with the fact that SCR has not been installed on a cyclone boiler that burns North Dakota lignite. We do not believe that this analysis adequately addresses the criteria cited above. As such, it appears that the case-specific NO_x BACT analysis submitted for Minnkota MRYS is deficient in terms of improperly eliminating SCR from consideration at step 2 of the BACT analysis for technical feasibility.

EERC's March 19, 2007 Response:

EPA did not examine the EERC report in detail. The deposition and plugging was much more pronounced for the Coyote Station testing as compared to the Columbia and Baldwin Station. The pressure drop increased much more rapidly and the soot blowing was not as effective..... The most important unresolvable technical difficulty is the impact of sodium on the formation of bonded sulfate phases that plug and mask the catalyst and on the ability of sodium to deactivate the catalyst.

EPA Response:

EPA's original assessment of some of the general statements on the results of the pilot testing conducted by EERC at the three power plants are based on a direct quotation from the EERC report in Appendix B, which states that there was significant catalyst plugging at all three test sites. While it is true that the problems were most pronounced at the Coyote Station and the facility experienced higher pressure drop during the test, the results from the three facilities taken together do not demonstrate whether SCR would be technically feasible or infeasible at any or all of the facilities tested, since no quantitative NO_x control or catalyst deactivation data was provided in the EERC report in Appendix B of the BACT analysis. While the pilot study does suggest that catalyst plugging at a facility burning North Dakota lignite would likely be more of a challenge than at a facility burning PRB coal, EPA can not conclude that the test is determinative of whether an SCR system would not work at MRYS. See EPA's previous detailed analysis for more information.

EPA has since received the background documents for project participants and reviewed quarterly progress reports. For reference, below is a summary of some of the relevant history and background information from the pilot study.

Original goals of the test (2000 EERC Proposal)

- "Determine the mechanistic and fundamental causes of potential blinding or masking of selective catalytic reduction (SCR) catalysts due to flue gas constituents in low-rank coals." (Objectives)
- "Utilities will gain scientific and engineering information related to potential fouling of SCR catalyst material and will be able to negotiate guarantees and performance criteria for SCR systems and materials, and SCR manufacturers and distributors will gain an appreciation for potential challenges facing utilities using low-rank coals that could cause SCR masking and will be able to adjust future systems." (Expected Results)
- "The test chamber will be constructed so that periodic samples of the catalyst can be removed to ***assess the reactivity as a function of time***." (Emphasis added) (Task 4 – SCR Test Chamber Installation and Data Collection)
- "The end result is that research is needed to determine the true extent of potential SCR blinding for lower-rank coals. If indeed masking of SCR catalyst material is an issue, then SCR technology may not be the "best available" technology for NO_x control at North Dakota utility sites and the EPA ruling (1998 NSPS limit) may need to be amended. Other options may surface as result (sic) of this research include providing technological and fundamental science and engineering knowledge for manufacturing catalysts that resist blinding from low-rank coal-type ash material or designing SCR systems that can be cleaned on-line." (Rationale for the Project)

Here are some relevant excerpts taken from the final results of the test. (November 2004 Final Report for period November 1, 2004-June 30, 2004, with two exceptions noted below)

- Baldwin Station (cyclone boiler, PRB coal) catalyst reactivity testing at 2 months – 100%, 4 months – 96%, and 6 months – 84%. 6 month sample showed "extensive sulfation of alkaline-earth elements present in the deposits." "Regions of the catalyst where all of the pores were blocked and a minimal amount of deposit on the surface of the catalyst." "Higher magnification view of the deposit that is filling the pore."

- Columbia Station (tangentially fired boiler, PRB coal) catalyst reactivity testing at 2 months – 93%, 4 months – 90%, and 6 months – 90%. (December 22, 2006 email from Isato Morita, Hitachi Power Systems America Ltd. to Dr. Steven Benson, EERC) "The Columbia Station showed more significant accumulation and plugging than the Baldwin Station." "The six month sample from the Columbia Station showed particles adhering to the surface and filling pores in the catalyst."

- Coyote Station (cyclone boiler, ND lignite) – No catalyst testing conducted and no NO_x data submitted. "The most significant accumulation was noted for the Coyote Station." "The Coyote Station had some large pieces of ash deposit material on the surface as well as plugging of the catalyst passages." "The six month sample from the Coyote Station showed particles adhering to the surface and filling pores in the catalyst." Describing photos of the catalyst inlet after two months of operation, "the left side of the catalyst is indicative of the amount of fouling present whereas the ash present on the right side of the catalyst fell from the upstream flue section when the joint was separated. Nevertheless, the entire surface appears coated with ash deposits, and some of the catalyst channels were plugged." (February 2004 Quarterly Report – not noted in the final report) (Note: The right side of the catalyst face looks FAR worse than the left side in the photo.)

- Study Conclusions: "The pressure drop across the catalyst was found to be the most significant for the lignite-fired plant as compared to the subbituminous-fired plants. Both coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels."

  "This study suggests careful evaluation of each SCR installation in applications using subbituminous and lignite coals. Improvements are needed to ensure technical feasibility, especially with lignite-fired units. Installations involving lignite fuels will need advanced cleaning techniques to handle the high sodium and high dust loads associated with burning most lignite fuels."

Below is EPA's assessment of these additional background documents and reports received after the original comments were submitted on January 8, 2007 and January 26, 2007 and how to compare the results from the three facilities tested during the pilot study.

1. Quantitative Data Analysis

   - EERC apparently did no catalyst reactivity testing for the Coyote Station and did not monitor NO_x control performance of the SCR system during the test period. (Original test proposals from 2000 included mention of instrumentation "able to monitor whether NO_x control is occurring", but EERC has not provided this data to EPA, nor is there further evidence that it was ever collected.)
   - Pressure drop data for Coyote Station does not show gradual increase, but a sudden dramatic increase likely resulting from the ash dropping from upstream flue sections, as described in the February 2004 Quarterly report. EPA's conversation with Haldor Topsoe is consistent with this interpretation.

Pressure drop data and comparisons to Columbia and Baldwin Stations are therefore not meaningful.

2. Qualitative Catalyst Analysis

- While Coyote Station is described as having the most significant catalyst inlet ash accumulation, it is entirely possible that this is due in large part to the ash dropping from upstream flue sections.
- The microscopic catalyst description for Coyote Station was not entirely unlike that of the Columbia Station, where both "showed particles adhering to the surface and filling pores in the catalyst."
- Due to the upstream flue section ash contribution at Coyote Station and the similarities between microscopic analyses presented by EERC between the North Dakota lignite and PRB coals (both showed particles adhering to the surface and filling catalyst pores), the qualitative information does not provide meaningful conclusions for comparatively assessing SCR technical feasibility for North Dakota lignite and PRB coal applications. The one exception would be that the study shows lignite at Coyote Station showed more sodium deposition and less calcium compared to PRB coal. It is unclear what the basis is for EERC's statement that the sample at Coyote Station "shows significant evidence of sulfation after only 2 months of exposure and was much more pronounced than the 2-month samples for the Baldwin and Columbia Stations." Even if this is based on visual observation of the SEM images, it is not quantitatively compelling information. As stated in EERC's final report, "both coals had significant accumulations of ash on the catalyst, on both macroscopic and microscopic levels."

3. EPA's Conclusions of the EERC Pilot Study

- The quantitative data provided for catalyst deactivation for Baldwin (reduced to 84%) and Columbia (reduced to 90%) indicates that the visual observations from the pilot study are not meaningful ways to quantitatively represent the ash impacts on SCR systems. In fact, the reactivity results ***show the opposite trend*** as would be expected when comparing the visual observations at Baldwin and Columbia Station. "Columbia Station showed more significant accumulation and plugging than the Baldwin Station," but Columbia Station's catalyst showed less deactivation than Baldwin Station's catalyst. As such, it does not appear that a correlation can be made between the visual observations and the effects on catalyst performance. Without representative catalyst deactivation testing or NO_x control data from the Coyote Station, EPA

does not believe the pilot study provides meaningful results that could lead to a definitive conclusion that SCR would be infeasible at MRYS.

- The quantitative data on pressure drop is not compelling since it is not directly related to catalyst performance and is suspect for the Coyote Station due to upstream flue ash dropping on to the catalyst face.
- The catalyst analysis on both micro and macroscopic levels does support the claim by EERC that catalyst deposits will contain more sodium when exposed to lignite compared to PRB coal, but does not clearly support the assertion by EERC that SCR would not work on a lignite plant. In fact, EERC's conclusions seem to question how well SCR would work at PRB plants, which has been disproved with operating plants.
- In summary, the primary goal of the pilot test was to determine mechanistic and fundamental causes of potential blinding or masking of SCR catalysts due to flue gas constituents in low-rank coals. In the test proposals, it was clear that this included reactivity testing for the catalyst. EERC did not test the catalyst at Coyote Station, because the catalyst was allegedly too plugged to conduct the testing. This appears to be a failure of the pilot test to meet the original goal for North Dakota lignite. As explained above, the plugging appears to be in large part, due to the upstream flue ash dropping onto the catalyst face. As such, it is not clear whether the catalyst testing would have been conducted if the catalyst would have been kept cleaner. Additionally, EPA understands that the catalyst deactivation testing still could have been conducted, it just would not have provided a very quality "data point" because of the irregular catalyst exposure over time in light of the substantial ash deposition on the catalyst face and the resulting high gas flows through the catalyst. This effect may have also contributed to the differences in catalyst deactivation rates between Baldwin and Columbia Stations.

B&McD's March 19, 2007 Response:

……The EPA's review offered no specific documented and published substantive demonstrated experience ……of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application at Milton R. Young Station. Burns & McDonnell disagrees that the lack of SCR catalyst deactivation data from the Coyote slipstream SCR catalysts field test completely refutes the premise of Dr. Benson's referenced technical paper and the Minnkota NOx BACT Analysis Study conclusions that SCRs are technically infeasible for lignite-fired cyclone boilers.

The EPA's NSR Manual does not specifically define …… in order for said alternative to be excluded from further consideration.

When a BACT analysis is performed on a new unit, there has typically been significant conceptual and detailed engineering and design work already performed that forms the basis of the subsequent

capital cost estimate and associated expected O & M costs for the particular emission control technologies to be employed or that were considered as part of the overall project effort. Performing a BACT analysis on an existing unit should not require similar substantial resources to develop conceptual designs and create technical details that determine the estimated site-specific retrofit costs for overcoming significant technical challenges that would otherwise preclude the ability of the technique or technology from successfully controlling the emissions in question. The EPA's NSR Manual 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." There are no cited examples where successful solutions to such challenges as posed by such highly complex interactions between flyash, flue gas, and gas temperatures produced by lignite firing for SCR coal-fired boiler applications.....

EPA Response:

Again, EPA believes that in the case of deciding on technical infeasibility for SCR at a utility boiler, the burden of proof is on the applicant and is considerable. EPA's position is that the hundreds of SCR installations at utility boilers worldwide demonstrate a wealth of experience within the industry to address various factors over a very wide range of boiler designs and fuel types. The qualitative results of catalyst plugging for the pilot testing at Coyote Station do not provide empirical evidence that SCR would be ineffective at controlling NO_x emissions, since there was no quantitative data provided for either NO_x reduction or catalyst deactivation. As such, EPA is not convinced that the specific challenges presented for an SCR installation at MRYS is a matter of technical infeasibility and could not be overcome with a robust suite of ash (including sodium) mitigation measures and/or maintenance measures. While EERC has had verbal contact with Haldor Topsoe, Minnkota's March 17, 2007 response letter simply says that this vendor would have concerns about providing a performance guarantee in light of the specific sodium content of the lignite burned at MRYS. It is not clear based on this statement whether Haldor Topsoe would or would not in fact provide a performance guarantee (or what the guarantee would entail) for an SCR installation at MRYS. Also, as noted previously, during EPA's own discussion with Haldor Topsoe, Mr. Flemming Hansen did not rule out bidding on a project that involved North Dakota lignite.

B&McD's assertion that a BACT analysis for an existing unit "should not require similar substantial resources to develop conceptual designs and create technical details that determine the estimated site-specific retro-fit costs for overcoming significant technical challenges that would otherwise preclude the ability of the technique or technology from successfully controlling the emissions in question" does not appear to have a basis in EPA regulations or policy. Prevention of Significant Deterioration (PSD) regulations make no distinction between BACT requirements for new and existing units undergoing PSD review. In fact, EPA's position has been that when it is discovered that a source avoided PSD review, but it was later determined that PSD permitting requirements, including BACT, should have applied, the source would need to address the appropriate requirements "as if construction had not yet commenced."[17]

17 See April 20, 1999 letter from Richard R. Long (EPA Region 8) to Dennis Myers (Colorado Department of

In addition, B&McD's reference to page B.18 of the NSR Workshop Manual is taken out of context and is not relevant to their discussion on how a BACT analysis for an existing source should be less rigorous than for a new source. The NSR Workshop Manual citation is a discussion of whether a given control technology or technique should be considered "available" in the context of the technical feasibility analysis under step 2 of the Top-Down analysis.[18] There is little question of whether SCR is "available" for installation at MRYS. In fact, Minnkota's original BACT analysis contends that SCR meets the criterion for being "available".[19] So, it is inappropriate for B&McD to bring up this passage from the NSR Workshop Manual. The question has been whether SCR would be "applicable" (the second criterion under step 2). B&McD's reference on page B.18 of the NSR Workshop Manual would only apply for a "new technique." Given the vast experience in the utility industry with SCR and the EPA policy on technology transfer considerations, EPA does not believe it is reasonable to consider SCR as a "new technique" for MRYS, even if there are no SCR installations specifically operating on cyclone boilers burning North Dakota lignite.[20] In conclusion, EPA does not believe Minnkota has satisfied the high threshold of demonstration that SCR would not be technically feasible at MRYS. While EPA agrees there are engineering challenges with operating an SCR system at MRYS, EPA believes these would largely be a matter of cost and should be examined under step 4 of the Top-Down BACT analysis.

B. Low-Dust SCR

Burns & McDonnell has eliminated Low-Dust SCR as technically infeasible due to issues described below. EPA's response on each issue is also described below

1. EPA Analysis of the Catalyst Fouling and Deactivation Issue:

EPA's January 9, 2007 Comment:

A few SCR systems installed on coal-fired boilers have been designed with the SCR catalyst installed after the ESP or baghouse. This approach eliminates virtually all of the poisoning, plugging and erosion problems that have been associated with SCR catalyst. (Christman Memo, 2/18/03) For the same reasons noted above under the high-dust SCR analysis, the catalyst fouling and deactivation problems may be resolvable technical problems that do not warrant elimination of low-dust SCR under

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Public Health and Environment). http://epa.gov/region7/programs/artd/air/nsr/nsrmemos/amersoda.pdf

18 Page B.18 of NSR Workshop Manual: "A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique."

19 See Page A1-32 of October 2006 Minnkota BACT Analysis Study for MRYS.

20 See June 15, 1989 letter from Gary McCutchen (EPA Office of Air Quality Planning and Standards, New Source Review Section Chief) to John Daniel (Department of Air Pollution Control, Commonwealth of Virginia). http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/finlbact.pdf

step 2 of the Top-Down BACT analysis.....Similarly, permit applications for three recent Circulating Fluidized Bed projects in North Dakota (MDU Westmooreland Gascoyne, South Hart, and Gascoyne 500MW) did not eliminate low-Dust SCR based on unresolvable technical feasibility issues with catalyst fouling and deactivation. While there would be inherent costs associated with gas-reheat, other possible physical modifications to the plant to accommodate low-dust SCR, and engineering designs to minimize and manage catalyst fouling and deactivation, these factors, consistent with the NSR Manual, should be accounted for when considering the economic impacts of the technology.

EERC's March 19, 2007 Response:

Sodium-rich aerosols are a problem that can get through the ESP. These aerosols are known to be present in high sodium coal combustion fuel gases. These species are known to produce pyrosulfates. These will cause blinding and deactivation of the low-dust catalyst.

EPA Response:

As described previously, general qualitative statements that the sodium-rich aerosols will cause blinding and deactivation do not necessarily support the conclusion that a low-dust SCR system would be technically infeasible at MRYS. The effects of this blinding and deactivation should either be quantified and used within the economic analysis under step 4 of the Top-Down BACT analysis, or described in sufficient detail to demonstrate that the problems associated with catalyst blinding and deactivation are unsolvable and would result in the unsuccessful operation of a low-dust SCR. As stated on page B.20 of the NSR Workshop Manual, "(p)hysical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts."

B&McD's March 19, 2007 Response:

The need for a major source of heat to reheat the flue gas stream downstream of the ESP in a low-dust SCR application will require either an expensive natural gas supply pipeline or an unacceptable derate of the net unit electrical output associated with extensive modifications of the components in steam cycle power generation and balance-of-plant systems and boiler gas systems to supply high pressure, high temperature steam as suggested by the EPA and their consultant. The magnitude of such retrofit modifications and risks of failure in applying low-dust SCR technology at MRYS are much greater than is considered reasonable.

EPA Response:

B&McD contemplates the use of natural gas (and associated construction of a natural gas pipeline) and plant steam for flue gas reheat and makes a general statement that the "magnitude of such retrofit modifications and risks of failure in applying low-dust SCR technology at MRYS

are much greater than is considered reasonable." Absent from B&McD's consideration for flue gas reheat are fuel oil and propane (instead of natural gas and the associated pipeline). These options would likely require a less complex analysis. Based on their response, it is unclear if B&McD is still eliminating low-dust SCR as technically infeasible or if it is dismissing further analysis as unreasonable as part of the economical analysis under step 4 of the Top-Down BACT analysis. While EPA acknowledges that the two options described by B&McD would require engineering and cost estimates, EPA does not agree that a cost analysis for low-dust SCR should not be required. Furthermore, as stated in EPA's original January 8, 2007 comments, recent permit actions issued by both the North Dakota Department of Health and Region 8 included a cost analysis for low-dust SCR. B&McD did not respond to this original comment.

2. **EPA Analysis of the Site Space Constraint Issue:**

EPA's January 9, 2007 Comment:

While the extent of the physical plant modifications necessary to accommodate low-dust SCR at the MRYS is not entirely clear, the above description does not indicate that the site space constraints at MRYS would necessarily preclude the possible installation of low-dust SCR. It does sound like major and costly equipment relocation may be necessary to provide the space necessary for low-dust SCR. However, consistent with the NSR Manual, "physical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility." These costs should be accounted for when estimating the cost and economic impacts of low-dust SCR, but should not be used as a basis for eliminating the technology as technically infeasible.

B&McD's March 19, 2007 Response:

Significant engineering resources would need to be devoted to investigate and estimate the capital costs of major boiler and air pollution equipment relocations, facility additions, and boilerhouse building modifications required to implement low-dust SCR technology at MRYS. Burns & McDonnell believes the expected levelized total annual costs required to apply low-dust SCR technology to North Dakota lignite-fired cyclone boilers are unacceptably high.

EPA Response:

If B&McD "believes the expected levelized total annual costs required to apply low-dust SCR technology to North Dakota lignite-fired cyclone boilers are unacceptably high", more detail should be provided within step 4 of the Top-Down BACT analysis. EPA acknowledges that extensive work may be required for installation of low-dust SCR and the costs might turn out to be unacceptably high, but the NSR Workshop Manual does not allow for dismissing a control option based on unsubstantiated beliefs about costs. B&McD should do a cost estimate based on reasonable expected reheat fuel requirements, equipment installations, plant modifications, etc. A comprehensive analysis would be unnecessary if it is shown that costs of

one or two aspects of installing low-dust SCR (i.e. the reheat fuel costs) would be unacceptably high. Since there have been low-dust installations at utility boilers, EPA cannot concur with the general assessment that the costs are expected to be unacceptably high for MRYS.

3. EPA Analysis of the Burns & McDonnell's Conclusion:

EPA's January 9, 2007 Comment:

As explained above, EPA Region 8 believes that the inherent challenges with installing and operating low-dust SCR at MRYS are resolvable on a technical basis. The fact that a few low-dust SCR applications are currently used in practice indicates that the small-particle catalyst fouling and deactivation problem described would not preclude the use of low-dust SCR..... B&D's statement's that "low-dust SCR performance and catalyst life could be severely negatively impacted resulting in premature, extended, frequent outages for replacement" can be minimized by proper SCR design and on-line cleaning. As stated previously, any real costs associated with the construction and maintenance required to operate the low-dust SCR should be accounted for under the economic impacts stage of the Top-Down BACT analysis (step 4). Similarly, physical plant modifications that would be required to accommodate the low-dust SCR (and auxiliary equipment) should be considered in the economic impact evaluation, rather than used as evidence of technical infeasibility.

B&McD's March 19, 2007 Response:

As previously stated by the EERC, the EPA fails to recognize that lignite-fired cyclones partition the ash, increasing the proportion of sodium in the smaller particles, resulting in increased propensity for the formation of the complex sulfate phases. The fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components that cause bonding, blinding, and deactivation of individual catalyst reaction sites, even in a low-dust SCR application.

EPA Response:

B&McD appears to be saying that a significant portion of the sodium in the flyash is in the vapor phase when it enters the ESP. Therefore, these smaller sodium particles would not be controlled by the ESP and would condense to a liquid at the temperature range for a low-dust SCR. This results in bonding, blinding, and deactivation of individual reaction sites of the catalyst. There is no quantification of the flyash sodium in the vapor phase that would cause the severe catalyst plugging and blinding described under the high-dust SCR portions of the BACT analysis. Presumably, if a significant portion of the flyash sodium is in vapor phase when it would be entering the ESP, that same portion would also be in vapor phase when entering a high-dust SCR and therefore not affect the catalyst. EPA is not disputing that there may be some vapor phase flyash sodium that will bypass the ESP and deposit on the low-dust SCR catalyst. Based on B&McD and EERC's assertions that a high-dust SCR system at MRYS would see a sodium environment higher than any other SCR system in the world, it would seem that most of

the flyash sodium is not expected to be in vapor phase at the temperature of the high-dust SCR and ESP. If this is the case, EPA expects a very large portion of the flyash sodium would be removed by the ESP and not effect a low-dust SCR installation.

Additionally, during EPA's April 16, 2007 phone conversation with Flemming Hansen of Haldor Topsoe, Mr. Hansen indicated Haldor Topsoe did run some catalyst "test coupons" at the Wisconsin Electric Power (WE Energies) Presque Isle Station, which burns Powder River Basin coal with similar sodium levels to North Dakota lignite. Mr. Hansen recollected that there was a significant difference in the deactivation of the test coupons upstream of the particulate control device (ESP) compared to downstream of the ESP at Presque Isle. Mr. Hansen did not offer a reason why or attempt to quantify the difference. The most obvious explanation for the difference would be that the ESP removed a great deal of material that deactivates catalyst. This experience suggests that catalyst deactivation observed at a low-dust SCR would be less than at a high-dust SCR.

III. Additional Information Useful to Evaluating Technical Feasibility of SCR at MRYS

A. EPA Headquarters Believes SCR is the Correct Technology for MRYS in Developing the Clean Air Interstate Rule (CAIR)

EPA's January 9, 2007 Comment:

During the preparation of the CAIR rule, EPA developed a scenario for best controls across coal-fired units in the United States based on an assessment of boiler type, fuel type, and existing controls. This assessment recommended that SCR technology would be the best technology for the two units at MRYS.

Several commenters -- Montana-Dakota Utilities Co. (VI.C-0754); Otter-Tail Power Co. (VI.C-0628); Lignite Energy Council (VI.C-0935); Lloyd, Gosselink, Blevins, Rochelle, Baldwin & Townsend, P.C. for Texas Lignite Coalition (VI.C-1037); and Basin Electric Power Cooperative (VI.B-0690) -- argued that SCR technology is not feasible for application on lignite-fired boilers. Some of these commenters claimed that an SCR pilot test on a slipstream from a boiler firing lignite had shown catalyst plugging and blinding. One commenter attributed this problem to sulfates of calcium and sodium, which are present in the flue gas stream entering the SCR, as a result of firing of lignite in the boiler. One of these commenters also claimed that SCR was not feasible for boilers firing sub-bituminous.

In its response at VI.B. of the CAIR docket, EPA noted that there is considerable experience in the industry to show that use of SCR on sub-bituminous coals and lignite is technically feasible. SCR is currently in use on several sub-bituminous coal-fired boilers in the U.S. firing Powder River Basin coal. Regarding the use of SCR on boilers firing lignite, EPRI testing of SCR catalyst in a slipstream at the Martin Lake plant showed acceptable results from Texas Lignite. Furthermore, the technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. From this experience, it can be concluded that SCR can be used on sub-bituminous coal and lignite boilers in the

U.S. and catalyst suppliers have indicated that they will offer performance guarantees on these applications in the U.S.

In the docket information regarding this issue, one of the SCR catalyst vendors, Argillon, provided a list a SCR installations at EGUs in Europe that burn lignite or similar rank coal, including:

- *Riedersbach installations in 1995 and 2001(hard coal/lignite)*
- *Voitsberg (lignite)*
- *Dormagen installations in 1994 and 1996 (lignite)*

EPA also noted that the commenters have not provided any details of the pilot test that has been mentioned with regards to the plugging and blinding of a catalyst from lignite-generated fuel gases. Without this information, this part of the comment cannot be addressed properly. The EPA's own investigations show that the main reason for this problem was ash build up on the catalyst, which is a problem commonly experienced in pilot test facilities. In the full-scale installations, this concern is addressed during the SCR design stage. The methods used to avoid this problem include duct design to promote ash fallout prior to the SCR, catalyst reactor design to avoid ash build up, and on-line cleaning methods (sootblowers and sonic horns).

In addition, the following catalyst vendors stated that they could provide catalysts/SCR for lignite-fired boilers: Haldor-Topsoe……Cormetech…….Argillon……

In a memo dated August 20, 2004, Jim Staudt of Andover Technology Partners to Sikander Khan of EPA CAMD, discussed both the EERC pilot testing results and some of the negative issues raised by B&M and documented how Haldor Topsoe was aware of these issues, but nevertheless felt comfortable providing SCR catalyst……

EERC's March 19, 2007 Response:

EPA's cited experience from subbituminous coals and SCR does not have direct application to the North Dakota lignite-fired cyclone boilers at MRYS because of the high sodium content of the lignite. The SCR experience with German brown coals does not have direct application to ND lignite because of the lower sodium levels of the German coals.

EERC spoke to Flemming Hansen of Haldor Topsoe ……on February 2, 2007 about the issues associated with high sodium North Dakota lignite. Haldor Topsoe has experience with sodium and potassium from biomass fired systems and their experience has not been good. After describing the issues related to sodium……after 6000 to 7000 hours of operation with a coal having elevated levels of sodium.

EPA Response:

EPA's presentation of some U.S. subbituminous coal and German brown coal experience was intended to demonstrate that SCR systems have been shown to work worldwide on lower-ranked coals. While direct application of SCR experience on these coals may not be entirely appropriate for North Dakota lignite, EPA did use this information (along with the other factors

described in the January 8, 2007 comments) to conclude that SCR was technically feasible for lignite boilers in general.

As described above, EPA's discussion with Flemming Hansen of Haldor Topsoe also revealed that despite concerns about an SCR system subject to the sodium environment that would exist for a North Dakota lignite application, Haldor Topsoe would not rule out bidding such a project.

B. SCR Technology is Presumptive BART for Cyclone Boilers in EPA's BART Guidelines

EPA's January 9, 2007 Comment:

EPA made a specific and informed decision in its BART Guidelines regarding cyclone-fired utility boilers. For all other boiler types, some form of combustion control was deemed to be the presumptive level of control. However, for cyclone units burning any type of coal (bituminous, subbituminous, or lignite), presumptive BART is SCR. SCR was selected because the technology is feasible and cost-effective……..

B&McD's March 19, 2007 Response:

EPA ignored the numerous comments received for the draft BART guidelines (similar to that cited in the EPA's CAIR discussion for the preceding issue) about the infeasibility of SCR applied to North Dakota lignite. The unit capital cost capacity factor for SCR retrofits applied to cyclone boilers by the EPA in the cost-effectiveness analysis used for establishing presumptive BART was $100/kW.

Burns & McDonnell believes the EPA's cost-effectiveness analysis is inaccurate and significantly underestimates the expected capital plus operating and maintenance costs required to apply high-dust or low-dust SCR technology to North Dakota lignite-fired cyclone boilers.

EPA Response:

B&McD contends that EPA ignored numerous comments received on the draft BART guidelines about infeasibility of SCR applied to North Dakota lignite. As stated above, EPA weighed many different factors and concluded that SCR is technically feasible for a plant fired on North Dakota lignite.

B&McD also contends that EPA underestimated the capital costs for SCR on cyclone boilers and that total cost estimates in the BART guidelines are inaccurate for applying SCR to North Dakota lignite-fired cyclone boilers. EPA is not suggesting that the cost figures used in the BART analysis need to be used in the BACT analysis for MRYS. EPA has maintained that Minnkota should provide a cost analysis for Units 1 and 2 according to step 4 of the Top-Down BACT analysis.

C. February 27, 2006 Final Revisions to 40 CFR Part 60, Subpart Da, New Source Performance Standards for Electric Utility Steam Generating Units Set Final NOx Limit Based on Technical Feasibility of SCR for Lignite-Fired Units.

EPA's January 9, 2007 Comment:

In its response to public comments on the February 28, 2005 draft NSPS, Subpart Da proposal, EPA rejected comments received on NOx control requirements for lignite-fired units. Specifically, EPA took the same position as it did in the CAIR and BART rules, rejecting commenters' concerns that SCR would not be feasible for lignite units. No legal challenges were made to the final rule regarding EPA's response to the lignite concerns……..

B&McD's March 19, 2007 Response:

Burns & McDonnell rejects the EPA's argument that the lack of a lawsuit protesting the establishment of revised NSPS limits for new electric utility steam generating units (EUSGUs) that require SCRs for NOx control means that this is appropriate technology for a BACT retrofit on existing lignite-fired cyclone boilers. Cyclone boilers are no longer commercially available, so there are no new cyclone boilers being permitted and built. Utility owners of existing North Dakota lignite-fired boilers would not be expected to comment on the draft revisions to the NSPS proposed by the EPA because they apply only to new units with different methods of firing coal than cyclone boilers. It is doubtful that the EPA considered firing lignite in new cyclone boilers would be a possibility when they proposed the draft NSPS standards.

Any recently built or permitted lignite-fired boilers have been predominantly circulating fluidized bed (CFB) type and have not incorporated SCR technology for NOx emissions control. There have been recent permit applications filed for constructing pulverized coal boilers burning Texas lignite that propose to include high-dust SCR technology. However, there are distinct differences between North Dakota and Texas lignites that preclude assuming that this supports the technical feasibility of applying high-dust SCR technology to existing cyclone boilers burning North Dakota lignite.

EPA Response:

B&McD contends that since no new cyclone units are being permitted and built, existing utility owners in North Dakota would not be expected to comment on draft revisions to the NSPS proposed by EPA because they apply only to new units with different methods of firing coal than cyclone boilers and that it was doubtful that EPA considered firing lignite in new cyclones when proposing the draft NSPS standards. Actually, the new NSPS standards apply to affected utility boilers that commence construction, reconstruction, or modification after February 28, 2005.[21] (EPA's original comments erroneously said that the standards only applied to new units.) This would include any existing cyclone units firing North Dakota lignite that undergo reconstruction

21 See 40 CFR §60.44Da(e)

or modification. The standards that would apply to reconstructed units (1.0 lb/MWh or 0.11 lb/MMBtu on a 30-day average) and modified units (1.4 lb/MWh or 0.15 lb/MMBtu) are well below the BACT limit proposed by Minnkota. Since these standards apply to modified and reconstructed affected units and not just new units, the exclusive construction of new circulating fluidized bed (CFB) boilers in North Dakota and the differences between Texas lignite and North Dakota detailed by B&McD and EERC are not particularly relevant to the revised NSPS. EPA does not disagree that all of the recently-permitted utility boilers have been CFB boilers (although that does not rule out the possibility of a PC-fired unit in North Dakota in the future). EPA also agrees that there have been some recently-permitted units burning Texas lignite that have proposed SCR and that there are some differences in characteristics between North Dakota and Texas lignite. EPA believes these differences might affect the design and operation of an SCR system for the different lignites. EPA does not believe these differences indicate that EPA did not consider North Dakota lignite in revising the NSPS for utility boilers.

EERC Response:

North Dakota lignites are substantially different than Texas lignites in composition and fouling tendencies. The following comparison shows the proximate analyses, sulfur contents and heating values for various lignites, plus ash compositional analyses of Texas lignites.....Comparison of North Dakota and Texas Lignites.....Table 3 summarizes ash composition analysis expressed as equivalent oxide. The compositional analyses show that the ash has relatively low sodium and lower calcium content than North Dakota lignite. The problems of SCR catalyst blinding due to the formation of sodium calcium sulfates created from the firing of Texas lignites will be much less severe than for North Dakota lignites.

EPA Response:

EPA has reviewed the coal data submitted by EERC and, in general, agrees that the sodium content of Texas lignites is lower than North Dakota lignites. However, it appears that the Jackson South Texas lignite has a somewhat comparable ash sodium content above 3% (EPA assumes this is an average) compared to the average (or 50th percentile) value of 4.4% for Center mine coal (per the April 23, 2007 coal analysis submitted by Minnkota). Considering the high ash content of the Jackson South lignite (42% average) and low heating value (3,972 Btu/lb as received), compared to the ash content (9.53% average) and heating value (6,572 Btu/lb) of Center Mine lignite, the Jackson South lignite of Texas would actually have a much higher sodium loading (on average) than Center Mine lignite (by roughly a factor of 4). The Yegua East lignite with an ash content of 18% and a heating value of 5,761 Btu/lb would have a sodium loading of roughly 60% of average Center Mine lignite. As explained in previous comments, EPA does not believe a strict linear comparison can be made from these loading levels, but it appears that some Texas lignite has comparable sodium levels on a per Btu basis to Center Mine lignite.

Notwithstanding the differences between North Dakota lignite and Texas lignite, a modified cyclone boiler firing North Dakota lignite would still need to meet the most recent NSPS Da limit for modified units, which is much lower than the BACT limit proposed by Minnkota. The likely choice to meet this limit of 0.15 lb/MMBtu would be SCR.

D. SCR and Catalyst Vendor Information

EPA's January 9, 2007 Comment:

As noted above, the following catalyst vendors were comfortable providing catalysts/SCR for lignite-fired boilers: Haldor-Topsoe, Cormetech, and Argillon.

In addition, the above-cited memo dated August 20, 2004, Jim Staudt of Andover Technology Partners to Sikander Khan of EPA CAMD, discussed both the EERC pilot testing results and some of the negative issues raised by B&M and documented how Haldor Topsoe was aware of these issues, but nevertheless felt comfortable providing SCR catalyst.

EPA Region 8 also contacted the Institute of Clean Air Companies website to obtain the following list of 21 companies offering "SCR Systems, Equipment, Supplies and Services:"

EPA Region 8 has visited most of the vendors' websites and found many vendors with experience that would be germane to the MRYS situation.....We believe it would be prudent for Minnkota to obtain information and proposals from more than one vendor and involve the NDDH and EPA in their findings.

EERC's March 19, 2007 Response:

EERC has already included some comments from discussions with Haldor Topsoe regarding their concerns about the sodium content in North Dakota lignite and its tendencies for catalyst deactivation. Some of the EPA-cited SCR catalyst vendors' websites discuss the problems of sodium and deactivation. However, EPA has not provided a review of that information.

EPA's Response:

EPA has already discussed its phone conversation with Flemming Hansen of Haldor Topsoe and how Mr. Hansen, while acknowledging some difficulty dealing with the sodium issue with North Dakota lignite, did not dismiss that an SCR system might be technically feasible for a North Dakota lignite application, nor the possibility that Haldor Topsoe would bid on such a project.

B&McD March 19, 2007 Response:

EPA's listing of 21 suppliers of "SCR Systems, Equipment, Supplies, and Services..." has not been screened to eliminate companies that are not active in the U.S. coal-fired SCR market.....EPA's

evidence of SCR catalyst vendor's willingness to guarantee performance on a lignite-fired boiler is very general in nature and does not include typical qualifying statements related to the client's need to adhere to specified SCR design conditions, which are yet to be established……

……from Burns & McDonnell's experience, what a vendor or supplier says pre-bid does not always match what they actually will offer in a firm contract….. a commercial guarantee does not mean the system provided by the vendor will work long term; all it means is that based on the language in the contract and the amount of money the supplier has allocated to cover their risk or exposure, the vendor will guarantee the system performance……commercial contract guarantees always have a finite life, which means the owner of the system only benefits from the vendor's guarantee for 3 years typically….

EPA's cites SCR catalyst vendor statements lack substantive language that deals with mitigating the client's risks of failure to meet catalyst activity versus life guarantees, and the concerns recently expressed by Haldor Topsoe when EERC described sodium components in the flue gas. In Burns & McDonnell's opinion, SCR system vendors have not provided adequate documented and published demonstrated catalyst experience with supporting technical information to support these claims. The vendors offered no specific comparative peer-reviewed data as proof that currently-available catalysts can survive and provide effective NOx reduction when exposed to the flue gas and flyash constituents exhausted from combustion and operation of any cyclone boiler firing North Dakota lignite, particularly one located in a high-dust, hot-side application at Milton R. Young Station.

EPA Response:

EPA had originally suggested that Minnkota "obtain information and proposals" from some of the other companies that EPA had listed. EPA envisioned this to include more of the level of detail described by B&McD in their March 19, 2007 response. While B&McD seems to discount the value of a performance guarantee, EPA's NSR Workshop Manual states that "(v)endor guarantees may provide an indication of commercial availability and the technical feasibility of a control technique and could contribute to a determination of technical feasibility or technical infeasibility, depending on the circumstances." While EPA does not believe the vendor guarantee is the sole factor in determining technical feasibility of SCR for MRYS, EPA does believe it would be useful information to obtain for making the determination.

EPA's RESPONSE TO EERC AND B&McD APRIL 23, 2007 LETTER TO NDDH COMMENTS – FEBRUARY 1, 2007 (INCLUDING RESPONSE TO U.S. EPA REGION 8 COMMENTS – JANUARY 26, 2007): REQUEST FOR ADDITIONAL INFORMATION AND THE NON-SCR COMMENTS FROM EPA

IV. MINNKOTA'S RESPONSES TO ADDITIONAL INFORMATION REQUESTED

A. Center Mine Lignite Coal Ash Content and Variability

EPA's January 26, 2007 Request:

Please provide data currently available on the Center Mine coal constituents (presented in Minnkota's October 2006 NO_x BACT Analysis), including all available data sampling for future and presently-mined areas of the mine. Please provide the data in terms of averages, in addition to value ranges.

EERC April 23, 2007 Response:

The historical database was obtained from samples collected for the purpose of testing the impacts of lignite characteristics on plant performance. The database consists of 1317 as-fired samples. The average, standard deviation, maximum, minimum and selected percentiles for ash, sulfur, heating value, and selected ash constituents are included in Table 1.

The use of average coal properties for design and performance of combustion and environmental control systems typically under estimates adverse problems such as fireside ash deposition, opacity, and sulfur emissions. Designs of power systems must consider the challenging coal characteristics in order to develop designs and operating parameters with sufficient flexibility that allow for the combustion of coals that at least represent the 90th and 10th percentile of selected constituents.....The frequency distributions of components of the coal provide better understanding of the potential challenges....The results of the analysis show that the lignite ash has a 4.4% average sodium content; however, there is a multimodal distribution of sodium levels in the coal ash.....The average properties as well as the minimum and maximum values do not adequately represent the characteristics of the fuel. As indicated in Figure 1, the MRYS boilers are firing some very high-sodium-containing coals that can cause significant problems when sodium reacts with silicate, aluminosilicate, and sulfur species in the furnace and lower temperature regions of the power plant.

EPA Response:

EPA has reviewed the coal data submitted by Minnkota. EPA believes the future coal data appears to show little change from the 2007 core samples. EPA is not sure what the basis is for EERC's statement that "sodium levels have shown increased levels in the future coals that will likely contribute to increased fouling challenges."[22] The sodium oxide percentages from 2007

22 See page 10 of April 23, 2007 letter from Minnkota to EPA, DOJ, and NDDH.

compare very closely to the 2009-2010 cores samples (Ave. = 5.8% vs. 5.6%, Max = 13.3% vs. 13.4%) as do the ash percentages (Ave. = 7.9% vs. 7.1%, Max = 24.6% vs. 23.8%). As explained in great detail above, these differences in coal characteristics are useful for making general comparisons with other fuel types, but it is unclear how these differences can be directly applied when making determinations on feasibility of SCR at MRYS.

B. High Economizer Exit Temperature

NDDH's February 1, 2007 Request:

The temperature between the economizer and the air heaters is described as "much higher than 750 degrees". Please provide more specific data on the temperatures that would be encountered at the location an SCR would be installed.

B&McD's April 23, 2007 Response:

The primary superheat (PSH) outlet flue gas temperatures for Unit 1 are provided instead of the economizer outlet temperatures. Unit 1 at the M.R. Young Station has a two-pass tubular air preheater (APH). The economizer for Unit 1 is situated between the first and second pass of the air preheater. The flue gas passes on the inside of the tubes of the APH…… The configuration of the economizer and air preheater physically precludes locating a conventional high-dust SCR upstream of the existing air preheater-economizer on Unit 1 in its current location and configuration. The flue gas temperature is reduced by transferring heat to the boiler's feedwater and the boiler's combustion and drying system air streams, respectively. In addition, temperatures at the existing air preheater outlet for Unit 1 are far below the temperatures needed for operation of a conventional hot-side high-dust SCR.

The Unit No. 1 boiler is shut down for cleaning at intervals ranging from approximately 90 to 120 days. The gas temperatures at the PSH outlet vary inversely with the boiler cleanliness during each operating run…… Note that at low loads and clean conditions, the PSH outlet flue gas temperatures are 170-270 degrees F below the acceptable range for conventional hot-side high-dust SCR catalyst ….Unit 1's PSH full-load flue gas temperatures historically range between 840 F and 960 F, depending upon the cleanliness of the boiler…..there have been instances when Unit 1's PSH full-load average flue gas temperatures have exceeded 1000 F and individual temperature measuring elements have exceeded 1050 F.

A portion of MRYS Unit 2 boilers' feedwater heating surface is in a location normally occupied by a traditional conventional economizer section in the convection pass of the boiler……The configuration of the boiler's economizer and the air preheater physically precludes locating a conventional high-dust SCR upstream of the existing air preheater/economizer on Unit 2 in its current location and configuration……Unit 2 boiler is shut down for cleaning at intervals ranging from approximately 80 to 110 days. …….at low loads and clean conditions, boiler outlet flue gas temperatures are 170-270 degrees F below the acceptable range…….Unit 2's boiler-exit economizer-outlet full-load flue gas temperatures historically range from 780 to 880 F…..there have been instances when Unit 2's

average full-load economizer outlet flue gas temperatures have exceeded 930 F and individual temperature measuring elements have exceeded 990 F.

EPA Response:

This information that was requested by NDDH was reviewed by EPA. EPA acknowledges that there are times when the flue gas temperature at the portion of the boiler where a high-dust SCR would be located (primary superheat outlet for Unit 1 and presumably the economizer exit for Unit 2) would be higher than the temperature range typically suitable for SCR.

While B&McD seems to indicate in the March 19, 2007 letter that the dual-air preheater design suggested by ERG would be problematic, it later concedes that it conceptually could work, but would be at an additional cost. EPA agrees that such a design would cost more than a typical high dust SCR application. A more refined cost estimate that reflects real costs associated with constructing and operating a split air heater design can certainly be submitted by Minnkota. EPA believes this would be conducted under step 4 of the Top-Down BACT analysis.

For further information on this topic, please refer to the August 2007 Christman Memo response regarding the split air heater.

C. Low-Dust SCR Fouling

NDDH's February 1, 2007 Request:

It is indicated that a low dust SCR would be subject to the same fouling problems as a high dust SCR due the emissions of small (< 5 micron) particles containing sodium-calcium sulfur rich materials. Please provide any existing data on the composition of the particulate matter exiting the electrostatic precipitators.

EERC April 23, 2007 Response:

As previously discussed in responses to the EPA's January 8, 2007 comments, the MRYS cyclone boilers' fly ash becomes enriched in components that vaporize and, subsequently, condense upon gas cooling to form liquid phases and small particles that are very reactive to gas-phase components, resulting in formation of compounds that cause bonding, blinding, and deactivation of individual catalyst reaction sites, even in a low-dust SCR application. Sodium-rich aerosols can get through the electrostatic precipitator (ESP). These aerosols are known to be present in high-sodium coal combustion flue gases. These species are known to produce pyrosulfates. These will cause blinding and deactivation of the low-dust catalyst.

Stack sampling was conducted downstream of the EPS and set FGD on Unit 2 at the MRY plant. The filters were examined using scanning electron microscopy and x-ray microanalysis to determine the microscopic features and chemical compositions.....The chemical compositions of the analysis areas and points were determined through the use of energy dispersive x-ray microanalysis....

EPA Response:

This information that was requested by NDDH was reviewed by EPA. While the relative effects of vaporized particles passing through the ESP and condensing prior to a low-dust SCR system might be more pronounced compared to the non-vapor particles impacting a high-dust environment, EPA maintains that the ESP will remove a very substantial portion of the ash that would affect a high-dust SCR and the overall effects of catalyst plugging and deactivation in a high-dust application would be greater than in a low-dust application. This is substantiated by EPA's discussion with Flemming Hansen of Haldor Topsoe and his experience with SCR test coupons at the WE Energies Presque Isle Station, as discussed above. EPA acknowledges that there are other technical and cost issues related to low-dust SCR that were discussed previously.

D. <u>SCR Deactivation</u>

EPA's January 26, 2007 Request:

Please provide any and all data and information related to catalyst deactivation rates and NO_x control effectiveness measured at the three facilities tested during the "Ash Impacts on SCR Catalyst Performance" study that is extensively referred to in the "EERC Report" included as Appendix B of the Minnkota NOx BACT analysis. This should include the original proposal, all test plans, all raw catalyst deactivation and NO_x control data collected during the test, and all final reports and conclusions that were produced for the study's participants. In addition, please provide a quantitative analysis of the application of the multiple engineering solutions (e.g. catalyst rejuvenation and regeneration, acoustic horns, etc.) described by Roger Christman and EPA to address specific concerns highlighted in the BACT analysis and EERC Report and their effect on SCR catalyst deactivation rates and NO_x control effectiveness at MRYS.

EERC's April 23, 2007 Response:

The EERC offered to send them to Haldor Topsoe for evaluation; the catalyst vendor indicated that the Coyote SCR test catalysts were too plugged and deactivation testing could not be conducted. The lack of published catalyst activity data for the Coyote slipstream SCR catalyst field test is a result of the severity of the catalyst fouling from North Dakota lignite ash. The requested data is available; this information has been copied, compiled, and due to its volume, will be submitted separately.

Information on catalyst deactivation rates and NOx reduction effectiveness for the Baldwin and Columbia Station slip-stream SCR catalyst field testing was determined and some of the information was in the final report. EERC recently received information from Hitachi on catalyst deactivation for the

catalysts at Columbia. This information is included in the EERC data compiled and being submitted to the NDDH.

Regeneration has been attempted in Europe with SCR catalysts exposed to biomass as with high potassium (elemental symbol K, similar in chemistry to sodium, Na), and they had some significant problem in recovering reactivity (Khodayari and Odenbrand, 2001).

EPA Response:

EPA has reviewed the background documents. Please see EPA's previous detailed analysis related to the review of the pilot study documents under the section,"EPA Analysis of Burns & McDonnell's Conclusion" (responding to the March 19, 2007 letter response.)

B&McD's April 23, 2007 Response:

A quantitative analysis on the application of the multiple engineering solutions suggested by the EPA's commenter mentioned above has not been performed. Significantly more time would be required. A definitive analysis would require pilot-scale slipstream SCR reactor testing on the flue gas streams emitted from the boilers at MRYS over a significant length of time to simulate real-time effects of gas and flyash constituents and their interactions with the catalyst. Using assumptions of the effectiveness of solutions suggested by EPA's commenter based on use of theoretical data developed from laboratory testing and/or empirical data gathered from other high-dust SCR installations that do not treat flue gases produced from cyclone boilers firing North Dakota lignite coal would be hypothetical. Such a theoretical quantitative analysis of EPA's claimed SCR catalyst improvements cited and whether this would actually be translatable into preventing the catalyst layers from being susceptible to macro-pore blinding and plugging by calcium-based compounds and the impact on the individual catalyst reaction sites from sodium-based compounds discussed in Dr. Benson's referenced technical paper would be speculative.

Burns & McDonnell believes it would not be accurate to burn lignite or use flyash samples collected from a MRYS electrostatic precipitator with artificial flue gas to simulate catalyst fouling and blinding phenomenon in a laboratory- or pilot-scale test setting.....Performing a quantitative analysis would require substantial resources to develop slip-stream SCR catalyst test equipment designs and operational conditions to address the significant technical challenges that were evident in the reference field demonstration testing at Coyote station. It is unreasonable that the EPA expects that such an in-depth investigation is required under a BACT analysis.

Performing a BACT analysis on an existing unit should not require substantial resources .....

EPA Response:

Many of the concerns in this section have been previously presented verbatim by B&McD and have been largely addressed elsewhere in EPA's previous responses. See the March 19, 2007 response to "North Dakota Industrial Commission project Evaluation of Potential SCR Catalyst Blinding During Coal Combustion (from the January 8, 2007 ERG Memo)" and "EPA Analysis of Burns & McDonnell's Conclusion."

B&McD's response indicates that a complete evaluation of the engineering solutions to address macro-pore plugging and individual catalyst site deactivation goes beyond the requirements of a BACT analysis and would be speculative without doing additional pilot testing. As noted previously, EPA believes that Minnkota faces a high threshold for demonstrating that a technology like SCR, that has been widely-deployed in the same industry, is technically infeasible. While results from a well-designed and operated pilot test would certainly be useful in optimizing a potential SCR system to deal with the plugging, blinding, and deactivation issues, EPA is not convinced that it would be required if a conservative design approach is taken.

In the previously mentioned meeting with Sargent & Lundy, LLC, Mr. William DePriest, Senior Vice President and Director or Environmental Services, indicated that an SCR system could theoretically be designed to operate on North Dakota lignite, but indicated the design would likely have to be conservative in terms of the catalyst design and sizing of the reactor and could result in significant maintenance requirements and associated outages. Sargent & Lundy representatives were of the opinion that a well-run pilot test would yield valuable information that could be used in conjunction with previous SCR experience to evaluate and design an SCR system for a North Dakota lignite application.

In EPA's view, the unanswered questions related to North Dakota lignite described by Sargent & Lundy would likely result in exaggerated capital costs (conservative design) and/or potentially result in additional operational costs to Minnkota. EPA agrees it would be preferable to have additional data related to catalyst deactivation on North Dakota lignite in order to select the optimum catalyst design and reactor size. It is unfortunate that the pilot testing at Coyote Station did not capture this information. However, the risks involved in the capital and operational costs cannot be used as the basis for a determination of technical feasibility. The NSR Workshop Manual states that "(w)here the resolution of technical difficulties is a matter of cost, the applicant should consider the technology as technically feasible."[23] EPA believes that the cost for a conservatively-designed SCR system at MRYS that minimizes the associated risks described and includes an anticipated catalyst operation and maintenance schedule can be estimated and accounted for under step 4 of the Top-Down analysis.

23 See NSR Workshop Manual page B.19-20

E. SCR Vendor Guarantees

EPA's January 26, 2007 Request:

Although EPA's Draft 1990 NSR Workshop Manual recognizes that vendor guarantees by themselves are not sufficient to show that a technology is feasible, vendor guarantees can contribute to a technical feasibility determination in some situations. In light of statements EPA has received from three SCR vendors (Haldor Topsoe, Cormetech, and Argillon) indicating they would provide performance guarantees on SCR lignite applications, please provide additional vendor information, from multiple vendors, that Minnkota believes is more specific to MRYS than the statements received by EPA and cited in EPA's analysis submitted to North Dakota on January 8, 2007. We would expect that the catalyst suppliers cited above would be among the vendors contacted by Minnkota.

EERC's April 23, 2007 Response:

EERC has already included some comments from February 2007 telephone discussions with Haldor Topsoe regarding their concerns about the sodium content in North Dakota lignite and its tendencies for catalyst deactivation.

EPA Response:

EPA has previously presented its own discussions with Haldor Topsoe.

B&McD's April 23, 2007 Response:

A query of SCR catalyst vendor's willingness to guarantee performance on a lignite-fired boiler to address comments in EPA's cited documents mentioned above has not been completed. Additional time is required. The information on SCR performance guarantees for MRYS applications has been requested; it will be submitted separately when it is available. A copy of the information request letter and attachments issued to the SCR vendors is attached (Appendix A).

System and equipment vendors have a self-interest to sell technology that they offer, and to manage financial risks by specifying the limits of their system design in case of potential operating conditions that cause performance problems that prevent achievement of guarantees and/or warranty claims……..

EPA Response:

B&McD states obtaining this information will require more time. They have sent a letter to four catalyst system suppliers and five catalyst suppliers. The letter goes into great detail about the worst-case nature of Center Mine coal. During the May 23, 2007 meeting in Bismark with Minnkota and NDDH, B&McD indicated that they did get some feedback from a few vendors, but were unable to disclose any written response at that time. EPA has still not seen any vendor responses to the information request. EPA does note that the request seems to have been written

with a pessimistic tone that would likely lead the vendor to believe that the requestor was not serious about obtaining a contract for the described SCR project. There is also reference to comments made by EPA on the Minnkota MRYS BACT analysis, which would provide further disincentive on the part of the vendor to properly evaluate and give serious consideration to the request. Because of this EPA is suspect that the feedback might be negatively biased and not provide a realistic response to whether a vendor would be interested in bidding a performance guarantee on an SCR project at MRYS.

F. MRYS Boiler Cleaning Outages

EPA's January 26, 2007 Request:

The Minnkota MRYS NO_x BACT analysis includes discussion of periodic boiler outages that are required to address the slagging effects of the Center Mine lignite. Please provide historical dates of these outage periods and their duration for the previous 10 years. Also, please provide an estimate of boiler outage frequency that would be expected due to SCR maintenance, based on information collected in response to items 1 and 2 of this list.

B&McD's April 23, 2007 Response:

Information to estimate MRYS boiler outage frequency expected for high-dust SCR maintenance based upon a query of SCR catalyst vendors mentioned in item 2 above is not available at this time. Additional time is required.

A review of historic outage data shows that over the past 10 years (1997-2006), the typical MRYS Unit1 boiler cleaning outage was between 67 and 82 hours in duration, but these can be as short as 56 hours and as long as 206 hours.....Over this same time period, the typical MRYS Unit 2 boiler cleaning outage was between 64 and 102 hours in duration, but these can be as short as 37 hours and as long as 244 hours.....A boiler fireside cleaning outage is typically scheduled for 96 hours (four days) duration.

A high-dust SCR would need to be isolated from the gas path between the boiler and the inlets to the electrostatic precipitator during boiler cleaning outages to prevent the moisture and deposits liberated during boiler fireside surface cleaning from entering the SCR reactor. Beginning the work of removing ash accumulation or catalyst from the SCR reactor(s) will be delayed by 48 to 60 hours after the start of the outages, depending on ambient temperatures, because the inside of the reactor(s) will be too hot for personnel health and safety. Because the length of the boiler cleaning outages is typically less than 4 days (96 hours), that does not leave much time to do any significant catalyst cleaning or replacement work without delaying boiler startup. The estimated amount of time and difficulty in removing lignite ash accumulation from the SCR reactor(s), or replacing fouled catalyst with clean spare catalyst, is expected to require at least 144 hours (6 days), plus 60 hours upfront for allowing the reactor to cool-down. This is based upon the use of mobile industrial vacuum cleaning methods ("super-sucker" truck). The total SCR maintenance outage time will be around 200 hours from boiler shutdown end to

beginning of startup. The frequency of such SCR maintenance outages are expected to be required at least annually, or more often.

There were only two outages other than major scheduled overhauls during the historic ten-year period that appeared to be of sufficient length (greater than 8 days) that could have lent themselves to significant catalyst cleaning or replacement work without delaying startup: one on Unit 1 and one on Unit 2.....There are basic concerns that using short boiler cleaning outages as SCR catalyst maintenance opportunities could be detrimental to catalyst life due to thermal stresses and passing through various dewpoint temperatures. Bringing the very large mass of ceramic catalyst material and the reactor structure down in temperature and then back up rapidly and any more frequently than absolutely necessary should be avoided.....

EPA Response:

EPA looks forward to reviewing the information obtained from the vendor request. During the previously discussed phone conversation with Flemming Hansen of Haldor Topsoe, Mr. Hansen gave a rough estimate that an SCR system for North Dakota lignite could be designed (larger) to accommodate a catalyst replacement schedule of about every year. Mr. Hansen said that an SCR reactor could be cooled down within 24 to 36 hours (need for the cool air draft requires the boiler to be shut down) and the catalyst layers rotated in about two or three days, three days all around. This is significantly less than the roughly 200 hours (or eight days) estimated by B&McD for catalyst replacement. This discrepancy would probably warrant further examination of both figures if in the context of a cost analysis.

G. Hydrocarbon-Enhanced Selective Non-Catalytic Reduction (HE SNCR)

EPA's January 26, 2007 Comment:

Minnkota eliminates this technology primarily based on the fact that it has not been applied to cyclone boilers or units burning lignite or high-slagging western subbituminous coals. There are two full scale installations of this technology on eastern pulverized coal-fired boilers. There is some general discussion about the slagging problems that lignite would cause the HE SNCR technology, but it is unclear whether the vendor of this technology would be able to overcome these issues. At this point, it is unclear whether HE SNCR is technically feasible. Minnkota should provide a more thorough analysis on whether this control option is "available and applicable" (as described in the NSR Manual) at MRYS by examining the physical and chemical characteristics of the exhaust stream in terms of technical feasibility and soliciting vendor information. A quantitative analysis of its technical feasibility should be provided and supported with data and vendor statements.

B&McD's April 23, 2007 Response:

The October 2006 MRYS NOx BACT analysis was performed using technical literature available in the public domain, proprietary vendor customer experience information, and limited engagement of selected vendors for capital cost, operating and maintenance costs, and emissions performance estimates along with Burns & McDonnell's technical expertise. This analysis approach meets the requirements of the EPA's NSR Manual.

A detailed query of the potential availability and applicability of hydrocarbon-enhanced (HE) selective non-catalytic reduction (SNCR) on a lignite-fired cyclone boiler from the single vendor mentioned in the October 2006 MRYS NOx BACT Analysis reports has not been performed. Additional time would be required. It is important and appropriate to specify the composition of the Center lignite coal and ash constituents and boiler configuration sufficiently to provide a sound basis for allowing the HE-SNCR vendors' reviews and qualified responses. HE-SNCR design conditions that are reasonably reflective of actual operating conditions and boiler fouling experience are yet to be established. The lack of detailed development of MRYS unit-specific HE-SNCR injection lance design schemes to deal with the high boiler fouling conditions and varying boiler gas temperatures and loads will require HE-SNCR design operating conditions to be assumed before workable design concepts have been confirmed....It is interesting to note that other non-cyclone BART-eligible boilers burning North Dakota lignite did not mention or evaluate HE-SNCR technology as a possible NOx control alternative in their BART analyses.

EPA Response:

EPA has simply asked Minnkota to get the vendor's input on the facility in question. Minnkota's original BACT analysis describes theoretical problems that might be encountered if HE SNCR is installed at MRYS and states that the lack of experience with cyclone boilers burning low-rank western coal satisfies a showing that HE SNCR is technically infeasible. The vendor who offers this technology states that it is not sensitive to fuel type or burners, so EPA still questions whether the determination of technical infeasibility is valid without getting vendor input or substantiating data.

EPA does not agree with B&McD's interpretation of the NSR Workshop Manual. B&McD states that in order for the vendor to develop a realistic technical basis that would support estimated unit-specific HE SNCR performance, capital and operation and maintenance costs, they would need specific customer data. B&McD claims this is not required by an applicant because the NSR Workshop Manual 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." This statement is in the context of determining whether the technology is "available." According to Minnkota's BACT analysis, the vendor of this technology believes the technology is not sensitive to fuel or burner types. As such, it would appear that, in general, this technology is "available" for MRYS. Therefore, the reference to the NSR Manual made by B&McD is only relevant if the vendor would not offer the technology to a customer based on specific conditions of the plant. Minnkota can go through this process if it believes the

technology is not available, but apparently does not wish to do so. Hence, EPA believes the technology is "available." If B&McD does not believe it is "applicable," further information should be provided. The reasons given by B&McD to this point (high boiler fouling conditions and varying gas temperatures and loads) appear themselves to be theoretical. EPA believes statements from vendors or more quantitative information might be helpful for making this determination.

EPA does not believe that whether other non-cyclone fired BART applicants included an analysis of HE SNCR is evidence, in and by itself, that the technology is infeasible at MRYS. If the technology is "available," it should be evaluated. According to statements from the vendor in question, the technology is generally available to power plants.

H. Reburn with SNCR

EPA's January 26, 2007 Comment:

While various forms of reburn systems were determined to be technically feasible in the Minnkota analysis, reburn combined with SNCR was ruled out based on technical infeasibility. Although full scale pulverized coal installations of gas reburn with SNCR and overfire air were found to exist, Minnkota did not analyze whether the technology combination would be "available and applicable" to MRYS, as described in the NSR manual. Instead, the application states, "(t)he lack of experience with these combinations on a cyclone-fired boiler, especially for lignite-firing, makes the application for MRY Station's boiler infeasible." Minnkota should provide a more thorough analysis.....

B&McD Response:

A detailed query of the potential availability and applicability of fuel reburn technology combined with SNCR on a lignite-fired cyclone boiler from the reburn technology vendors has not been performed. As mentioned in Appendix A1 of the October 2006 MRYS NOx BACT Analysis reports, while SNCR may potentially be installed downstream of separated overfire air and various types of fuel reburn, there is a lack of demonstrated experience of this combination on cyclone boilers. Only one example of gas reburn with SNCR, applied to a tangentially-fired boiler, was found in available technical literature. Moreover, the very high capital and O&M costs already estimated for coal and gas reburn technologies with ASOFA in Section 3 of the October 2006 MRYS NOx BACT Analysis reports showed that such alternatives were significantly above the BACT Dominant Controls Cost Curves for MRYS Unit 1 and Unit 2. Thus, even if fuel reburn technology combined with SNCR were available and applicable to lignite-fired cyclone boilers, the average and incremental unit control costs ($ per ton) would not be expected to be on the NOx BACT Dominant Controls Cost Curves for MRYS Unit 1 and Unit 2. Such reburn with SNCR alternatives would thus be considered as "inferior", and would not be considered as BACT Substantial resources would be required....It is interesting to note that other non-cyclone BART-eligible boilers burning North Dakota lignite did not mention or evaluate reburn with or without SNCR technology as possible NOx control alternatives in their BART analyses.

EPA Response:

B&McD has declined to perform an analysis of whether Reburn with SNCR would be "available and applicable" because the technology has not been "demonstrated" on cyclone boilers. However, according to the NSR Workshop Manual, the "available and applicable" analysis is only required whenever the technology in question has not been demonstrated in practice. If the technology has been demonstrated, it is considered technologically feasible without going through further analysis. Hence, B&McD's logic for not doing the "available and applicable" analysis appears to be contrary to the NSR Workshop Manual.

B&McD also makes the argument that the average and incremental cost associated with Reburn with SNCR would not expected to be on the NO_x BACT Dominant Control Cost Curves, so they would be eliminated on that basis, if they were found to be technically feasible. However, Reburn with SNCR would offer greater NO_x emissions reductions than just SNCR (assuming each would also include ASOFA), so this data point on the curve would be above and right of the data point for SNCR. EPA can not say with certainty that the average and incremental cost effectiveness of Reburn with SNCR would be ruled out based on cost because the analysis is not presented by B&McD.

B&McD also points out that non-cyclone BART eligible sources in North Dakota did not provide an analysis of Reburn with or without SNCR as a control alternative in their BART analysis. For the reasons cited above, EPA does not agree that Reburn with SNCR can be ruled out based on technological infeasibility or cost effectiveness at this time.

I. Rich Reagent Injection (RRI)

EPA's January 26, 2007 Comment:

Minnkota eliminates this technology because of the difficulty in achieving proper sub-stoichiometric boiler conditions necessary to get effective NO_x control. As described in the application, the problem occurs because of the variable heat content of Center Mine lignite. While RRI has been successfully demonstrated at cyclone units burning blends of Powder River Basin coal with Midwestern bituminous coal, Minnkota has ruled RRI out as technically infeasible. However, there does not appear to be an analysis of whether RRI meets the "available and applicable" criteria described in the NSR Manual for elimination under step 2. If RRI would be less effective for the reasons cited in Minnkota's application, that would result in a lower ranking under step 3 and possible elimination under step 4. At this time, it does not seem appropriate to eliminate RRI under step 2. Minnkota should provide a more thorough analysis.....

B&McD Response:

Since the publication of the MRYS NOx BACT Analysis report, two commercial Rich Reagent Injection systems have completed design, fabrication, and installation in late 2006 at Ameren Sioux Unit 1 and Unit 2. Full optimized routine operation is expected to begin by early May, 2007. Although RRI NOx emissions reduction technology appears to satisfy the "available" criteria (as described in the NSR Manual for technical feasibility) for potential application on the cyclone boilers at MRYS, the substantive issue is "applicability". The expected insurmountable difficulties in achieving consistent control effectiveness..... from this technology if applied to modestly air-starved cyclone combustion on these lignite-fired boilers and the reasons for technical infeasibility of RRI at MRYS were included in Appendix A1 of the October 2006 NOx BACT Analysis reports.

A query of the single RRI licensee mentioned in the MRYS NOx BACT analysis, and a quantitative analysis of its technical feasibility for the expected boiler operating conditions has not been performed. The transient variability of the fired lignite coal at MRYS was discussed in Appendix A1 of the October 2006 NOx BACT Analysis reports. This variability makes it impossible to accurately predict realistically achievable NOx emissions reductions even with sophisticated computational fluid dynamics (CFD) modeling of the MRYS boiler combustion reactions and in-furnace NOx reduction processes associated with RRI technology under reasonably realistic boiler operating conditions. This is due to the static (i.e. steady-state) nature of the boiler furnace operating conditions assumed to exist in order to simulate the performance of modestly air-starved cyclone combustion on these lignite-fired boilers with varying heat and air inputs to individual cyclones using CFD modeling techniques. Because of the dynamic variability of the higher heating value of the fuel burned and the lack of ability to precisely control the actual stoichiometry in real-time on an individual cyclone basis, RRI CFD model predictions would be unrealistic and thus these vendor statements would not be reflective of realistically achievable NOx emissions reductions. Substantial resources would be required.....

EPA Response:

EPA believes that the recent installation of RRI at the Sioux 1 and 2 cyclone units is also strong evidence that the technology is "applicable" to MRYS. The NSR Workshop Manual states that "if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible." While the Sioux plant does not burn lignite, PRB coal is also a low-ranking western coal. This indicates to EPA that before ruling out RRI as technically infeasible, detailed analysis should be provided.

While predicting the exact level of NO_x control for RRI and MRYS may not be possible, EPA believes some informed estimates could be made. Further, EPA does not believe predicting exact levels of NO_x control is necessarily crucial to whether a control option is technically feasible. Hence, EPA does not believe B&McD has demonstrated that RRI should be considered technically infeasible. In fact, EPA believes the recent operation of RRI at the Sioux plant provides strong evidence that RRI would be technically feasible at MRYS.

J. Rotating Opposed Fire Air (ROFA)

EPA's January 26, 2007 Comment:

Minnkota eliminates this technology because it "lacks demonstrated cyclone-fired experience, and thus was considered infeasible." While a technology that has been demonstrated on the source type under review would show it is technically feasible, lack of such demonstration for the specific type of emission unit does not necessarily lead to a conclusion of infeasibility. Minnkota should provide a more thorough analysis……

B&McD Response:

A detailed query of the potential availability and applicability of ROFA technology on a lignite-fired cyclone boiler from the single vendor mentioned in the October 2006 MRYS NOx BACT Analysis reports has not been performed. Burns & McDonnell has reviewed available ROFA technical literature, attended sales presentations and participated in discussions with ROFA vendor personnel regarding the application of ROFA to cyclone boilers, including lignite-fired units. As an engineer and design/builder of numerous commercial separated overfire air systems specifically designed for cyclone-fired boilers, Burns and McDonnell believes that ROFA technology is not superior to the evaluated version of SOFA in the October 2006 MRYS NOx BACT Analysis to warrant such a vendor query and a quantitative analysis …… ROFA does not offer any significant advantages in lignite-fired cyclone-specific application of separated overfire air technology.

EPA Response:

EPA does not currently have information to the contrary and will agree that this option may not differ substantially from ASOFA or offer greater NO_x reduction on cyclone boilers. Since ASOFA has been addressed elsewhere in the BACT analysis, further consideration of ROFA is unnecessary.

K. Control Efficiency for SNCR

EPA's January 26, 2007 Comment:

Based on the proposed emission rate of 0.36 lb/MMBtu and the emission rate expected from installing Advanced Separated Overfire Air (ASOFA) alone (0.513 lb/MMBtu), it appears as though the SNCR controls will only be achieving approximately 30% reduction. (p. 3-18) AP-42 states that SNCR can achieve NOx reductions between 30-60%. Many recent PSD permit applications also include discussion of SNCR being able to achieve NO_x control in the 60% range or higher. Considering that Minnkota's cyclone boiler will have high uncontrolled NO_x emissions (even considering the ASOFA), the high end of this range should have been considered in the BACT analysis. Minnkota's analysis really provides no technical discussion on why it ruled out higher capabilities of SNCR control and why they used the control efficiency that is proposed. Using 60% control would yield an emissions rate of 0.21 lb/MMBtu for a BACT limit with ASOFA and SNCR, compared to the proposed 0.36 lb/MMBtu.

B&McD's April 23, 2007 Response:

There were pertinent references in Appendix A1 of the MRYS NOx BACT analysis discussing long-term examples where SNCR has been applied for NOx emission control on two cyclone-fired boilers, achieving reductions around 30 percent from high uncontrolled baseline levels. There was also another relevant cyclone boiler SNCR demonstration test listed in Appendix A2 of the MRYS NOx BACT analysis that controlled NOx in this same 30 percent range. NOx control effectiveness of SNCR is highly boiler-specific. It is important to note that PSD permit applications are for new boilers; there are no new cyclone boilers being built, and few new boilers (other than CFB boilers) are required to install and operate SNCR. The cited AP-42 NOx emissions rate reduction percentage for SNCR application on coal-fired boilers isn't applicable to the specific conditions expected at the MRYS boilers....Burns & McDonnell estimated the level of emission reductions expected from SNCR based on information from an experienced urea-based SNCR vendor. B&McD believes that 60 percent reduction of NOx emissions is inappropriate, and not reflective or realistic for long-term levels of control at MRYS.

EPA Response:

After further review of the information provided, EPA agrees that the 60% reduction cited at the upper end of the control range is likely not appropriate for MRYS. It appears likely that something closer to 30% than 60% would be reasonable.

L. <u>Selection of 30-day Average BACT Emission Limit</u>

EPA's January 26, 2007 Comment:

The baseline emission rate used for calculating the proposed BACT limit is based on the highest NO_x emission rate (0.884 lb/MMBtu) during actual operations from 2001-2005. (p. ES-9) This period also includes the longest reported startup event during that period (61 hours). How does this 30-day baseline compare with the rest of the historical data? Does this emission rate represent a realistic upper bound value, or is it an outlier compared with the majority of the data? If the data point does not reasonably compare with the vast majority of the other data, it does not make sense to set a BACT limit based on an outlier data point. Furthermore, the baseline emissions rate used for calculating the 30-day limit is based on the highest 30-day period during actual operations from 2001-2005, which included the longest startup event. If this highest 30-day period was used as the baseline to calculate the 30-day average limit, and the worst-case startup event occurred during this historic 30-day period, it is not necessary to include the recommended "startup adjustment" (+0.041 lb/MMBtu) per startup event with this limit.

B&McD's April 23, 2007 Response:

According to MRYS Unit 1's October 2006 BACT Analysis, the control effectiveness calculations were determined based upon the highest historical 12-month rolling NOx emission summation operating conditions for Milton R. Young Station boilers during years 2001-2005.....MRYS operating conditions

during the highest historical 30-day rolling NOx emission periods for years 2001-2005 were then compared to the highest 12-month historic pre-control baseline period conditions. The average unit NOx emission rate (lb/mmBtu) from the highest historic pre-control 30-day baseline period was compared with the average NOx emission rate (lb/mmBtu) from the 12-consecutive month period with the highest historic unit NOx mass emissions (pounds) reported for actual operation during the same 5-year look-back period. It was coincidental that the highest historical 30-day rolling NOx emission period for MRYS Unit 1 (December 17, 2003 through January 15, 2004) was within the same highest 12-month historic pre-control baseline period (ending on October 30, 2004). The longest individual Unit 1 startup period during actual operation between January 1, 2001 and December 31, 2005 occurred during the 61-consecutive hour period from June 27-29, 2005..... The highest historical 30-day rolling NOx emission period for MRYS Unit 2 (March 7, 2003 through April 5, 2002) was not within the same highest 12-month historic pre-control baseline period (ending April 30, 2004). The longest individual Unit 2 startup period during actual operation between January 1, 2001 and December 31, 2005 occurred during the 115-consecutive hour period from October 25-30, 2001. Note that this did not fall within either the 30-day or the 12-month highest historic rolling average NOx mass emission periods. ..... The selected highest baseline pre-control 30-day rolling average NOx unit emission rates for MRYS Unit 1 and Unit 2 boilers are considered to be realistic upper bound cases, not "outliers"..... The recommended 30-day Rolling, Average unadjusted (i.e. steady-state) BACT NOx emission rates do not include the impact of the worst-case startup events for either MRYS Unit 1 or Unit 2. The "startup adjustment" as described in the October 2006 MRYS Unit 1 and Unit 2 NOx BACT Analysis reports is appropriate as the recommended (unadjusted) 30-day Rolling Average NOx Emission Rate permit limitations basically reflect steady-state rates.

EPA Response:

EPA has reviewed B&Mc's detailed description of how it established the baseline emission rates and the startup/shutdown adjustment factor and now understands that the startup periods did not fall within the relevant baseline period. EPA will consider the startup adjustment concept to the extent it is relevant to NDDH's proposed BACT determination.

M. <u>BACT Limit 18-Month Trial Period</u>

EPA's January 26, 2007 Comment:

EPA has concerns with Minnkota's proposal for an 18-month trial period for establishing a final BACT limit. (p. ES-11) This proposal appears to be in direct conflict with the process for establishing and potentially revising the NO_x BACT limits set forth in Sections V. B & D of the Consent Decree. Therefore, EPA believes the proposed 18-month trial period for establishing a final BACT limit in Minnkota's BACT analysis cannot be accepted.

B&McD's April 26, 2007 Response:

.....Paragraph 73 of the referenced Consent Decree states "The Settling Defendants shall submit any petition for any Unit under this Paragraph no later than six (6) months after the final compliance

date specified for that Unit in Paragraph 67". Paragraph 67 requires that MRYS Unit 1 and Unit 2 shall achieve and maintain a Phase II 30-Day Rolling Average NOx Emission Rate established by the NDDH through its NOx BACT Determination beginning no later than December 31, 2011 and December 31, 2010, respectively. This does not preclude an early installation of Consent Decree Phase II NOx emission reduction systems with associated commissioning at Milton R. Young Station prior to the CD compliance dates for MRYS Unit 1 and Unit 2, respectively. This could allow Minnkota to gain operating experience in advance of the June 30, 2012 and June 30, 2011 deadlines for submitting a petition. If the Settling Defendants do not accelerate the schedule for Phase II NOx control implementation, recognizing that the CD apparently does not allow an 18-month trial demonstration period following the stated final compliance dates, the applicant will have to make use of the petition process as described in the CD in this circumstance, if appropriate.

EPA Response:

EPA agrees this is an acceptable approach.

Minnkota Power
MPC COOPERATIVE, INC.
Your Touchstone Energy® Partner

1822 Mill Road • P.O. Box 13200 • Grand Forks, ND 58208-3200 • Phone (701) 795-4000

November 9, 2007

NOV 2007
Received
Air Quality

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Subject: Response to EPA's October 4, 2007 Letter

Dear Mr. O'Clair:

Enclosed, please find Minnkota's comments in response to EPA's letter dated October 4, 2007. Should you have any questions concerning our comments, please contact me at 701-795-4221.

Sincerely,

John T. Graves, P.E.
Environmental Manager

C: David Sogard w/o encl
Luther Kvernen w/o encl
Craig Bleth w/encl
Kevin Thomas w/o encl
Stu Libby w/o encl
Tom Anseth w/o encl
Young Station File w/encl

Comment & Response to EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station

Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (together "Minnkota") are pleased to provide their comments on the U.S. Environmental Protection Agency's ("EPA") October 4, 2007, response to Minnkota's letters dated March 19, 2007 and April 23, 2007 ("EPA Response"). After having exhaustively reviewed the EPA Response and Minnkota's original and supplemental submissions regarding the selection of the best available control technology ("BACT") at Milton R. Young Units 1 and 2, we have concluded that the administrative record fully supports a finding by the North Dakota Department of Health ("NDDH") that selective catalytic reduction technology is technically infeasible for electric generating units that include cyclone burners firing North Dakota lignite. We have summarized the bases for our conclusion below, and have responded in Appendix A to each of EPA's October 4, 2007 comments.

Minnkota has demonstrated that SCR technology is not available for use at Young Station

EPA's 1990 Draft New Source Review Workshop Manual[1] ("Workshop Manual") concludes that a control technology is unavailable as BACT—and therefore technically infeasible—if it is not commercially available for use at the source under consideration. Specifically, the Workshop Manual provides: "[It is not] 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."[2].

It is indisputable that "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 heaters."[3] Cyclone burner boilers firing

[1] See Reference number 1.
[2] Ibid, EPA NSR Workshop Manual at B.18
[3] See Reference number 2 at A1-32.

North Dakota lignite are in fact dissimilar from all other commercial-scale sources that have applied SCR, and Minnkota has described the facts supporting dissimilarity at length in its original and supplemental BACT reports. Indeed, this dissimilarity is apparent on its face in that the only sources of information upon which Minnkota or EPA rely in their various discussions of technical feasibility for SCR on similar sources are from pilot scale testing. Any SCR catalyst vendor's willingness to guarantee performance on a North Dakota lignite-fired boiler will be very limited, requiring certain specific criteria to be met that are yet to be proven to exist or capable of existing at MRYS. This limitation to the SCR catalyst guarantee is required by the vendor in order to manage financial risks by specifying the limits of their system design in case of potential operating conditions that cause performance problems that prevent achievement of guarantees and/or warranty claims. SCR catalyst vendors assume that the system suppliers have already solved (or will solve) the stated temperature problems, and proven solutions to these conditions have not been identified.

EPA attempts[4] to minimize the significant dissimilarities in boiler operation and fuel source at cyclone burner-based units firing North Dakota lignite from other units utilizing SCR by citing a 1989 guidance document exploring the notion of dissimilarity. The so-called dissimilarities scrutinized by the 1989 guidance are nothing like the real dissimilarities between Minnkota's units and other units using SCR.[5] Moreover, Minnkota has followed the guidance in explaining very clearly in its original and supplemental BACT reports the impacts of different gas stream characteristics (in terms of content and temperature) on an SCR add-on control. NDDH therefore has reasonable grounds upon which to conclude that Minnkota's units are dissimilar from other units that have successfully employed SCR.

EPA also attempts to close off discussion on the notion of "availability" by citing out of context a single sentence in Minnkota's original BACT study[6]. Minnkota's original BACT study clearly noted at multiple points that the Young Station units are dissimilar from units at which SCR has

[4] See Reference number 3, EPA October 4, 2007 Response Enclosure at 2.
[5] The 1989 guidance focuses on differences in unit size, less important differences in boiler design, and modest differences in fuel blends. As Minnkota has established in its original and supplemental reports, the cyclone burner design, high outlet temperatures, fuel type, and resultant gas streams are significant differences that result in dissimilarity for purposes of BACT.
[6] Ibid Reference number 3, EPA Response Enclosure at 31.

been applied[7]. Though many of the same facts are relevant to a determination of "availability" and "applicability," Minnkota has clearly raised the issue of availability and NDDH may reasonably conclude that SCR is not available for Minnkota's units.

In summary, Minnkota has demonstrated that SCR is not commercially available for applications similar to Minnkota's Young Station units. NDDH may therefore reasonably conclude that SCR is not available as BACT, and characterize SCR as a technically infeasible technology that need not complete steps three through five of the top-down BACT analysis.

Minnkota has demonstrated that SCR technology is not applicable for use at Young Station

The Workshop Manual concludes that an available control technology is "applicable" if one of two conditions are satisfied: (1) "a commercially available control option will be presumed applicable if it has been or is soon to be deployed on the same or a similar source type;" or (2) "[a]bsent a showing of this type, technical feasibility would be based on examination of the physical and chemical characteristics of the pollutant-bearing gas stream and comparison to the gas stream characteristics of the source types to which the technology had been applied previously."[8] Minnkota has demonstrated that SCR technology has not been nor soon will be deployed on a "same or similar source type"—that is, a cyclone burner-based unit firing North Dakota lignite. Accordingly, the presumption of "applicability" under the first condition is not met, and NDDH has a reasonable basis upon which to conclude under the first test that SCR is not applicable at Young Station.

[7] Ibid Reference number 2, e.g., Minnkota BACT Report at A1-23–A1-24 ("There are, however, no existing full-scale SCR installations on units that fire North Dakota lignite."); *id.* at A1-26–A1-27 ("The question is whether SCR is a feasible technology for a unit firing North Dakota lignite."); *id.* at A1-28 ("There have been no installations of SCR systems (full-scale) on units that fire North Dakota lignite."); *id.* at A1-31 ("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 boiler."); *id.* at A1-32 ("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 heaters.").

[8] Ibid, Reference number 1 at B.18.

Regarding the second condition, the Workshop Manual states "[d]eployment of the control technology on an existing source with similar gas stream characteristics is [a] generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary."[9] In practice, the "similar gas stream characteristics" analysis compares the physical and chemical characteristics of the unit under review to the units at which the technology has been successfully applied, and analyzes how the a particular control technology (here SCR) responds to the different gas stream characteristics. Vendor guarantees provide an important insight into the ability of an existing technology to be applied successfully on a unit with different gas stream characteristics.[10]

Minnkota has exhaustively described the significant physical and chemical differences between gas stream characteristics at Young Units 1 and 2 and other units at which SCR has been applied. Chief among these differences are the low and high flue gas temperatures that exist throughout the range of boiler loads that vary with the extent of boiler cleanliness; and an abundance of fine sodium particles emitted from the boilers along with sulfur, calcium, and other alkali and alkaline earth elements that are in a physical and chemical form that will contaminate and rapidly cause SCR catalyst to be ineffective. Moreover, Minnkota has provided detailed information regarding how SCR might react to these very different gas stream characteristics, and has cited a number of technical sources and pilot projects to illuminate the unresolvable technical difficulties precluding the successful deployment of SCR to the Young Station. These unresolvable technical difficulties include: the inability to maintain catalyst effectiveness by avoiding severe micropore plugging by sodium-sulfur compounds that are present in the flue gas even after it has passed through an electrostatic precipitator and wet scrubber. Last, Minnkota has been unable—despite a detailed request for a guarantee document—to secure a detailed catalyst vendor's or supplier's guarantee covering a full-scale SCR system at Minnkota's units. While the lack of a vendor guarantee is not dispositive of technical inapplicability, it is an important indication that the engineering companies that would be financially responsible for SCR performance are unwilling to take that risk.[11]

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[9] Ibid, Reference number 1 at B.19.
[10] Ibid, Reference number 1 at B.20.
[11] EPA sidesteps the lack of a vendor guarantee by describing Minnkota's request for a vendor guarantee as overly voluminous and having "a pessimistic tone." EPA Response at 5, 49. Minnkota disagrees with EPA's

EPA has cited an opinion by Electric Power Research Institute (EPRI) issued on September 7, 2006 that "SCR designs can accommodate fuel types never before used in practice on a full scale", and "While experience specifically with Texas lignite is limited, this should not prevent suppliers from providing an SCR system that meets these objectives..."[12] The ash chemical and physical properties of Texas lignite (Wilcox formation) that TXU proposes to burn at the new Oak Grove powerplant do not represent all Texas lignites. This fuel also may be co-fired with Powder River Basin coal at TXU, which may mitigate some of its less desirable characteristics. Texas lignites cited by the EPA do not represent what is fired in North Dakota, and its technical feasibility and expected performance in an SCR application is not transferable to North Dakota lignite-fired cyclone burner units due to the significant differences in ash chemical and physical properties.

EPA attempts to minimize these technical inapplicability arguments by suggesting that if enough money were spent on an (experimental) SCR, Minnkota would find that the device could eventually be made to work, and that the BACT decision should therefore turn on cost-effectiveness considerations.[13] This argument puts the cost-effectiveness cart before the technical feasibility horse. The top-down BACT process very clearly eliminates technically infeasible alternatives from the cost-effectiveness analysis. Minnkota has demonstrated that SCR is—under the definitions provided in the Workshop Manual relating to availability and applicability—technically infeasible. It is an invalid response to suggest that it may be cost effective for Minnkota to conduct an extended pilot test project or full-scale experimental construction and testing project when the definition of a technically feasible control excludes those projects. EPA's suggestion that a technically infeasible, but hypothetically cost-effective control constitutes BACT is at odds with the Workshop Manual.

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characterization and would respond by stating that the risks to technical feasibility that EPA so easily dismisses are an important part of the vendor guarantee process that adequately reflects the willingness of the vendor to "make good" any deficiencies in performance and provide an "evergreen warranty" that recognizes the importance of catalyst life over the SCR's lifespan. That these risks have dissuaded engineering companies from offering a guarantee is strong evidence that EPA is mistaken in its technical feasibility opinion.

[12] Ibid Reference number 3, EPA Response Enclosure at 16-17.

[13] Ibid Reference number 3, EPA Response Enclosure at 2-3.

In the end, EPA's objections to Minnkota's voluminous submittals on BACT may be reduced to disputing Minnkota's characterization of the gas stream characteristics and the impacts of those characteristics on boiler and control operations. Certainly a final technical judgment will be required by NDDH regarding these issues, while Minnkota has provided a detailed and reasonable position regarding technical infeasibility. In the end, the administrative record would support a reasonable finding by NDDH that SCR is technically infeasible for application on North Dakota lignite-fired cyclone burner units at Young Station.

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

2 "*NO_X Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc.*" and a separate "*NO_X Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative*", October 2006, by Burns & McDonnell, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement.

3 United States Environmental Protection Agency (U.S. EPA or EPA) Region 8 letter by Martin Hestmark, Director, Air and Toxics Technical Enforcement Program, ECEJ to Terry L. O'Clair, North Dakota Department of Health, Environmental Health Section, Division of Air Quality and David Sogard and John Graves, Minnkota Power Cooperative, *Re: Transmittal of EPA's Response to Minnkota's Letters Dated March 19, 2007 and April 23, 2007, Regarding the October 2006 NO_x BACT Analysis Study Report for Milton R. Young Station, date stamped October 4, 2007.*

APPENDIX A

MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO EPA and ERG COMMENTS REGARDING SCR TECHNICAL FEASIBILITY and NON-SCR CONCERNS MILTON R. YOUNG STATION UNIT 1 and UNIT 2 NOx BACT ANALYSIS STUDY

November 6, 2007

Region 8 of United States Environmental Protection Agency (U.S. EPA or EPA) has provided North Dakota Department of Health's, Environmental Health Section, Division of Air Quality (NDDH) and Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") with their comments regarding their review[14] of Minnkota's letters dated March 19, 2007[15] and April 23, 2007[16] regarding the October 2006 Best Available Control Technology (BACT) Analysis Study reports[17] for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station ("MRYS"). Additional comments from Eastern Research Group (ERG) (Christman) dated August 20, 2007[18], and an Enclosure of additional EPA responses[19] were also attached.

Burns & McDonnell was retained by MPC as an independent consultant to perform the referenced NO_X BACT Analysis Studies of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station (MRYS) in accordance with the requirements of a Consent Decree (CD)[20].

Minnkota, along with Burns & McDonnell (B&McD), and Energy & Environmental Research Center (EERC) of the University of North Dakota, have reviewed the referenced EPA and ERG letters which provided additional comments regarding selective catalytic reduction (SCR)

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[14] See Reference number 1, October 4, 2007.
[15] See Reference number 2, March 19, 2007.
[16] See Reference number 3, April 23, 2007.
[17] See Reference number 4, October 2006.
[18] See Reference number 5, August 20, 2007, provided with Reference number 1.
[19] See Reference number 6, provided with Reference number 1.
[20] See Reference number 7, April 24, 2006.

technology feasibility and non-SCR concerns pertaining to the referenced NO_X BACT Analysis Studies. The following are combined responses by EERC and B&McD to the comments by U.S. EPA Region 8 and ERG involving the referenced study reports for the two units at MRYS.

The following responses follow the outline of the attached ERG memorandum and Enclosure to the EPA's October 4, 2007 letter.

ERG's Memorandum to U.S. EPA, August 20, 2007[21]:
"Core" Issue number 1
Center Mine Ash Content Variability:
ERG memorandum to EPA, August 20, 2007, page 2
Original Reference: NDDH letter to Minnkota February 1, 2007 request item number 1 and EPA Region 8 letter to NDDH January 26, 2007 request item number 4:

> *..."Center Mine coal does not have unusual variability in ash content and in no case has an ash content five times higher than PRB coal as B&McD has contended." [ERG August 20, 2007 letter, page 2]*

EERC Response:

The Center mine coal is extremely variable as compared to Powder River Basin (PRB) coals. Christman ignores information provided in the form of responses to comments and presentation that compares the ash percentages in PRB coals. This information was provided in detail in the document entitled "Center Lignites Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative -- Responses to EPA Comments NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Technical Feasibility," March 2007.

Christman ignores the fact that the core data provides the actual variability of the lignite and focuses his attention on the 700 coals in the as-fired database for Unit 2, which have been affected by blending that occurs in the coal storage building and coal handling system. The true Center coal variability is represented in the coal core data. Unit 1 receives unblended coal. The levels of ash in the core samples range from 3.7 to 22.2 % on an as-received basis. This information was provided in the Responses to EPA comments March 2007. Recent stop belt

[21] Ibid Reference number 5.

sampling of the feed coal to Unit 1 has shown ash contents as high at 22.0 wt % on an as received basis.

> *"Along with the general discussion of ash variability, Dr. Benson introduced the concept of "acid-to-base ratio" of the ash (pages 7-9, Minnkota, March 2007) as having relevance to the technical feasibility of SCR as applied to North Dakota Lignite...Dr. Benson does not, in fact, make a direct connection between his discussion of base-to-acid ratio and the functioning of an SCR system. B&McD also only mentions impact on "operation of the boilers at MRYS" (page 9) and makes no connection specifically to an SCR system. As a final note, I have been involved in one way or another with SCR since the early 1970's and I have never heard or read anything about acid-to-base ratio of ash in any SCR document or discussion, prior to Dr. Benson's introduction to the subject." [ERG August 20, 2007 memo, pages 2 and 3]*

First of all, it is the base-to-acid ratio, not the acid-to-base ratio. Unfortunately Christman is not aware of the importance of the use of the base-to-acid ratio. The base-to-acid ratio ($B/A=[Na_2O+MgO+CaO+ K_2O+FeO]/[SiO_2+Al_2O_3+TiO_2]$) provides a means of simply evaluating ash characteristics. The B/A ratios are an effective way of examining variability and ash behavior impacts on power system performance. This relationship has several applications and in SCRs the application is the assessment of potential for sulfation. Coals that have a high B/A ratios will produce entrained particulate and vapor phase species enriched in the basic components. The basic constituents are prone to form sulfate-based deposits that were found to plug and blind catalysts. The partitioning of the basic components into the vapor phase and small particle fractions is the greatest for cyclone-fired systems. This information has been provided on numerous occasions in writing and in presentations. The B/A ratio has been utilized for decades to evaluate ash behavior in combustion systems. I am surprised that Christman is unaware of the use of B/A ratios since work supported by EPA in the area of SCR and SO_3 reactions to form sulfates has been ongoing for several years. The following is a quote from a final report relevant to this issue[22]:

> "Given the strong correlation between SO_3 uptake and the base:acid ratios of the ashes, it appears that chemi-sorption rather than physical adsorption dominates the process and that temperature plays a strong role as well."

B&McD Response:

[22] See Reference number 9, November 14, 2006.

Variations in the coal delivered and burned at MRYS have posed difficulties in maintaining consistent combustion and slag-formation and tapping conditions in the cyclones and lower furnaces of the boilers. Low B/A ratio correlates to undesirable cyclone operation. High viscosity ash, related to low B/A ratio, causes more incompletely burned coal and ash particles to be exhausted from the cyclone, which increases the amount of flyash that can create slagging and fouling problems in the furnace and convection passes of the boiler. This causes furnace exit gas temperatures to increase, requiring more aggressive heat transfer surface cleaning, which means higher gas temperatures with more ash and deposit fragments are exhausted from the boiler, which are problematic for potential blinding, deactivation, and longevity of the SCR catalyst.

"Core" Issue number 2
Catalyst deactivation by sodium and regeneration difficulties:
ERG memorandum to EPA, August 20, 2007, page 3
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH request item number 1:
[Comments regarding Khodayari's work on SCR catalyst deactivation and regeneration due to poisoning by sodium and potassium] [ERG August 20, 2007 memo, page 3]

EERC Response:
Christman appears to ignore key statements made by Khodayari in his thesis and other publications. The following is a quote from the abstract of his PhD thesis[23]:

> "Potassium and sodium were found to be two of the worst poisons that had significant effects on the activity of the SCR catalyst due to their selective chemisorption on the Brønsted acid sites."

[Comments regarding Beck's work on contributions of phosphorus, potassium and sodium].
"His subsequent work focused on phosphorus and did not address sodium at all." [ERG August 20, 2007 memo, page 3]

EERC Response:
Beck and others focused on phosphorus because it was at a higher concentration than sodium in the materials he was investigating.

[23] See Reference number 10.

…"University of Utah and REI on application of SCR to low-rank coals …but masking by flyash is a problem. The study further concluded that the poisoning potential of the alkali materials ranked as: K>Na>Ca." [ERG August 20, 2007 memo, page 3]

EERC Response:
The University of Utah studies did not consider high sodium coals in their testing. They examined lower sodium coals. We agree with the assessment that masking is a problem.

Christman brings up an important point regarding the impacts of potassium on catalyst deactivation, but ignores its presence in lignite coals. Potassium can be as high as 2.3% in Center lignite. Potassium, like sodium, is prone to vaporize in combustion systems and condense to form small particles upon gas cooling.

Work was conducted at MRY Unit 1 to examine accumulations of sticky ash at 300°F downstream of the ESP. Figure 1 shows a polished cross-section of a deposit that has formed on a silicon dioxide surface when exposed to flue gas derived from the combustion of Center lignite. The red line shows the path of a line scan where the composition was determined using x-ray microanalysis. Figure 1 also shows the change in chemical composition along the red line beginning at the outside and moving to the silicon dioxide for selected components. The results show levels of potassium (K) as high as 17% and sodium (Na) as high as 16% in the line scan. The material is highly sulfated as indicated by the high levels of sulfur (S). The deposit shown in Figure 1 formed at about 300°F. In addition, potassium-rich materials were found in deposits plugging SCR catalysts at the Coyote Station as shown in Figure 2 and Table 1. Levels of potassium ranging from 2 to 8 elemental wt% were observed.

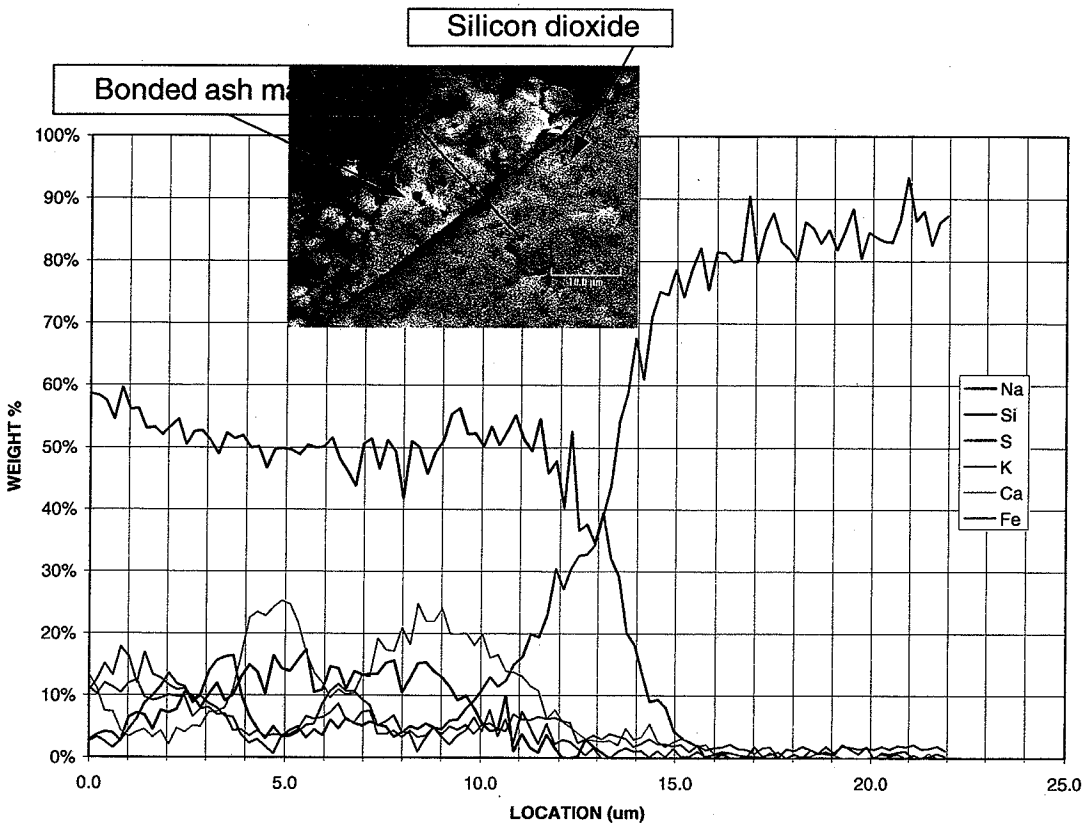

Figure 1. Cross-section of a surface exposed to flue gas at about 300° F in MRY Unit 1.

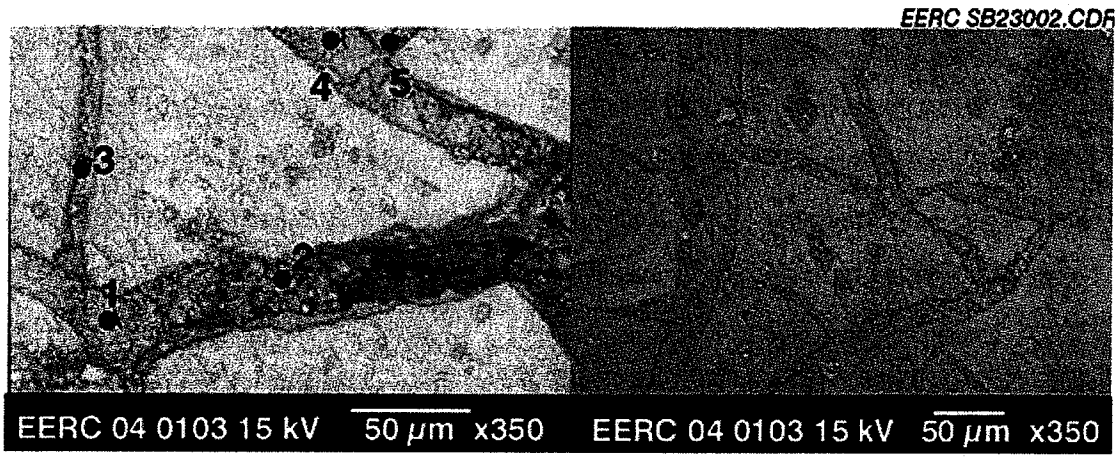

Figure 2. Ash accumulations in pores of SCR catalyst exposed to Coyote flue gases for 4 months.

Table 1. Chemical Analysis of Selected Points Shown in Figure 2.

	Point Locations, Elemental Wt %				
Element	Point 1	Point 2	Point 3	Point 4	Point 5
Na	5.09	1.88	0.58	2.68	2.04
Mg	2.49	0.88	4.23	4.38	1.39
Al	2.23	3.95	1.50	0.80	1.55
Si	4.86	1.79	4.67	5.82	4.42
P	0.00	0.85	0.06	0.10	0.00
S	32.51	29.43	31.35	30.33	27.55
Cl	0.00	0.00	0.22	0.33	0.15
K	6.64	2.54	8.74	7.85	4.64
Ca	16.08	29.69	19.42	16.91	25.20
Ti	0.00	0.11	0.64	0.16	6.02
Cr	0.00	0.00	0.00	0.00	0.00
Fe	7.76	7.52	0.00	3.44	7.37
Ba	4.99	0.00	5.34	6.00	3.19
O	17.35	21.37	23.25	21.20	16.49
TOTAL	100.00	100.00	100.00	100.00	100.00

"While Dr. Benson concludes that the sodium levels in North Dakota Lignite ash are so high...others at EERC do not share that opinion..." [ERG August 20, 2007 memo, page 3]

EERC Response:
The cited work conducted by Folkedahl (2006) was on a stoker-fired system and does not represent the partitioning that occurs in a cyclone or pulverized coal-fired system. They had significant problems during the testing because large pieces of unburned biomass kept plugging the inlet to the slipstream system.

Christman ignores work conducted by the EPA. Mussatti (2002) indicated in the "EPA Air Pollution Control Cost Manual – Sixth Edition" the following primary mechanisms for catalyst deactivation:

> "Poisoning - Certain fuel constituents which are released during combustion act as catalyst poisons. Catalyst poisons include **calcium oxide and magnesium oxide**, potassium, **sodium**, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them irreversibly. Catalyst poisoning represents the main cause of catalyst deactivation."

"Blinding/Plugging/Fouling - Ammonia-sulfur salts, fly ash, and other particulate matter in the flue gas cause blinding, plugging or fouling of the catalyst. The particulate matter deposits on the surface and in the active pore sites of the catalyst. This results in a decrease of the number of sites available for NOx reduction and an increase in flue gas pressure loss across the catalyst."

"Since catalyst deactivation is due to alkaline materials ... This dependency is probably not linear, since the overwhelming amount of ash in any installation does not deposit on the catalyst(it passes through the catalyst channels and ends up in the ESP hopper or is emitted), but it is most appropriate to consider average values of chemical poisons. This is because the total exposure will be less than the average for about half the time and more that average about half the time. The overall deactivation rate "averages out"." [ERG August 20, 2007 memo, page 4]

EERC Response:
These statements are an indication of Christman's lack of understanding of partitioning of alkali species during combustion and the transport of those species to catalyst surfaces and the importance of variability. During combustion the sodium, potassium, and other species vaporize and end up concentrated in the finer size fractions of ash. As the gas and entrained particles are transported through the catalyst channels the finer fraction of ash is deposited on the catalyst and in the pore via diffusion processes. Next to the surface of the catalyst there is a stagnant boundary layer where diffusion processes take place. The diffusion across the boundary layer results in selective accumulation of the problematic species such as sodium, potassium, sulfur, and other elements on the catalyst. Considering the average value of poisons is not appropriate; it does not average out. Values of poisoning higher than the average will cause rapid and irreversible plugging from which there is no recovery.

"Although the high sodium content of Center Mine coal ash is an economic issue (it will contribute to catalyst deactivation), Dr. Benson provides no evidence that it will render SCR technically infeasible at MRYS". [ERG August 20, 2007 letter, page 4]

B&McD Response:
Catalyst activity for the severely plugged and blinded SCR catalyst removed from the Coyote pilot test was not able to be determined by the catalyst vendor who supplied it. Based on EERC's observation under a scanning electron microscope that every micropore of the entire area of the Coyote pilot test SCR catalyst section analyzed was plugged, it could be inferred that the as-removed test catalyst activity would effectively be zero. The length of exposure for plugging of the micropores in the Coyote pilot test for these results was less than or equal to

two months, as described in EERC's October 2005 referenced paper[24]. The micropore plugging occurs when there is flyash and flue gas flow through that portion of the catalyst. It is reasonable to believe that the micropores would have become plugged prior to the observed ash accumulations. The gross ash deposits were found prior to the end of the six month test but were not removed. These ash deposits subsequently caused high velocity flow through a portion of the test catalyst and consequently low or no flow through the portion where there are significant ash deposits.

"Core" Issue number 3
Downtime for catalyst cleaning and change out:
ERG memorandum to EPA, August 20, 2007, page 4
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH request item number 3:

> *"If one assumes a rather extreme short catalyst life of one year and if the change out is coordinated with a boiler cleaning outage, the SCR unit would only contribute one or two days of downtime per year". [ERG August 20, 2007 letter, page 4]*

B&McD Response:
The EPA's commenter's and the catalyst vendor's comments do not appear to recognize the impacts from isolating the high-dust SCR catalyst from the gas path during boiler cleaning outages. Ambient airflow through the boiler during the beginning of a cleaning outage normally aids in the cooldown of a hot-side SCR reactor. Keeping the SCR reactor inlet closed to prevent moisture and deposits liberated during off-line boiler fireside surface cleaning from entering the SCR reactor impairs the ability to cool the reactor after shutdown. The estimated amount of time and difficulty in removing lignite ash accumulation from the SCR reactor(s), or replacing fouled catalyst with clean spare catalyst, depends on the volume of catalyst and ash requiring cleaning/removal and replacement, and the ability to access the reactor after cool-down. Performing such SCR maintenance outages during boiler cleaning outages is expected to require more boiler downtime than assumed by the EPA's commenter.

Because the EERC SCR pilot test at Coyote Station showed severe catalyst ash and micropore pluggage and fouling within two to four months of exposure, the frequency of full-scale SCR catalyst cleaning and changeout events when exposed to the expected conditions in the gas

[24] Ibid, included with Reference number 4.

path of a North Dakota lignite-fired cyclone boiler could be more often than the boiler cleaning outage frequency. This was described in Minnkota's April 2007 letter to NDDH and EPA.

Documentation of successful on-line and off-line cleaning of such severely plugged catalyst has not been found. Conventional on-line catalyst cleaning methods will be ineffective in removing the bulk of the small particles formed and bonded in a matrix observed throughout the Coyote catalyst (macro- and micropores). Catalyst regeneration will not be productive if the micropores of the catalyst cannot be adequately cleaned of deposits. Thus, the catalyst will become irreversibly contaminated and the level of activity and related NO_X reduction performance is expected to diminish rapidly upon installation and short-term exposure during SCR operation.

The only effective countermeasure will be to frequently change-out the exposed catalyst with fresh catalyst. An SCR that needs to have its catalyst replaced every four months or less in order to maintain NO_X control performance would be unreasonable to operate and maintain.

"Core" Issue number 4
Sticky ash:
ERG memorandum to EPA, August 20, 2007, page
Original Reference: ERG Letter to EPA, January 8, 2007:

> *"[would] sootblowing (steam or horns) effectively prevent [SCR catalyst] plugging from the ash that is normally entrained in the flue gas (not falling accumulations)"... [ERG August 20, 2007 letter, page 4]*

B&McD Response:
The answer given (attributed to Sargent & Lundy during their May 24 presentation to NDDH and EPA) is presumably based on experience with PRB coal ash, not North Dakota lignite ash. As Dr. Benson has previously stated, the low melting temperature fouling deposits from North Dakota lignite cyclone firing can be extremely tenacious in their bonding characteristics. The EPA commenter's response appears to minimize what is likely to be a significant operating and maintenance problem for SCR catalyst exposed to flue gas and flyash generated by cyclone boilers burning North Dakota lignite. Burns & McDonnell stands by their comments made in Minnkota's April 2007 response (pages 25-26) to the question of multiple engineering solutions suggested by the EPA's comment in the EPA's January 26, 2007 letter (page 2).

"Core" Issue number 5

EERC pilot test procedure/design:

ERG memorandum to EPA, August 20, 2007, page 4

Original Reference: EGR Letter to EPA and EPA Region 8 letter to NDDH, January 8, 2007:

> *".. In summary, the catalyst should have been cleaned with some frequency so that it could be continuously exposed to flue gas. Tests at Coyote station were not useful in determining plugging potential and the attempt at simulating sootblowing was not effective. By EERC's own admission ...the plugging was a result of ash accumulations falling onto the catalyst... Mr. Hansen also confirmed that the catalyst pitch at Coyote (6 mm) was too small....S&L presenters suggested that a 10 mm pitch might be required for North Dakota lignite applications." "[ERG August 20, 2007 letter, pages 4 and 5]*

EERC Response:

The reactor was sootblown based on recommendations of the catalyst vendors. Christman misinterpreted EERC's comments during the meeting at the North Dakota Department of Health (NDDH) in Bismarck. The ash that was on top of the surface of the catalyst shown in one of the images fell on the surface during dismantling the reactor and was not there during the testing. During cross sectioning of the SCR catalyst EERC specifically looked for evidence of deposit fragments plugging the catalyst. Numerous cross sections of the material plugging the catalyst were examined, and there was no evidence that deposit had fallen and accumulated. However, ash falling on the catalyst surface is possible. The slip stream reactors worked well at the Baldwin Station (cyclone PRB-fired) and Columbia (pulverized coal tangential PRB-fired) with minor to moderate fouling. The same reactor used at Baldwin was used at the Coyote Station. The pitch of the catalyst used at Coyote Station was 6 mm as recommended by Hansen at Haldor Topsoe. A comparison of the first 500 hours with both systems using fresh catalysts is shown in Figures 3 and 4 for Baldwin and Coyote Stations, respectively. Initially, at Baldwin there were some problems with start up and operation of the reactor because of plant outages. The pressure drop at the end of 500 hours averaged about 0.6 inches of water. The pressure drop for Coyote Station is shown in Figure 4, and at the end of 500 hours the pressure drop averaged about 0.85 inches of water. During these first 500 hours of operation the impacts of any falling deposits would be minimal. In addition, after each 2 months of operation the ductwork upstream of the reactor was cleaned.

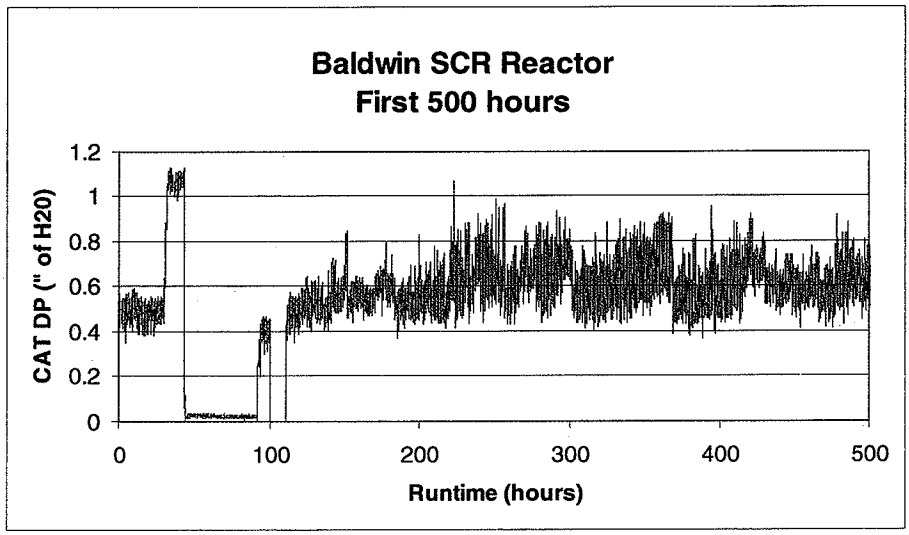

Figure 3. Pressure drop across SCR reactor during first 500 hours of testing at Baldwin.

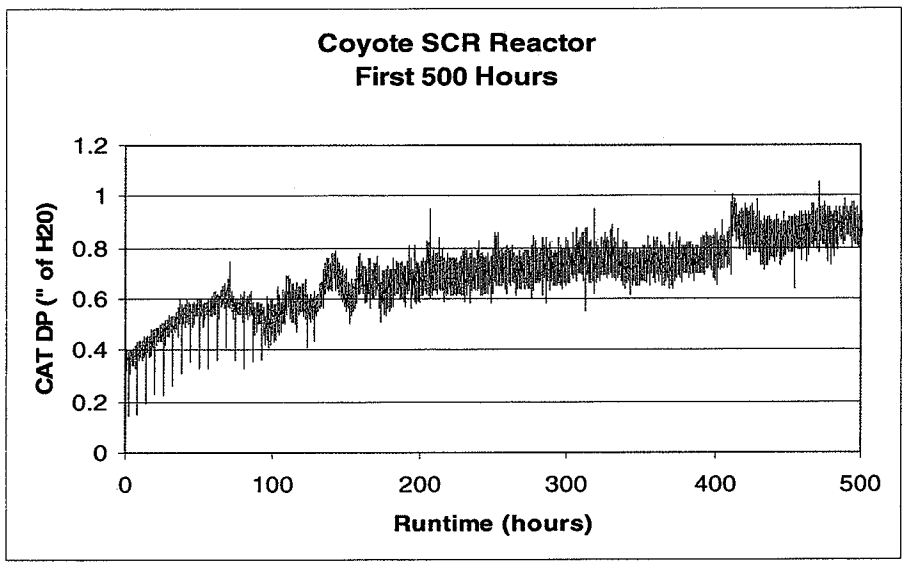

Figure 4. Pressure drop across SCR reactor during first 500 hours of testing at Coyote.

B&McD Response:
An increase in pressure drop is an indicator of gross pluggage of the flue gas passages in the catalyst. Ash deposits that cause the pressure drop to significantly increase can also create maldistribution of the flue gas through the catalyst. Serious maldistribution causes some of the catalyst passages to be significantly underexposed to flue gas flow and ammonia, so they will not contribute to effective NO_X control performance, regardless of whether there is a high level of catalytic activity or not. Likewise, catalyst that has severe micropore pluggage will be ineffective whether it is located within flue gas passages that are exposed to flue gas flow or

not. Prevention of significant ash accumulation, flue gas flow maldistribution, and micropore pluggage needs to be effective in order to maintain high catalyst activity and subsequent NO_X removal. Solving the first two conditions does not ensure that the last (most important) factor is also eliminated. In fact, it will contribute to reducing the amount of time required to cause it.

It seems curious that the cause of the apparent failure of the pilot test at Coyote seems to be pointed at EERC, the design of the test, its equipment, and methods. It is difficult to believe that a consortium of EERC, EPRI, USDOE, utilities, and three catalyst vendors would purposely design a test of SCR technology with the expectation from the onset that it would fail dismally. The fact that it produced deactivation data at two of the three pilot test installations would appear to prove that failure (of the test to show the ability of the catalyst to survive the conditions) was not the intended goal. The SCR vendors that participated were advised of the nature of North Dakota lignite and its challenges during the development of test procedures and design of the equipment. The lack of positive results in the Coyote pilot test shows that the ability of the catalyst to overcome exposure to the test conditions was not as easy and assured as perhaps was initially believed by the SCR catalyst vendors.

"Core" Issue number 6
Split air preheater:
ERG memorandum to EPA, August 20, 2007, page 5
Original Reference: EPA Region 8 letter to NDDH and EGR Letter to EPA, January 8, 2007:

> *"The discussion of the split air preheater approach...seems a bit ambivalent, implying first that it couldn't be done and later stating that conceptually, it could be done. Further evidence is found in the fact that SCR retrofits a[t] New Madrid (two large, PRB-fired cyclone boilers) included replacement of the tubular air preheaters with new regenerative air preheaters with enamel-coated baskets." [ERG October 4, 2007 letter, page 5]*

B&McD Response:
The ERG commenter's response appears to misinterpret B&McD's responses in Minnkota's March 2007 and April 2007 letters to comments made in ERG's January 2007 letter and subsequent request in the February 2007 request that included the EPA's January 26, 2007 letter.

The arrangement and operation of the split air preheater concept proposed by ERG was flawed and would not work satisfactorily as described. Burns & McDonnell suggested alterations to

the concept that would appear to satisfy the basic boiler air temperature requirements for proper lignite coal drying and combustion [March 2007 response page 15].

This is not the same as saying that a high-dust SCR would be technically feasible for installation on the subject units assuming that the alterations suggested to the split air preheater arrangement and operation to satisfy the basic boiler air temperature requirements for proper lignite coal drying and combustion were the only limitations to overcome.

The ERG and EPA comments still do not address the relevant technical issues of operating the high-dust SCR effectively with such wide ranges of flue gas temperatures as shown in Minnkota's April 2007 response letter. Specifically, low load-clean boiler conditions have temperatures below the minimum at which conventional SCR catalysts are effective in coal-fired applications. Operating MRYS Unit 1 and Unit 2 during such periods without effective post-combustion NO_X emissions control by the high-dust SCR would have negative impacts on compliance with NO_X emission limits required for consecutive 30-day rolling periods.

"Core" Issue number 7
B&McD low dust SCR assessment:
ERG memorandum to EPA, August 20, 2007, page 5
Original Reference: EPA Region 8 letter to NDDH and EGR Letter to EPA, January 8, 2007:
"...do not believe that resort to the low dust approach is warranted...." [ERG memorandum to EPA, August 20, 2007, page 5]

B&McD Response:
It is Burns & McDonnell's opinion that there are sufficient quantities of sodium-rich particles that will be in the flue gas stream from a North Dakota lignite-fired cyclone boiler to pose significant catalyst pore blinding, pluggage, and deactivation problems to drastically inhibit effective NO_X emissions control and catalyst life, regardless of whether it is placed in a high-dust or low-dust SCR installation. See EERC's reply regarding this topic contained within the responses in this letter to the EPA's related comments [EPA October 4 letter enclosure page 34].

"Core" Issue number 8

Texas lignite assessment:

ERG memorandum to EPA, August 20, 2007, page 5

Original Reference: EPA Region 8 letter to NDDH and EGR Letter to EPA, January 8, 2007:

> *"George Offen's letter provides some useful insights, particularly with regard to erosion. S&L personnel confirmed that Texas lignite ash is more erosive than North Dakota Lignite ash. This means that the TXU pilot test currently underway should resolve any concerns regarding erosion at a future MRYS SCR installation." [ERG August 20, 2007 letter, page 5]*

EERC Response:

Texas lignites are prone to form silicate base deposits in the boilers and have more of an abundance of silicate-rich entrained particles that can be erosive. However, the erosive nature of the ash is highly dependent upon the source of Texas lignite. The coals fired at the TXU plants and others from the southern part of Texas can be highly erosive.

For example, the coals in the Southern Jackson formation have high ash contents (range 6 to 48%, average 22%, as received basis) and produce a combination of highly porous ash particles and dense hard particles derived from quartz. The quartz materials will cause erosion. The porous particles will produce highly vesicular deposits if the ash accumulates on heat transfer surface. Large vesicular deposits are typically the origin of popcorn ash.

The coals from the Wilcox formation typically have lower ash contents (range 1.4 to 58.6, average 10.6% as received basis). The ash chemical and physical properties of Wilcox based ash materials are significantly different than the Southern Jackson. In addition, TXU co-fires Powder River Basin coal with the lignite. The Texas lignite fired at TXU is from the Wilcox formation and does not represent all Texas lignite. It also does not represent what is fired in North Dakota.

B&McD Response:

Burns & McDonnell does not disagree that Texas lignite contains ash more abrasive than North Dakota lignite. Dr. Benson's discussion of lignite ash deposition in SCR catalyst (August 2007) indicates that small sodium-rich particles are more important in their impact than the large inorganic fraction of the entrained flyash. Burns & McDonnell stands by their comments in Minnkota's March 2007 response (pages 30-31).

"Core" Issue number 9

SCR vendor quote request:

ERG memorandum to EPA, August 20, 2007, page 5

Original Reference: EPA Region 8 letter to NDDH, January 26, 2007:

> *"The ability to provide flue gas at the appropriate temperature is not discussed and the startup/shutdown requirements may be unreasonable." [ERG August 20, 2007 letter, pages 5 and 6]*

B&McD Response:

Burns & McDonnell provided pertinent situation- and plant-specific data to the SCR system vendors and catalyst suppliers. The vendors need to be aware of the seriousness of the situation involving this request and the severity of the operating conditions imposed. The ability to successfully control SCR reactor inlet temperatures in a high-dust SCR application without impairing lignite pre-drying has not been confirmed. It would be inappropriate to assume these challenges have been solved or to request meaningful responses from vendors without advising them of the nature of the query and conditions involved.

The following responses follow the outline of the Enclosure attached to EPA Region 8's October 4, 2007 letter[25].

I. Introduction and Summary of EPA's Preliminary Analysis:
EPA October 4, 2007 letter Enclosure, page 6
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH request item number 1:

> *"Additionally, based on a July 2, 2004, conversation between Jim Standt of Andover Technology Partners and Flemming Hansen of Haldor Topsoe, the sudden build up of fly ash on the catalyst surface that occurred during the pilot testing at Coyote Station was determined to be caused by the accumulation of ash upstream of the catalyst and sudden dropping of that ash accumulated ash onto the catalyst face." [EPA October 4, 2007 letter Enclosure, page 6]*

EERC Response:
The increase in pressure drop across the catalyst was likely not solely due to ash falling in the reactor. The first 500 hours of operation previously shown in Figures 3 and 4 are likely due only to accumulation of ash materials on the catalyst surfaces. In addition, the ductwork was cleaned at two-month intervals. Jim Staudt and Flemming Hansen (Hansen) could not have reasonably determined that the pressure drop was due to ash deposits falling into the reactor. Neither of them was present to view the opening of the reactor or observed the deposits and accumulations in detail. Flow through the catalyst was maintained. See EERC's discussions in response to ERG's core issue number 5 above.

> *"Clearly the two facilities operating on PRB coal experienced catalyst plugging that required extensive and aggressive cleaning measures...." [EPA October 4, 2007 letter Enclosure, page 6]*

EERC Response:
The accumulations at Baldwin and Columbia were minor or moderate in comparison to the results obtained at the Coyote Station. The fact that the reactor ran well for both the Baldwin and Columbia Stations are indications that the results for Coyote Station are valid. Similar testing protocol was initiated for both tests.

> *"EPA also spoke with Flemming Hansen regarding the feasibility of an SCR installation at MRYS and the nature of the SCR pilot testing at the Coyote station conducted by EERC." [EPA October 4, 2007 letter Enclosure, page 7]*

[25] Ibid Reference number 6.

EERC Response:
EPA discussion with Hansen seemed to not focus on one of the key issues we discussed with him. During EERC discussions with Hansen at Haldor Topsoe, his major concern was the soluble sodium. The fact that sodium is in a soluble form impacts the catalysts. No discussion with Hansen and EPA was held on the impacts of the high sodium in the soluble form. Much of his subsequent discussion was on plugging and not pore plugging.

"...nothing has been provided that would demonstrate that SCR would be an ineffective means of NOx control at MRYS". [EPA October 4, 2007 letter Enclosure, page 2] and "EPA believes B&McD's conclusions regarding the use of the "empirical data" from the Coyote Station pilot–scale testing is not relevant for an analysis of technical feasibility, and fails to consider the observations on catalyst maintenance frequency and pressure drop trends from the Baldwin and Columbia Station pilot tests. [EPA October 4, 2007 letter Enclosure, page 4] and

"For the Coyote Station, EPA agrees that the plugging and pressure drop observed during the pilot test were more pronounced and occurred quicker than what was observed at the two facilities burning PRB coal. Additionally, based on the deposition sampling, EPA agrees there is evidence that sodium was a factor in the plugging at Coyote, where it did not appear at the other two facilities. However, EPA disagrees that these test results can lead to a conclusion that extended forced outages would be needed at two month intervals as stated by B&McD in Minnkota's March 19, 2007 letter."[EPA October 4, 2007 letter Enclosure, page 5] and

"Based on the above comparison, of the pilot testing results by EERC, it is unclear to EPA that any definitive conclusions can be extrapolated from the results about SCR technical feasibility and/or timing or extent of SCR maintenance requirements and boiler outages ...as was done by B&McD for MRYS. Clearly the two facilities operating on PRB coal experienced catalyst plugging that required extensive and aggressive cleaning operation ...." [EPA October 4, 2007 letter Enclosure, page 6]

"...B&McD has not provided a response to EPA's statements regarding normally observed pronounced ash deposition during pilot testing, the small catalyst pitch, used at Coyote Station, and how a larger pitch might have affected the test results, and how the air pulsing did not properly represent sootblowing capabilities on a full-scale SCR application." [EPA October 4, 2007 letter Enclosure, page 7]

B&McD Response:
Burns & McDonnell stands by their comments made in response to ERG's "core issue" number 2 and number 4 (herein), and Minnkota's April 2007 response (pages 25-26) to the question of multiple engineering solutions suggested by the EPA's comment in the EPA's January 26, 2007 letter (page 2). Related additional information has subsequently been provided in EERC's discussion included in Minnkota's August, 2007 letter (page 22).

"Mr. Hansen said that Haldor Topsoe would not rule out bidding on a project that involved North Dakota lignite ... they would look at computer modeling for the specific coal analysis and boiler ...." [EPA October 4, 2007 letter Enclosure, page 8]

EERC Response:
Current computer models have difficulty in providing adequate information on the transport of submicron particles into the pore structure of catalyst, subsequent sulfation, bonding strength development, and removal potential.

"Mr. Hansen was unaware that Haldor Topsoe sent emails to EPA Headquarters stating that Haldor Topsoe (and two other catalyst vendors) could provide guarantees for the MRYS coal." [EPA October 4, 2007 letter Enclosure, page 9]

B&McD Response:
It is unclear what the referenced sentence is intended to convey. Burns & McDonnell continues to express concerns that any SCR catalyst vendor's willingness to guarantee performance on a North Dakota lignite-fired boiler will be very limited, requiring certain specific criteria to be met that are yet to be proven to exist or capable of existing at MRYS. This limitation to the SCR catalyst guarantee is required by the vendor in order to manage financial risks by specifying the limits of their system design in case of potential operating conditions that cause performance problems that prevent achievement of guarantees and/or warranty claims. SCR catalyst vendors assume that the system suppliers have already solved (or will solve) the stated temperature problems, and proven solutions to these conditions have not been identified. Burns & McDonnell stands by their comments made in Minnkota's April 2007 response (pages 27-28).

II. EPA Case-Specific Review of Burns & McDonnell & EERC Technical Feasibility Analysis for Selective Catalytic Reduction

A. High-Dust SCR

1. Ash Deposition Issue Raised by Burns & McDonnell:

EPA October 4, 2007 letter Enclosure, page 10
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"EPA is also not aware that any catalyst formulations have been developed to deal specifically with the issue of sodium." [EPA October 4, 2007 letter Enclosure, page 10]

EERC Response:
Khodayari's major conclusion in his Ph.D. thesis was "Potassium and sodium were found to be two of the worst poisons that had significant effects on the activity of the SCR catalyst due to their selective chemisorption on the Brønsted acid sites." A reference to the source for this thesis is provided in response to Christman's August 2007 comments.

> *"EPA asked Minnkota to look further into Engineering solutions currently available and determine whether or not the macro-pore plugging issue described in the EERC report could be effectively managed." [EPA October 4, 2007 letter Enclosure, page 10]*

EERC Response:
During the discussions with Haldor Topsoe we asked if they had been pursuing developing SCR catalyst materials that would be less prone to the impact of alkali and alkaline earth elements. They indicated that they had not pursued developing new catalysts or modifying current formulations that could be adapted for use with high base-to-acid ratio coal ash.

> *"EPA does not dispute EERC's description of the chemical and physical fate of sodium in a cyclone boiler." [EPA October 4, 2007 letter Enclosure, page 12] and*
>
> *"EPA acknowledges that the sodium content of the Center Mine lignite is generally higher than PRB coals. EPA also recognizes that ash partitioning in a cyclone boiler and resulting sodium deposition presents certain problems that could pose engineering challenges to the design and operation of an SCR system at MRYS. However, Minnkota has not provided any quantitative data that shows that the plugging and deactivation of the SCR system would be an unresolvable technical barrier and/or the ability of the SCR to control NOx would be so limited that SCR would be an ineffective control option." [EPA October 4, 2007 letter Enclosure, page 14] and*
>
> *"Due to the lack of NOx emission and catalyst deactivation data, the Coyote Station study does not support utilizing any definitive conclusions, other than there was significant plugging, which also appeared at both the Baldwin and Columbia Stations." [EPA October 4, 2007 letter Enclosure, page 15] and*
>
> *"EPA believes that the experience the utility industry has gained from the installations at PRB facilities... while Sargent & Lundy indicated that further data from well designed pilot study would enhance their ability to optimally design a more cost-effective SCR system...." [EPA October 4, 2007 letter Enclosure, pages 15, 16]*

EERC Response:
In recent discussions with Sargent & Lundy regarding the EERC SCR reactor testing, they were unaware that 6 months of testing occurred at the Baldwin Station using the same reactor

as was used at Coyote station. We recently advised Mr. DePriest of Sargent & Lundy that all the pores in the catalyst had plugged with sodium calcium and sometimes potassium sulfates and he indicated he had not been aware of this prior to our discussion.

"The response from EERC simply restates their position regarding the high sodium content of the Center Mine lignite and how this will cause both catalyst pore plugging and gas path plugging. EERC fails to consider the use of available engineering solutions to address these problems with operation of an SCR at MRYS." [EPA October 4, 2007 letter Enclosure, page 17] and

"...aggressive on-line cleaning and/or frequent extended outages would be required to remove ash accumulation or remove catalyst for cleaning...." [EPA October 4, 2007 letter Enclosure, page 18]

"EPA acknowledges that the sodium content in North Dakota lignite presents engineering challenges. EPA also thinks it is possible that the "sodium-related deposition on SCR catalyst will shorten the time between outages for off-line cleaning... Unfortunately, the pilot testing conducted at Coyote Station did not provide any quantitative results that could be used to predict the time periods between catalyst cleaning/replacement on a full-scale application." [EPA October 4, 2007 letter Enclosure, page 19] and

EERC Response:
Discussions on engineering solution have been conducted with catalyst vendors. None of them have indicated they have solutions for the sulfate based deposits in the pores of the catalyst that form by vapor phase and small particle diffusion and subsequent reaction to form sulfates.

B&McD Response:
Burns & McDonnell stands by their comments made in response to ERG's "core issue" number 3 and number 4 (herein), and Minnkota's April 2007 response (pages 25-26) to the question of multiple engineering solutions suggested by the EPA's comment in the EPA's January 26, 2007 letter (page 2). Related additional information has subsequently been provided in EERC's discussion included in Minnkota's August, 2007 letter (pages 22 and 23) and in the response immediately above.

"The intent of referencing the EPRI letter on Texas lignite was not to imply that North Dakota lignites are exactly the same as Texas lignites. The intent of referencing this letter was to show that a major utility research organization is of the opinion that the existing experience of SCR designers would greatly help in designing SCR systems for accommodating fuel types never before used in practice on a full scale." [EPA October 4, 2007 letter Enclosure, page 18]

B&McD Response:
The information included elsewhere in this letter and previously provided by EERC and B&McD shows that the obstacles to applying SCR on North Dakota lignite-fired cyclone boilers are much more problematic than those faced by designers for PRB or Texas lignite-fired systems. None of the catalyst suppliers have developed proven solutions preventing or removing sodium- and sulfur-based deposits in the micropores of the catalyst that form by vapor phase and small particle diffusion and subsequent reaction to form sulfates that are bonded tightly to the catalyst surface.

> *"However, the EPA cannot concur that the qualitative pilot testing results at the Coyote Station cited in the EERC report demonstrate that a full-scale SCR installation at MRYS, ... would not be technically feasible...EPA pointed out some of the inherent limitations in the pilot testing that might have contributed to the "failure" of that test. ... EPA questions the design and operation of the pilot test in light of critical data obtained." [EPA October 4, 2007 letter Enclosure, page 20]*

EERC Response:
Regarding EPA questioning the design and operation of the Coyote Station SCR testing, the design and operation was conducted at Columbia and Baldwin Stations prior to the testing at Coyote. Based on those results the project team that involved EERC, EPRI, USDOE, Haldor Topsoe, Cormetech, Hitachi, and associated utilities decided that the testing protocol should not be changed and testing at Coyote Station should go on even with the concerns about the high sodium lignite. The blinding and plugging was extremely rapid and severe as compared to testing at the PRB fired systems. It surprised the catalyst vendors and they did not have suggestions on how to minimize the impacts. They reviewed all publications and final reports, but did not provide any suggestions on further work to solve the problem.

B&McD Response:
It appears that because of the lack of quantifiable catalyst deactivation and NO_X reduction data from the severely plugged pilot-scale SCR catalyst tested at Coyote Station, EPA discounts the observations resulting from short-term exposure of SCR catalyst to flue gas and flyash produced from burning North Dakota lignite in a cyclone-fired boiler. The Baldwin and Columbia Station pilot tests had significant ash deposition but still were able to be analyzed for catalyst deactivation while the Coyote catalyst was worse and could not be analyzed.

Reduction of ash deposition within the catalyst in the Coyote pilot SCR testing would have reduced the amount of pressure drop increase through the catalyst layer. This is the "macro-effect" of the limitations of the pilot SCR testing to duplicate full-scale PRB cyclone and pulverized coal-fired boiler SCR installation experience because pilot-scale on-line ash cleaning and accumulation prevention measures were subsequently considered to be not as effective as the participants expected.

However, the plugging of the Coyote pilot catalyst micropores effectively prevents exposure of the catalyst to flue gas and ammonia so that NO_X emissions reduction across the fouled catalyst cannot take place. The expected catalyst activity would essentially be zero and NO_X reduction would be zero from a practical standpoint. This supposition is reasonable, based on the macroscopic and microscopic evidence.

EPA's statement of Minnkota's arguments lacking "quantifiable data" appears to ignore this supposition. Such drastic, negative results from such a short amount of time (4 months) of Coyote pilot SCR catalyst testing should be interpreted as an unsuitable application of the technology, sufficient to satisfy 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.

Burns & McDonnell stands by the comments in the October 2006 NO_X BACT analysis, March 2007, April 2007, and August 2007 response letters, and the additional responses provided herein.

2. <u>EPA Analysis of the "Popcorn Ash" Issue</u>:
EPA October 4, 2007 letter Enclosure, page 21
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH

"No response given to EPA's comment by EERC or B&McD. The topic was similarly addressed in the January 2007 Christman Memo." [EPA October 4, 2007 letter Enclosure, page 21]

B&McD Response:

Based primarily on one European power generating company's experiences (Steag, Babcock Power) referenced in ERG's January 8, 2007 memo letter, there have been significant improvements in the design and implementation of reliable and effective SCR inlet "popcorn" ash screens since the late 1990's/early 2000's. It is difficult to compare such experience with a hypothetical installation on a cyclone boiler firing North Dakota lignite, without knowing more specifics about the referenced boilers' operating conditions related to furnace and backpass surface slagging and fouling, and the means and frequency employed to clean such surfaces in association with the deployment of the large particle ash screens.

3. <u>EPA Analysis of the Temperature Issue</u>:

EPA October 4, 2007 letter Enclosure, page 21
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH

"No response given to EPA's comment by EERC or B&McD. The topic was similarly addressed in the January 2007 Christman Memo." [EPA October 4, 2007 letter Enclosure, page 21]

B&McD Response:

As stated in Minnkota's April 23, 2007 response to NDDH and EPA, and included in this letter in response to ERG core issue number 6, the suggested split air preheater scheme does not raise the temperature exiting either boiler's primary superheater (PSH) section that is located upstream of the high-temperature pass of the tubular air preheater when the boiler is clean and the load is low. This PSH exit flue gas temperature is too low under these conditions for effective NOx reduction by a conventional hot-side SCR. We know of no coal-fired utility boiler with a hot-side SCR using flue gas bypass around the primary superheater section. Reheating flue gas to acceptable temperatures for these conditions may be another solution, but this has been discounted due to the gross amount of reheat fuel or steam required. Even if such solutions were developed in more detail before they could be considered to be technically feasible and evaluated, it does not resolve the issues around catalyst micropore plugging and the fact that on-line cleaning measures have yet to be proven effective for SCRs on North Dakota lignite-fired cyclone boiler applications.

4. <u>EPA Analysis of the Erosion Issue</u>:
EPA October 4, 2007 letter Enclosure, page 21
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH

"No response given to EPA's comment by EERC or B&McD. The topic was similarly addressed in the January 2007 Christman Memo." [EPA October 4, 2007 letter Enclosure, page 21]

B&McD Response:

Various means of resolving catalyst erosion were referenced in ERG's January 8, 2007 memo letter. Effective on-line catalyst cleaning of deposits seen in the Coyote pilot testing, especially in the micropores plugged with sodium-sulfur compounds, may not be achievable. Aggressive sootblowing using steam may damage the catalyst even with the suggested erosion prevention measures in place. It is difficult to compare current experience with a hypothetical installation on a cyclone boiler firing North Dakota lignite, without knowing more specifics about the referenced catalysts surface and micropore fouling and cleaning operation conditions.

5. <u>EPA Analysis of the Energy & Environmental Research Center Report (Appendix B)</u>:
EPA October 4, 2007 letter Enclosure, page 23
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH

"... a better effort to keep the catalyst face clean. Mr. Hansen recalled the Coyote Station test reactor became quickly plugged with fly ash causing rapid increases in pressure loss caused mainly by wall duct ash accumulations dropping on the catalyst face." [EPA October 4, 2007 letter Enclosure, page 23] and

"Based on the EERC response, the degree of catalyst plugging observed at Coyote Station was the reason no deactivation testing on the catalyst was conducted. If the testing were designed and conducted in a way that could have greatly reduced the effects of ash deposition on the catalyst face, presumably catalyst deactivation data could have been obtained. As stated previously, EPA questions Minnkota's heavy reliance on the questionable results from the Coyote Station pilot testing and cannot support using this data to draw definitive conclusions on the feasibility of SCR at MRYS." [EPA October 4, 2007 letter Enclosure, page 23]

EERC Response:

Visual observations and the SEM analysis of the plugging materials do not support Hansen's suggestions that all the deposits came from walls of the vessel. Evidence of flow patterns in the plugging materials that were not consistent with the geometry of the catalyst was not observed. In addition, if the gases were not allowed to flow through the catalyst and they were

rapidly plugged begs the questions: Why were the pores being plugged in the middle and at the outlet regions of the catalysts? Why were deposits evident at the outlet of the catalyst and in the catalyst vessel as shown in Figure 5?

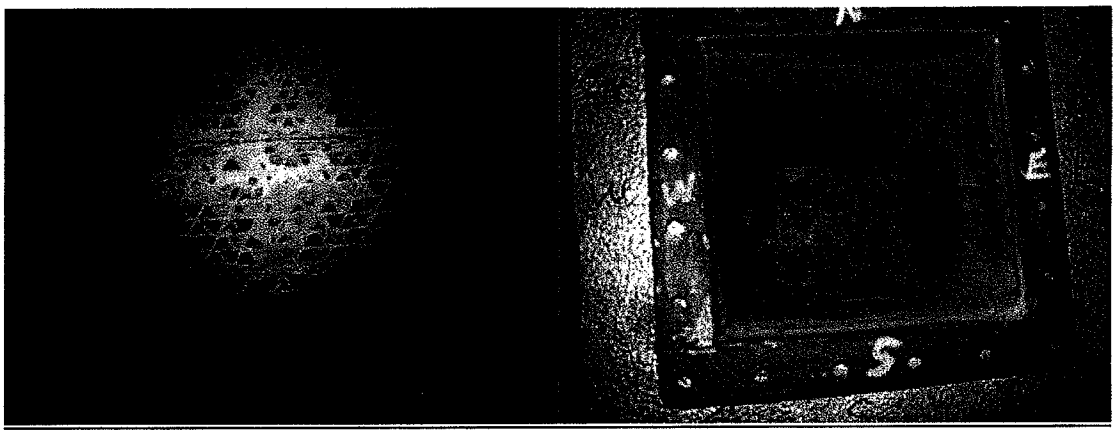

Figure 5. Plugging of SCR catalyst and deposits formed downstream of center section after removal from Coyote Station. The image at the left is the catalyst outlet after it was removed. The image at the right is of the hard deposits that remained in the vessel at the outlet of the catalyst after the catalyst was removed.

"In addition, Sargent & Lundy indicated that they were disappointed in how the Coyote Station pilot test was carried out and found the results to be of very little value for evaluating an SCR system for facility burning North Dakota lignite." [EPA October 4, 2007 letter Enclosure, page 23]

EERC Response:
Sargent & Lundy was unaware that the same reactor was used for the Coyote testing as was used for the Baldwin testing, and that the testing at Baldwin occurred over a six-month period. They were also unaware of the degree of blinding and plugging of the pores. The information from the Baldwin testing was used as input for the design of SCR systems. Sargent & Lundy did not have an in depth appreciation of the challenges high sodium lignite has on SCR catalysts.

6. <u>EPA Analysis of the Burns & McDonnell's Conclusion</u>:
EPA October 4, 2007 letter Enclosure, pages 25-31
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH[26]

"While the pilot study does suggest that catalyst plugging at a facility burning North Dakota lignite would likely be more of a challenge than at a facility burning PRB coal,

[26] Ibid Reference number 9.

EPA can not conclude that the test is determinative of whether an SCR system would not work at MRYS." [EPA October 4, 2007 letter Enclosure, page 25] and

"...the qualitative information does not provide meaningful conclusions for comparatively assessing SCR technical feasibility for North Dakota lignite and PRB applications. The one exception would be that the study shows lignite at Coyote Station showed more sodium deposition and less calcium compared to PRB coal." [EPA October 4, 2007 letter Enclosure, page 28] and

"Without representative catalyst deactivation testing or NO_X control data from the Coyote Station, EPA does not believe the pilot study provides meaningful results that could lead to a definitive conclusion that SCR would be infeasible at MRYS." [EPA October 4, 2007 letter Enclosure, pages 28 and 29] and

"... reactivity testing for the catalyst. EERC did not test the catalyst at Coyote Station, because the catalyst was allegedly too plugged to conduct the testing. This appears to be a failure of the pilot test to meet the original goal for North Dakota lignite. ... in light of substantial ash deposition on the catalyst face...". [EPA October 4, 2007 letter Enclosure, page 29] and

"The qualitative results of catalyst plugging for the pilot testing at Coyote Station do not provide empirical evidence that SCR would be ineffective at controlling NOx emissions, since there was no quantitative data provided for either NOx reduction or catalyst deactivation. As such, EPA is not convinced that the specific challenges presented for an SCR installation at MRYS is a matter of technical infeasibility and could not be overcome with a robust suite of ash (including sodium) mitigation measures and/or maintenance measures." [EPA October 4, 2007 letter Enclosure, page 30]

EERC Response:
The deactivation testing was not conducted because the gas paths were severely plugged. Haldor Topsoe indicated that they would have to rod out the deposits to provide the catalyst activity testing. They indicated that the results of reactivity testing would be inclusive in the cleaned catalyst before making the measurements. The conclusion that the plugging and blinding is largely due to upstream deposition is not correct.

B&McD Response:
Burns & McDonnell stands by the comments in the October 2006 NO_X BACT analysis, March 2007, April 2007, and August 2007 response letters and the additional responses provided herein.

B. Low-Dust SCR

1. EPA Analysis of the Catalyst Fouling and Deactivation Issue:

EPA October 4, 2007 letter Enclosure, page 32

Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"...general qualitative statements that the sodium-rich aerosols will cause blinding and deactivation do not necessarily support the conclusion that a low-dust SCR system would be technically infeasible at MRYS. The effects of this blinding and deactivation should either be quantified and used within the economic analysis under step 4 of the Top-Down BACT analysis, or described in sufficient detail to demonstrate that the problems associated with catalyst blinding and deactivation are unsolvable and would result in the unsuccessful operation of a low-dust SCR. As stated on page B.20 of the NSR Workshop Manual, "(p)hysical modifications needed to resolve technical obstacles do not in and of themselves provide a justification for eliminating the control technique on the basis of technical infeasibility. However, the cost of such modifications can be considered in estimating cost and economic impacts." [EPA October 4, 2007 letter Enclosure, pages 32-33]

B&McD Response:

As EERC has described previously and elsewhere in this document, effective solutions to prevent or remove micropore pluggage and blinding of SCR catalyst from sodium-sulfur compounds evident in the flue gas stream exhausted from a North Dakota lignite-fired boiler, whether installed in a conventional hot-side or cold-side application downstream of a wet scrubber, have not been developed by SCR catalyst vendors. Burns & McDonnell previously discussed the estimated energy requirements for reheating flue gas upstream of a low-dust and tail-end SCR in the October 2006 NO_X BACT analysis and March 2007 response letters. Propane or fuel oil will certainly be more expensive to supply than pipeline natural gas, because of the additional over-the-road transportation requirements. These alternate fuels do nothing to address the fundamental issues of the composition of the flue gas and flyash being unsuitable for low-dust SCR applications. We believe these are credible arguments that adequately describe the reasons that preclude the successful deployment of this technology on the cyclone boilers at MRYS.

2. EPA Analysis of the Site Space Constraint Issue:

EPA October 4, 2007 letter Enclosure, page 33

Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"EPA acknowledges that extensive work may be required for installation of low-dust SCR...based on reasonable expected reheat fuel requirements, equipment installations, plant modifications...." [EPA October 4, 2007 letter Enclosure, pages 33-34]

B&McD Response:

Burns & McDonnell believes it is appropriate to consider SCR technology for the cyclone boilers at MRYS to be technically infeasible and thus eliminated it during the Top-Down BACT analysis prior to the economic analysis step. The extensive plant modifications anticipated to deploy SCR at Unit 1 and Unit 2 at MRYS still do not resolve the catalyst micropore plugging and blinding problems evident in the Coyote Station pilot-scale testing.

3. <u>EPA Analysis of the Burns & McDonnell's Conclusion</u>:
EPA October 4, 2007 letter Enclosure, page 34
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"B&McD appears to be saying that a significant portion of the sodium in the fly ash is in the vapor phase when it enters the ESP." [EPA October 4, 2007 letter Enclosure, page 34]

EERC Response:
EPA misinterpreted B&McD and EERC's response. B&McD and EERC do not suggest in any of the documentation that sodium is in the vapor phase at the temperatures of the SCR. Initially in cyclone-fired systems much of the sodium is vaporized. Vaporized sodium will condense upon gas cooling heterogeneously on entrained particles or homogeneously to form aerosols. The condensed material will react with other gas phase materials such as SO_2 and SO_3 to form sulfates. There is evidence of sodium, potassium, calcium, and sulfur deposition downstream of the ESP as illustrated in Figure 1 presented in response to ERG Core Issue number 2.

III. Additional Information Useful to Evaluating <u>Technical Feasibility of SCR at MRYS</u>

A. <u>EPA Headquarters Believes SCR is the Correct Technology for MRYS in Developing the Clean Air Interstate Rule</u>

EPA October 4, 2007 letter Enclosure, page 36
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"...EPA's discussion with Flemming Hansen of Haldor Topsoe also revealed that despite the concerns about an SCR system subjected to the sodium environment... Haldor Topsoe would not rule out bidding such a project." [EPA October 4, 2007 letter Enclosure, page 37]

EERC Response:
The most significant part of the discussion with Haldor Topsoe is left out, and that was on the soluble form of sodium. His indication that this form of sodium is the worst kind relative to poisoning and would have a major influence on whether they would consider bidding or not.

B&McD Response:
As previously discussed in Minnkota's March 2007 response, SCR catalyst vendors willingness to bid on a project for applying SCR to a North Dakota lignite-fired cyclone boiler does not ensure that the identified issues will be satisfactorily resolved and that appropriate guarantees for catalyst performance and life will be agreed upon in the final contract.

B. SCR Technology is Presumptive BART for Cyclone Boilers in EPA's BART Guidelines
EPA October 4, 2007 letter Enclosure, page 37
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"EPA is not suggesting that the cost figures used in the BART analysis need to be used in the BACT analysis for MRYS." [EPA October 4, 2007 letter Enclosure, page 37]

B&McD Response:
Burns & McDonnell believes it is appropriate to consider SCR technology for the cyclone boilers at MRYS to be technically infeasible due to catalyst micropore plugging and blinding problems and thus eliminated it during the Top-Down BACT analysis prior to the economic analysis step.

C. February 27, 2006 Final Revisions to 40 CFR Part 60, Subpart Da, New Source Performance Standards for Electric Generating Units Set Final NOx Limit Based on Technical Feasibility of SCR for Lignite-Fired Units
EPA October 4, 2007 letter Enclosure, page 38
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"...the new NSPS standards apply to affected utility boilers that commence construction, reconstruction, or modification after February 28, 2005. (EPA's original comments erroneously said that the standards only applied to new units.) This would include any existing cyclone units firing North Dakota lignite that undergo reconstruction or modification. The standards that would apply to...modified units (1.4 lb/MWh or 0.15lb/MMBtu)...EPA also agrees that there have been some recently-permitted units burning Texas lignite that have proposed SCR and that there are some differences between

North Dakota and Texas lignite. EPA believes these differences might affect the design and operation of an SCR system for the different lignites. EPA does not believe these differences indicate that EPA did not consider North Dakota lignite in revising the NSPS for utility boilers." [EPA October 4, 2007 letter Enclosure, pages 38 and 39] and

"Notwithstanding the differences between North Dakota lignite and Texas lignite, a modified cyclone boiler firing North Dakota lignite would still need to meet the most recent NSPS Da limit for modified units, which is lower than the BACT limit proposed by Minnkota. The likely choice to meet this limit of 0.15 lb/MMBtu would be SCR." [EPA October 4, 2007 letter Enclosure, page 40]

B&McD Response:

B&McD concurs with EPA's analysis that reconstructed or modified units would be required under the NSPS rules to meet emission limitations that are well below those proposed by Minnkota as BACT. However, these NSPS limits are not applicable in this case and the existence of the EPA's new NSPS standards is not proof that Minnkota's October 2006 BACT analyses and subsequent responses are insufficient to meet the requirements of the process following the NSR Workshop Manual in accordance with the Consent Decree. B&McD continues to submit that there is no proven NO_X control technology that is capable of achieving these NSPS emission limits on cyclone-fired unit burning North Dakota lignite.

"EPA has reviewed the coal data submitted by EERC and, in general, agrees that the sodium content of Texas lignites is lower than North Dakota lignites. However, it appears that the Jackson South Texas lignite has a somewhat comparable ash sodium content above 3%..." [EPA October 4, 2007 letter Enclosure, page 39]

EERC Response:

The lignite from the Jackson formation is a famous coal relative to the fate and behavior of sodium. The sodium in the Jackson South and Yegua formations of Texas is in the form of a zeolite-type mineral. During combustion, most of the sodium is retained in the aluminosilicate melt phase and is not vaporized. As a result the sodium released as a vapor for the Texas lignite is much less as compared to a North Dakota lignite from a cyclone-fire boiler. Therefore, making the comparison on a sodium mass per unit of heat input (lb Na/MMBTU) basis is not an accurate assessment of sodium impacts from North Dakota lignite compared with the Texas lignites cited by EPA.

D. SCR and Catalyst Vendor Information
EPA October 4, 2007 letter Enclosure, page 40, 41
Original Reference: EPA Region 8 January 8, 2007 letter to NDDH:

"EPA had originally suggested that Minnkota "obtain information and proposals" from some of the other companies that EPA had listed. EPA envisioned this to include more of the level of detail described by B&McD in their March 19, 2007 response." [EPA October 4, 2007 letter Enclosure, page 41]

B&McD Response:
Burns & McDonnell provided pertinent situation- and plant-specific data to the SCR system vendors and catalyst suppliers. The vendors need to be aware of the seriousness of the situation involving this request and the severity of the operating conditions imposed. The ability to successfully control SCR reactor inlet temperatures in a high-dust SCR application without impairing lignite pre-drying has not been confirmed. It would be inappropriate to assume these challenges have been solved or to request meaningful responses from vendors without advising them of the nature of the query and conditions involved.

EPA's Response to EERC and B&McD April 23, 2007 Letter to NDDH Comments – February 1, 2007 (Including Response to U.S. EPA Region 8 Comments – January 26, 2007): Request for Additional Information and the Non-SCR Comments from EPA
IV. Minnkota's Responses to Additional Information Requested
A. Center Mine Lignite Coal Ash Content and Variability
EPA October 4, 2007 letter Enclosure, page 42
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"EPA has reviewed the coal data submitted by Minnkota. EPA believes future coal data appears to show little change from the 2007 cores." [EPA October 4, 2007 letter Enclosure, page 39]

EERC Response:
The challenges for the future are related to the decreased availability of the lower sodium coals. The abundance of the lower sodium coal depicted by the lower mode in Figure 6 is decreasing in availability resulting in higher sodium levels. Historically, higher sodium means an increase in lower temperature sulfate based fouling problems in combustion systems.

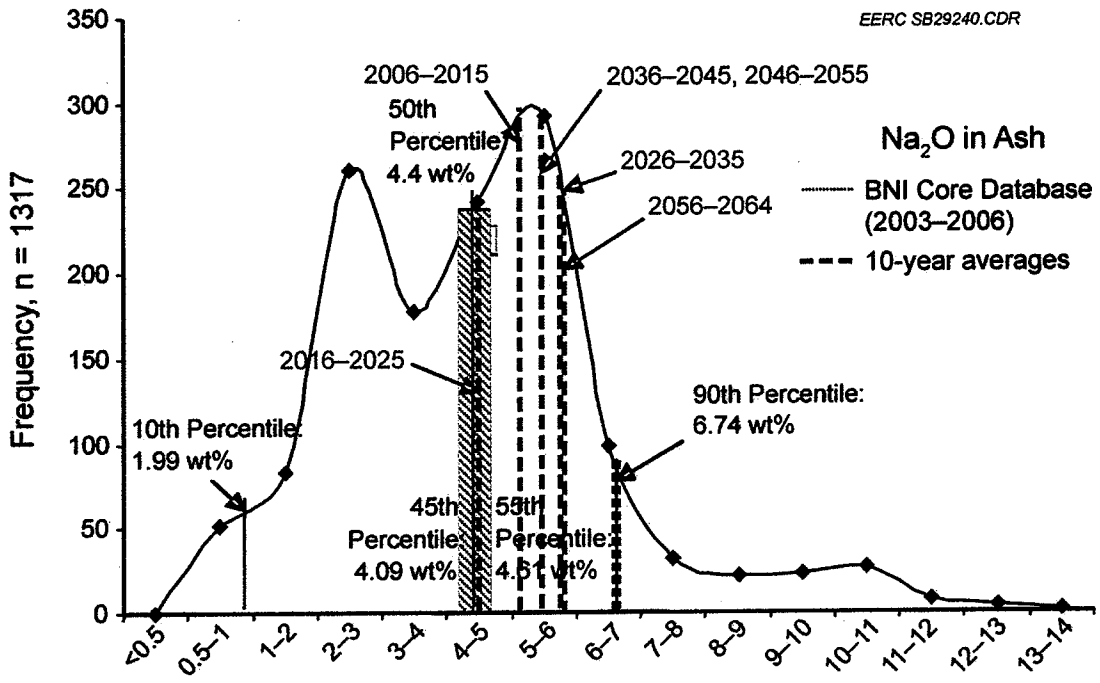

Figure 6. Sodium oxide in ash frequency distribution for as-fired database compared to 10-year averages and weighted Core Database values

B. <u>High Economizer Exit Temperature</u>
EPA October 4, 2007 letter Enclosure, page 43
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"EPA acknowledges that there are times when the flue gas temperature at the portion of the boiler where a high-dust SCR would be located (primary superheater outlet for Unit 1 and presumably the economizer exit for Unit 2) would be higher than the temperature range typically suitable for SCR. While B&McD seems to indicate in the March 19, 2007 letter that the dual-air preheater design suggested by ERG would be problematic, it later concedes that it conceptually could work, but would be at additional cost." [EPA October 4, 2007 letter Enclosure, page 44]

B&McD Response:

The EPA commenter's response appears to misinterpret B&McD's responses in Minnkota's March 2007 and April 2007 letters to comments made in ERG's January 2007 letter and subsequent request in the February 2007 request that included the EPA's January 26, 2007 letter.

The arrangement and operation of the split air preheater concept proposed by ERG was flawed and would not work satisfactorily as described. Burns & McDonnell suggested alterations to the concept that would appear to satisfy the basic boiler air temperature requirements for proper lignite coal drying and combustion [March 2007 response page 15].

This is not the same as saying that a high-dust SCR would be technically feasible for installation on the subject units assuming that the alterations suggested to the split air preheater arrangement and operation to satisfy the basic boiler air temperature requirements for proper lignite coal drying and combustion were the only limitations to overcome.

The ERG and EPA comments still do not address the relevant technical issues of operating the high-dust SCR effectively with such wide ranges of flue gas temperatures as shown in Minnkota's April 2007 response letter. Specifically, low load-clean boiler conditions have temperatures below the minimum at which conventional SCR catalysts are effective in coal-fired applications. Operating MRYS Unit 1 and Unit 2 during such periods without effective post-combustion NOx emissions control by the high-dust SCR would have negative impacts on compliance with NO_X emission limits required for consecutive 30-day rolling periods.

As stated in Minnkota's April 23, 2007 response to NDDH and EPA, and included in this letter in response to ERG core issue number 6, the suggested split air preheater scheme does not raise the temperature exiting either boiler's primary superheater (PSH) section that is located upstream of the high-temperature pass of the tubular air preheater when the boiler is clean and the load is low. This PSH exit flue gas temperature is too low under these conditions for effective NOx reduction by a conventional hot-side SCR. We know of no coal-fired utility boiler with a hot-side SCR using flue gas bypass around the primary superheater section. Reheating flue gas to acceptable temperatures for these conditions may be another solution, but this has been discounted due to the gross amount of reheat fuel or steam required. Even if such solutions were developed in more detail before they could be considered to be technically feasible and evaluated, it does not resolve the issues around catalyst micropore plugging and the fact that on-line cleaning measures have yet to be proven effective for SCRs on North Dakota lignite-fired cyclone boiler applications.

C. <u>Low-Dust SCR Fouling</u>
EPA October 4, 2007 letter Enclosure, page 44
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"While the relative effects of vaporized particles passing through the ESP and condensing prior to a low-dust SCR system might be more pronounced compared to the non-vapor particles impacting a high dust environment, EPA maintains that the ESP will remove a very substantial portion of the ash that would affect a high-dust SCR and the overall effects of catalyst plugging and deactivation in a high-dust application would be greater than a low-dust application." [EPA October 4, 2007 letter Enclosure, page 45]

EERC Response:
These materials are submicron sodium-rich aerosols that will cause problems in low dust operations. Please note the deposits that formed downstream of the ESP on MRY Unit 1 as previously illustrated in Figure 1. The chemical composition of the deposit is consistent with various pyrosulfates that have melting points as low as 530°F.

D. <u>SCR Deactivation</u>
EPA October 4, 2007 letter Enclosure, page 45, 47
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"Meeting with Sargent & Lundy ... indicated that an SCR system could theoretically be designed to operate on North Dakota lignite... Sargent & Lundy representatives were of the opinion that a well-run pilot test would yield valuable information that could be used in conjunction with previous SCR experience to evaluate and design an SCR for a North Dakota lignite application." [EPA October 4, 2007 letter Enclosure, page 47]

EERC Response:
Recent discussions with Mr. William DePriest (DePriest) from Sargent & Lundy indicated that he did not appreciate the challenges encountered due to high sodium lignite characteristics. We discussed reactor design and he was familiar with the one used at the Baldwin Station. He did not know that the same reactor used at Baldwin was used at Coyote Station. In addition, DePriest was not aware that the reactor was operated for six months at Baldwin Station.

B&McD Response:
Burns & McDonnell stands by the comments in the October 2006 NO_X BACT analysis, March 2007, April 2007, and August 2007 response letters and the additional responses provided herein.

E. <u>SCR Vendor Guarantees</u>
EPA October 4, 2007 letter Enclosure, page 48
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"The letter goes into great detail about the worst-case nature of Center Lignite coal." [EPA October 4, 2007 letter Enclosure, page 48]

EERC Response:
EPA indicated that a worst-case nature of Center lignite was provided. Designs of systems must be able to accommodate the more challenging coals, and in this case, sodium oxide levels of 6 to 8 % in the ash. The information provided was information that would be provided to any vendor of equipment that would utilize Center lignite coal. Specifically, the fuel compositional information provided included compositions for candidate design and performance coal compositions. Systems cannot be designed based on average coal properties.

"EPA has still not seen any vendor responses to the information request. EPA does note that the request seems to have been written with a pessimistic tone..." [EPA October 4, 2007 letter Enclosure, pages 48-49]

B&McD Response:
Responses have not been provided by all of the SCR catalyst and system vendors that B&McD requested information from. Burns & McDonnell stands by the comments in the April 2007 response letter and the additional responses provided herein (e.g. ERG Core Issue number 9).

F. <u>MRYS Boiler Cleaning Outages</u>
EPA October 4, 2007 letter Enclosure, page 50
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"Flemming Hansen of Haldor Topsoe...gave a rough estimate that an SCR system for North Dakota lignite could be designed (larger) to accommodate a catalyst replacement schedule of about every year. Mr. Hansen said that an SCR reactor could be cooled down within 24-36 hours (need for cool air draft requires the boiler to be shutdown) and the catalyst layers rotated in about two of three days, three days all around." [EPA October 4, 2007 letter Enclosure, page 50]

B&McD Response:
Burns & McDonnell continues to express concern that EPA and their discussions with the catalyst vendors have not emphasized the activities involving a boiler cleaning outage at

MRYS that are different than any other coal-fired boiler plant that may employ a hot-side SCR. The need for cool air draft immediately upon shutdown of boiler fuel firing would require an alternate path from the SCR inlet to the stack that would not interfere with (or be contaminated by) the boiler interior cleaning flow, but which would provide simultaneous air flow through the reactor to aid in cooling the large mass of catalyst. We believe that the SCR catalyst vendor's estimates for replacement frequency and duration are optimistic, and significantly underestimate the conditions that are expected at MRYS which have been previously described and discussed.

G. Hydrocarbon-Enhanced Selective Non-Catalytic Reduction (HE-SNCR)

EPA October 4, 2007 letter Enclosure, page 51
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"The reasons given by B&McD to this point (high boiler fouling conditions and varying gas temperatures and loads) appear themselves to be theoretical.... EPA does not believe that whether other non-cyclone fired BART applicants included an analysis of HE SNCR is evidence, in and by itself, that the technology is infeasible at MRYS. " [EPA October 4, 2007 letter Enclosure, page 52]

B&McD Response:

The high boiler fouling conditions and varying gas temperatures and loads at MRYS are actual, not theoretical. The vendor's stated position that this technology is insensitive to fuel or burner types does not refute the lack of experience with HE-SNCR on boilers with such severe surface fouling and temperature conditions. If boiler conditions in the area where HE-SNCR distribution lances are located are not precisely known to be suitable and/or controlled for survival of the reagent, steam, and fuel injection hardware and effective NOx emissions reduction throughout the range of operation of the boiler in question continuously between startup and shutdown events, the supposition that the technology can "theoretically" be applied to any boiler and any fuel is not supported as fact. Any discussion with the HE SNCR vendor without providing the pertinent boiler conditions would be speculative and potentially misleading.

The point about non-cyclone fired North Dakota lignite burning boilers operated by other BART applicants not being evaluated for their potential application of HE SNCR has been

missed. The intention was to show that EPA has been selective in their review comments towards Minnkota's BACT, which appear to be biased against whatever non-SCR NOx control technology was evaluated for MRYS.

H. Reburn with SNCR

EPA October 4, 2007 letter Enclosure, page 53
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"If the technology has been demonstrated, it is considered technologically feasible without going through further analysis. ... B&McD also points out that non-cyclone BART eligible sources in North Dakota did not provide an analysis of Reburn with or without SNCR as a control alternative in their BART analysis." [EPA October 4, 2007 letter Enclosure, page 53]

B&McD Response:

EPA appears to say that differences in specific conditions of the MRYS boilers compared with the single unit where Reburn with SNCR has been demonstrated are not pertinent to whether the control technology would be technically feasible. Successful implementation of NO_X controls is highly dependent on the specific configuration and process conditions that lend themselves to be compatible within the limits of constructability, survivability, and effectiveness. Just because a control technology is "technically feasible" based on EPA's interpretation of the NSR Manual does not mean it will work effectively at MRYS. These responses indicate that EPA has been selective in their review comments towards Minnkota's BACT, which appear to be biased against whatever non-SCR NOx control technology was evaluated for MRYS.

I. Rich Reagent Injection (RRI)

EPA October 4, 2007 letter Enclosure, page 54
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"While predicting the exact level of NOx control for RRI and MRYS may not be possible...EPA does not believe B&McD has demonstrated that RRI should be considered technically infeasible." [EPA October 4, 2007 letter Enclosure, page 54]

B&McD Response:

EPA appears to ignore the arguments regarding the expected lack of effective NO_X reduction from RRI if it were applied at MRYS with modest cyclone air-staged combustion. Successful implementation of NO_X controls is highly dependent on the specific configuration and process conditions that lend themselves to be compatible within the limits of constructability, survivability, and effectiveness. Just because a control technology is "technically feasible" based on EPA's interpretation of the NSR Manual does not mean it will work effectively at MRYS. These responses indicate that EPA has been selective in their review comments towards Minnkota's BACT, which appear to be biased against whatever non-SCR NOx control technology was evaluated for MRYS.

J. <u>Rotating Opposed Fire Air (ROFA)</u>
EPA October 4, 2007 letter Enclosure, page 55
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"further consideration of ROFA is unnecessary." [EPA October 4, 2007 letter Enclosure, page 55]

B&McD Response:

We agree with EPA's response regarding ROFA.

K. <u>Control Efficiency for SNCR</u>
EPA October 4, 2007 letter Enclosure, page 55
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"EPA agrees that the 60% reduction cited at the upper end of the control range is likely not appropriate for MRYS. It appears likely that something closer to 30% than 60% would be reasonable." [EPA October 4, 2007 letter Enclosure, page 56]

B&McD Response:

We stand by our use of the estimated levels of NO_X control for alternatives involving SNCR included in Minnkota's October 2006 MRYS BACT analysis.

L. <u>Selection of 30-day Average BACT Emission Limit</u>
EPA October 4, 2007 letter Enclosure, page 56
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"EPA ... now understands that the startup periods did not fall within the relevant baseline period." [EPA October 4, 2007 letter Enclosure, page 57]

B&McD Response:

We stand by our use of the estimated levels of NO_X control included in Minnkota's October 2006 MRYS BACT analysis.

M. <u>BACT Limit 18-Month Trial Period</u>
EPA October 4, 2007 letter Enclosure, page 57
Original Reference: EPA Region 8 January 26, 2007 letter to NDDH:

"EPA agrees this is an acceptable approach." [EPA October 4, 2007 letter Enclosure, page 58]

B&McD Response:

Acknowledged.

REFERENCES

1 United States Environmental Protection Agency (U.S. EPA or EPA) Region 8 letter by Martin Hestmark, Director, Air and Toxics Technical Enforcement Program, ECEJ to Terry L. O'Clair, North Dakota Department of Health, Environmental Health Section, Division of Air Quality and David Sogard and John Graves, Minnkota Power Cooperative, *Re: Transmittal of EPA's Response to Minnkota's Letters Dated March 19, 2007 and April 23, 2007, Regarding the October 2006 NO_x BACT Analysis Study Report for Milton R. Young Station, date stamped October 4, 2007.*

2 Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative "*Response To EPA Region VIII Comments – January 8, 2007", March 19, 2007*".

3 Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative "*Response To NDDH Comments – February 1, 2007 (Incl. Resp. to U.S. EPA Region 8 Comments – January 26, 2007)",* April 23, 2007.

4 "*NO_X Best Available Control Technology Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc.*" and a separate "*NO_X Best Available Control Technology Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative*", October 2006, by Burns & McDonnell, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "*BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc. Final Report, October 2006*" submitted by Minnkota to North Dakota Department of Health.

5 Eastern Research Group (ERG) letter by Roger Christman, to U.S. EPA, *Summary Discussion in Response to the Burns & McDonnell and EERC Reports (Minnkota, March 19, 2007, and Minnkota, April 23, 2007), and the Subsequent Meeting on May 23, 2007, at the Offices of the Division of Air Quality, North Dakota Department of Health (NDDH), dated August 20, 2007.*

6 Enclosure, *"Responses To EERC and C and B&McD's March 17, 2007 Letter Responding to EPA Region VIII Comments - January 8, 2007,* and *EPA's Response To EERC and B&McD April 23, 2007 Letter to NDDH Comments – February 1, 2007 (Including Response to U.S. EPA Region 8 Comments – January 26, 2007): Request for Additional Information and the Non-SCR Comments from EPA. (provided with reference number 1 and reference number 3)*

7 Consent Decree filed 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, filed April 24, 2006.

8 North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative,

Re: BACT Determination Milton R. Young Station, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.

9 Evaluation and Mitigation of Visible Acidic Aerosol Plumes from Coal Fired Power Boilers, Final Report, by Peter M. Walsh, Joseph D. McCain, and Kenneth M. Cushing, EPA Contract No. EP-C-04-056, Southern Research Institute Project No. 11402 November 14, 2006.

10 PhD Thesis "Selective Catalytic Reduction of NOx: Deactivation and Regeneration Studies and Kinetic Modeling of Deactivation," 2001, by R. Khodayari, Dept. of Chemical Engineering II, P. O. Box 124, SE-221 00 Lund, Sweden.

11 ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007. and *EPA Region 8 Preliminary Analysis of Burns & McDonnell BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007* faxed by North Dakota Department of Health to Minnkota, January 9, 2007.

12 *"Appropriateness of Conducting Pilot Testing of Selective Catalytic Reduction (SCR) Technology at Milton R. Young Station .Units 1 and 2, For Use In A NOx BACT Analysis",* prepared for Minnkota Power Cooperative, Inc. by Dennis Arfmann, Hogan & Hartson, Steven A. Benson, Energy & Environmental Research Center, and Carl V. Weilert, Burns & McDonnell, August 14, 2007.

Minnkota Power
MPC COOPERATIVE, INC.

Your Touchstone Energy® Partner

1822 Mill Road • P.O. Box 13200 • Grand Forks, ND 58208-3200 • Phone (701) 795-4000

November 29, 2007

DEC 2007
Received
Air Quality

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Subject: Milton R. Young Station
BART Conference –11/21/2007

Dear Mr. O'Clair:

This letter is to follow-up on our discussions during the above subject meeting. As I indicated during the meeting, the methodologies the Department is pursuing with respect to the various emission limitations has merit. However, we do take exception to some of the actual limitations proposed. These are addressed below.

Unit 1

The Department proposed a SO_2 limitation of 95% removal (30 d.r.a.) or 0.12 lb/10^6 Btu (30 d.r.a.). The Department may wish to remove the lb/10^6 emission rate provision, as Minnkota is subject to a Consent Decree which stipulates that the removal shall be 95%.

The Department has proposed a NO_x limitation of 0.36 lb/10^6 Btu (30 d.r.a.), except during startups. Minnkota requests the exception be extended to startups, shutdowns, and malfunctions. Unless all cyclones are in operation over-fired air and selective non-catalytic reduction technologies are ineffective or of limited effectiveness. During startups and shutdowns, individual cyclones are put in service or taken out of service as the Unit generation is increased or decreased. A malfunction can also cause cyclones to be taken out of operation.

The Department proposed a NO_x startup limitation of 1070.7 lb/hr (24-hr rolling avg.) Utilizing a NO_x lb/hr emission rate for startups that is derived from data obtained when the Unit is at full load is not appropriate; The NO_x controls are effective at full load conditions whereas the NO_x controls are ineffective or of limited effectiveness during startup. Based upon the information presented

previously in the NO_x BACT analysis, Minnkota requests a NO_x startup/shutdown/malfunction limitation of 2070.2 lb/hr (24-hr rolling average).

Unit 2

The Department proposed a SO_2 limitation of 95% removal (30 d.r.a.) or 0.12 lb/10^6 Btu (30 d.r.a.). The limitation of 0.12 lb/10^6 Btu (30 d.r.a.) is not acceptable to Minnkota. During periods of time when the sulfur content of the coal being burned is lower than normal, wet FGD systems can not remove as high a percentage of the SO_2 as would normally be removed, due to mass transfer limitations. Minnkota requests the SO_2 emission limitation be increased to 0.15 lb/10^6 Btu (30 d.r.a.). As Minnkota has a SO_2 limitation of 90% removal requirement under a Consent Decree, the Department may wish to add this restriction for clarity. Therefore, the revised limitation would be 95% SO_2 removal (30 d.r.a.) or 0.15 lb/10^6 Btu (30 d.r.a.), whichever is least restrictive, but not less than 90% removal (30 d.r.a.)

The Department has proposed a NO_x limitation of 0.35 lb/10^6 Btu (30 d.r.a.), except during startups. Minnkota requests the exception be extended to startups, shutdowns, and malfunctions. Unless all cyclones are in operation over-fired air and selective non-catalytic reduction technologies are ineffective or of limited effectiveness. During startups and shutdowns, individual cyclones are put in service or taken out of service as the Unit generation is increased or decreased. A malfunction can also cause cyclones to be taken out of operation.

The Department proposed a NO_x startup limitation of 2011.6 lb/hr (24-hr rolling avg.) Utilizing a NO_x lb/hr emission rate that is derived from data obtained when the Unit is at full load is not appropriate; The NO_x controls are effective at full load conditions whereas the NO_x controls are ineffective or of limited effectiveness during startup. Based upon the information presented previously in the NO_x BACT analysis, Minnkota requests a NO_x startup/shutdown/malfunction limitation of 3995.6 lb/hr (24-hr rolling average).

As discussed, a more exact definition of startup is needed than initially proposed by the Department. Minnkota proposes the following:

Startup is that period of time 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 4800 million Btu/hr for Unit 2); or
- The amount of time reported for the longest individual startup period during actual operation between January 1, 2001 and December 31, 2005 (61 hrs. for Unit 1, or 115 hrs. for Unit 2) elapses, whichever occurs first; or
- Fuel firing is discontinued prior to satisfying either previous criteria.

The above definition was included in our previously submitted BACT analysis.

A definition of "shutdown" may also be appropriate. Minnkota proposes the following definition (if a definition is required):

> Shutdown is that period of time beginning when the Unit's generation is reduced in a continuous manner with the intention of discontinuing fuel firing, until fuel firing is discontinued.

Because the anticipated NO_x emissions are based upon computer modeling of the boiler and the chemistry associated with the particular NO_x control technology, the NO_x emissions may be more or less than indicated in the BACT and BART analyses. Therefore, Minnkota reserves the right to request changes to an operating permit which may be issued, or the State Implementation Plan, which incorporates NO_x limitations.

Minnkota thanks the Department for its attention to the issues raised during our recent meeting and those in this letter. Should you have any questions concerning the above, please contact me at 701-795-4221 or at jgraves@minnkota.com.

Sincerely,

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard
Luther Kvernen
Craig Bleth
Kevin Thomas
Stu Libby
Tom Anseth
Young Station File

Minnkota Power
MPC COOPERATIVE, INC.

Your Touchstone Energy® Partner

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May 8, 2008

Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, North Dakota 58501-1947

Re: Consent Decree – July 27, 2006
Minnkota Power Cooperative, Inc., et al
U.S. District Court for the District of ND
Civil Action No. 1:06-CV-034

Dear Mr. O'Clair:

Enclosed, please find a report on vendor responses you recently requested from Minnkota. This report, which was prepared by Burns & McDonnell, also includes recent additions and clarifications from vendors. As the report indicates, vendors are not able to make viable guarantees. Additionally, the vendors generally indicate that additional testing would need to be done prior to any design of an SCR for use on a North Dakota lignite-fired cyclone unit.

Should you have any questions, please contact me at jgraves@minnkota.com or 701-795-4221.

Should you have any questions concerning this submittal, please contact me at (701) 795-4221.

Sincerely yours,

MINNKOTA POWER COOPERATIVE, INC.

John T. Graves

John T. Graves, P.E.
Environmental Manager

C: David Sogard w/o encl.
Luther Kvernen w/o encl.
Craig Bleth w/o encl.
Stu Libby w/o encl.
Tom Anseth w/o encl.
Young Station File w/o encl.

MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

ADDITIONAL INFORMATION AND DISCUSSION OF VENDOR RESPONSES ON SCR TECHNICAL FEASIBILITY NORTH DAKOTA'S NOx BACT DETERMINATION for MILTON R. YOUNG STATION UNITS 1 & 2

May 8, 2008

In order to address the issue of vendor guarantees in the NSR Workshop Manual, Burns & McDonnell and Energy & Environmental Research Center (EERC) developed an SCR Vendor Query[1] which was emailed by Burns & McDonnell on April 18, 2007 to selective catalytic reduction (SCR) technology system suppliers and catalyst suppliers. The query requested information from these vendors pertaining to their willingness to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at North Dakota lignite-fired Units 1 and 2 at Minnkota's Milton R. Young Station (MRYS) near Center, North Dakota. Burns & McDonnell described the unit-specific SCR system design conditions and site-specific technical challenges in this query document and its attachments.

This query document (without vendor responses) was originally submitted to the NDDH and EPA as part of an April 18, 2007 response[2] to NDDH's request for information (RFI)[3] regarding their review of the two BACT Analysis Study reports for control of NO_X emissions from existing Unit 1 and Unit 2 at MRYS required by the Consent Decree[4] that were originally submitted to the agencies in October 2006. Additional comments from Region 8 of U.S. EPA[5] were also attached to the NDDH's RFI. A summary of vendor initial responses was initially presented at a meeting of the NDDH, EPA Region 8, and Minnkota on May 23, 2007, in Bismarck by Burns & McDonnell[6].

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[1] See Reference number 1, April 18, 2007.
[2] See Reference number 2, April 18, 2007.
[3] See Reference number 3, February 1, 2007.
[4] See Reference number 4, April 24, 2006.
[5] Ibid Reference number 3.
[6] See Reference number 5, May 23, 2007.

In April 2008, Burns & McDonnell became aware that the record on the BACT determination issue for Unit 1 and Unit 2 at MRYS was still open. Due to the fact that one year had passed since the development of the initial SCR Vendor Query document and the vendor responses, Burns & McDonnell initiated contact with several of the vendors in order to more fully understand their initial responses, and to gather additional information.

Appendix A to this document contains emails and letter received from six of the eight SCR technology system suppliers and catalyst suppliers that responded to the referenced original SCR Vendor Query. Subsequently, followup telephone conferences have been held and emails have been exchanged with four of the six companies that responded to the original query. The following are comments pertaining to the SCR vendor's original and followup responses to the April 18, 2007 query.

SCR Vendor Query:

In the referenced April 18, 2007 SCR Vendor Query, Burns & McDonnell requested any information that the SCR system or catalyst supplier could provide regarding the following:

- Detailed information regarding the post-combustion controlled emission rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time, with appropriate pre-controlled baseline emission data.

  That is, Burns & McDonnell requested information that supports a level of emission reductions that could be guaranteed over the course of time, and not merely performance test or limited-duration emissions data, including the following.

  - Data of source-specific boiler and SCR design and operating parameters, along with lignite coal quality characteristics (analytical data) representative of the lignite-fired coal-burning boiler operations associated with long-term post-combustion controlled emission rates that SCR systems have achieved in practice at full-scale installations.
  - If provided, non-full scale laboratory, pilot or bench-scale exposure testing, short-term full-scale compliance or acceptance test data shall be clearly identified as such.

- Definitive statements of expected guaranteed life and control effectiveness performance for SCR catalyst when located in high-dust, hot-side applications at MRYS.

  These statements were requested to be supported by detailed descriptions of the vendor's interpretation of the technical information Burns & McDonnell provided, the vendor's awareness of proven methods of dealing with similar site-specific applications, the vendor's own qualifications and experience, and any stated or assumed design and operational requirements. That is, the guarantee must specifically reference the site-specific operating conditions at MRYS, with an SCR system calibrated to operate in that environment.
- Definitive statements regarding Burns & McDonnell's and EERC's serious concerns involving catalyst blinding and deactivation due to high sodium concentrations along with sulfate and other known components in the flue gas expected from cyclone boilers firing North Dakota lignite.

  Burns & McDonnell provided an analysis of the lignite fuel fired at MRYS, and asked that the guarantee specifically discuss the impact of this particular fuel on SCR system and catalyst performance and longevity.
- A detailed description of the vendor's approach to mitigating Minnkota's risks of failure to meet NO_X emissions control requirements and catalyst activity versus life guarantees, stating what the vendor would do to improve the probability of success prior to initial operation, and how they would respond if the emission control effectiveness and catalyst activity did not match the expectations of the guarantee.

It was understood that the vendor was expected to make certain assumptions regarding SCR system design operating conditions, because detailed development of MRYS unit-specific design schemes to deal with the high boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite have not been confirmed. Recognizing that such SCR design details were not currently available, SCR system and catalyst vendors were requested to review the technical information Burns & McDonnell provided. This data was offered as a supplement to the vendors' own technical knowledge, commercial experience, and proprietary data to aid in the understanding of

technical feasibility of installing and successfully operating and maintaining currently-available coal-fired SCR system technology on the referenced North Dakota lignite-fired cyclone boilers.

The SCR vendors were also advised of the background of the Consent Decree and BACT Analysis that included Selective Catalytic Reduction (SCR) technology for the Milton R. Young Station. They were made aware that the EPA had issued comments regarding the agency's reviews of the NO_X BACT Analyses. A basic issue to be resolved in order to address the EPA's comments was stated as:

- Would continuous exposure of available high-dust SCR catalyst to current flue gas temperatures and flyash with high sodium concentrations along with sulfate and other known components in the flue gas expected from MRYS cyclone boilers cause severe catalyst fouling, deactivation, and degradation resulting in unacceptable long-term NO_X emission control effectiveness, catalyst life, and cost-effectiveness?

The SCR system and catalyst vendors were asked to consider the current operating conditions and identify solutions to address boiler outlet flue gas temperatures and other conditions resulting from operation of these cyclone boilers firing North Dakota lignite. Vendor responses also needed to consider historic MRYS boiler outlet flue gas temperature data provided with the query that showed wide variations with boiler fireside cleanliness and load.

Comments on SCR Vendor Query Responses:

Information requests via email were sent to four SCR system vendors and four catalyst vendors[7]. Two of the original eight SCR system vendors and catalyst vendors (Argillon and Cormetech) indicated they would provide a response but subsequently did not, even after further followup. Six of the eight vendors did provide information: Alstom Power Environment, Babcock & Wilcox, Babcock Power Environmental, Ceram, Haldor Topsoe, and Hitachi.

[7] See Reference number 6, April 18, 2007.

None of the vendors provided all of the information requested. The initial vendor responses that were unclear or provided information appearing to be stated without substantive basis or backup with identified source data were targeted for followup and telephone conference. The following includes comments by Burns & McDonnell (and EERC where so indicated) regarding the initial individual vendor responses from May 2007, and the subsequent supplemental responses following the late April 2008 telephone conference calls.

Summary of Alstom Power's Responses and 2008 Followup:

Alstom Power's initial response was provided in a letter dated May 30, 2007[8] submitted via email. Their initial comments provided information on lignite-fired boiler SCR applications, alternative tail-end SCR, predicted SCR performance, and indicative pricing and delivery for conventional SCR technology.

Alstom confirmed that there have not been any SCRs applied to boilers in the United States firing North Dakota or Texas lignites. Experience with an in-situ mini SCR reactor installed at TXU Energy's Martin Lake Unit 3, tested with two types of catalyst, was not detailed. Alstom recognized that North Dakota lignite is higher in sodium than Texas lignite, but stated that fuels high in sodium and potassium can be treated with specially selected catalyst. Wood and biomass-fired European boilers equipped with a hot-side electrostatic precipitators (ESPs) were cited as examples of dealing effectively with these catalyst poisons in such hot-side SCR applications.

Alstom expects acceptable emissions control and maintenance requirements can be achieved on North Dakota lignite service, assuming that the SCR system operates between 600-750°F. They anticipate that a modification or replacement of the economizer will be required to control boiler flue gas temperature within an acceptable range.

A Tail End SCR was mentioned as an alternative solution, with advantages and disadvantages briefly described. No plants firing fuels similar to North Dakota lignite with a Tail End SCR were identified.

[8] See Reference number 7, included in Appendix A, dated May 30, 2007.

Alstom predicts that a properly designed SCR (presumably on a boiler firing North Dakota lignite) should be capable of achieving up to 90% [NO_X] removal efficiency with 2 ppm ammonia slip. They acknowledge minimal field data to predict how often the catalyst would need to be replaced, with 16,000 hours between replacements as a suggested average based on lab results.

Indicative pricing for materials and labor to provide conventional SCR technology at MRYS was stated, absent detailed analysis and without potential additional scope because of unusual design requirements to deal with the boiler flue temperatures and catalyst contaminants.

Alstom's April 28, 2008 Telephone Conference Call and Followup Response:

Alstom could not offer any new or different information that agrees with or refutes information presented in the October 2005 EERC report of slipstream catalyst testing at Coyote Unit 1 referenced in the SCR vendor query. Alstom acknowledged that "there are no known existing applications of SCR to ND lignite fired boilers, therefore there is some risk on any first [of] a kind application". Alstom's May 2008 letter also states:

> "Application of a traditional SCR to Lignite fired units will require some R&D, custom engineering, and likely a pilot testing program. This will be time consuming and expensive but will reduce the risks involved in a new application such as this one".

Alstom indicated its belief that Tail End SCR downstream of a hot-side ESP would be immune to catalyst poisoning from sodium-potassium-sulfur compounds. They agree that biomass and wood-fired boiler SCR experience with low sulfur is not the same situation as cyclone boilers firing North Dakota lignite.

Based on current data, Alstom indicated that they cannot guarantee SCR system performance for MRYS boilers firing North Dakota lignite because it hasn't been installed full-scale on a boiler firing this fuel. Additional pilot-testing of at least one year would be needed.[9]

[9] See Reference number 8, included in Appendix A, dated May 5, 2008.

Comments on Alstom Power's Responses and April 28, 2008 Telephone Conference Call:
Alstom did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Sources of field and laboratory test results of catalyst were cited but not substantiated with actual technical references or submittal of data.
An Alstom representative involved with Alstom's initial and followup responses (John Buschmann) acknowledged familiarity with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station.

Alstom did not appear to fully recognize how the method of firing the fuel in a cyclone boiler alters the character and composition of the flyash exhausted from the boiler, and that such contaminants pass through high-efficiency air cleaning equipment and create deposits that can blind and plug catalyst. The temperature of cyclone firing is higher and causes more vaporization of sodium and potassium in the lignite ash than occurs with a wood-fired boiler system. The wood-fired boiler systems have lower flame temperatures and thus less vaporization of alkali elements. This is evident based on the abundance of sodium and potassium-rich particles in the small ash size fraction found in the Coyote pilot SCR test catalyst and the particulate filter described in the referenced SCR vendor query. The sodium and potassium-rich materials combine with sulfur species to form sulfates that are significantly different and more problematic in their impacts on catalyst than Alstom's wood-fired boiler SCR experience indicates.

Alstom's wood-fired boiler SCR experience is not closely comparable to North Dakota lignite firing in cyclone boilers at MRYS. In general, alkali content of fly ash from wood firing is similar to the alkali content in the fly ash from the cyclones firing Center lignite. However, the form of the alkali in fly ash from the lignite-fired cyclone is likely in the oxide/hydroxide and partially sulfated forms; in wood fly ash, it will take another form, such as a chloride, if available. The lignite cyclone combustion derived alkali species are highly reactive with sulfur oxides resulting in the formation of a cohesive ash that produce stronger bonds and fill and coat catalyst pores and surfaces.

Alstom appeared to be unfamiliar with the unique high temperature air and flue gas requirements associated with the lignite drying systems on these MRYS boilers. Their expectation that a boiler economizer modification or replacement would resolve the low load-clean boiler-low flue gas temperature and high load-dirty boiler-high flue gas temperature situation appears to be a gross assumption based on an incomplete understanding of the thermodynamics of the flue gas, air, and fuel treatment systems employed at this facility[10].

No offer of any kind of SCR performance or service life guarantee was made by Alstom. The 16,000 hours between replacements, suggested as an average based on lab results[11], is not a guarantee or warranty, and was stated without the source data of the laboratory tests.

Summary of Argillon's Responses:

Argillon acknowledged the initial emailed query but failed to provide an actual initial response via phone call or email.[12]

Summary of Babcock & Wilcox's Responses:

Babcock & Wilcox did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Babcock & Wilcox's initial response via email[13] confirmed that there is not any full-scale operational experience with SCR systems retrofit to boilers firing North Dakota lignite or any other type of lignite in the United States. Therefore, neither B&W nor any other SCR system supplier can "provide detailed information regarding the post-combustion controlled emissions rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time."

B&W agrees with Burns & McDonnell that there are significant challenges associated with both boiler operation (high economizer exit gas temperature) and lignite firing (flue gas constituents) at Milton R. Young Station (MRYS). They mentioned the lack of justification and the need to invest significant dollars in research and development efforts to fully

[10] See Reference number 9.
[11] Ibid Reference number 7, included in Appendix A, dated May 30, 2007.
[12] See Reference number 10, included in Appendix A.
[13] See Reference number 11, included in Appendix A.

investigate and understand both technical and commercial risks involved with applying SCRs on a limited number of units firing North Dakota lignites.

B&W has not fully explored the issues presented in the SCR vendor query with catalyst suppliers to better understand and quantify these challenges, or what may be needed to identify their concerns or the lengths to which they may need to go to address them especially if catalyst guarantees must be offered.

No offer of any kind of SCR performance or service life guarantee was made by B&W.

Summary of Babcock Power's Responses and 2008 Followup:

Babcock Power Environmental's (BPE's) initial response[14] recognized that "there have been a few tests performed to ascertain the possibility of using a high dust SCR on lignite and the potential for fouling/poisoning of the catalyst has been in question". BPE also indicated an expectation that "an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel", while recognizing uncertainty regarding the ability of a high dust SCR on a boiler firing North Dakota lignite because there has not been any testing or installation of an SCR reactor of any significant size on such a boiler. BPE also "identified the MY1 and MY2 boilers as a very difficult one on which a high dust SCR would be applied because of the unique configuration of the boiler and the wide temperature swings that are encountered".

BPE indicated that "several possible solutions exist with varying certainties of outcome. The SCR technology location may potentially mitigate the issues with the possible poisoning of the catalyst by constituents in the gas from the combustion of Northern lignite". Babcock Power recommended that "an engineering study be conducted to evaluate three key issues":

- Initial estimates of the actual deactivation of SCR catalyst in the high dust location by the use of coupons positioned in the hot gas stream downstream of the economizer.
- Initial estimates of the actual deactivation of SCR catalyst in other locations by the use of coupons positioned in the gas stream downstream of the airheater.

[14] See Reference number 12, included in Appendix A.

- Possibility of a retrofit of an SCR into the MY1 and MY2 boiler considering the wide range of temperature for the flue gas and possible boiler modifications required.

Comments on Babcock Power's Responses and April 28, 2008 Telephone Conference Call: Babcock Power Environmental did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. BPE's original email statements seem to be based upon the vendor's experience with other lignite fuels not specifically identified by location or composition. Subsequent email[15] and telephone[16] followup in 2008 indicated that the use of high activity SCR catalyst coupons positioned in the hot gas stream downstream of the boiler economizer, would also include test locations downstream of the existing cold-side electrostatic precipitator (and in Unit 2's case, a wet lime/flyash scrubber). BPE considers this a kind of "fatal flaw" investigation that would be conducted first. This would allow BPE to analyze the test catalyst coupons for deactivation to see if a high-dust SCR location could work. This initial testing would be conducted without ammonia reagent being injected into the flue gas stream ahead of the test catalyst. If BPE determined that there was potential for SCR success after analyzing the test catalyst coupons, a test reactor of appropriate size would be designed and built and installed. BPE indicated that such a test SCR reactor would need to be operated for a minimum of 4000 hours.

A Babcock Power Environmental representative involved with BPE's initial and followup responses (Clay Erickson) appears to be familiar with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station. BPEI's second emailed response stated that they have not nor know of any further work on this topic since the response they previously provided via email on May 11th 2007[17].

No offer of any kind of SCR performance or service life guarantee was initially made by Babcock Power Environmental. BPE would not guarantee performance unless the catalyst vendors would provide such a guarantee[18]. Furthermore, BPE indicated that it would not

[15] See Reference number 13, included in Appendix A.
[16] See Reference number 14.
[17] Ibid Reference number 13, included in Appendix A.
[18] Ibid Reference number 14.

provide a guarantee of SCR performance on this fuel at these units without additional data such as that which would be derived from the test reactor described above[19].

Summary of Ceram's Responses and 2008 Followup:

Ceram reviewed the information provided by Burns & McDonnell regarding the technical feasibility of SCR on the Milton R. Young Station Units 1 and 2 firing North Dakota Lignite fuel[20]. Ceram's initial response comments acknowledged the lack of any catalyst installations currently operating with North Dakota lignite fuel. One brown coal SCR installation (not specifically identified) in Europe, and a large experience base with coals, refineries and incinerators combined with familiarity with the effects of a wide range of fuel and flue gas constituents was mentioned. They indicated that their brown coal from Europe was more like a Texas lignite ash. They indicated that sodium is a concern since it has a potential to infiltrate into the catalyst and cause deactivation especially during heat-up and cool-down. They were not familiar with cyclone firing and enhancement of sodium in the fines[21].

Ceram initially noted that North Dakota Lignite fuel and ash characteristics present certain challenges related to SCR operation and reliability. Additionally, the high flue gas temperatures needed for purposes of drying the fuel were mentioned as a challenge for SCR catalyst design, but no specific solution to this situation other than "flue gas tempering" being required was proposed.

Ceram's initial comments pertinent for this SCR application largely included items that needed to be considered or included in the SCR catalyst selection and reactor design, such as the presence of pyrosulfates (sodium, iron and sulfur) having the potential to increase the oxidation of sulfur (SO_2 to SO_3 conversion rate). Ceram could only guarantee the initial SO_2 to SO_3 conversion rate and not the end of life conversion rate.

Ceram provided a preliminary catalyst design that utilized a 7.4 mm pitch catalyst to minimize the risk of catalyst pluggage due to high concentrations of calcium and sulfates in the fuel. A

[19] Ibid Reference number 14.
[20] See Reference number 15, included in Appendix A.
[21] See Reference number 16.

full SCR bypass system with an air drying or dehumidification system was recommended to keep the catalyst warm and dry during lay-up periods because of the high sodium and iron concentrations. The maximum continuous operating temperature of the preliminary SCR catalyst design was 850° F, with an allowance of short periods of operation up to 900 degrees F. A high temperature reference list of Ceram's SCR catalyst installations was provided.

Ceram developed a preliminary catalyst design for each Unit (outlined in attached files) that were expected to provide 85% NOx reduction (0.08 lb/MBtu outlet) with an SO_2 to SO_3 conversion rate of 1.0% and ammonia slip of 2.0 ppm for a guarantee life of 16,000 hours.

A Ceram representative involved with Ceram's initial response (Noel Rosha) acknowledged he was unfamiliar with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station[22]. After the April 23, 2008 telephone conference call, Ceram obtained a copy of the referenced October 2005 EERC report. The Ceram representative responding to the followup request (John Cochran) after reviewing EERC's report believed it was "certainly premature to assume that there is a fatal flaw for the use of high dust SCR behind cyclones burning North Dakota lignite". Also, Ceram stated: "Certainly a number of circumstances are present that necessitate a pragmatic approach to the application of catalyst for a lignite application" and "Sodium is not a poison to catalyst at SCR operating temperatures. Significant deactivation can occur if condensed moisture transports sodium residing at the surface into the catalyst pore structure during outage or layup"[23].

Ceram's second emailed response included Ceram's reasons for why it believes the application of SCR technology on North Dakota lignite-fired cyclone boilers can be successful. Ceram also advised that "in no event would any ammonia be allowed to be injected below 530 F for any likely combination of reasonable sulfur and NOx removal parameters. The NOx reduction for a reduced MOT [minimum operating temperature] should be considered in 30-day rolling average scenarios. Minimum flue gas temperatures listed for Units 1 and 2 are well below this threshold"[24].

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[22] Ibid Reference number 16.
[23] See Reference number 17, included in Appendix A.
[24] Ibid Reference number 17.

Ceram also included the following statement in their followup response: "based on the information provided as well as our large foundation of work related to the fuel considerations noted in the query and study CERAM can provide a commercial offering regarding this project. However, considering some of the remaining uncertainties we would recommend further testing to ensure a successful result"[25].

Comments on Ceram's Responses and April 23, 2008 Telephone Conference Call:
Ceram did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Their comments mentioned high sodium contents and fine fume as concerns reported by Dr. Benson and the EERC report on slipstream pilot SCR testing having "flawed pitch and resultant pluggage of the catalyst used during Coyote Station testing" as "inadequate evidence ... that this could be a fatal flaw to application of SCR"[26].

What appears to be missing from Ceram's comments are recognition that North Dakota lignite firing in cyclones promotes formation of low melting point eutectic combinations of sodium, potassium, and sulfur to form sulfates which produce extremely strong deposits that fill and plug the pores of the catalyst, regardless of the pitch. The effects of this eutectic melting and blinding was not considered, as Ceram's comments focus on the issue of significant deactivation from sodium due to mobilization of sodium if condensed moisture becomes available.

Ceram's initial response mentions a guaranteed catalyst service life of 16,000 hours and the initial SO_2 to SO_3 conversion rate, but did not actually expressly state that they would guarantee NOx reduction performance. Their willingness to provide a commercial offering is based upon recommended "further testing to ensure a successful result"[27].

[25] Ibid Reference number 17.
[26] Ibid Reference number 17.
[27] Ibid Reference number 17.

Summary of Cormetech's Response:

Cormetech acknowledged the initial emailed query but failed to provide an actual initial response via phone call or email.[28]

Summary of Haldor Topsoe's Responses and 2008 Followup:

After its initial review of information and data provided by Burns & McDonnell regarding the viability of SCR technology on the Milton R. Young Station (MRYS) Units 1&2, Haldor Topsoe (HT) indicated that two separate issues exist with this application: extremely high flue gas exit temperatures (FGET) and lack of flue gas temperature control over the long term; and fuel-related issues specific to this variety of North Dakota lignite[29]. Haldor Topsoe did not address the high FGET as a unit-specific problem, presumably because they are not boiler heat transfer solution providers. HT indicated that they don't have a catalyst for coal-fired boiler applications that will survive 900°F flue gas that can be offered with a guarantee[30].

Based on the provided fuel and ash analysis of the North Dakota lignite that is burned at MRYS, Haldor Topsoe estimates that the deactivation rate of the catalyst will be high but manageable. A deactivation rate in line with wood-fired boilers which have been successfully fitted with SCR was predicted in HT's initial response; now, HT states this rate is higher than what they have seen on wood-fired boilers[31]. HT initially expected the deactivation rate to be steep initially but to flatten out considerably after about 4000 hours, and has recently (May 2008) modified this estimated time frame to 10,000 hours, where the catalyst is expected to lose about 60 percent of its initial activity during this time period. HT stated that the revised deactivation rate number is based mostly on comparison of the expected catalyst service conditions compared to that of wood-fired boilers. Higher flyash loading and catalyst attrition, combined with much more sulfur that leads to blinding of the catalyst were briefly described[32].

[28] See Reference number 18, included in Appendix A.
[29] See Reference number 19, included in Appendix A.
[30] See Reference number 20.
[31] See Reference number 21, included in Appendix A.
[32] Ibid Reference number 21, included in Appendix A.

HT originally stated that the expected catalyst poisons are mostly water soluble, therefore periodic water washing of the catalyst can be used to regain activity and to increase overall service life. This technique is used on many wood and some PRB coal-fired applications.

Besides the deactivation, Haldor Topsoe identified another catalyst impact problem: clogging[33]. Ineffective sootblower simulation in the Coyote pilot test was the primary concern/experience, which HT infers does not represent full-scale SCR installations.

HT suggests that the next step is to install a larger pilot scale experiment with cross section of catalyst on the order of 2 meters by 2 meters. This would allow better catalyst cleaning and give a better determination of the catalyst degradation over time[34].

Based on the fuel analysis provided to HT and assuming that FGET can be controlled, HT would be willing to guarantee SCR catalyst performance on these units[35]. Haldor Topsoe expects 60 percent deactivation over the first 10,000 operating hours. HT can not provide a "make good" guarantee, but is willing to warrant their catalyst performance up to the contract value[36].

A subsequent email dated May 7, 2008 from Dr. Joakim Thøgersen of Haldor Topsoe (Denmark) to Robert Blakley to address additional followup questions to Flemming Hansen's May 5, 2008 email response provided further information regarding the wood-fired boiler SCR experience versus a hypothetical North Dakota cyclone boiler SCR situation[37].

One issue was the difference in flyash loading between ND lignite-fired cyclone boilers and wood-fired boilers mentioned previously by HT. The fly ash concentration in lignite flue gas is 5-10 times higher than in wood-fired boiler flue gas. But the fraction of alkali in flyash that deposits in the catalyst is a much smaller portion of the total flyash loading in lignite flue gas than wood-fired boilers. The reason according to Dr. Thøgersen has to do with the alkali being

[33] Ibid Reference number 21, included in Appendix A.
[34] Ibid Reference number 21, included in Appendix A.
[35] Ibid Reference number 19, included in Appendix A.
[36] Ibid Reference number 21, included in Appendix A.
[37] See Reference number 22, included in Appendix A.

bound in coarse aluminum/silicate fly ash particles that don't contribute to the deposits in the catalyst to the same extent. When the alkali is incorporated in aluminum/silicate fly ash, the alkali also becomes inactive as a SCR poison. The lignite fly ash also has a cleaning effect by attrition of the surface that causes re-entrainment of particle deposits. Attrition is re-entrainment or cleaning of the catalyst surface by particle impaction[38].

Another issue was the much higher concentration of sulfur in ND lignite cyclone boiler flue gas compared to wood-fired boiler flue gas. Haldor Topsoe recognizes that SO_2 levels in ND lignite flue gas are 700-800 ppm whereas it is less than 10 ppm in wood flue gas. The sulfur leads to a strengthening and densification of the blinding layers that originates from deposition of calcium, sodium, and potassium aerosols[39]. The sulfur reacts with deposited sodium chloride (NaCl), calcium oxide (CaO), and potassium chloride (KCl), which means that the particles swell and the blinding layer becomes more impermeable[40].

A telephone conversation between Dr. Joakim Thøgersen and Steve Benson on May 2, 2008 indicated that the deactivation rates would be greater than that of the worst wood-fired system because of the high sodium and sulfur (greater than 60% in 10,000 hours). Dr. Thøgersen indicated that at this point, Haldor Topsoe would not be in a position to make a 100% "make good" guarantee[41]. Haldor Topsoe's predictions of SCR catalyst deactivation are somewhat semi quantitative since the predictions are based on extrapolation/interpolation from wood firing and PRB fired boilers[42].

<u>Comments on Haldor Topsoe's Responses and April 24, 2008 Telephone Conference Call</u>: Haldor Topsoe (HT) did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Sources of catalyst experience on wood-fired boilers were cited but not substantiated with actual technical references or submittal of data.

[38] Ibid Reference number 22, included in Appendix A.
[39] Ibid Reference number 21, included in Appendix A.
[40] Ibid Reference number 22, included in Appendix A.
[41] See Reference number 23.
[42] Ibid Reference number 22, included in Appendix A.

The Haldor Topsoe representative involved with their initial response (Wayne Jones) acknowledged he was unfamiliar with the October 2005 EERC report of the SCR catalyst pilot testing at Coyote station[43]. Flemming Hansen provided the followup response, and was a participant in the referenced Coyote Station SCR catalyst pilot testing.

The amount and basis of HT's initial estimate of 4000 hours for rapid catalyst deactivation when exposed to North Dakota lignite-fired cyclone boiler flue gas and flyash was not provided, only that it was originally of the same magnitude as wood-fired boiler SCRs[44]. Now the expectation is stated to be worse than wood-fired boiler SCRs, with 60% deactivation over the first 10,000 operating hours[45].

Haldor Topsoe' apparent initial willingness to guarantee SCR catalyst performance on Unit 1 and Unit 2 at Milton R. Young Station firing North Dakota lignite is based largely on their experience on boilers firing wood with SCRs that have 5 to 10 times less flyash and 70 to 80 times less sulfur[46]. It also requires that the high flue gas temperatures presented in the query document are lowered and controlled, without knowing if or how this might be accomplished.

Haldor Topsoe's wood-fired boiler SCR experience is not closely comparable to North Dakota lignite firing in cyclone boilers at MRYS. In general, alkali content of fly ash from wood firing is similar to the alkali content in the fly ash from Center lignite. However, the form of the alkali in fly ash from cyclone-fired lignite is an oxide/hydroxide and sulfate; in wood fly ash, it will take another form, such as a chloride, if available. There are differences in reactivity between these forms of alkali with sulfur oxides that make the lignite flyash produce stronger bonded deposits on catalyst surfaces and in pores.

The temperature of cyclone firing is higher and causes more vaporization of alkali elements in the lignite ash than occurs with a wood-fired boiler system. The wood-fired boiler systems have lower flame temperatures and thus less vaporization of alkali elements. This is evident

[43] See Reference number 24.
[44] Ibid Reference number 19, included in Appendix A.
[45] Ibid Reference number 21, included in Appendix A.
[46] Ibid Reference number 21, included in Appendix A

based on the abundance of sodium and potassium-rich particles in the small ash size fraction found in the Coyote pilot SCR test catalyst and the particulate filter described in the referenced SCR vendor query. The sodium and potassium-rich materials combine with sulfur species to form sulfates are significantly different and more problematic in their impacts on catalyst than HT's wood-fired boiler SCR experience.

The pathway to the formation of bonded deposits on catalyst surfaces and pores for wood firing is different in lignite fired systems. HT suggested sodium chloride (NaCl) and potassium chloride (KCl) along with calcium oxide (CaO) are the intermediate species that become sulfated for the lignite application. It is evident that HT bases their assumptions on wood firing. In lignite, the intermediate species differ from wood because of the low levels of chlorine in the lignite coal. The reactions for sodium and potassium likely follow the path from vaporized atomic sodium and potassium in the flame to condensed sodium and potassium oxides or hydroxides. The calcium oxide (CaO) particles will form on the surface of the burning char particles and will be released as the char burns out. This resulting mixture (Na_2O/NaOH, K_2O/KOH, and CaO) of small particles (aerosols) will undergo minor sulfation during entrainment. As the particles are being transported with the bulk gas flow through the catalyst, they will deposit in the pores and on the surface of the catalyst. Once deposited, the particles will react with SO_3 to form sulfates and pyrosulfates causing the particles to swell filling pores and creating an impermeable layer. Another key point is that the rate of reaction to form sulfate is very fast in the pores because of the ability of the catalyst to convert SO_2 to SO_3.

Regarding the differences between ND lignite-fired cyclone boilers and wood-fired boilers mentioned previously by HT, loadings of ash are presumably higher for Center lignite and the potential for the scrubbing action of the silicate materials is possible. However, this scrubbing action will be unlikely for operations firing lignite with high sodium-low ash combinations supplied from the Center mine. In the low ash cases of ND lignite from the Center mine, the sulfated sodium and calcium particles are highly cohesive because of sulfate/pyrosulfate bonding that occurs between the particles. These types of bonded phases will be resistant to attrition and sulfate/pyrosulfate materials will capture the silicate particles resulting in

increased growth and plugging. The scanning electron microscope (SEM) images in the October 2005 EERC paper[47] show evidence of captured aluminosilicate particles bonded in a sodium calcium sulfate matrix. The attrition effect described by Dr. Thøgersen assumes that erosion of the deposited materials will take place subsequent to particle impaction. However, if the deposit on the catalyst surface is cohesive and sticky, deposit growth will take place as described above.

Summary of Hitachi's Response:

Hitachi did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Hitachi's initial response via email[48] confirmed that there has been very little testing and data available on North Dakota lignite. After their initial review of information and data provided by Burns & McDonnell regarding the viability of SCR technology on the Milton R. Young Station (MRYS) Units 1&2, Hitachi expressed several concerns about the difficulty of installing and operating a hot-side, high-dust SCR:

- Without a plan to reduce the flue gas temperature, the catalyst will deactivate very quickly above 850 degrees F.
- High sodium content of the ash may cause serious deactivation of the catalyst.
- High sulfur trioxide (SO_3) content in ash may also cause faster catalyst deactivation.
- Sticky ash will cause a pluggage problem.

Because of all these unknowns, Hitachi strongly recommended that a slipstream test be performed to confirm the applicability of the catalyst for this flue gas[49].

Summary Comments on SCR System Suppliers' and Catalyst Suppliers' Responses:

The responses were mixed, with the SCR System Suppliers (boiler original equipment manufacturers) being pessimistic (B&W, Hitachi) to optimistic (Alstom, BPE) about the ability of an SCR system to be successful on these cyclone boilers burning North Dakota lignite. The SCR Catalyst Suppliers that provided technical responses (Ceram, Haldor Topsoe, and Hitachi) were mixed in their response, with Ceram and HT being more positive and Hitachi more

[47] See Reference number 25.
[48] See Reference number 26, included in Appendix A.
[49] Ibid Reference number 26, included in Appendix A.

negative. Of the catalyst vendors that were favorable, both indicated that their willingness to offer performance guarantees requires solving the flue gas temperature problems for which they are not responsible. Haldor Topsoe further qualified their willingness to warrant their catalyst performance was not a "make good" guarantee, but is limited to the amount of contract value of supplying the catalyst, which is a small portion of a typical full-scale full-time SCR system installation. Ceram did not specify their catalyst performance guarantee nor service life warranty limits. None of the SCR system suppliers offered any performance guarantees, not even Alstom and Babcock Power who believe that SCRs could be successfully utilized on MRYS cyclone boilers firing North Dakota lignite.

SCR suppliers and catalyst suppliers did not provide detailed information completely responsive to all aspects of the subject raised in the original SCR Vendor query. Some responses were more detailed than others; none included reference plant information or specific fuel and ash analysis data that presumably forms the basis of their opinions, estimates and predictions.

The vendors did not offer any new or different field pilot testing or laboratory/bench scale information including catalyst analysis from samples exposed to flue gas and flyash created from firing North Dakota lignite that agrees with or refutes information presented in the October 2005 EERC report of slipstream catalyst testing at Coyote Unit 1 referenced in the SCR vendor query. Several acknowledged that there are no known existing applications of full-scale, full-time SCR technology to ND lignite fired boiler, therefore there is some risk in this application. Suppliers did not provide much detail in identifying solutions to mitigate risks; mostly their comments suggested or recommended various tail-end SCR or low-dust SCR configurations to minimize flyash deposition. These responses largely ignored the evidence presented in the April 2007 query and October 2005 EERC report that fine alkali particles pass though the dust collection equipment (ESPs) that would be located ahead of these SCR reactors, which will plug pores and blind the catalyst surfaces, making the catalyst ineffective in reducing NOx emissions.

Of the SCR suppliers and catalyst suppliers providing additional responses, all recommend or favor a course of further research and pilot-scale testing before they would be confident of catalyst deactivation rates, service life, location in the gas stream for placement of the SCR reactor, and amount of catalyst required.

Conclusions on SCR Technical Feasibility for North Dakota's BACT Determination:

Minnkota has previously submitted arguments regarding the appropriateness of conducting pilot testing of selective catalytic reduction (SCR) technology at Milton R. Young Station Units 1 and 2 for use in a NOx BACT Analysis[50]. The vendor responses summarized and included herein have not altered the rationale of Minnkota's arguments that:

- Pilot-scale testing of SCR technology is specifically not required by the BACT determination procedures established by the U.S. Environmental Protection Agency (EPA).
- Previous research, including previous SCR pilot testing conducted at Coyote Station[51], indicates that there is not sufficient reason to believe that additional pilot testing suggested by SCR system suppliers and catalyst suppliers will produce results substantially different than those obtained from the prior pilot test.

Vendor responses to an SCR Vendor Query[53] did not adequately address guarantees and warranty of system performance and catalyst service life to mitigate potentially significant, long-term operational and financial risks based on the specific applications involved. This query sought information that forms the basis of the vendors' responses to the issue of guarantees, including:

- Whether such guarantees would satisfy a "make good" requirement;
- Would the vendor provide a catalyst service life guarantee and replacement warranty; and

[50] See Reference number 27.
[51] Ibid Reference number 25.
[53] Ibid Reference number 1, April 18, 2007.

- Whether any catalyst service life that a vendor would propose is based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment.

All vendors that responded to the query mentioned the significant challenges involved with the design considerations for applying SCR technology to these MRYS boilers. Only two vendors provided responses that included willingness to offer any guarantees on catalyst performance, with significant limitations on acceptable operating conditions which are yet to be achieved and would require solutions provided by other vendors. One of these catalyst suppliers responded that they would not be willing to offer a "make good" guarantee. The lack of suppliers' willingness to extend system and catalyst performance guarantees that satisfy "make good" requirements, as well as a lack of detail on service life warranty offers, does not support a substantial endorsement of applying SCR technology to these MRYS boilers with sufficient guarantees and certainty of results without having to perform substantial pilot testing, research and development, and specialized design as provided in the vendor responses.

Minnkota has previously presented the regulatory basis for the decision to not conduct pilot testing, as well as the reasons for technical infeasibility of SCR technology, for use in a NOx BACT Analysis[54]. The significant limitations stated by the catalyst suppliers regarding acceptable operating conditions which are yet to be attained and would require solutions provided by other vendors are significant caveats to believe that any suggested guarantees on catalyst performance or service life would be achieved with certainty. The fact that all the SCR suppliers responding to query recommend or favor pilot testing means that this technology is insufficiently developed to be considered "available" for the Unit 1 and Unit 2 boilers at MRYS burning North Dakota lignite as discussed in the EPA's NSR Manual[55].

Minnkota has provided sufficient information and documentation to NDDH and EPA, including responses to issues raised and requests made after submittal of the BACT Analysis Study reports[56] in October, 2006, to establish that SCR cannot be reasonably installed and

[54] Ibid Reference number 27.
[55] See Reference number 28,
[56] See Reference number 29, October, 2006,

operated on the cyclone-fired boilers burning North Dakota lignite located at Milton R. Young Station.

REFERENCES

1 Burns & McDonnell and Energy & Environmental Research Center (EERC), *"Information Request"* (SCR Vendor Query and Attachments), April 2007.

2 Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative "*Responses To NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns, Milton R. Young Station Unit 1 And Unit 2 NOx BACT Analysis Study, April 18, 2007*".

3 North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Determination Milton R. Young Station*, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.

4 Consent Decree filed 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, filed April 24, 2006.

5 Burns & McDonnell and Energy & Environmental Research Center (EERC) presentation to North Dakota Department of Health, Environmental Health Section, Division of Air Quality, and United States Environmental Protection Agency, *"Summary of Responses to EPA/DOH Questions on Minnkota Power's NOx BACT Analysis for Milton R. Young Units 1 & 2"*, May 23, 2007.

6 Burns & McDonnell list of SCR System Suppliers and SCR Catalyst Suppliers (for sending SCR Vendor Query Information Request via email), 4/18/2007.

7 Electronic mail, Robert Blakley to Chuck Nordhausen (Alstom Power) April 18, 2007, and Letter (submitted via email), Michael G. Phillips (Alstom Power Environmental Control Systems) to Robert Blakley, May 30, 2007. See Appendix A for copies.

8 Electronic mail, Robert Blakley to John Buschmann (Alstom Power Environmental Control Systems), April 28, 2008; and Letter (submitted via email), Michael G. Phillips (Alstom Power Environmental Control Systems) to Robert Blakley, May 5, 2008. See Appendix A for copies.

9 Personal notes from Telephone Conference, John Buschmann (Alstom Power Environmental Control Systems) with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 28, 2008.

10 Electronic mail, Robert Blakley to Cindy Khalaf (Argillon) April 18, 2007, and April 19, 2007 email reply. See Appendix A for copies.

11 Electronic mail, Robert Blakley to Steve Moorman (Babcock & Wilcox) April 18, 2007, and May 10, 2007 email reply. See Appendix A for copies.

12 Electronic mail, Robert Blakley to Rich Abrams (Babcock Power Environmental) April 18, 2007, and response email, May 11, 2007. See Appendix A for copies.

13 Electronic mail, Robert Blakley to Clay Erickson (Babcock Power Environmental, April 28, 2008, and response email May 6, 2008. See Appendix A for copies.

14 Personal notes from Telephone Conference, Clay Erickson and Joe Langone (Babcock Power Environmental) with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 28, 2008.

15 Electronic mail, Robert Blakley to John Cochran (Ceram) April 18, 2007, and response email from Noel Rosha with attachments, May 11, 2007. See Appendix A for copies.

16 Personal notes from Telephone Conference, Noel Rosha (Ceram) with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 23, 2008.

17 Electronic mail, Robert Blakley to Noel Rosha (Ceram) April 22, 2008, and response email from John Cochran, May 6, 2008. See Appendix A for copies.

18 Electronic mail, Robert Blakley to Scot Pritchard (Cormetech) April 18, 2007, and May 14, 2007 email reply. See Appendix A for copies.

19 Electronic mail, Robert Blakley to Flemming Hansen (Haldor Topsoe) April 18, 2007, and response email, May 10, 2007. See Appendix A for copies.

20 Personal notes from Telephone Conference, Flemming Hansen (Haldor Topsoe), with Robert Blakley, Carl Weilert, and Steve Benson (EERC), April 24, 2008.

21 Electronic mail, Robert Blakley to Flemming Hansen (Haldor Topsoe), April 28, 2008, and response email May 5, 2008. See Appendix A for copies.

22 Electronic mail, Robert Blakley to Flemming Hansen (Haldor Topsoe), May 5, 2008, and response email by Joakim Thøgersen (Haldor Topsoe) May 7, 2008. See Appendix A for copies.

23 Personal notes from Telephone Conference, Dr. Joakim Thøgersen (Haldor Topsoe) call to EERC with Steve Benson (EERC), May 2, 2008.

24 Personal notes from Telephone Conference, Wayne Jones (Haldor Topsoe), with Robert Blakley, April 22, 2008.

25 "*Ash Impacts On SCR Catalyst Performance*", Steven A. Benson, Ph.D., Energy & Environmental Research Center (EERC) of the University of North Dakota", October 2005.

26 Electronic mail, Robert Blakley to Anthony Favale (Hitachi), April 18, 2007, and response email, May 11, 2007. See Appendix A for copies.

27 Burns & McDonnell, EERC, and Hogan & Hartson, *"Appropriateness Of Conducting Pilot Testing Of Selective Catalytic Reduction (SCR) Technology At Milton R. Young Station Units 1 And 2 For Use In A NOx BACT Analysis, August 14, 2007"*.

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

29 Burns & McDonnell, "*BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc.*" and a separate "*BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative*", October 2006, submitted to EPA Region 8 and EPA Office of Regulatory Enforcement, and included with the "*BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc. Final Report, October 2006*" submitted by Minnkota to North Dakota Department of Health.

APPENDIX A -

Initial Vendor Responses to 4/18/2007 SCR Vendor Query Information Request (and Attachments), May 2007, and Followup Vendor Responses to 4/18/2007 SCR Vendor Query Information Request (and Attachments), May 2008, arranged in alphabetical and chronological order by vendor name.

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:58 PM
To: 'Charles.nordhausen@power.alstom.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Chuck,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Alstom to review the attached request document and respond within three weeks if possible. If Alstom's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: charles.nordhausen@power.alstom.com [mailto:charles.nordhausen@power.alstom.com]
Sent: Wednesday, May 30, 2007 11:03 AM
To: Blakley, Robert
Cc: mike.phillips@power.alstom.com; john.buschmann@power.alstom.com; kthingelstad@minnkota.com; jgraves@minnkota.com
Subject: Re: Request for Lignite SCR Feasibility Commercial and Technical Information

Bob,

Please find attached the Alstom ECS response to the Burns and McDonnell RFI on behalf of Minnkota Power. If you have any further questions or would like to discuss this topic further, do not hesitate to contact me.

Best Regards,

Chuck

Chuck Nordhausen
Alstom GPS
Office: (913) 393-2585
Mobile: (651) 492-7420

ALSTOM

Power Turbo-Systems / Power Environment

Environmental Control Systems
North America

May 30, 2007

Mr. Robert Blakley
Burns and McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Request For SCR Information
Milton Young Units 1&2

Dear Mr. Blakley:

As Burns and McDonnell and Minnkota Power are aware, ND Lignite does create many challenges for SCRs, but even with all of those challenges, it is possible to use ND Lignite if the system is designed properly and Minnkota Power elects to pay for the increased capital and O&M costs associated with this fuel. Alstom Power Environmental Control Systems (ECS) would like to offer Burns and McDonnell and Minnkota Power the following information in response to your request for SCR information on ND Lignite:

- Prior Applications of SCR to ND lignite fired boilers
- Alternative Tail End SCR
- Predicted SCR Performance
- Indicative Pricing and Delivery for Conventional SCR

Prior Applications of SCR to ND lignite fired boilers

Lignite coal burning units have not yet had any post combustion NOx controls installed on these units as environmental regulations have not yet required the installation of these controls. Investigative tests were performed on TXU Energy's Martin Lake Unit 3 to evaluate SCR catalyst performance on Texas-lignite-fired units. An in-situ mini SCR reactor was used for long-term tests on two types of catalyst to collect data on the effects of Texas lignite on SCR catalyst life and performance. After approximately 8000 hours of exposure to economizer outlet flue gas at typical SCR velocities of 15-20 ft./sec. (4.6-6.1 m/sec), both honeycomb and plate-type catalyst samples were shown, by field test, to have relative activities (K/K0) in the range of 0.70 to 0.75. Laboratory tests of catalyst activity performed by the catalyst vendors were consistent with these field test results. These results are expected

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to be representative of the first layer of a full-scale SCR reactor system. Erosion of the catalyst samples was not significant enough to affect catalyst performance. Test results further suggest that applying SCR catalyst technology (using even a high-dust design) to Texas-lignite-fired power generating units may be a practical approach for NOx control. (Electric Power Research Institute, December 2003, "Impacts of Texas Lignite Coal on SCR Catalyst Life and Performance: Field Data from TXU's Martin Lake Plant")

It should be noted that North Dakota lignite is higher in sodium than Texas lignite. Fuels high in sodium and potassium require special selection of catalyst, but can be treated by SCR. An example of a such an application would be wood and other biofuel fired boilers in Europe. While SCR catalyst life in ND lignite service is not expected to be as long as in bituminous coal service, it is expected that acceptable emissions control and maintenance requirements can be achieved. Based on experience with wood fired units, a hot side (600-750 deg F) ESP is effective in removing the fly ash compounds that result in catalyst poisoning.

Proper operation of the SCR generally requires that the system operate in a temperature range of 600 to 750 deg F. Per the information provided, the Milton R Young boiler flue gas temperature at the economizer outlet currently varies quite a bit outside this range. Based on this temperature information, we anticipate that modification or replacement of the economizer will be required to control the temperature within an acceptable range.

Alternative Tail End SCR

While likely more expensive, an alternative solution to the conventional SCR , is a Tail End SCR where the SCR is located just before the stack. For this application, the location of the SCR just before the stack can provide significant advantages. The economizer outlet temperature variations will have no effect on the SCR, and the fly ash constituents that can poison the catalyst will have been removed from the flue gas stream by the existing ESPs. This would mean that modification of the existing economizer and any existing ESP would not be required with the application of a Tail End SCR.

The key disadvantage of the Tail End SCR is that the flue gas stream will need to be reheated from the current stack temperature up to approximately 600 deg F. Typically the flue gas is reheated using natural gas, however high pressure steam has been used in some cases. Heat recovery can be utilized to reduce the amount of energy required, however, the heating requirement is typically in the range of tens of millions of Btu per hour.

Predicted SCR Performance

Designed properly, the SCR should be capable of up to 90% removal efficiencies with an associated ammonia slip below 2 ppm. The significant unknown is how often the catalyst itself would need to be replaced. There is minimal field data to demonstrate expected catalyst life, but lab results suggest an average up to 16,000 hours between replacements.

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Indicative Pricing, Sizing and Delivery

Because of the unusual design associated with this SCR and the potential additional scope items (heat exchangers or hot ESPs) required, it is expected that the cost will be significantly higher than for a conventional bituminous coal fired SCR. Without detailed anlaysis, the material and labor pricing below is our best estimate of the cost of a conventional SCR based on the increased sizing requirements.

Milton Young 1:	$50M
Milton Young 2:	$75M
Lead Time:	32 to 36 months

This estimated pricing does not include BOP costs, costs to modify the economizer, costs to modify existing precipitators, or costs to install gas to gas heat exchangers. Obviously, depending on the path forward and the resultant equipment required, the costs could be even more than stated above.

Alstom Power ECS hopes that this information can assist you in your SCR decision for Milton Young. In summary, it is possible to design and operate an SCR on this fuel if required, but doing so is not without challenges and can be very costly depending on which approach you may choose to pursue. Should you decide to pursue an SCR for these units, Alstom would be very interested in supporting you as we consider ourselves one of the industry leaders in this technology. Please contact Chuck Nordhausen, John Buschmann or me at your convenience with any questions or clarifications regarding this discussion.

Respectfully Submitted,

Michael G. Phillips
Business Applications Manager
Environmental Control Systems

CC: John Graves
Karen Thingelstad

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:29 PM
To: 'john.buschmann@power.alstom.com'
Cc: 'charles.nordhausen@power.alstom.com'; 'mike.phillips@power.alstom.com'
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

John -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to revisit the April 18, 2007 query, and review results of pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Alstom's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers, both in hot-side/high-dust and low-dust/tail end SCR applications.

We are interested in learning more about the basis of lab results mentioned in discussion of the 16,000 hours as a suggested number of operating hours between catalyst replacements. Particularly, if Alstom were asked to provide a catalyst service life guarantee and replacement warranty, whether this or any other operating time that Alstom would propose is based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

We are also interested in knowing more about Alstom's willingness to offer SCR performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Alstom's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution to these temperature conditions yet to be developed.

It would be beneficial to reference Alstom's previous May 30, 2007 response when sending a supplemental response addressing this subject and issues raised in today's discussion.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Alstom provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: mike.phillips@power.alstom.com
[mailto:mike.phillips@power.alstom.com]
Sent: Tuesday, May 06, 2008 8:55 AM
To: Blakley, Robert
Cc: charles.nordhausen@power.alstom.com;
john.buschmann@power.alstom.com
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Sorry for the delay!

(See attached file: Response to B&M for Minnkota SCR Inquiry 050608.doc.zip)

Regards,
Mike

Michael G. Phillips
513-543-0055 mobile
865-560-1389 office
1409 Centerpoint Blvd.
Knoxville, TN. 37932

ALSTOM

Power Turbo-Systems / Power Environment

Environmental Control Systems
North America

May 5, 2008

Mr. Robert Blakely
Burns and McDonnell
9400 Ward Parkway
Kansas City, MO 64114

Subject: Minnkota Power Cooperative
Milton R Young SCR Inquiry

Dear Mr. Blakely:

Alstom Power Environmental Control Systems (ECS) has reviewed the information available to us regarding SCR installations on ND Lignite units and feel that our original response to Minnkota dated May 27, 2007 is still valid. The highlights of that letter are clarified / summarized below.

- There are no known existing applications of SCR to ND lignite fired boilers, therefore there is some risk on any first a a kind application
- Alstom believes that hot side SCRs can be utilized in this application if a hot ESP is used upstream for ash collection before the SCR, but would as a result be very expensive from both a capital and O&M standpoint compared to non ND lignite SCRs
- In order to provide catalyst life guarantees, it is anticipated that catalyst manufacturers would require a pilot test of at least one year
- Tail end SCRs remain an alternative, but are also very expensive from a O&M standpoint

While SCR catalyst life in ND lignite service is not expected to be as long as in bituminous coal service, it is expected that acceptable emissions control and maintenance requirements can be achieved. Based on experience with wood fired units, a hot side (600-750 deg F) ESP is effective in removing the fly ash compounds that result in catalyst poisoning.

Proper operation of the SCR generally requires that the system operate in a temperature range of 600 to 750 deg F. Per the information provided, the Milton R Young boiler flue gas temperature at the economizer outlet currently varies quite a bit outside this range. Based on this temperature information, we anticipate that modification or replacement of the economizer will be required to control the temperature within an acceptable range.

Application of a traditional SCR to Lignite fired units will require some R&D, custom engineering, and likely a pilot testing program. This will be time consuming and expensive but will reduce the risks involved in a new application such as this one.

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While likely more expensive, an alternative solution to the conventional SCR , is a Tail End SCR where the SCR is located just before the stack. For this application, the location of the SCR just before the stack can provide significant advantages. The economizer outlet temperature variations will have no effect on the SCR, and the fly ash constituents that can poison the catalyst will have been removed from the flue gas stream by the existing ESPs. This would mean that modification of the existing economizer and any existing ESP would not be required with the application of a Tail End SCR.

We hope this helps assist you with Minnkota on its future NOx requirements Please contact Chuck Nordhausen, John Buschmann or me at your convenience with any questions or clarifications. We look forward to having the opportunity to meet with you to discuss our proposal in detail.

Respectfully Submitted,

Michael G. Phillips
Business Sales Manager
Environmental Control Systems

Cc: Chuck Nordhausen – Alstom GPS
John Buschmann – Alstom ECS

From: Khalaf Cindy R [mailto:Cindy.Khalaf@argillon.com]
Sent: Thursday, April 19, 2007 4:50 AM
To: Blakley, Robert
Subject: Re: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,
We'll take a look and let you know if we need longer. Bruce Gobbel will be responding. Have you taken Bob Johnson's pllace?
Regards,
Cindy

Sent from my BlackBerry Wireless Handheld

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:48 PM
To: 'cindy.khalaf@argillon.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Cindy,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Argillon to review the attached request document and respond within three weeks if possible. If Argillon's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, April 18, 2007 3:59 PM
To: Moorman, Steve A
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Steve,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Babcock & Wilcox to review the attached request document and respond within three weeks if possible. If B&W's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Moorman, Steve A [mailto:samoorman@babcock.com]
Sent: Wednesday, May 09, 2007 4:44 PM
To: Blakley, Robert
Cc: Telesz, Robert W; Hansen, Elizabeth A
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,

The Babcock & Wilcox Company has reviewed your request of April 18, 2007 regarding information related to the application of SCR technology on steam generating units that fire North Dakota lignite.

As you indicate in your Information Request, there is no full scale operational experience with SCR systems that have been retrofit onto an ND lignite-fired boiler. In fact, we are aware of no SCR retrofit that to date has been done on any boiler here in the US where lignite of any type has been fired. Therefore, neither we nor any other SCR system supplier can "provide detailed information regarding the post-combustion controlled emissions rates that full-scale, full-time SCR systems in lignite-fired coal-burning boiler operations have consistently achieved over a period of time."

B&W agrees with Burns & McDonnell that there are significant challenges associated with both boiler operation (high economizer exit gas temperature) and lignite firing (flue gas constituents) at Milton R. Young Station (MRYS). We have had cursory conversations with catalyst suppliers in an attempt to better understand and quantify these challenges. However we have not been able to fully explore these issues and at this time have no knowledge of the full extent of the catalyst suppliers concerns or the lengths to which they may need to go to address them especially if catalyst guarantees must be offered. In addition, with the limited number of units firing North Dakota lignites, it would be difficult for a supplier like B&W to justify investing significant dollars in R&D efforts to fully investigate and understand both the technical and commercial risks that would be involved when installing SCRs on ND lignite fired boilers.

During our delivery of over 26,000 MW of SCR systems and our evaluation of several times that many customer inquiries, B&W has identified creative solutions to address a host of boiler-SCR system integration challenges. Some were implemented while others were necessarily abandoned as economically unfeasible. B&W would welcome the opportunity to work with Burns & McDonnell and the Minnkota Power Cooperative, Inc. to further investigate opportunities to successfully meet the NOx emission challenges at MRYS should Minnkota find it necessary to do so.

Steve Moorman

Steve Moorman --- District Sales Manager, Babcock & Wilcox

2096 Edgcumbe Road Saint Paul, MN 55116

Office 651-690-3795, Home 651-690-1558, Cell 612-670-8261

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 4:02 PM
To: 'rabrams@babcockpower.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Rich,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Babcock Power to review the attached request document and respond within three weeks if possible. If Babcock Power's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: rabrams@babcockpower.com [mailto:rabrams@babcockpower.com]
Sent: Friday, May 11, 2007 1:37 PM
To: Blakley, Robert
Cc: cerickson@babcockpower.com; MGialanella@babcockpower.com; Perrie Schafer; dgustafson@babcockpower.com
Subject: Re: Request for Lignite SCR Feasibility Commercial and Technical Information

Dear Mr. Blakely:

Babcock Power Environmental (BPE) has reviewed the information provided to us on Milton Young Units 1 & 2 lignite fired boiler and the request for information on the applicability of SCR technology these boilers and their fuel. As you are aware, there have been a few tests performed to ascertain the possibility of using a high dust SCR on lignite and the potential for fouling/poisoning of the catalyst has been in question.

BPE and its licensor have supplied >60,000 MW of SCR systems around the world, including in applications with lignite in Europe and active lignite projects in the states. We have examined the various lignite fuels from around the world and, while there are differences, we expect an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel however, uncertainty exists because an SCR has yet to be tested/provided on a meaningful scale to a Northern lignite application.

Furthermore, during our review of the information provided, we have identified the MY1 and MY2 boilers as a very difficult one on which a high dust SCR would be applied because of the unique configuration of the boiler and the wide temperature swings that are encountered.

BPE is very interested in working with Burns & McDonnell and Minnkota Power to provide the optimum solution to this problem. Several possible solutions exist with varying certainties of outcome. The SCR technology location may potentially mitigate the issues with the possible poisoning of the catalyst by constituents in the gas from the combustion of Northern lignite.

We recommend an engineering study be conducted to evaluate three key issues:

Initial estimates of the actual deactivation of SCR catalyst in the high dust location by the use of coupons positioned in the hot gas stream downstream of the economizer.

Initial estimates of the actual deactivation of SCR catalyst in other locations by the use of coupons positioned in the gas stream downstream of the airheater.

Possibility of a retrofit of an SCR into the MY1 and MY2 boiler considering the wide range of temperature for the flue gas and possible boiler modifications required.

BPE would lead this effort with collaboration from Burns & McDonnell and Minnkota Power. .

BPE is planning to be in the Bismarck area during the week of June 18 and offer to visit the plant and to meet to discuss our thoughts on the program, its cost, and the sharing of those costs. Furthermore, we

would like to discuss issue #3 in greater detail to better understand options in the boiler area. Please let me know the availability of Minnkota and B&Mc personnel to meet and discuss this subject. We look forward to hearing from you.

Rich Abrams
Director of Business Development
Babcock Power Environmental Inc.
Worcester, Massachusetts
Phone: 508.854.1140

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:41 PM
To: cerickson@babcockpower.com
Cc: MGialanella@babcockpower.com; rabrams@babcockpower.com; Tyler Schafer; 'jlangone@babcockpower.com'; Perrie Schafer
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Clay -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to revisit the April 18, 2007 query, and review results of pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Babcock Power's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers, both in hot-side/high-dust and low-dust/tail end SCR applications.

We are interested in learning more about the "fatal flaw" SCR catalyst coupon testing approach mentioned in today's discussion, and additional pilot-scale SCR catalyst testing in various locations relative to gas cleaning equipment.

We are also interested in knowing more about Babcock Power's willingness to offer SCR performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Babcock Power's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution to these temperature conditions yet to be developed. Particularly, if Babcock Power were asked to provide a catalyst service life guarantee and replacement warranty, whether a minimum operating time that Babcock Power would propose is based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

It would be beneficial to reference Babcock Power's previous May 11, 2007 response when sending a supplemental response addressing this subject and issues raised in today's discussion.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Babcock Power provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell

From: cerickson@babcockpower.com [mailto:cerickson@babcockpower.com]
Sent: Tuesday, May 06, 2008 10:58 AM
To: Blakley, Robert
Cc: MGialanella@babcockpower.com; jlangone@babcockpower.com
Subject: Lignite SCR Response

Robert,

Per our phone conversion concerning the application of SCR technology to Northern Lignite fired boilers, BPEI has not nor knows of any further work on this topic since the response provided below on May 11th 2007. As discussed BPEI believes the issues related to the application of SCR technology for northern lignite fired units to be addressable in design.
The EERC reports have indicated significant issues however BPEI feels further tests investigating different locations and using tests alternate methods must be performed to make a final determination.
BPEI, as the worldwide leader in SCR technology, continues to offer its services for to the industry to resolve the application of SCR technology to northern lignite fired units.

If you have further questions please contact me or Joe Langone.

Clay Erickson

May 11th 2007 Response below

Babcock Power Environmental (BPE) has reviewed the information provided to us on Milton Young Units 1 & 2 lignite fired boiler and the request for information on the applicability of SCR technology these boilers and their fuel. As you are aware, there have been a few tests performed to ascertain the possibility of using a high dust SCR on lignite and the potential for fouling/poisoning of the catalyst has been in question.

BPE and its licensor have supplied >60,000 MW of SCR systems around the world, including in applications with lignite in Europe and active lignite projects in the states. We have examined the various lignite fuels from around the world and, while there are differences, we expect an SCR system could be successfully utilized on a boiler fired with Northern lignite fuel however, uncertainty exists because an SCR has yet to be tested/provided on a meaningful scale to a Northern lignite application.

Furthermore, during our review of the information provided, we have identified the MY1 and MY2 boilers as a very difficult one on which a high dust SCR would be applied because of the unique configuration of the boiler and the wide temperature swings that are encountered.

BPE is very interested in working with Burns & McDonnell and Minnkota Power to provide the optimum solution to this problem. Several possible solutions exist with varying certainties of outcome. The SCR technology location may potentially mitigate the issues with the

possible poisoning of the catalyst by constituents in the gas from the combustion of Northern lignite.

We recommend an engineering study be conducted to evaluate three key issues:

Initial estimates of the actual deactivation of SCR catalyst in the high dust location by the use of coupons positioned in the hot gas stream downstream of the economizer.

Initial estimates of the actual deactivation of SCR catalyst in other locations by the use of coupons positioned in the gas stream downstream of the airheater.

Possibility of a retrofit of an SCR into the MY1 and MY2 boiler considering the wide range of temperature for the flue gas and possible boiler modifications required.

BPE would lead this effort with collaboration from Burns & McDonnell and Minnkota Power. .

(Embedded image moved to file: pic24350.gif)

BabcockPower

Clayton Erickson, PhD
Director, Process Engineering
Babcock Power Inc.
5 Neponset Street
Worcester, MA 01606

T: 508-854-4039 F: 508-854-1177
M: 508-245-2383

cerickson@babcockpower.com
http://www.babcockpower.com

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:50 PM
To: 'john.cochran@ceram-usa.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

John,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Ceram to review the attached request document and respond within three weeks if possible. If Ceram's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Noel Rosha [mailto:Noel.Rosha@CERAM-USA.COM]
Sent: Friday, May 11, 2007 4:44 PM
To: Blakley, Robert
Cc: John Cochran
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Mr. Blakley,

CERAM has reviewed the information provided by Burns & McDonnell regarding the technical feasibility of SCR on the Milton R. Young Station Units 1 and 2 firing North Dakota Lignite fuel. Based on the information provided we have developed preliminary catalyst designs for each Unit, as outlined in the attached files. Unit 1 and Unit 2 were both designed with 85% NOx reduction (0.08 lb/MBtu outlet) with an SO_2 to SO_3 conversion rate of 1.0% and ammonia slip of 2.0 ppm for a guarantee life of 16,000 hours. We have also included for your information our high temperature reference list.

CERAM currently does not have a catalyst installation with North Dakota Lignite fuel. CERAM does have a very wide fuels experience base for coals, including one brown coal reference in Europe. We also have a large experience base with refineries and incinerators and are familiar with the affects of a wide range of fuel and flue gas constituents.

North Dakota Lignite fuel and ash characteristics present certain challenges related to SCR operation and reliability. Additionally, the high flue gas temperatures needed for purposes of drying the fuel can be a challenge for SCR catalyst design. Please note the following technical clarifications that CERAM feels are pertinent for this application:

- The presence of pyrosulfates (sodium, iron and sulfur) have the potential to increase the SO_2 to SO_3 conversion rate. Based on this, CERAM could only guarantee the initial SO_2 to SO_3 conversion rate and not the end of life conversion rate.
- CERAM has utilized a 7.4 mm pitch catalyst to minimize risk of catalyst pluggage. High concentrations of calcium and sulfates in the fuel increase the potential for catalyst pluggage.
- Due to the high sodium and iron concentrations, CERAM would recommend a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry, for instance with an air drying or dehumidification system.
- CERAM would require the maximum continuous operating temperature of the SCR be designed for 850° F. Short periods of operation up to 900° F could be allowed. Boiler outlet temperatures greater than these would require flue gas tempering prior to reaching the SCR reactor.

Please let us know if you have further questions or would like additional information.

Best regards,

Noel Rosha
Applications Engineer

CERAM Environmental, Inc.
7304 W. 130th Street, Suite 140
Overland Park, KS 66213

Phone: (913) 239-9896
Fax: (913) 239-9821

CERAM CATALYSTS + HONEYCOMBS		
	PROJECT	**Milton R. Young Unit 1**
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	PROPOSAL NO.	NR042307-1

	Case	Limiting case
		Design Load
	Load	Design Load
Design Basis:	**Fuel**	North Dakota Lignite
Gas flow	acfm,w	2483737
Gas temperature	°F	850
H_2O	Vol%	18.87
O_2-actual	Vol%,w	2.87
O_2-reference	Vol%,d	3.00
Inlet NOx	lb/MMBtu	0.53
SO_2	lb/hr	8970.0
SO_3	lb/hr	135.0
Particulate	lb/hr	20809.0

Catalyst Design:

Orientation		Vertical
Catalyst Volume per reactor	m^3	**625.7**
Number of SCR reactors	[-]	1
Number of units	[-]	1
Catalyst Volume, total	m^3	**625.7**
Cells of catalyst n x n	[-]	20
Specific area of catalyst Ap	m^2/m^3	469
Pitch of catalyst	mm	7.4
Catalyst length	mm	1071
Catalyst elements per one module	n x n	6 x 12
Number of layers per reactor		3
Module arrangement per layer	n x n	12 x 10
Module dimensions:		
length x width	mm x mm	958 x 1901
	ft x ft	3.14 x 6.24
height	mm	1411
	ft	4.63
Reactor dimensions:		
length x width	mm x mm	11816 x 19830
	ft x ft	38.77 x 65.06
Weight per module incl. catalyst	kg	1115
	lb	2457
Module frame material		H II

CERAM CATALYSTS + HONEYCOMBS	PROJECT	Milton R. Young Unit 1
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	FILE	NR042307-1

	Case	Limiting case
		Design Load
	Load	Design Load
Catalyst Performance:	**Fuel**	North Dakota Lignite
NOx outlet	ppmvd,ref.O_2	43.2
	lb/MMBtu	0.08
NOx reduction rate	%	85
NH_3 slip	ppmvd,ref.O2	2.0
NH3 100% consumption	kg/h	249.5
per reactor	lb/h	550.0
Catalyst pressure drop, clean	mbar	6.0
	inwg	2.4
	mm WC	61.1
Catalyst pressure drop, dirty	mbar	6.6
	inwg	2.7
	mm WC	67.4
SO_2/SO_3 conversion rate	%	1.00
Catalyst life	hr / years	16000 / 2

Technical Requirements:

Minimum NH_3 injection temperature	°C	317
	°F	602
Molar ratio distribution	% absolute	10
Velocity distribution	% absolute	15
Temperature distribution	°C absolute	10
Soot blower or sonic horns	yes / no	y

CERAM CATALYSTS + HONEYCOMBS		
	PROJECT	Milton R. Young Unit 2
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	PROPOSAL NO.	NR042307-1

	Case	Limiting case	
		Design Load	
	Load	Design Load	
Design Basis:	**Fuel**	North Dakota Lignite	
Gas flow	acfm,w	4371000	
Gas temperature	°F	818	
H_2O	Vol%	17.08	
O_2-actual	Vol%,w	4.77	
O_2-reference	Vol%,d	3.00	
Inlet NOx	lb/MMBtu	0.52	
SO_2	lb/hr	15474.0	
SO_3	lb/hr	236.0	
Particulate	lb/hr	34584.0	

Catalyst Design:

Orientation		Vertical		
Catalyst Volume per reactor	m^3	**947.1**		
Number of SCR reactors	[-]	1		
Number of units	[-]	1		
Catalyst Volume, total	m^3	**947.1**		
Cells of catalyst n x n	[-]	20		
Specific area of catalyst Ap	m^2/m^3	469		
Pitch of catalyst	mm	7.4		
Catalyst length	mm	1298		
Catalyst elements per one module	n x n	6	x	12
Number of layers per reactor		2		
Module arrangement per layer	n x n	15	x	15
Module dimensions:				
length x width	mm x mm	958	x	1901
	ft x ft	3.14	x	6.24
height	mm	1638		
	ft	5.37		
Reactor dimensions:				
length x width	mm x mm	14750	x	29735
	ft x ft	48.39	x	97.56
Weight per module incl. catalyst	kg	1310		
	lb	2889		
Module frame material		H II		

CERAM CATALYSTS + HONEYCOMBS	PROJECT	Milton R. Young Unit 2
	DATE	4/23/2007
	PREPARED BY	Noel Rosha
	REVISION	0
	FILE	NR042307-1

	Case	Limiting case
		Design Load
	Load	Design Load
Catalyst Performance:	Fuel	North Dakota Lignite
NOx outlet	ppmvd,ref.O_2	44.7
	lb/MMBtu	0.08
NOx reduction rate	%	85
NH_3 slip	ppmvd,ref.O2	2.0
NH3 100% consumption per reactor	kg/h	370.5
	lb/h	816.7
Catalyst pressure drop, clean	mbar	4.3
	inwg	1.8
	mm WC	44.2
Catalyst pressure drop, dirty	mbar	4.8
	inwg	1.9
	mm WC	48.7
SO_2/SO_3 conversion rate	%	1.00
Catalyst life	hr / years	16000 / 2

Technical Requirements:

Minimum NH_3 injection temperature	°C	316
	°F	602
Molar ratio distribution	% absolute	10
Velocity distribution	% absolute	15
Temperature distribution	°C absolute	10
Soot blower or sonic horns	yes / no	y

CERAM
CATALYSTS + HONEYCOMBS

Reference List for High Temperature SCR Applications (≥ 400°C / 752°F)

as of August 2006

Project	Client	End user / Engineering company	Plant location	Application	SCR-temperature	Shipped quantity	Delivery date
FHKW Mellach	SGP	STEWEAG	AUT	Bituminous coal, High dust	400°C 752°F	287 m³	1986
BHKW Donaustadt Block 2	SGP	Wiener Stadtwerke	AUT	Oil / Gas	420°C 788°F	80 m³	1987
BHKW Donaustadt Block 1	SGP	Wiener Stadtwerke	AUT	Oil / Gas	420°C 788°F	80 m³	1988
FHKW Mellach 4. Lage	SGP	STEWEAG	AUT	Bituminous coal, High dust	400°C 752°F	94 m³	1988
Weiher 3	Steinmüller	SaarEnergie	DEU	Coal, High dust	400 - 420°C 752 - 788°F	617 m³	1990
VA-Stahl 85 MW Block 6	AEE	VÖEST Alpine Stahl	AUT	Blast furnance-, Coking plant- and Natural gas	420°C 788°F	41 m³	1994
FHKW Mellach	AEE	STEWEAG	AUT	Bituminous coal, High dust, Additional delivery	400°C 752°F	95 m³	1995
Smurfit Newsprint, Pomona	WAHLCO	Energy Products of Idaho	USA	Natural gas	440°C 824°F	26 m³	2000
Hot Strip Mill Oven 22	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	550°C 1022°F	37 m³	2000
Tripan	Tripan Leichtbauteile		AUT	Diesel engine	550°C 1022°F	1 m³	2000
KW Weiher 3	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	400 - 420°C 752 - 788°F	369 m³	2001
Hot Strip Mill Oven 21	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp.	550°C 1022°F	37 m³	2002
PSEG Tracy	HRC	GWF Energy	USA	Natural gas, Simple cycle, High temp.	466 - 549°C 870 - 1020°F	44 m³	2002
Michigan City Unit 12	Black & Veatch	NIPSCO	USA	Coal, High dust	427°C 800°F	583m³	2002
KW Weiher 3	BASF	Saarenergie	DEU	Coal, High dust, Additional delivery	400 - 420°C 752 - 788°F	369 m³	2002
Hot Strip Mill Oven 22	Seiler	Hoogovens Staal BV	NLD	Steel production, Low dust, High temp., Additional del.	550°C 1022°F	39 m³	2002
Dallman Station Unit 33	Black & Veatch	City of Springfield	USA	Bituminous Coal, High dust	410°C 770°F	218 m³	2002/3
Tracy	GWF Energy		USA	Nat. gas, GT Simple cycle, High temp., Additional del.	466 - 549°C 870 - 1020°F	44 m³	2004

CERAM
CATALYSTS + HONEYCOMBS

Reference List for High Temperature SCR Applications (≥ 400°C / 752°F)

as of August 2006

Project	Client	End user / Engineering company	Plant location	Application	SCR-temperature	Shipped quantity	Delivery date
Grenelle	HRC	CPCU	FRA	Heavy oil, High dust	420°C 788°F	35 m³	2005
FHKW Mellach, Repl. 4th layer	VERBUND	VERBUND	AUT	Coal, High dust, Additional delivery	400°C 752°F	94 m³	2005
Gas engines	BASF	Steuler	FRA	Gas engines, High temp.	approx. 500°C approx. 932°F	4 m³	2005
Hot Strip Mill - Oven 23	Seiler	Corus Strip Products	NLD	Steel production, Low dust, Additional delivery	420°C 788°F	12 m³	2006
Thomas Hill Unit 3	Associated Electric Coop.	Associated Electric Coop.	USA	Coal, High dust	404 - 427°C 760 - 800°F	802 m³	2007
Hot Strip Mill - Oven 21	Seiler	Corus Strip Products	NLD	Steel mill Additional delivery	550°C 1022°F	21 m³	2006
TOTAL AMOUNT						**3,425 m³**	

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:50 PM
To: 'Noel Rosha'
Cc: 'John Cochran'
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Noel -

We also would like Ceram to comment on this question: if Ceram were asked to provide a catalyst service life guarantee and replacement warranty, whether a minimum operating time that Ceram would propose would be based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

It would be good to note in the response to the above question whether Ceram would require additional SCR catalyst coupons or slip-stream pilot testing with laboratory analysis in order to be confident in their proposed catalyst selection, design, and performance and service life guarantees.

It would be beneficial to reference Ceram's previous May 11, 2007 response when sending a supplemental response addressing this subject and issues raised in our 4/23/08 discussion.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Blakley, Robert
Sent: Monday, April 28, 2008 8:47 AM
To: 'Noel Rosha'
Cc: 'John Cochran'
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Noel & John -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to obtain Dr. Benson's paper on the pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Ceram's positions on catalyst fouling, poisoning, and blinding appropriate

to high sodium, medium sulfur coal flyash and flue gas produced from these boilers.

We are also interested in knowing more about Ceram's willingness to offer performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Ceram's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution developed by others.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Ceram provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: John Cochran [mailto:John.Cochran@CERAM-USA.COM]
Sent: Tuesday, May 06, 2008 3:12 PM
To: Blakley, Robert
Cc: Noel Rosha; Greg Holscher; kurt.orehovsky@frauenthal.net
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Bob,

My apologies for not being able to meet your schedule for return of a response regarding your emails dated April 28, 2008.

We have reviewed the information provided including Dr. Benson's paper. We believe that the information and test work presented indicate that it is certainly premature to assume that there is a fatal flaw for the use of high dust SCR behind cyclones burning North Dakota lignite. The concerns presented are similar in argument to those that were used 10 years ago against the application of PRB for high dust applications. The results of the cited test reactor work for Baldwin and Columbia would even seemingly indicate that the use of high dust SCR on PRB applications would be similarly difficult to an installation on a lignite application. Meanwhile, dating from 1999 starting with the New Madrid project (a 2 by 660 MW cyclone base project burning 100% PRB where I was the responsible process engineer for Black & Veatch) there has been in excess of 25,000 MW of SCR installed on PRB fueled cyclone, wall, and tangential fired units with good success. Operating results for PRB units nonetheless indicate great success. The backpass fouling cited in the vendor query document is very similar to that found at the New Madrid project where backend temperatures rise from 720 F to 800 F every 6 months dependent on cleanliness. Meanwhile the cleanliness of the catalyst has been maintained to very low levels after 8 to 9 years of SCR operation.

Certainly a number of circumstances are present that necessitate a pragmatic approach to the application of catalyst for a lignite application. CERAM has more than 20 years of experience with dealing with all variety of fuels. Of particular concern with low rank fuels such as lignite and sub-bituminous coal is proper geometric and chemical design to address the unique characteristics of the ash and flue gas. As was well illustrated by the testing, the first critical parameter to consider is the geometric design of the catalyst. CERAM has experience with the slipstream test reactor used for testing at Baldwin and can confirm that this reactor is susceptible to ash accumulation due to wall effects. Additionally, the 6 mm pitch Haldor Topsoe catalyst used for the Coyote Station testing was an inadequate choice considering the ash loading and ash characteristics. Considering this choice of catalyst pitch and use of this slipstream reactor the results cannot be assumed to be representative of a full scale application. Based on the ash loading and chemistry for Milton R. Young Units 1 and 2 we would consider that at least a 7.4 mm pitch catalyst be utilized. This is the catalyst pitch we proposed in our May 11, 2007 budgetary sizing. A more conservative approach would be to use either an 8.2 or 9.2 mm catalyst. This could have alleviated the noted test element ash pluggage issues.

Sodium is a catalyst poison. Concerns reported by Dr. Benson regarding high sodium contents and fine fume are duly noted, but inadequate evidence is presented that this could be a fatal flaw to application of SCR considering the flawed pitch and resultant pluggage of the catalyst used during Coyote Station testing. Sodium is not a poison to catalyst at SCR operating

temperatures. Significant deactivation can occur if condensed moisture transports sodium residing at the surface into the catalyst pore structure during outage or layup. CERAM has experience with high sodium applications to substantiate this effect. Important to avoid deactivation from sodium is the need to protect the catalyst from going through a condensation event.

With consideration of these factors we would agree that there is good cause for further testing on a lignite fired unit to further mitigate risks and optimize design. For this testing we would propose a program utilizing our CoPilot reactor (description attached) whereas wall effects can be minimized and representative ash loading can be better assured. The CoPilot reactor would be installed directly in the flue gas stream at the economizer outlet. The CoPilot reactor has been used in a number of difficult fuel circumstances to obtain accurate results supporting full scale design. If this testing is of interest to you we could prepare a test program proposal for your review.

CERAM can certainly confirm that there are certainly challenges present regarding the application of SCR to the Milton R Young Station. The following lists design requirements necessary to assure successful application of catalyst for Units 1 or 2.

- For coal, lignite, or sub-bituminous fired applications CERAM catalyst can be used to a maximum steady-state single point temperature of 900 F. Beyond this temperature severe permanent degradation of the catalyst will occur due to sintering. System configuration and design must ensure temperatures are maintained below 900 F. A design temperature of 850 F ±20 °F would be necessary.
- Based on the fuel quality presented a catalyst pitch of 7.4 mm or greater should be used. Fly ash angles entering the catalyst should be maintained approximately within ±15° from vertical. Sootblowers are recommended in this circumstance to maintain catalyst cleanliness.
- High carbon ash would carry the risk of increasing the pluggage of catalyst and possible result in a fire within the catalyst. Unburned carbon should be limited to less than approximately 15% to minimize the chance for pluggage and fire. Any catalyst that has a fire will be permanently destroyed due to sintering.
- Large particle ash (LPA) must be controlled prior to the catalyst. LPA escaping capture will cause pluggage of the catalyst.
- Ammonia should not be injected below minimum operating temperatures (MOT). Based on the SO2 and SO3 reported the MOT would be approximately 600 F. For lower sulfur fuels and/or reduced NOx removal performance a lower MOT would be possible. Additionally, brief periods of operation below the MOT would be possible without permanent degradation. In no event would any ammonia be allowed to be injected below 530 F for any likely combination of reasonable sulfur and NOx removal parameters. The NOx reduction for a reduced MOT should be considered in 30-day rolling average scenarios. Minimum flue gas temperatures listed for Units 1 and 2 are well below this threshold.
- Due to the high sodium and iron concentrations it is recommended that a full SCR bypass system be installed. During lay-up periods the catalyst would need to remain warm and dry (above condensing conditions), for instance with an air drying or

dehumidification system. This may necessitate the use of a dehumidifier and air lock system to access the reactor.

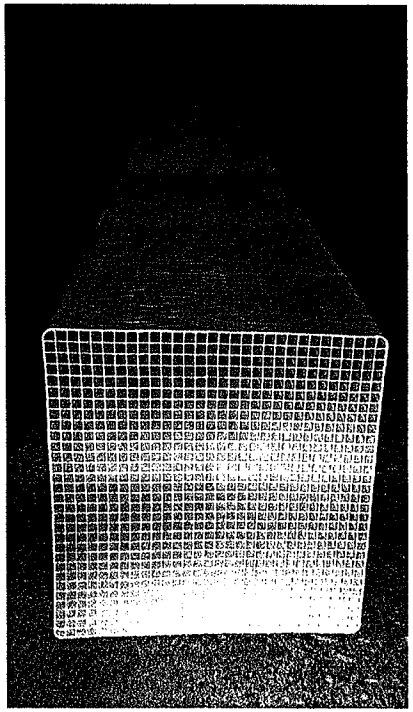
- Molar ratio NH3/NOx distribution ± 10% absolute.
- Gas velocity distribution ± 15% absolute.

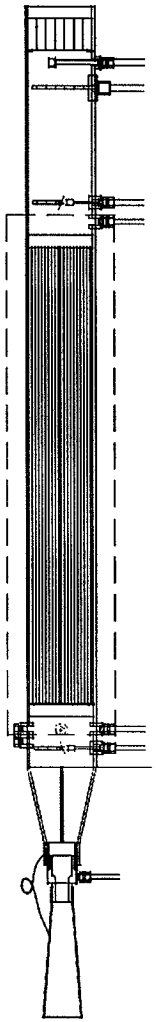
I would like to note that in CERAM's catalyst production history dating from 1985 and concerning more than 350 deliveries we have never had a guarantee or warrantee claim. We certainly want to maintain this record of success. However, based on the information provided as well as our large foundation of work related to the fuel considerations noted in the query and study CERAM can provide a commercial offering regarding this project. However, considering some of the remaining uncertainties we would recommend further testing to ensure a successful result. We agree that it would be beneficial to jointly explore common concerns to ensure that any full scale application would be a success. Please advise if we could be of help to further develop a test plan or answer any questions.

Best Regards,
John Cochran

CERAM Environmental, Inc.
www.frauenthal.net
913.239.9896 (phone)
913.205.5615 (cell)

CERAM's CoPilot® Catalyst Test Reactor





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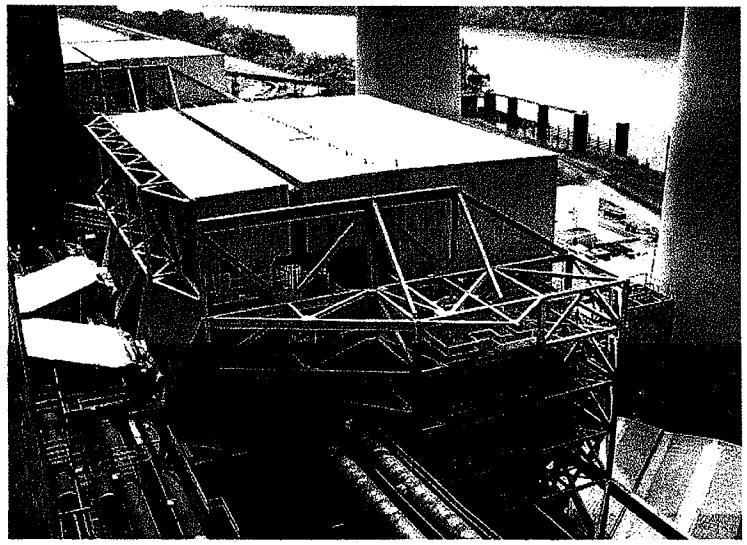
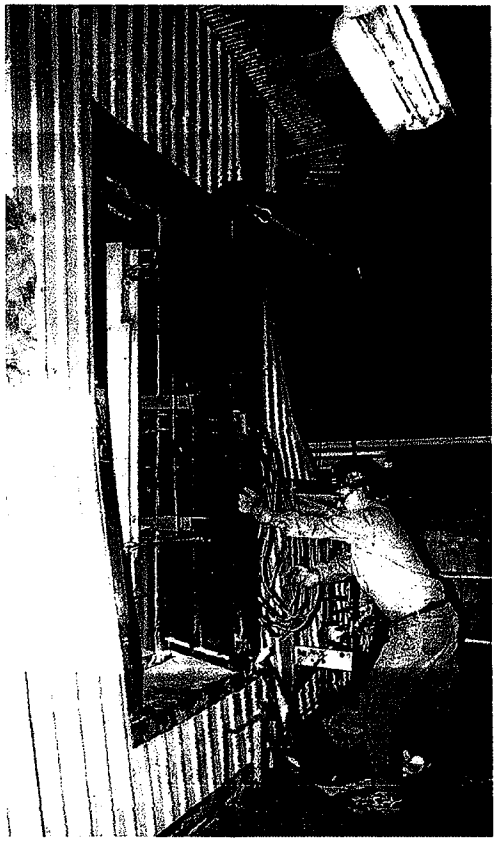
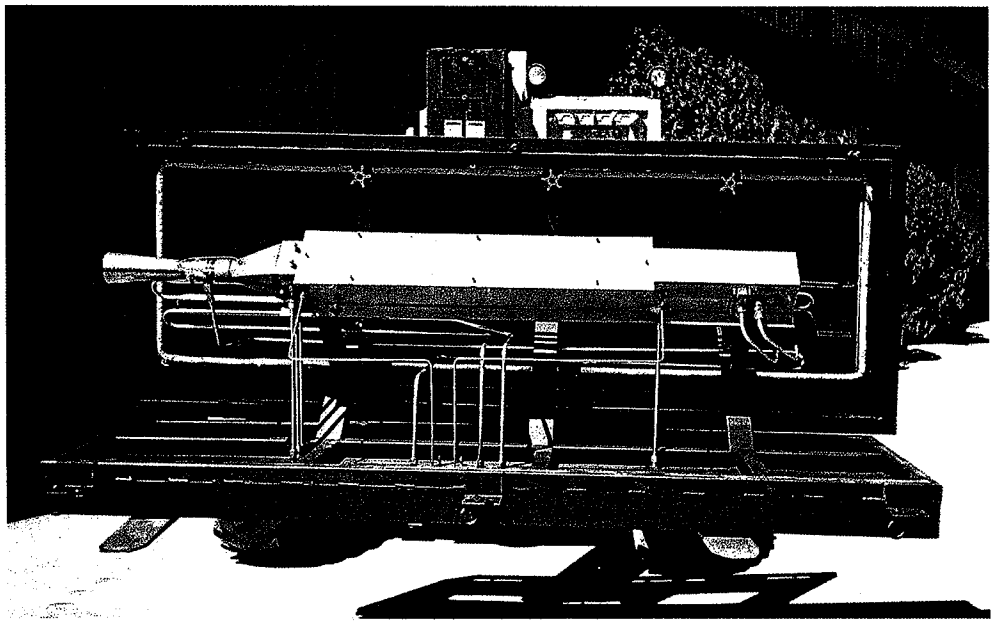




CoPilot® Catalyst Test Reactor

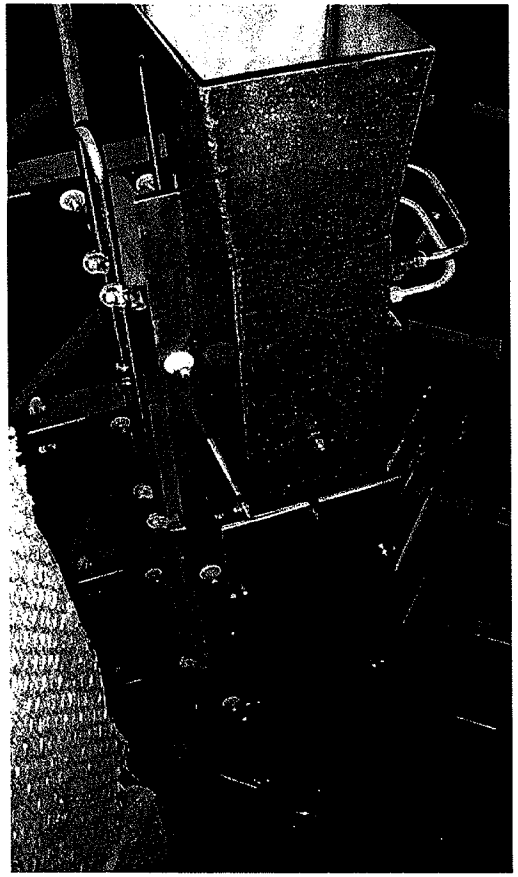
- Patented In-Situ Self Contained Catalyst Testing Apparatus
- In-Situ Reactor Allows for Catalyst Exposure to Actual Flue Gas Conditions Present
  - Fly Ash
  - Flue Gas Constituents
  - Temperature
- Allows Modulation of Gas Flow Velocity to Match SCR Reactor Conditions
- Allows On-Line Access to Test Elements – No Outage Required for Access
- Proven on 8 References



CoPilot® Catalyst Test Reactor

CERAM ENVIRONMENTAL, INC.

CoPilot® Catalyst Test Reactor



- Can House Honeycomb, Plate, or Fiber Based Catalyst Elements (6" x 6" x 38" long)
- Venturi Flow Inductor for Control of Flue Gas Velocity to Match SCR Reactor Conditions
- Includes Sootblower and LPA Screen to Maintain Catalyst Cleanliness
- Temperature, Pressure, and Inlet/Outlet Sampling Taps for On-Line Monitoring
- Allows for On-Line NOx Measurement
- Provisions for NH_3 Injection to Fully Replicate Reactor Conditions

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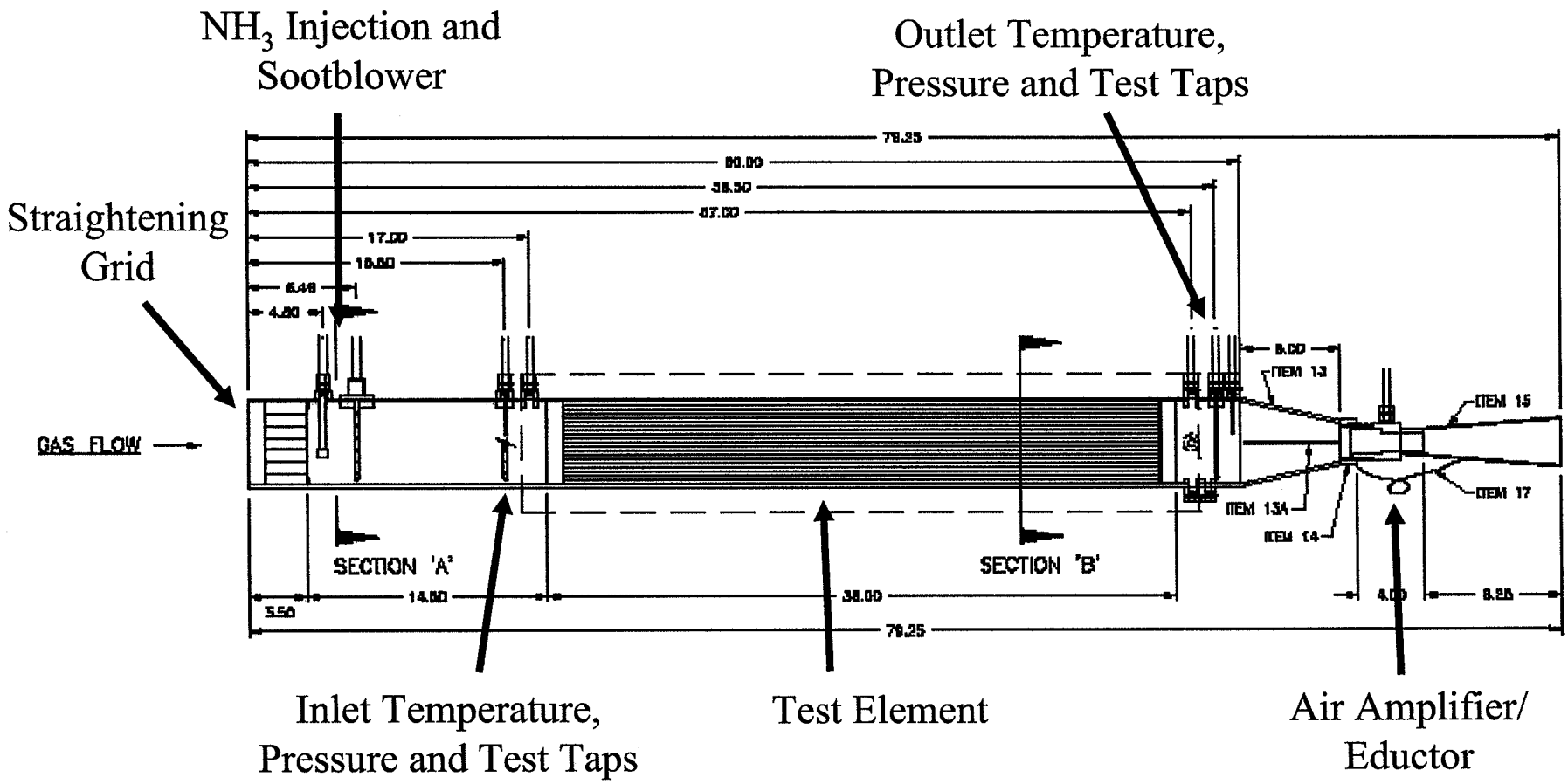
CoPilot® Catalyst Test Reactor



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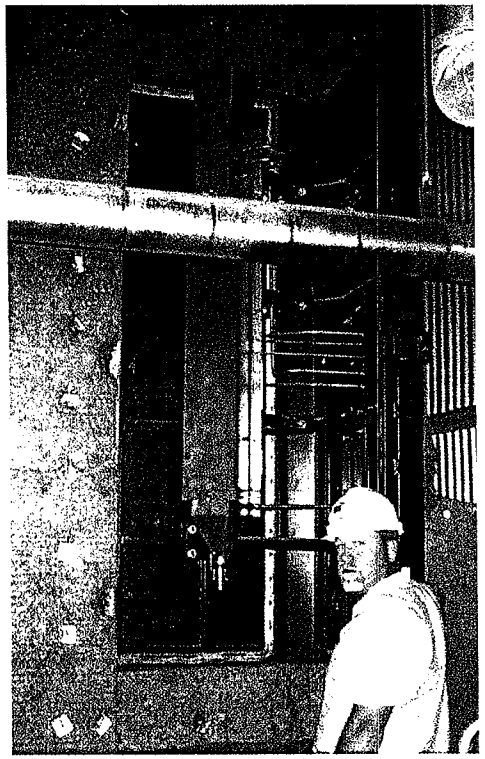
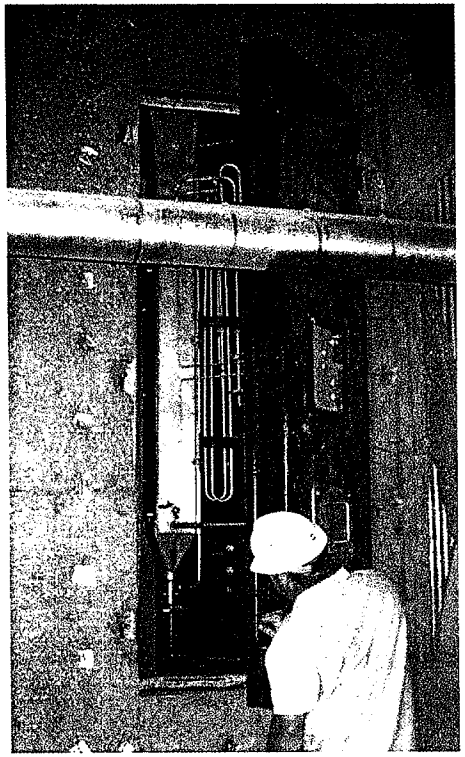
Door Operation



1. Open Door



2. Remove/Install Element

3. Close Door

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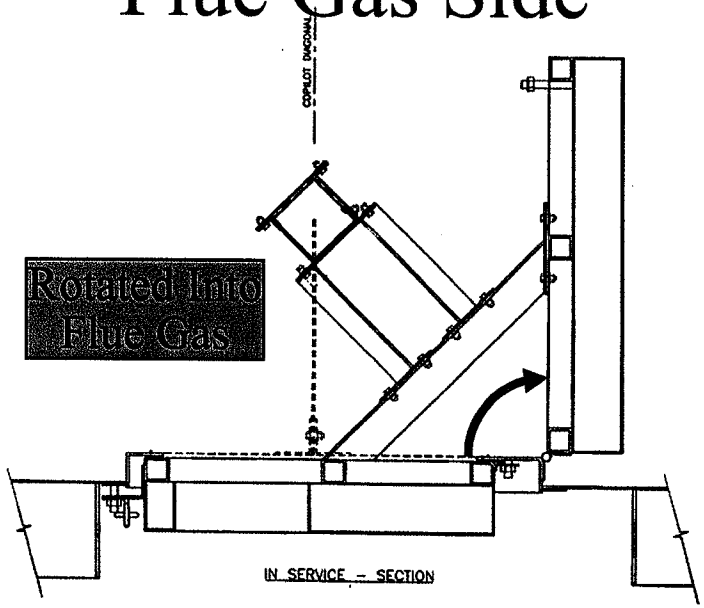
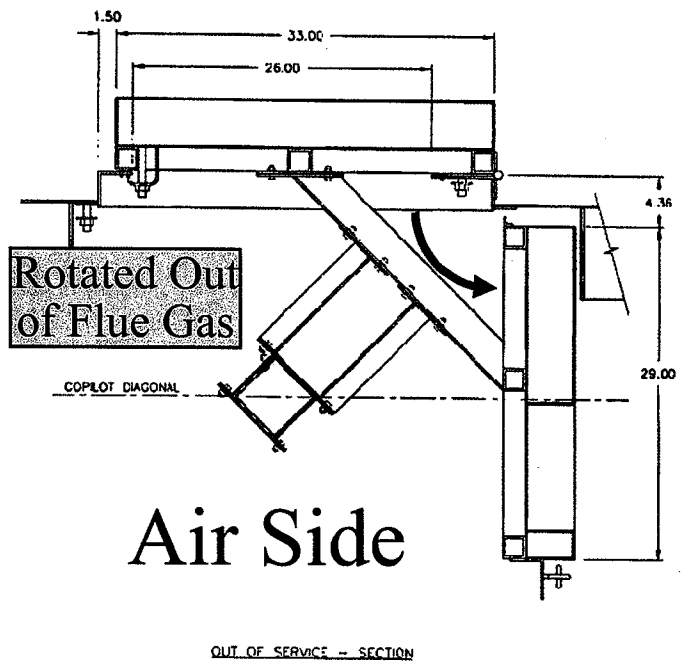
CoPilot® Door Action

Flue Gas Side

Allows for Catalyst Test Element Removal Without Unit Outage

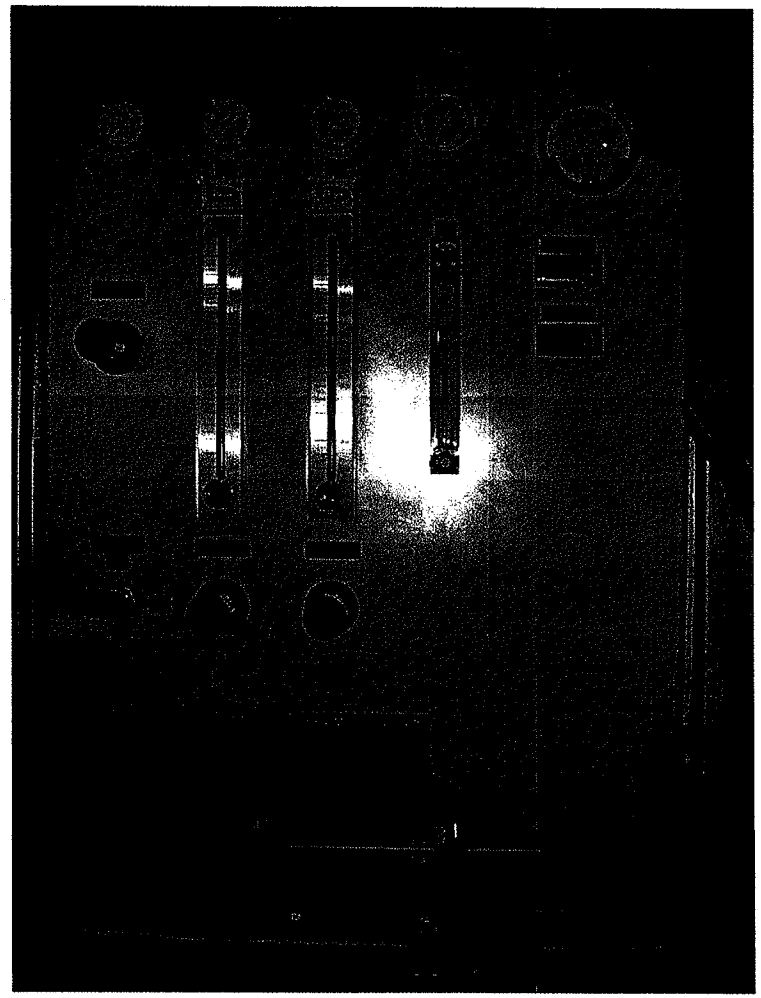




Air Side

CERAM ENVIRONMENTAL, INC.

Instrument Panel



- Regulates Flue Gas Flow Through Test Reactor
- Interface for Sootblowing
- Monitor Pressure Drop and Temperature
- Ammonia Injection Flow Control (if required)
- Main Supply Air Shut Off

CERAM
ENVIRONMENTAL, INC.

CoPilot® Uses and Advantages

- Allows Assessment of Process Feasibility for New Application Types
- Allows Accurate Assessment of Impacts on SCR Catalyst from Existing Fuels and Plant Operations
- Minimizes Chances for Surprises Prior to Initial Operation
  - Excessive Catalyst Deactivation
  - Large Particle Ash
  - High LOI

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ENVIRONMENTAL, INC.

Fuels Assessment

- Determine SCR Catalyst Impacts of Specific Fuels
  - Highly Erosive Ash (Catalyst Mechanical Durability, Wall Thickness)
  - High Ash Loadings (Catalyst Pitch Selection)
  - Determine Impacts of Challenging Fuels (Catalyst Deactivation and Oxidation Rates)

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ENVIRONMENTAL, INC.

Year-Round Catalyst Management

- Annual Catalyst Sample Testing is Recommended
- Year-Round SCR Operation will Limit the Opportunity to Remove Catalyst Samples for Testing
- CoPilot® Provides On-line Access to Catalyst Samples Exposed to Real Flue Gas Conditions
- Will Allow "Anytime" Access to Elements for Annual Catalyst Testing for Units With 2 to 3 Year Outage Intervals

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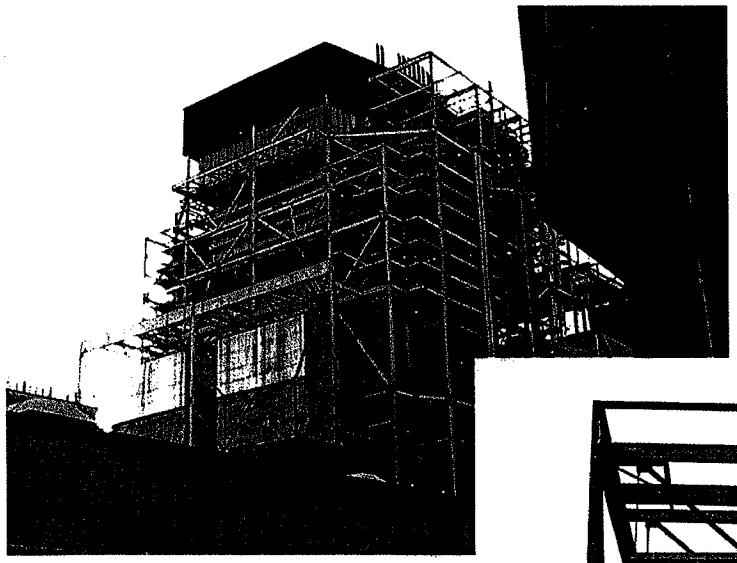
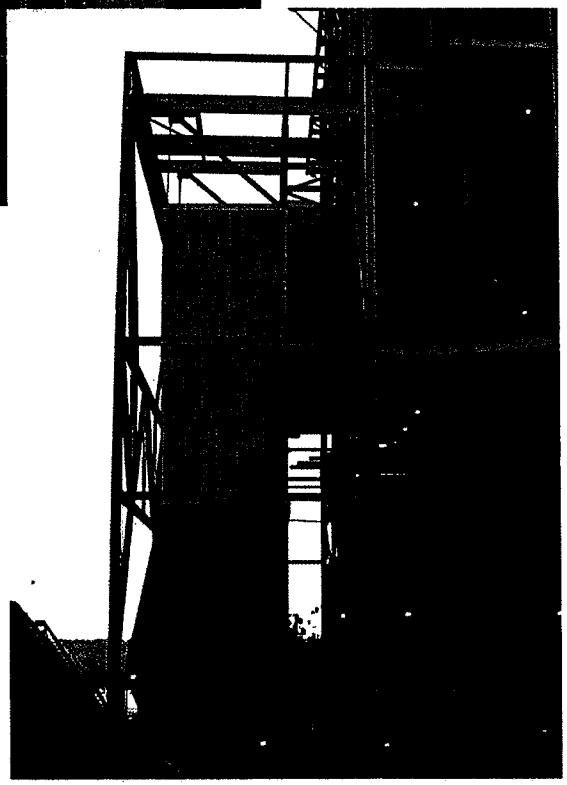
CoPilot® Installation Locations





- Preferred Location: Long Vertical Downward Section of Duct Downstream of Economizer
- Ash Exposure Important Component of Simulating SCR Application
  - Representative Pluggage Risk
  - Ash Abrasion Effect on Catalyst
  - Catalyst Absorption of Catalyst Poisons

CERAM
ENVIRONMENTAL, INC.

Installation

- Required Duct Opening of Approximately 36 x 101 inches
- Lift CoPilot® Into Place and Weld Frame to Duct Wall
- Install Instrument Panel on Floor/Grating/Handrail in Vicinity of the CoPilot®
- Connect Air Supply, Eductor Air, Sootblower Air, Differential Pressure Lines, and Ammonia (if applicable)
- Install Thermocouples
- Install Catalyst Test Element and Seal to Prevent Leakage

CERAM Can Provide Full Installation Support

CERAM
ENVIRONMENTAL, INC.

-----Original Message-----
From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, April 18, 2007 4:52 PM
To: Pritchard, Scot G.
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Scot,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Cormetech to review the attached request document and respond within three weeks if possible. If Cormetech's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Blakley, Robert
Sent: Tuesday, June 26, 2007 3:28 PM
To: 'Pritchard, Scot G.'
Cc: Rutherford, Scott J.; Freeman, Jeremy T.
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Scot -

We have not been favored with a final response from Cormetech on this request. We want to inform Minnkota about the timing of when Cormetech expects to reply. They have been asked by the NDDH for the vendor's responses.

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Pritchard, Scot G. [mailto:PritchardSG@Cormetech.com]
Sent: Monday, May 14, 2007 11:00 PM
To: Blakley, Robert
Cc: Rutherford, Scott J.; Freeman, Jeremy T.
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,

Thank you for the inquiry and opportunity to discuss the the subject opportunity. We have started the review process, however we will require additional time to provide our comments and any related questions back to you. At this time we expect that we will be bale to submit initial information at the end of the month.

Please acknowledge receipt and let us know if any additional relevant information has become available on the subject project to date.

Thank you and regards,

Scot Pritchard
VP, Sales & Marketing
Cormetech
919-595-8708 o
919-815-2380 c

From: Blakley, Robert
Sent: Wednesday, April 18, 2007 3:54 PM
To: 'fgh@topsoe.com'
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Flemming,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Haldor Topsoe to review the attached request document and respond within three weeks if possible. If Haldor Topsoe 's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Wayne Jones [mailto:WSJ@topsoe.com]
Sent: Thursday, May 10, 2007 10:24 AM
To: Blakley, Robert
Subject: HTI: Comments to SCR Technology at MRYS Units 1&2

Bob,

Haldor Topsoe has reviewed in detail the information and data sent regarding the viability of SCR technology on the Milton R. Young Station (MRYS) Units 1&2. We believe that two separate issues exist with this application. First are the extremely high flue gas exit temperatures (FGET) and lack of flue gas temperature control over the long term and second are the fuel related issues specific to this variety of North Dakota lignite. Since high (FGET) is a unit specific problem we are not going to address this issue. We will however address the North Dakota lignite fuel that is burned at MRYS.

Based on the fuel and ash analysis that was provided, we estimate that the deactivation rate of the catalyst will be high but manageable. We expect a deactivation rate in line with wood fired boilers which have been successfully fitted with SCR. We also expect the deactivation rate to be steep initially but to flatten out considerably after about 4000 hours.

The expected poisons are mostly soluble, therefore periodic water washing of the catalyst can be used to regain activity and to increase overall service life. This technique is used on many wood and some PRB fired applications.

Based on the fuel analysis provided to HT and assuming that FGET can be controlled HT would be willing to guarantee SCR catalyst performance on these units.

Regards,
Wayne

Wayne S. Jones
Account Manager, SCR Catalyst & Technology
Haldor Topsoe, Inc.
281-228-5136 (office)
281-228-5129 (fax)
281-684-8811 (cell)
wsj@topsoe.com
www.HaldorTopsoe.com

From: Blakley, Robert
Sent: Monday, April 28, 2008 3:57 PM
To: 'fgh@topsoe.com'
Cc: 'Wayne Jones'
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Flemming -

We would like Haldor Topsoe to comment on this question: if Haldor Topsoe were asked to provide a catalyst performance and service life guarantee and replacement warranty, whether a minimum operating time that Haldor Topsoe would propose would be based on the special nature of this fuel and ash composition method of firing (in a cyclone) and the location relative to gas cleaning equipment. As mentioned during our telephone conference, the April 2007 SCR vendor query contained evidence of fine sodium particles downstream of MRY Station Unit 2's cold-side ESP and wet FGD scrubber.

We are also interested in learning more about the basis of statements mentioned in the May 10, 2007 response of the 4,000 hours as a suggested number of operating hours for the initially steep but tapering catalyst deactivation rate. It would be good to note in the response to the above questions whether Haldor Topsoe would require additional SCR catalyst coupons or slip-stream pilot testing with laboratory analysis in order to be confident in their proposed catalyst selection, design, and performance and service life guarantees.

It would be beneficial to reference Haldor Topsoe's previous May 10, 2007 response when sending a supplemental response addressing this subject and issues raised in our 4/24/08 discussion.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Blakley, Robert
Sent: Monday, April 28, 2008 8:54 AM
To: 'fgh@topsoe.com'
Cc: 'Wayne Jones'
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Flemming -

Thank you for discussing the issues of SCR feasibility involving North Dakota lignite-fired cyclone boilers.

Hopefully you've gotten a chance to review the April 18, 2007 query, and pilot SCR testing performed at Coyote Station, on a boiler of the same size, cyclones and similar fuel as fired at Milton R. Young Station's Unit 2 boiler.

We would appreciate an email response to this followup, with discussion of the technical research and experience basis of Haldor Topsoe's positions on catalyst fouling, poisoning, and blinding appropriate to high sodium, medium sulfur coal flyash and flue gas produced from these boilers. We are interested in learning more about the experience you mentioned about washing of catalyst fouled with high sodium alkalis that was ineffective at restoring catalyst activity.

We are also interested in knowing more about Haldor Topsoe's willingness to offer performance guarantees, and what that would include from a commercial standpoint along with a catalyst warranty. Of particular interest is whether Haldor Topsoe's guarantee would satisfy a "make good" requirement, require full-scale field testing of each boiler prior to catalyst selection and design, testing catalyst in a slipstream arrangement or other exposure demonstrations, and if there are any other qualifiers beyond the assumption that the high flue gas temperatures in a conventional hot-side, high-dust SCR were limited by a solution developed by others.

We realize that this is a concentrated effort that does not allow much time to review and provide such responses.

We ask that Haldor Topsoe provide their email response by Monday, 5/5 12 pm (noon), so that we can review this and forward to Minnkota.

Again, thank you for your attention to this matter.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Flemming Hansen [mailto:FGH@topsoe.com]
Sent: Monday, May 05, 2008 1:42 PM
To: Blakley, Robert
Cc: Wayne Jones; jmj@topsoe.dk; hajh@topsoe.dk; trs@topsoe.dk
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Bob,

We have reviewed the design basis and experience on ND lignite.

Our general conclusion was that the deactivation rate is probably going to be at the high in the initial 10,000 hours. Somewhat longer than the 4,000 hours stated earlier. The deactivation rate will be tapering off as the catalyst ages. We expect the catalyst to loos about 60% of its initial activity over the first 10,000 operating hours. This deactivation rate is higher than what we have seen for wood fired boilers.

The number is based on the following assumptions:

1) Alkali content is at the same order as it is found in a wood fly ash.

2) The fly ash load is 5 to 10 times higher than it is seen in wood fired boilers which means that the deactivation should be 5 -10 higher with ND lignite with the assumption that the fraction of alkali aerosol that is captured in the catalyst is constant (this is not the case, cf. 3).

3) The fly ash size distribution of North Dakota lignite is broader compared to wood fly ash, which is an advantage since the attrition of the catalyst surface is higher. However, the attrition effect is not as high as in most coal fired applications since cyclone fired boilers are typically used in ND lignite fired boilers. The carry over of coarse fly ash from the furnace is much lower in cyclone fired boilers. All together we expect that the effect of fly ash distribution compensates for the higher fly ash load compared to a wood fired boiler.

3) The effect of sulfur in the flue gas adds to the deactivation rate compared to typical wood firing. SO2 levels in ND lignite flue gas are 700-800 ppm whereas it is <10 ppm in wood flue gas. The sulfur leads to a strengthening and densification of the blinding layers that originates from deposition of Ca, Na, K aerosols.

Besides the deactivation there is a clogging issue. At the Coyote station test this was the primary concern/experience. It is well known that soot blowing is difficult in pilot scale due to edge effects but also due to the dimensions of the soot blower tubes (max about 1/2"). Orifices have to be smaller compared to full scale in order to distribute the soot blower air. As a consequence the soot blower should be moved closer to the catalyst in order to obtain the same dynamic pressure at the catalyst surface which makes it difficult to actually cover the entire catalyst surface. We suggest that the next step is a larger pilot scale experiment with in the order of 2x2m of catalyst installed. We would like to participate in such an experiment. This would allow better catalyst cleaning and give a better determination of the catalyst degradation over time.

Based on our current information we expect 60% deactivation over the first 10,000 operating hours.
We can not provide a "make good" guarantee, but are willing to warrant the catalyst performance up to the contract value.

I trust the above will be helpful in your design of SCRs for this type of application.

Flemming G. Hansen
Manager SCR DeNOx Catalyst
Haldor Topsoe, Inc.
281-228-5120 (office)
281-228-5129 (fax)
281-684-8820 (cell)
FGH@Topsoe.com
www.topsoe.com

From: Blakley, Robert
Sent: Monday, May 05, 2008 5:44 PM
To: 'Flemming Hansen'
Cc: Wayne Jones; jmj@topsoe.dk; hajh@topsoe.dk; trs@topsoe.dk
Subject: RE: Comments to SCR Technology at MRYS Units 1&2

Flemming -

We have reviewed your response to our followup to the query, and had some clarifications:

Do we understand your meaning correctly in item 1 of your email that due to the increased flyash loading for a hot-side, high-dust SCR application at MRY Station, Haldor Topsoe thinks the deactivation rate will be 5-10 percent higher than what is typically seen in wood-fired boiler SCR applications?

The meaning of the attrition effect is not readily understood. We are not sure if you are referring to erosion or gross pluggage of the catalyst gas passages from the flyash particles.
Can you provide some additional explanation?

The expected impact of sulfur on the catalyst deactivation rate compared to wood firing was not provided, as was given for the higher flyash loading. It would seem to be a much more significant impact if it is at all related to the gross difference in sulfur concentration (70-80 times more sulfur on a volume basis).
Can you provide some additional explanation of the expected impact of sulfur on the catalyst deactivation rate compared to wood firing, especially given that the Coyote pilot SCR test catalyst pores were completely filled with sodium and potassium-sulfate compounds.

We also assume that the comments about sootblowing and clogging of catalyst with flyash relate to the impact largely as an issue of avoiding gross flow channeling or maldistribution that would make some sections of the catalyst non-effective, assuming that the pores were otherwise not blinded or plugged?

We would appreciate any immediate reply to these questions, so that we can forward these to Minnkota.

Bob Blakley
Burns & McDonnell
(816) 822-3842

From: Joakim Reimer Thøgersen [mailto:jmj@topsoe.dk]
Sent: Wednesday, May 07, 2008 8:09 AM
To: Blakley, Robert
Cc: Wayne Jones; jmj@topsoe.dk; hajh@topsoe.dk; trs@topsoe.dk
Subject: Re: FW: Comments to SCR Technology at MRYS Units 1&2

Bob,

Some answers to your questions/comments:

Do we understand your meaning correctly in item 1 of your email that due to the increased flyash loading for a hot-side, high-dust SCR application at MRY Station, Haldor Topsoe thinks the deactivation rate will be 5-10 percent higher than what is typically seen in wood-fired boiler SCR applications?

No we don't think the the deactivation is 5-10 times higher. The alkali concentration in the fly ash is similar. The fly ash concentration is 5-10 times higher i lignite flue gas. But the fraction of flue alkali alkali that deposits in the catalyst is much smaller in lignite flue gas. The reason is that part of the alkali ihe furnace is bound in coarse aluminum/silicate fly ash that don't to the same extent deposits in the catalyst. When the alkali is incorporated in aluminum/silicate fly ash the alkali also becomes inactive as a SCR poison. The lignite fly ash also has a cleaning effect by attrition of the surface that causes re-entrainment of particle deposits.

The meaning of the attrition effect is not readily understood. We are not sure if you are referring to erosion or gross pluggage of the catalyst gas passages from the flyash particles.
Can you provide some additional explanation?

Re-entrainment or cleaning of the catalyst surface by particle impaction

The expected impact of sulfur on the catalyst deactivation rate compared to wood firing was not provided, as was given for the higher flyash loading. It would seem to be a much more significant impact if it is at all related to the gross difference in sulfur concentration (70-80 times more sulfur on a volume basis).
Can you provide some additional explanation of the expected impact of sulfur on the catalyst deactivation rate compared to wood firing, especially given that the Coyote pilot SCR test catalyst pores were completely filled with sodium and potassium-sulfate compounds.

The sulfur reacts with deposited NaCl, CaO, KCl which means that the particles swell and the blinding layer becomes more impermeable.

We also assume that the comments about sootblowing and clogging of catalyst with flyash relate to the impact largely as an issue of avoiding gross flow channeling or maldistribution that would make some sections of the catalyst non-effective, assuming that the pores were otherwise not blinded or plugged? Exactly.

Our predictions are somewhat semi quantitative since the predictions are based on extrapolation/interpolation from wood firing and PRB fired boilers. I hope these clarifications are sufficient. Otherwise you can call me (+45) 22754374.

Best Regards, Joakim

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, April 18, 2007 4:55 PM
To: Anthony C. Favale
Subject: Request for Lignite SCR Feasibility Commercial and Technical Information

Tony,

On behalf of Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative (Minnkota), Burns & McDonnell (B&McD) is exploring the willingness of Selective Catalytic Reduction (SCR) vendors to offer guarantees for high-dust SCRs and catalyst with respect to NO_x emissions reduction performance at Milton R. Young Station (MRYS). Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 each fire 100% North Dakota lignite using cyclone furnaces in subcritical boilers.

Burns & McDonnell requests Hitachi to review the attached request document and respond within three weeks if possible. If Hitachi's response is expected to extend beyond the timeframe requested, please advise with an estimated date when such a response could be provided.

<MRY SCR Vendor Query (4-18-07 final).doc>

We appreciate your cooperation in this matter.

Sincerely,

Robert D. Blakley, P.E.
Project Engineer
Plant Services Department
Burns & McDonnell
(816) 822-3842
rblakley@burnsmcd.com

From: Anthony C. Favale [mailto:Anthony.Favale@hal.hitachi.com]
Sent: Friday, May 11, 2007 1:53 PM
To: Blakley, Robert
Cc: David Paz; David J. Brozek; Stephen Guglielmo; Masayuki Hirano; Isato Morita; Jennine Eickmeyer
Subject: RE: Request for Lignite SCR Feasibility Commercial and Technical Information

Robert,
As you know there has been very little testing and data available in North Dakota lignite. Hitachi has reviewed this data and we have the following comments:
1. Basically, it is quite difficult to install and operate the SCR at temperature over 850F. If there is no plan to reduce the flue gas temperature, the catalyst will deactivate very quickly above 850F.
2. The ash tables show the Na content as very high. It may cause serious deactivation of the catalyst.
3. Also, SO3 content in ash is very high. This means that there is Sulfur compounds in addition to the oxides. It may also cause faster catalyst deactivation.
4. There is also a concern over how sticky the ash is and if this will cause a pluggage problem.
Whit all these unknowns we strongly recommend that a slipstream test be performed to confirm the applicability of the catalyst for this flue gas.

Please advise if you have any comments,

Best Regards,

Tony Favale

Hitachi Power Systems America
645 Martinsville Rd.
Basking Ridge, NJ 07920
Office: 908 605 2758
FAX: 908 604 6211
Cell: 914 882 9384

Appendix B

Evaluation of Particulate Matter Emission Rate

MINNKOTA POWER COOP.
UNIT 2 STACK TEST
OCTOBER 19-26, 1977

TEST	LOCATION	INLET LOADING (LB/HR)	OUTLET EMISSION RATE (LB/HR)	OUTLET EMISSION RATE (LB/10^6 BTU)	ASH CONTENT (%)	HEAT CONTENT (BTU/LB)	HEAT INPUT (10^6 BTU/HR)	COAL FEED RATE (LB/HR)	PERCENT OF ASH REACHING ESP	EMISSION FACTOR (LB/TON)
1	A1+A2	15,200	42	0.0191	8.34	6,360	3246	500,165	55.57	11.11
4	B1+B2	5,700	20		6.7	6,620				
2	A1+A2	10,300	3	0.0012	7.41	6,690	4167	599,520	48.68	9.74
5	B1+B2	8,100	2		5.2	7,210				
3	A1+A2	10,400	8	0.0026	10.12	6,440	3846	568,537	36.45	7.29
6	B1+B2	5,100	2		4.84	7,090				
AVERAGE		**18,266**			**7.10**	**6,735**	**3,753**	**556,074**	**46.90**	**9.38**

THE ESP HAS FOUR OUTLET DUCTS A1, A2, B1 AND B2. TESTS 1 & 4, 2 & 5, AND 3 & 6 CONSTITUTE A COMPLETE TEST.

TABLE 7
Performance Test No. 1 & 4
Unit No. 2 Precipitator
Minnkota Power Cooperative, Inc.
Center, North Dakota
October 19, & 24, 1977

Parameter	Units	INLET OF PRECIPITATOR			OUTLET
		A1 + A2	B1 + B2	A1 + A2 + B1 + B2	A + B
Particulate Emission Rate	Lb/10^6BTU	--	--	--	0.0191
Particulate Emission Rate	Lb/Hr	15,200	5700	20,900	62
Particulate Concentration	Gr/SDCF	3.45	1.54	2.50	0.0078
Particulate Concentration	Gr/ACF	1.71	0.78	1.30	0.0039
GAS VOLUME RATES					
At Duct Conditions	ACFM	1,052,000	851,000	1,903,000	1,716,000
At 68°F, 29.92 in the Dry	SDCFM	523,000	430,000	953,000	903,000
Actual Gas Mass Rate	Lb/Hr	2,699,000	2,215,000	4,914,000	4,592,000
GAS PROPERTIES					
Temperature	°F	359	344	352	351
Moisture Content	Vol. %	14.1	14.3	14.2	12.8
Static Pressure	in. W.G.	-12.3	-10.8	-11.6	-12.6
Density	Lb/ft^3	0.0428	0.0434	0.0431	0.0432
GAS ORSAT ANALYSIS*					
Carbon Dioxide	Vol. %	12.4	11.6	12.0	11.1
Oxygen	Vol. %	6.6	5.0	5.8	7.5
Excess Air	Vol. %	45	29	37	55

TABLE 8
Performance Test No. 2 & 5
Unit No. 2 Precipitator
Minnkota Power Cooperative, Inc.
Center, North Dakota
October 20 & 25, 1977

Parameter	Units	INLET OF PRECIPITATOR			OUTLET
		A1 + A2	B1 + B2	A1 + A2 + B1 + B2	A+ B
Particulate Emission Rate	Lb/10^6BTU	--	--	--	0.0012
Particulate Emission Rate	Lb/Hr	10,300	8100	18,400	5
Particulate Concentration	Gr/SDCF	2.35	1.97	2.16	0.0006
Particulate Concentration	Gr/ACF	1.21	0.98	1.10	0.0003
GAS VOLUME RATES					
At Duct Conditions	ACFM	1,012,000	965,000	1,977,000	1,830,000
At 68°F, 29.92 in the Dry	SDCFM	521,000	478,000	999,000	936,000
Actual Gas Mass Rate	Lb/Hr	2,668,000	2,447,000	5,115,000	4,795,000
GAS PROPERTIES					
Temperature	°F	342	358	350	336
Moisture Content	Vol. %	13.4	14.2	13.8	13.7
Static Pressure	in. W.G.	-11.2	-12.1	-11.7	-13.5
Density	Lb/ft^3	0.0440	0.0422	0.0431	0.0437
GAS ORSAT ANALYSIS*					
Carbon Dioxide	Vol. %	11.9	11.1	11.5	11.4
Oxygen	Vol. %	6.1	4.7	5.4	6.7
Excess Air	Vol. %	40	27	34	45

TABLE 9
Performance Test No. 3 & 6
Unit No. 2 Precipitator
Minnkota Power Cooperative, Inc.
Center, North Dakota
October 21 & 26, 1977

Parameter	Units	INLET OF PRECIPITATOR			OUTLET
		A1 + A2	B1 + B2	A1 + A2 + B1 + B2	A + B
Particulate Emission Rate	$Lb/10^6 BTU$	--	--	--	0.0026
Particulate Emission Rate	Lb/Hr	10,400	5100	15,500	10
Particulate Concentration	Gr/SDCF	2.20	1.31	1.76	0.0012
Particulate Concentration	Gr/ACF	1.13	0.67	0.90	0.0006
GAS VOLUME RATES					
At Duct Conditions	ACFM	1,088,000	887,000	1,975,000	1,849,000
At 68°F, 29.92 in the Dry	SDCFM	558,000	453,000	1,011,000	960,000
Actual Gas Mass Rate	Lb/Hr	2,883,000	2,303,000	5,186,000	4,884,000
GAS PROPERTIES					
Temperature	°F	340	341	341	336
Moisture Content	Vol. %	13.9	13.5	13.7	13.0
Static Pressure	in. W.G.	-13.4	-12.1	-12.8	-13.2
Density	Lb/ft^3	0.0442	0.0433	0.0438	0.0440
GAS ORSAT ANALYSIS*					
Carbon Dioxide	Vol. %	13.1	10.5	11.8	11.0
Oxygen	Vol. %	4.9	4.2	4.6	6.2
Excess Air	Vol. %	29	23	26	40

F. C. BROEMAN & CO.

Established 1904

ANALYTICAL AND CONSULTING

CHEMISTS

1926 RACE STREET - - PHONE 621-5441

CINCINNATI, OHIO 45210

REPORT OF ANALYSIS

SAMPLE OF Coal Sample T1 10-19-77

FROM W.F.I. Sciences

November 18,19

RECEIVED November 8. 1977

	AS REC'D	DRY BASIS	
MOISTURE	37.00%		
VOLATILE MATTER	24.76%	39.30%	
FIXED CARBON	29.90%	47.46%	
ASH	8.34%	13.24%	
SULPHUR	.42%	.66%	
B.T.U.	6,360	10,100	
INITIAL DEFORMATION			
SOFTENING TEMPERATURE			
FLUID TEMPERATURE			
FREE SWELLING INDEX			
GRINDABILITY			
HYDROGEN		4.8%	
NITROGEN		.8%	
OXYGEN		16.3%	
CARBON		64.2%	
SULPHUR			
ASH			

REMARKS:

FIB:lmw
CG1025

SIGNED:

F. C. BROEMAN & CO.

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ANALYTICAL AND CONSULTING

CHEMISTS

1926 RACE STREET - - PHONE 621-5441 CINCINNATI, OHIO 45210

REPORT OF ANALYSIS

SAMPLE OF Coal Sample ~~T4~~ 10-22-77 Square Butte 1644 Test 4 November 18, 197

FROM W.F.I. Sciences RECEIVED November 8, 1977

	AS REC'D	DRY BASIS	
OISTURE	36.00%		
OLATILE MATTER	26.09%	40.76%	
XED CARBON	30.50%	47.66%	
SH	7.41%	11.58%	
ULPHUR	.90%	1.40%	
T. U.	6,690	10,450	
ITIAL DEFORMATION			
OFTENING TEMPERATURE			
LUID TEMPERATURE			
EE SWELLING INDEX			
RINDABILITY			
YDROGEN		4.2%	
TROGEN		1.4%	
XYGEN		16.3%	
ARBON		65.1%	
ULPHUR			
SH			

REMARKS:

FIB:lmw
CG1027

SIGNED

F. C. BROEMAN & CO.

Established 1904

ANALYTICAL AND CONSULTING

CHEMISTS

1926 RACE STREET - - PHONE 621-5441

CINCINNATI, OHIO 45210

REPORT OF ANALYSIS

SAMPLE OF Coal Sample T3 10-21-77 From Square Butte 1644 Test 3 November 18

FROM W.F.I. Sciences

RECEIVED November 8 1977

	AS REC'D	DRY BASIS	
MOISTURE	35.60%		
VOLATILE MATTER	24.19%	37.55%	
FIXED CARBON	30.09%	46.73%	
ASH	10.12%	15.72%	
SULPHUR	.44%	.68%	
B. T. U.	6,440	10,000	
INITIAL DEFORMATION			
SOFTENING TEMPERATURE			
FLUID TEMPERATURE			
FREE SWELLING INDEX			
GRINDABILITY			
HYDROGEN		4.7%	
NITROGEN		.9%	
OXYGEN		14.9%	
CARBON		63.1%	
SULPHUR			
ASH			

REMARKS:

FIB:lmw
CG1026

F. C. BROEMAN & CO.

Established 1904

ANALYTICAL AND CONSULTING

CHEMISTS

1926 RACE STREET - - PHONE 621-5441

CINCINNATI, OHIO 45210

REPORT OF ANALYSIS

SAMPLE OF Coal Sample ~~T5~~ T4 10-24-77 From Square Butte 1644 Tests November 18,197

FROM W.F.I. Sciences RECEIVED November 8, 1977

	AS REC'D	DRY BASIS	
MOISTURE	36.80%		
VOLATILE MATTER	27.71%	43.85%	
FIXED CARBON	28.79%	45.55%	
ASH	6.70%	10.60%	
SULPHUR	.77%	1.22%	
B.T.U.	6,620	10,480	
INITIAL DEFORMATION			
SOFTENING TEMPERATURE			
FLUID TEMPERATURE			
FREE SWELLING INDEX			
GRINDABILITY			
HYDROGEN		4.3%	
NITROGEN		1.5%	
OXYGEN		16.6%	
CARBON		65.8%	
SULPHUR			
ASH			

REMARKS:

FIB:lmw
CG1028

SIGNED:

F. C. BROEMAN & CO.

Established 1904

ANALYTICAL AND CONSULTING

CHEMISTS

1926 RACE STREET - - PHONE 621-5441

CINCINNATI, OHIO 45210

REPORT OF ANALYSIS

SAMPLE OF Coal Sample T6 10-25-77 From Square Butte 1644 Test 6 November 18 197

FROM W.F.I. Sciences RECEIVED November 8 1977

	AS REC'D	DRY BASIS	
MOISTURE	33.70%		
VOLATILE MATTER	28.96%	43.68%	
FIXED CARBON	32.14%	48.47%	
ASH	5.20%	7.85%	
SULPHUR	.49%	.74%	
B.T.U.	7,210	10,880	
INITIAL DEFORMATION			
SOFTENING TEMPERATURE			
FLUID TEMPERATURE			
FREE SWELLING INDEX			
GRINDABILITY			
HYDROGEN		4.1%	
NITROGEN		1.2%	
OXYGEN		19.5%	
CARBON		66.6%	
SULPHUR			
ASH			

REMARKS:

FIB:lmw
CG1029

SIGNED:

F. C. BROEMAN & CO.

Established 1904

ANALYTICAL AND CONSULTING

CHEMISTS

1926 RACE STREET - - PHONE 621-5441

CINCINNATI, OHIO 45210

REPORT OF ANALYSIS

SAMPLE OF Coal Sample ~~T7~~ 10-26-77 From Square Butte 1644 Test 7 — November 18, 197

FROM W.F.I. Sciences — RECEIVED November 8, 1977

	AS REC'D	DRY BASIS	
MOISTURE	35.00%		
VOLATILE MATTER	28.84%	44.37%	
FIXED CARBON	31.32%	48.19%	
ASH	4.84%	7.44%	
SULPHUR	.49%	.76%	
B.T.U.	7,090	10,910	
INITIAL DEFORMATION			
SOFTENING TEMPERATURE			
FLUID TEMPERATURE			
FREE SWELLING INDEX			
GRINDABILITY			
HYDROGEN		4.3%	
NITROGEN		1.1%	
OXYGEN		19.6%	
CARBON		66.8%	
SULPHUR			
ASH			

REMARKS:

FIB:lmw
~~CG1030~~

SIGNED