North Dakota State Implementation Plan for Regional Haze

Amendment No. 1

A Plan for Implementing the Regional Haze Program Requirements of Section 308 of 40 CFR Part 51, Subpart P - Protection of Visibility

North Dakota Department of Health
Adopted: July 25, 2011

Division of Air Quality
Air Pollution Control Program
North Dakota Department of Health
918 East Divide Avenue
Bismarck, North Dakota 58501-1947
Telephone 701-328-5188

Terry Dwelle, M.D., M.P.H.T.M.
State Health Officer

Terry O'Clair, P.E.
Director

APPROVAL PAGE

North Dakota State Implementation Plan for Regional Haze Amendment No. 1

North Dakota Department of Health, Environmental Health Section, Division of Air Quality.

<u>Approval by the following North Dakota Department of Health Management Personnel</u>:

Terry O'Clair
Terry L. O'Clair, P.E., Director
Division of Air Quality

7/25/11
Date

L. David Glatt, P.E., Chief
Environmental Health Section

7/25/11
Date

<u>Adopted for the North Dakota Department of Health</u>

Terry L. Dwelle, M.D., M.P.H.T.M.
State Health Officer
North Dakota Department of Health

7-25-11
Date

Amendment No. 1

to

North Dakota State Implementation Plan

For

Regional Haze

July 2011

North Dakota Department of Health
Division of Air Quality
Air Pollution Control Program
918 E Divide Avenue
Bismarck, North Dakota 58501-1947

Table of Contents

Amendment No. 1 to North Dakota State Implementation Plan for Regional Haze

I. Summary of Additions/Changes

A. Coyote Station

In Section 10.6.1.2 of the original Regional Haze SIP, the NDDH had required the owners/operators of the Coyote Station to reduce nitrogen oxides emissions to 0.50 lb/10^6 (12-month rolling average). Compliance with the limit was to be achieved by July 1, 2019. This amendment revises the emission limit to 0.50 lb/10^6 Btu (30-day rolling average) and requires compliance by July 1, 2018. Section 10.6.1.2 and the Permit to Construct in Appendix A which establishes the limit, have been revised accordingly.

B. M.R. Young Station

This amendment adds additional information to Appendix C.4 of the SIP. The information was obtained and produced as part of Best Available Control Technology (BACT) determination for nitrogen oxides at the M.R. Young Station after the Best Available Retrofit Technology (BART) determination was made and submitted to EPA.

II. SIP Revisions and Changes

10.6.1.2 Coyote Station

Once reductions are achieved from the BART sources, the Coyote Station will be the largest point source of NO_x emissions in North Dakota. The analysis in Section 9.5.1 indicates that additional controls on the Coyote Station are not reasonable at this time; however, the State, through recent discussions with OtterTail Power Company, has reached an agreement whereby OtterTail has committed to reduce NO_x emissions at the station. OtterTail Power Company has indicated they will install equipment by July 1, 2018 in order to reduce NO_x emissions to 0.50 $lb/10^6$ Btu on a 30-day rolling average basis. This represents a 35% decrease from the 2008 annual average emission rate of 0.77 $lb/10^6$ Btu and 26% from the baseline emission rate evaluated in Section 9.5.1. The reductions are expected to be achieved by installing separated over fire air. This will reduce annual NO_x emissions by 4,213 tons from the 2000-2004 baseline, a 32% decrease. The Permit to Construct establishes July 1, 2018 as the date compliance must be achieved. The mechanism/requirement for reducing NO_x emissions is included in a Permit to Construct found in Appendix A. Although there will be NO_x reductions at this facility, it will be reevaluated during future planning periods to determine if additional emissions reductions are required.

Appendix A.4
Permit to Construct for Coyote Station

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

March 14, 2011

FILE

Mr. Terry Graumann
Manager, Environmental Services
OtterTail Power Company
P.O. Box 496
Fergus Falls, MN 56538-0496

Re: Amended Regional Haze Permit to Construct

Dear Mr. Graumann:

On February 23, 2010, the North Dakota Department of Health issued a Permit to Construct to OtterTail Power Company for the Coyote Station to reduce NO_x emissions as part of the North Dakota State Implementation Plan for Regional Haze. Due to concerns by the U.S. Environmental Protection Agency, the Department has revised Permit to Construct No. PTC10008. Enclosed is a copy of the revised Permit to Construct. Revisions to the Permit to Construct change the NO_x emission limit to a 30-day rolling average basis and establish a new compliance date of July 1, 2018.

If you have any questions, please contact us at (701)328 -5188.

Sincerely,

Terry O'Clair

Terry L. O'Clair, P.E.
Director
Division of Air Quality

TLO/TB:saj
xc: Gail Fallon, U.S. EPA, Region 8

Environmental Health Section Chief's Office	Division of Air Quality	Division of Municipal Facilities	Division of Waste Management	Division of Water Quality
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NORTH DAKOTA
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AIR POLLUTION CONTROL
AMENDED PERMIT TO CONSTRUCT
REVISION NO. 1

Pursuant to Chapter 23-25 of the North Dakota Century Code, and the Air Pollution Control Rules of the State of North Dakota (Article 33-15 of the North Dakota Administrative Code), a Permit to Construct is hereby issued for modifications at the following source:

I. **General Information**:

A. **Permit to Construct Number**: PTC10008

B. **Source**:

1. **Name**: Coyote Station
2. **Location**: Sec. 10, S½ of S ½ of Sec. 3 and W½ of Sec. 11, T143N, R88W, North Dakota, Mercer County
3. **Source Type**: Fossil-fuel fired steam electric unit with a nominal heat input of 5,800 million British thermal units per hour (10^6 Btu/hr).

C. **Owner Names**:
Montana-Dakota Utilities Co.
NorthWestern Energy
Northern Municipal Power Agency
(Minnkota Power Cooperative, Inc.)
Otter Tail Power Company

D. **Operator**:

1. **Name**: OtterTail Power Company
2. **Address**:
215 South Cascade Street
P.O. Box 496
Fergus Falls, MN 56538-0496

II. Permit Conditions:

This Permit to Construct establishes a revised nitrogen oxide (NO_x) emission limit for the main boiler at the Coyote Station (EUI 1) if, and when, EPA approves that limit as part of the Regional Haze SIP. The permit allows the construction and initial operation of new or modified air pollution control equipment and process modifications at the source to comply with the revised NO_x limit. If new emissions units are created, then a new Permit to Construct may be required in accordance with NDAC 33-15-14-02. The source shall be operated in accordance with the terms of this Permit to Construct and the Title V Permit to Operate until a revised Title V Permit to Operate is issued. The source is subject to all applicable rules, regulations, and orders now or hereafter in effect to the North Dakota Department of Health and to the conditions specified below:

A. Special Conditions:

1. **Emission Limits**: The permittee shall not discharge or cause the discharge of nitrogen oxides (NO_x) into the atmosphere from EUI 1 in excess of 0.50 pounds per million British thermal units ($lb/10^6$ Btu) of heat input, on a 30-day rolling average basis.

   The term "30-day rolling average," as used in this permit, shall be determined by calculating an arithmetic average of all hourly rates for the current boiler operating day and the previous 29 boiler operating days. A new 30-day rolling average shall be calculated for each boiler operating day. Each 30-day rolling average rate shall include start-up, shutdown, emergency and malfunction periods. The 30-day rolling average emission rate is calculated as follows:

   - Calculate the hourly average emission rate for any hour in which any fuel is combusted in the boiler.

   - Calculate the 30-day rolling average emission rate as the arithmetic average of all valid hourly average emission rates for the 30 successive boiler operating days.

   The term "boiler operating day," as used in this permit, means any 24-hour period between midnight and the following midnight during which any fuel is combusted at any time at the steam generating unit.

2. **Compliance Date**: Compliance with the revised NO_x emission limit shall begin by July 1, 2018.

3. **Continuous Emission Monitoring (CEM)**: The emissions from EUI 1 shall be measured by continuous emission monitors (CEM) for NO_x and CO_2, The monitoring requirements under Condition II.A.4 shall be the compliance determination method for NO_x.

4. **Monitoring Requirements and Conditions:**

a. Requirements:

Testing and monitoring protocols used to demonstrate compliance with the emission limits of Condition II.A.1 above shall be as follows:

Table 1
Monitoring Requirements by Pollutant/Parameter

Pollutant/Parameter	**Monitoring Requirement (Method)**	**Condition Number (II.A. ...)**
NO_x (lb/10^6 Btu)	CEM	4.b.(1), 4.b.(2), 4.b.(3) & 4.b.(4)
CO_2	CEM	4.b(1), 4.b.(2), 4.b.(3) & 4.b.(4)

b. Emission Monitoring Conditions:

(1) The monitoring shall be in accordance with the applicable requirements of the Acid Rain Program, 40 CFR 72 and 40 CFR 75. Emissions are calculated using 40 CFR Part 75.

(2) The Department may require additional performance audits of the CEM systems.

(3) When a failure of a continuous emission monitoring system occurs, an alternative method, acceptable to the Department, for measuring or estimating emissions must be undertaken as soon as possible. The procedures outlined in 40 CFR 75, Subpart D for substitution are considered an acceptable method for the emission rate. Timely repair of the emission monitoring system must be made.

(4) The permittee shall maintain and operate air pollution control monitoring equipment in a manner consistent with the manufacturer's recommended procedures or a site-specific QA/QC Plan required by 40 CFR 75. The permittee shall have the QA/QC Plan available on-site and provide the Department with a copy when requested.

5. **Recordkeeping Requirements**: The permittee shall maintain compliance monitoring records for Unit 1 as outlined in Table 2 – Monitoring Records that includes the following information:

a. A copy of the sample analysis report(s), including the date that the sample analysis was performed; the company, entity, or person that performed the analysis; and the testing techniques or methods used.

b. The records of quality assurance for emissions measuring systems including but not limited to quality control activities, audits and calibration drifts as required by the applicable test method.

c. A copy of all field data sheets from the emissions testing.

d. A record shall be kept of all major maintenance activities conducted on the emissions units or air pollution control equipment.

Table 2
Monitoring Records

Pollutant/Parameter	Compliance Monitoring Record
NO_x ($lb/10^6$ Btu)	CEM Data
CO_2	CEM Data

e. In addition to requirements outlined in Condition II.A.5, recordkeeping for EUI 1 shall be in accordance with the applicable requirements of the North Dakota Air Pollution Control Rules and the Acid Rain Program, 40 CFR 72 and 40 CFR 75.

f. The permittee shall retain records of all required compliance monitoring data and support information for a period of at least five years from the date of the compliance monitoring sampling, measurement, report, or application. Support information includes all maintenance records of the emission units and all original strip-chart recordings/computer printouts and calibrations of the continuous compliance monitoring instrumentation, and copies of all reports required by the permit.

6. **Reporting**:

a. Reporting for EUI 1 shall be in accordance with the applicable requirements of the North Dakota Air Pollution Control Rules and the Acid Rain Program, 40 CFR 72 and 40 CFR 75.

b. Quarterly excess emissions reports for EUI 1 shall be submitted no later than the 30th day of the following the end of each calendar quarter. Excess emissions are defined as emissions which exceed the emission limit for EUI 1 as outlined in Condition II.A.1.a. Excess emissions shall be reported for the following:

Parameter	Reporting Period
NO_x lb/10^6 Btu	30-day rolling average

c. The permittee shall submit a semi-annual report for all monitoring records required under Condition II.A.5 on forms supplied or approved by the Department. All instances of deviations from the permit must be identified in the report. A monitoring report shall be submitted within 45 days after June 30 and December 31 of each year.

d. 1) The permittee shall submit an annual compliance certification report within 45 days after December 31 of each year on forms supplied or approved by the Department.

2) For emissions units where the method of compliance monitoring is demonstrated by either an EPA Test Method or portable analyzer, the test report shall be submitted to the Department within 60 days after completion of the test.

3) The permittee shall submit an annual emission inventory report on forms supplied or approved by the Department . This report shall be submitted by March 15 of each year. Insignificant units/activities listed in this permit do not need to be included in the report.

4) The permittee shall notify the Department within 15 days of the actual startup date of the equipment required to meet the NO_x permit limit.

B. **General Conditions**:

1. The permit shall in no way permit or authorize the maintenance of a public nuisance or danger to public health or safety.

2. The permittee shall comply with all State and Federal environmental laws and rules. In addition, the permittee shall comply with all local building, fire, zoning, and other applicable ordinances, codes, rules and regulations.

3. All reasonable precautions shall be taken by the permittee to prevent and/or minimize fugitive emissions during the construction period.

4. The permittee shall at all times, including periods of startup, shutdown, malfunction, maintain and operate EUI 1 and all other emission units

including associated air pollution equipment and fugitive dust suppression operations in a manner consistent with good air pollution control practices for minimizing emissions.

5. Any duly authorized officer, employee or agent of the North Dakota Department of Health may enter and inspect any property, premise or place at which the source listed in Item I.B. of this permit is or will be located at any time for the purpose of ascertaining the state of compliance with the North Dakota Air Pollution Control Rules and the conditions of this permit.

6. The conditions of this permit herein become, upon the effective date of this permit, enforceable by the Department pursuant to any remedies it now has or may in the future have, under the North Dakota Air Pollution Control Law, NDCC Chapter 23-25. Each and every condition of this permit is a material part thereof, and is not severable.

FOR THE NORTH DAKOTA
DEPARTMENT OF HEALTH

Date: 3/14/11

By: Terry O'Clair
Terry L. O'Clair, P.E.
Director
Division of Air Quality

Appendix C.4
M.R. Young Station

Appendix C.4
Minnkota Power Cooperative
Milton R. Young Station Units 1 and 2

The following documents are added to Appendix C.4:

1. Minnkota Power Cooperative and Square Butte Electric Cooperative; Responses to Comments to NDDH Regarding Revised Draft NO_x BACT Determination and North Dakota State Implementation Plan for Regional Haze: Milton R. Young Station Unit 1 and Unit 2; July 30, 2010.

2. NDDH; Findings of Fact for Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2; November 2010.

3. NDDH; Response to Public Comments on Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2.

4. Minnkota Power Cooperative and Square Butte Electric Cooperative; Responses to NDDH Request, NO_x BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility; December 11, 2009.

5. Burns and McDonnell; Vendor Guarantee Information from Haldor Topsoe, Inc. and CERAM Environmental, Inc.; January 2010.

6. Excerpts from SCR Proposal for M.R. Young Station by Haldor Topsoe, Inc. and CERAM Environmental, Inc.

7. Minnkota Power Cooperative and Square Butte Electric Cooperative; Follow-up Responses to Presentation and NDDH Request for Additional Information Supplemental NO_x BACT Analysis Study – Milton R. Young Station Unit 1 and 2 Regarding SCR Economic Feasibility; February 11, 2010.

8. U.S. EPA; Comments on the North Dakota Department of Health's April 2010 Draft BACT Determination for NO_x for the Milton R. Young Station; May 10, 2010.

9. National Parks Conservation Association; Comments on the April 2010 Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2; May 10, 2010.

10. National Park Service; Comments on NDDH Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2; May 10, 2010.

11. Basin Electric Power Cooperative; Comments on NDDH April 2010 BACT Determination; May 7, 2010.

12. OtterTail Power Company; Comments on Notice of Intent to Issue a BACT Determination Pursuant to Consent Decree, M.R. Young Station; April 29, 2010.

13. Electronic copy of the complete record for the Best Available Control Technology Determination for Control of Nitrogen Oxides for Milton R. Young Station Units 1 and 2; June 2011.

14. State of North Dakota's Memorandum in Opposition to United States' Petition for Dispute Resolution under the 2006 Consent Decree.

15. Brief of Amici Curiae, States of South Dakota, Oklahoma, Wyoming, Nebraska, Alabama, Utah, Indiana, Kentucky and Alaska in Support of the State of North Dakota.

MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO COMMENTS TO NDDH REGARDING REVISED DRAFT NOx BACT DETERMINATION and NORTH DAKOTA STATE IMPLEMENTATION PLAN for REGIONAL HAZE MILTON R. YOUNG STATION UNIT 1 and UNIT 2

July 30, 2010

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has informed Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") of the opportunity to respond[1] to comments submitted by the United States Environmental Protection Agency (U.S. EPA or EPA)[2], National Park Service (NPS)[3], and National Parks Conservation Association (NPCA)[4] following NDDH's issuance of a revised draft Best Available Control Technology (BACT) Determination[5] and NDDH's Regional Haze State Implementation Plan (RH SIP) involving the Best Available Retrofit Technology (BART) determination[6] for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 boilers at Milton R. Young Station (MRYS).

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced 2006 NO_X BACT Analysis Study[7] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station in accordance with the requirements of a Consent Decree (CD)[8]. Burns & McDonnell also performed the November 2009 Supplemental NO_X BACT Analysis Study[9] and generated the referenced reports for each MRYS boiler in response to the NDDH's request[10] to see Steps 3 and 4 of the BACT analysis process[11] include low-dust and tail end selective catalytic reduction (SCR) alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has previously stated[12]. Minnkota provided additional information supplementing the November

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[1] See Reference number 1, May 12, 2010*.
[2] See Reference number 2, May 10, 2010*.
[3] See Reference number 3, May 10, 2010.
[4] See Reference number 4, January 8, 2010*.
[5] See Reference number 5, April 6, 2010*.
[6] See Reference number 6, November 25, 2009*.
[7] See Reference number 7, October 2006*.
[8] See Reference number 8, April 24, 2006.
[9] See Reference number 9, November 12, 2009*.
[10] See Reference number 10, July 15, 2009*. .
[11] See Reference number 11, October 1990.
[12] Ibid Reference number 5, April 6, 2010*.

* SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT/BART Analysis Study reports and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports and subsequent responses.

2009 Supplemental NO_X BACT Analysis Study as requested by the NDDH[13,14], which included detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives[15], and their subsequent presentation to NDDH[16], as performed by Burns & McDonnell, in December, 2009, and February, 2010[17]. A BART Analysis Study incorporating information developed in the referenced 2006 NO_X BACT Analysis Study was also performed for Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station by Burns & McDonnell in 2006[18].

These responses regarding selective catalytic reduction (SCR) technology pertain to the NDDH's draft NO_X BACT Determination for Nitrogen Oxides for Milton R. Young Station Units 1 and 2, dated April, 2010 (NDDH, 2010). We continue to believe that the administrative record fully supports a finding by the North Dakota Department of Health ("NDDH") that separated over-fire air (SOFA) in conjunction with selective non-catalytic reduction (SNCR) technology is Best Available Control Technology for electric generating units that utilize cyclone burners firing North Dakota lignite. The following sections address specific topics discussed in the EPA's comments and in a separate report written by the United States Department of Justice's (DOJ's) SCR consultant and other commenters' submitted comments in greater detail.

- Responses to May 2010 EPA Comments on NOx BACT Determination for Milton R. Young Station
    - EPA's NSR Workshop Manual and Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual for Calculating SCR Control Cost Effectiveness
    - Responses to EPA Comments on SCR Annual Cost Estimates and Methods
    - Responses to EPA Comments on SCR Catalyst Request For Proposal by DOJ's SCR Consultant
    - Responses to EPA's Submittals of SCR Catalyst Vendors' Responses to DOJ's SCR Consultant's Request For Proposal
    - Responses to DOJ's SCR Consultant's April 2010 Report
    - Responses to General Comments by DOJ's SCR Consultant
        - SCR Reactors, Gas-Gas Heat Exchangers, and General SCR Equipment Arrangements
        - SCR Catalyst Exchange Frequency
        - Microbeam Technologies report on MRYS Unit 2's measured flue gas particulate emissions
        - Responses on individual comments to NDDH's January 2010 request

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[13] See Reference number 12, November 25, 2009*.
[14] See Reference number 15, January 11, 2010*.
[15] See Reference number 13, December 11, 2009*.
[16] See Reference number 14, December 21, 2009*.
[17] See Reference number 16, February 11, 2010*.
[18] Ibid Reference number 7, October 2006*.

    - Responses to EPA's SCR Cost Analysis
    - Summary of Responses to EPA and DOJ's SCR Consultant's Comments
- Responses to May 2010 National Park Service Comments
- Responses to January 2010 National Parks Conservation Association Comments
- Conclusions

Responses to May 2010 EPA Comments on NOx BACT Determination for Milton R. Young Station

EPA's NSR Workshop Manual and OAQPS Control Cost Manual for Calculating SCR Control Cost Effectiveness

We believe that the EPA has incorrectly interpreted the New Source Review (NSR) Workshop Manual (NSR Manual) and improperly compared NO_X control costs of hypothetically-applied low dust and tail end SCRs on cyclone boilers firing North Dakota lignite to other emission sources of dissimilar type, and ignored the other mitigating circumstances that the NDDH considered before issuing their revised preliminary BACT Determination for the M.R. Young Unit 1 and Unit 2 boilers.

On page 2 of the EPA's comments, a quote from the NSR Manual was included: "if the cost of reducing emissions …as the cost previously borne by *other sources of the same type* [emphasis added] in applying that control alternative…the alternative should be *initially* [emphasis added] considered economically achievable…"[19].

In reference to comparing control costs of hypothetically-applied low dust and tail end SCRs on cyclone boilers firing North Dakota lignite, the EPA's use of examples from other types of NO_X emission sources ignores the NSR Manual's statement included above, with emphasis that the comparison is "to other sources of the same type". As the NDDH has pointed out in its "Selective Catalytic Reduction (SCR) Technical Feasibility for M.R. Young Station" report, the "EPA has recognized in the past, that cyclone boilers, such as those at Minnkota, that burn lignite from North Dakota is a separate source category for NO_X emissions limits under the New Source Performance Standards, Subpart D and Da" [20].

The disconnect between the EPA's argument and the NSR Manual appears to be related to the EPA's interpretation that the "determination of BACT is based upon the pollutant that triggered PSD, in this case NO_X, for any type of source can be compared to the cost effectiveness of any other source of NO_X"[21]. This

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[19] Ibid Reference number 2, page 2, May 2010*.
[20] Ibid Reference number 6, Appendix B.6, page 16.
[21] Ibid Reference number 2, page 4*.

does not agree with the quote from the NSR Manual that started the EPA's argument. The EPA provides no relevant references to regulatory documents that support their convoluted argument that disagrees with the NSR Manual statement that such comparisons are to be made to "other sources of the same type". It is obvious that Minnkota does not operate a refinery modified to produce low sulfur gasoline, nor other types of units mentioned in the EPA's BACT and permit application references. The word "initially" in the EPA's first quote referenced above also seems to have escaped detection by the EPA in the argument they presented.

We disagree with EPA claims that the NDDH's Draft BACT Determination "relied upon unreasonable assumptions and factors not authorized by law"[22] and "did not follow the requirements in these manuals"[23] in reference to the EPA's NSR Manual and OAQPS Control Cost Manual. The NSR Manual states "...procedures for estimating control equipment costs are based upon EPA's OAQPS Control cost Manual and are set forth in Appendix B of this document" [i.e. the NSR Manual]. It continues with "Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis. Also, "...where initial control cost projections on the part of the applicant appear excessive or unreasonable (in light of recent cost data) more detailed and comprehensive cost data may be necessary to document the applicant's projections". Furthermore, "costs should be site specific"....and "the applicant should document any unusual costing assumptions used in the analysis"[24].

Appendix B of the NSR Workshop Manual further states: "If standard costing factors are used, they may need to be adjusted due to site specific conditions". Also, "Indirect installation costs include *(but are not limited to)* [emphasis added] engineering, construction, start-up, performance tests, and *contingency* [emphasis added]. Estimates of these costs may be developed by the applicant for the specific project under evaluation". Futhermore, "These references [includes OAQPS Control Cost Manual] can be used by applicants *if they do not have site-specific estimates prepared...*" [emphasis added]. "Where an applicant uses different procedures or assumptions for estimating control costs than contained in the referenced material or outlines in the document, the nature and reason for the differences are to be documented in the BACT analysis"[25].

The costs estimated for the hypothetical low-dust and tail end SCR alternatives evaluated for Minnkota were site-specific, and based upon vendor equipment proposals with relevant materials, labor, and other direct and indirect cost factors. We believe the quoted statements from the NSR Manual indicate that a detailed, site-specific total capital investment cost estimate, such as developed for the Supplemental NO_X BACT Analysis

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[22] Ibid Reference number 2, page 1 May 2010, *.

[23] Ibid, page 10*.

[24] Ibid Reference number 11, page B.35.

[25] Ibid, pages b.3 and b.4.

Study for Unit 1 and Unit 2 at MRYS that uses assumptions different than those given in the EPA's OAQPS Control Cost Manual for SCRs, is allowed. Furthermore, the calculations given in the OAQPS Control Cost Manual for SCR as recommended by the NSR Manual to be used in BACT cases of typical hot-side, high dust installations when site-specific details are not available for low-dust or tail-end SCR configurations. In fact, the OAQPS Control Cost Manual specifically indicates those calculations should not be used for low-dust or tail-end SCR configurations including the use of flue gas reheat.

The NDDH's Draft BACT Determination for the M.R. Young Unit 1 and Unit 2 boilers relies upon the original 2006 NO_X BACT Analysis Study and the November 2009 Supplemental NO_X BACT Analysis Study, and numerous Minnkota-provided responses to agency questions and comments. This body of submitted technical information includes documentation of significant assumptions made as part of the control cost estimating approach used in the MRYS NO_X BACT Analysis studies. We believe that the EPA's interpretation of the requirements of the Consent Decree, NSR Manual, and OAQPS Control Cost Manual conflicts with the statements quoted above. The EPA's arguments fail to recognize the procedures and assumptions used to produce the cost estimate information submitted by Minnkota in these cases are not disallowed by the NSR Manual in keeping within the statements quoted herein. Deviations from the prescribed cost estimating procedures and assumptions described in the NSR Manual and OAQPS Control Cost Manual are misstated as "unauthorized by law"[26] when the former allows for such departures in such cases as Minnkota's NOx BACT Analysis studies.

We repeat our argument stated previously[27] that the OAQPS Control Cost Manual for SCRs cannot be used in Minnkota's cases for estimating control costs of hypothetical low-dust and tail end SCRs because of the disclaimer it contains: "*The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than high-dust systems due to flue gas reheating requirements*"[28] [emphasis added]. By similarity, this applies to cold-side low-dust SCRs as well, because of the need for flue gas reheating. The low-dust SCR configuration assumed in the OAQPS Control Cost Manual for SCR was a hot-side arrangement downstream of a hot-side electrostatic precipitator (ESP), which does not require flue gas reheat[29]. As per the quoted statements from Appendix B of the NSR Manual noted immediately above, preparing and using site-specific cost estimates with documentation of deviations from the prescribed assumptions is, in fact, allowed, and, in Minnkota's case, is more realistic in capturing the probable actual costs that would be incurred from implementing, operating, and maintaining the hypothetically-applied low-

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[26] Ibid Reference number 2, page 1, May 2010*.

[27] Ibid Reference number 13, December 11, 2009, pages 2 and 3*.

[28] Ibid Reference number 17, October 2000, page 2-41.

[29] Ibid, page 2-20.

dust and tail end SCRs studied than estimates prepared by strictly following the references cited in the EPA's May 2010 comments in violation of the disclaimer stated therein.

Again, we disagree that the EPA's [and NPS's] interpretations of the NSR Manual and OAQPS Control Cost Manual are consistent with the statements quoted above; in fact their interpretations are contrary to them.

The Supplemental NO_X BACT Analysis Study for Unit 1 and Unit 2 at MRYS applied appropriate cost estimating methods following standard engineering practices to avoid the conflicts posed by closely following procedures in the NSR Manual and OAQPS Control Cost Manual which are not in agreement with the qualifying disclaimer statements included above. This capital cost estimating methodology is generally supported by information presented in one of the reference documents (Cichanowicz, 2007)[30] in the EPA's May 2010 comments, which gives examples of indirect charges and assumptions to be included as part of a capital cost estimate for power plant emissions control technology implementation.

(by Cichanowicz, copied from Reference number 14, page 18, June 2007)

Table 5-1. Examples of Indirect Charges, Assumptions

Cost Element	Purpose	Range, %
Engineering	Establish design	7-15
General Facilities	Roads, buildings, shops, laboratories	2-5, based on process capital
Owner's Cost	Staff, management	5-10
Process Contingency	Uncertainty in process operation	5-10, for a mature process
Project Contingency	Uncertainty in site installation	5-10, if detailed engineering initially completed
Prime Contractor Fees	Business cost	2-8
AFDC	Financing during construction	5-10
Preproduction	Supply of parts, consumables	2, based on total process investment, plus 30 days fixed, variable O&M
Inventory Capital	Supply of consumables	Based on 30 day reagent, chemicals storage

It should be noted that percentages in the table of indirect charges and their assumptions are shown with a range, and the numbers presented are themselves based on various assumptions, such as "for a mature process" for process contingency, and "if detailed engineering initially completed" for project contingency.

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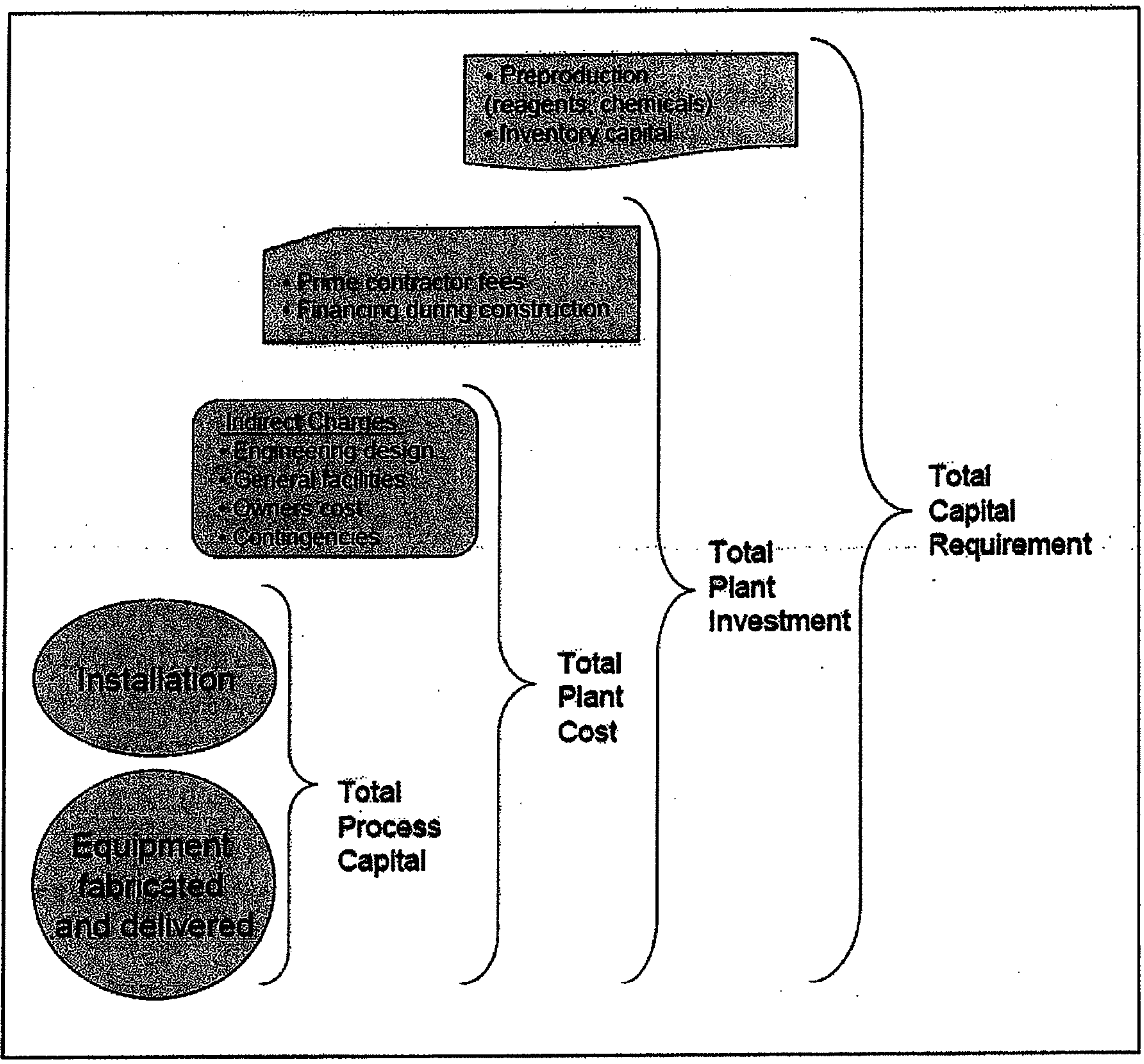
[30] See Reference number 18, June 2007.

(by Cichanowicz, June 2007 - copied from Reference number 14, page 18, Figure 5.1)



While we do not necessarily agree with the assumed percentages in the Cichanowicz paper as appropriate for Minnkota's non-typical hypothetical applications of low-dust and tail end SCR cases at this stage of project development, this methodology is illustrative of an alternate standard estimating approach. Also included in the indirect costs shown above is "Allowance for Funds During Construction (AFDC)" which the OAQPS Control Cost Manual for SCR assumed as zero[31] but Cichanowicz listed an assumption of 5-10% of Total Plant Cost (which is shown in Figure 5.1 copied herein). A significant portion of the Cichanowicz paper also discussed the rampant cost escalations incurred by many recent power plant emission control projects, involving both basic construction materials for shop and field-fabricated equipment, and construction labor.

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[31] Ibid Reference number 17, October 2000, page 2-44.

It is unrealistic to believe that low-dust and tail end SCR projects of such significant complexity, scarcity, size, and schedule duration can be accurately estimated based upon design, fabrication, and erection being delivered and completed "overnight" as a BACT analysis assumes, without including adequate allowances for costs which are not fixed and which will be incurred several years into the future. This is especially important when considering the volatility of project materials and labor costs, and the costs of capital funding which Cichanowicz's paper highlighted. These project execution allowance factors have been estimated by Burns & McDonnell separately from the various contingencies that are recognized in the OAQPS Manual for SCR. We reject the EPA's argument that the assumed contingencies shown in the OAQPS Control Cost Manual are all encompassing in their coverage, and "should" include sufficient amounts for such things as escalation, and that to include the latter separately is essentially double counting. This interpretation fails to recognize cost and scope risks that equipment suppliers and installation contractors will need to be compensated for if required to provide fixed lump-sum pricing for such a project. To expect the process and project contingencies assumed in the example shown in the OAQPS Control Cost Manual to adequately cover all unforeseen installed capital costs that the EPA's comments[32] describe is unrealistic.

We dispute EPA's comment that "The differences for the basic capital cost equipment at MRYS would not be expected to differ from other SCR installations on the scale estimated by B&McD and no reasonable explanation has been provided by Minnkota for the large disparity"[33]. Each cost estimate and BACT analysis case are based upon numerous conditions and assumptions that are unique to that particular situation. The fact that there was not a tail end SCR that had been designed, built, tested and was operating successfully on a coal-fired utility boiler in the United States when the original NOx BACT Analysis Study reports for MRYS were submitted in October 2006, and nowhere else in the world with such challenging fuel and flue gas constituents as present at MRYS, seems to have been disregarded by the EPA's commenter. Likewise, there were few low-dust SCRs with reheat installed that were operating in the U.S. on coal-fired utility boilers in 2006. There is a distinct lack of comprehensive design, operating, and maintenance technical and cost details in publicly-available documents pertinent to each case.

The EPA's claimed disparity between their expectation of estimated capital costs and the numbers provided in the November 2009 Supplemental NO_X BACT Analysis Studies for MRYS Unit 1 and Unit 2, with additional information included in subsequent responses to the NDDH, appears prejudicial on the EPA's part and does not recognize that significant efforts have been expended to produce and document these results. The fact that the estimated site-specific total installed capital costs of the hypothetical applications of SCRs in Minnkota's Supplemental NO_X BACT Analysis studies do not correspond with EPA's expectations is not a

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[32] Ibid Reference number 2, page13, May 2010*.

[33] Ibid, page 13, May 2010*.

result of Burns & McDonnell improperly accounting for design, procurement, and installation conditions. We believe it is a failure on the EPA's part to recognize the limitations of their own assumptions with respect to use of the OAQPS Control Cost Manual, which does not accurately estimate costs of these technologies as it includes the previously-stated caveat not to use the referenced report for such cases because of its inadequacies.

Of particular difficulty in comparing installed capital and operating/maintenance cost estimates for such NO_X control systems are the scope and factors involving plant equipment and site impacts requiring "balance of plant" modifications. We reject the EPA's statement that "many of the assumptions and design parameters that B&McD specified to SCR system and catalysts vendors resulted in excessive equipment components and sizing of the SCR system and the auxiliary/balance of plant components, which drove up materials and labor costs. If the system was designed to minimize capital costs, the general design would be different and the cost of materials and labor would be much less"[34].

Burns & McDonnell and Minnkota carefully considered many engineering, design, procurement, installation, operation and maintenance challenges involving hypothetical applications of low-dust and tail end SCRs at MRYS, and determined what could be required to avoid or compensate for such impacts. The approach of the SCR cost estimate effort performed by Burns & McDonnell for Minnkota was to develop scope and conceptual designs, involve knowledgeable vendors and equipment suppliers for technical information and pricing, and quantify equipment, procurement, installation, operation, and maintenance requirements while recognizing the substantial technical risks that the site and flue gas conditions imposed. The objective was not to minimize capital cost, for that is not a worthwhile pursuit if it is likely to result in failure of the project to be constructable, operable, reliable, maintainable, or meet performance requirements over the expected life of the equipment. As there are no assurances that low-dust and tail end SCRs will even meet all or some of the objective criteria noted above, it is purely speculative that the EPA or their consultant have provided estimates that minimize costs and technical risks while meeting and maintaining emissions performance for the life of the SCRs being considered for Milton R Young Station more comprehensively than what Minnkota has provided.

We reject the EPA's claim that "the B&McD analysis that the NDDH relied upon included redundant costs", where an example given was the SCR bypass ducts and isolation dampers[35]. The SCR system supplier that provided the indicative pricing for the major SCR system equipment has confirmed (verbally) that their June

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[34] Ibid, page 13, May 2010*.

[35] Ibid, page 14, May 2010*.

1, 2009 proposal[36] misstated their scope involving the SCR flue gas bypass ductwork for maintenance – it was not included in their scope and pricing, nor were any SCR reactor isolation dampers. These items were included as part of Burns & McDonnell's cost estimate that was described in the November 2009 Supplemental NO_X BACT Analysis Studies for MRYS Unit 1 and Unit 2, with additional information included in subsequent responses to the NDDH[37].

Minnkota's Consent Decree requires that a BACT analysis for NO_X emissions from MRYS be performed, which has been done. It should be noted that other impact factors, including incremental control costs, must be considered before the BACT alternative are established, which was done by NDDH.

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[36] Telephone conference call between Burns &McDonnell and Babcock Power on October 9, 2009. This document was submitted to the NDDH and claimed as confidential in accordance with Air Pollution Control Rules for the State of North Dakota at 33-15-01-16. See Reference number 16, page 2, for additional details.

[37] Ibid Reference number 9, November 12, 2009*; Reference number 13, December 11, 2009*; Reference number 14, December 21, 2009*; and Reference number 16, February 2010*.

Responses to EPA Comments on SCR Annual Cost Estimates and Methods

We disagree with the EPA's statement that "B&McD also used inflated and unjustified cost estimates for annual costs and used costing methods that are unauthorized by the Control Cost Manual"[38]. Our responses to several of the EPAs' comments are as follows:

1. We repeat our argument stated previously that the OAQPS Control Cost Manual for SCRs cannot be used in Minnkota's cases of hypothetical low-dust and tail end SCRs because of the disclaimer it contains. The OAQPS Control Cost Manual for SCR assumes that "the SCR system incorporates only a few pieces of rotating equipment (e.g. pumps , motors, etc.)". Also, "annual maintenance labor and material cost in dollars per year ($/yr), including nozzle tip replacement for injectors, is *assumed* [emphasis added] to be 1.5% of the Total Capital Investment (TCI) in dollars"[39]. Appendix B of the NSR Manual states "Maintenance costs in some cases are estimated as a percentage of total capital investment. Maintenance costs include actual costs to repair equipment and *also other costs potentially incurred due to any increased system downtime which occurs as a result of pollution control system maintenance*" [emphasis added][40].

Burns & McDonnell assumed 3% of the estimated total capital investment for annual maintenance costs due to anticipated and potential difficulties in maintaining the low-dust and tail end SCR-related equipment that is not part of the conventional hot-side high dust SCR installations to which the OAQPS Control Cost Manual for SCRs applies. Examples of such equipment include: rotary regenerative gas-gas heat exchangers (GGHs), which are the largest pieces of rotating equipment in the entire power plant; booster fans; urea-to-ammonia conversion equipment, which include burners and fans; isolation dampers, and related balance of plant equipment, including rotating equipment that is required for on-line cleaning of catalyst and GGH elements.

The high emissions reductions required for sulfur dioxide at MRYS per the Consent Decree will not allow significant flue gas leakage across the GGHs and still achieve low SO_2 stack emissions. Rotary regenerative GGHs are prone to such leakage problems, element fouling from ammonia and sulfur-related compounds, and corrosion. The harsh winter climate in North Dakota (below -40°F) and nearly constant high winds year-round are significant considerations for equipment located outside and adjacent to the plant's outdoor active coal storage area.

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[38] Ibid Reference number 2, page 17, May 2010*.
[39] Ibid Reference number 17, page 2-45, October 2000.
[40] Ibid Reference number 11, page b.8, October 1990.

We believe the EPA's assumption of 1.5% of the estimated total capital investment for annual maintenance costs is insufficient to adequately represent the costs needed to maintain the low-dust and tail end SCR-related equipment described above.

2. We disagree with the EPA's comment[41] that anhydrous ammonia is mandated as the only reagent to be used for NO_X control in Minnkota's cases of hypothetical low-dust and tail end SCRs. A gaseous, diluted ammonia mixture is required for injection into the SCR reactor to effect the reduction of nitrogen oxides in the presence of catalyst. The OAQPS Control Cost Manual for SCR simply assumes that "the annual cost of ammonia purchase in $/yr is estimated…."[42]. We point out that the DOJ's SCR consultant's Request for Proposal (RFP) included "SCR grade aqueous ammonia is intended to be used as a reagent"[43]. Apparently he also disagrees with the EPA's dictate for the use of anhydrous ammonia. Urea-to-ammonia conversions systems have been installed on several conventional hot-side, high dust SCRs at coal-fired utility power plants in the United States, so this equipment appears to be proven in similar circumstances. We see no evidence presented by the EPA that the least expensive reagent that has been previously used elsewhere and is assumed to be available at MRYS (which has not been confirmed with any suppliers) must be selected regardless of issues of public health and safety, or that this must override the other plausible reasons for the selection of urea as the reagent of choice.

3. The number of additional outage hours estimated for Minnkota's cases of hypothetical low-dust and tail end SCRs in the November 2009 Supplemental NOx BACT Analysis studies is not solely a matter of catalyst replacement duration and frequency. Other reasons for additional outage hours include considerations such as: frequent forced boiler outages due to boiler tube leaks that may cause severe fouling of the low-dust SCR catalyst, low-dust SCR GGHs or tail end FGD GGHs with flyash deposits rich in sticky sodium, calcium, sulfur-containing phases. The formation of these deposits would extend boiler outages to allow adequate removal of the deposits from the SCR equipment exposed to flue gas. In addition, other forced outages of SCR-related equipment such as booster fans, GGHs, and balance of plant equipment can occur. These components must be taken out of service for repairs, causing forced unit outages or load curtailments. We believe it is unrealistic to not include allowances for such potential problems that may occur or be aggravated by the nature of the equipment, fuel, flue gas, weather, and other plant operations when it comes to additional outage hours estimated for Minnkota's cases of hypothetical applications of low-dust and tail end SCRs.

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[41] Ibid Reference number 2, page 17, May 2010*.

[42] Ibid Reference number 17, page 2-46, October 2000,

[43] Ibid Reference number 2, Enclosure 15, February 2010*.

Additional boiler outage hours for MRYS NO_X BACT Analysis alternatives involving advanced separated overfire air (ASOFA) were estimated prospectively, i.e., based upon forecasting possible outcomes prior to installation and operation with actual available historical data. A Unit availability reduction of 2.2% (188 hours per year for M.R. Young Station Unit 1, 181 hours per year for M.R. Young Station Unit 2), was assumed, which allowed for forced or extended scheduled boiler outages that could result from problematic cyclone slag tapping, excessive heat transfer surface fouling, increases in boiler tube leaks and other problems related to the operation of air-staged cyclone combustion. Estimates of additional boiler outage hours for alternatives with technologies in combination with ASOFA were assumed to be additive, not overlapping. For MRYS NO_X BACT Analysis alternatives, such forced or extended scheduled boiler outages were assumed to not occur concurrently. This approach was consistently applied for SNCR with ASOFA, various forms of reburn with ASOFA, and hypothetical cases of SCR with ASOFA.

4. We disagree with the EPA's comments[44] that the NSR Manual does not allow the use of a levelizing cost approach for estimating annual control costs of alternatives in a BACT analysis. Under "Total Annual Costs" in Appendix B Estimating Control Costs of the EPA's NSR Manual, the first sentence states "The permit applicant should use the *levelized* [emphasis added] annual cost approach for consistency in BACT cost analysis"[45]. The original 2006 NO_X BACT Analysis Study of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station, and the November 2009 Supplemental NO_X BACT Analysis Study used a levelized annual cost method consistently for all alternatives analyzed for control cost effectiveness. It would not provide consistency between the MRYS 2006 and 2009 NO_X BACT Analysis studies to disallow the use of an annual cost levelizing factor only for the cases of hypothetical SCR application at MRYS. We believe it is especially relevant to use a levelizing cost factor due to different scenarios for catalyst replacement, boiler cleaning and major scheduled unit outages that affect annual operating hours assumed in the BACT analyses.

5. We reject the EPA's comment that Minnkota must justify reasons why regenerated replacement catalyst was not considered[46]. It is unproven that catalyst can be adequately restored after exposure to the flue gas emitted from cyclone boilers firing North Dakota lignite. Further, it is unreasonable that the use of such significant and unproven assumptions must be used in MRYS NO_X BACT Analysis alternatives involving hypothetical applications of low-dust and tail end SCR technologies. We see no evidence presented by the EPA or their consultant that regenerated catalyst was assumed in any of the other cost effectiveness analyses referenced in the EPA's comments.

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[44] Ibid, Reference number 2, page 22, May 2010*.

[45] Ibid Reference number 10, Appendix B, page b.4.

[46] Ibid Reference number 2, page 22, May 2010*.

6. We disagree that the Scenario B assumptions for possible catalyst life used in the Supplemental MRYS NO_X BACT Analysis alternatives involving hypothetical applications of low-dust and tail end SCR technologies are "unsubstantiated and arbitrary"[47]. Minnkota has previously provided proposals from catalyst vendors that refused to offer guarantees for catalyst life when these vendors have been given details of the measured MRYS flue gas contaminants including sodium-rich aerosols[48]. Comparisons between MRYS coal ash-forming constituents and flue gas characteristics, including amounts and size distribution of sodium-rich aerosols emitted versus other available published technical literature including data from bench, pilot, and full-scale catalysts tested for deactivation have been provided in previous responses and BACT Analysis Study reports by Minnkota. Because there have been no demonstrations of SCR catalyst exposed to flue gas emitted from any cyclone boilers firing North Dakota lignite that showed the ability to withstand the conditions without severe plugging and fouling, it is unproven that low-dust and tail end SCR technologies will even succeed in such applications. It is unreasonable for the EPA and their consultants to ignore this information as the basis of estimates for possible catalyst lifespans assumed in the 2009 Supplemental NOx BACT Analysis studies for MRYS Unit 1 and Unit 2. This is further discussed in responses to SCR catalyst Request For Proposal and the DOJ's SCR consultant in the sections that follow.

Furthermore, the identification of Scenario B, in which it is assumed that one layer of catalyst must be changed out at each scheduled boiler cleaning outage, is not arbitrary, but instead represents the minimum catalyst life that could be reasonably accommodated at M.R. Young Station. In light of the catalyst vendors' refusal to guarantee catalyst life until a pilot scale test has been successfully completed, Scenario B brackets (at the low end) the minimum catalyst life that could be considered. It should be noted that the NDDH has established its own criteria for minimum acceptable catalyst life at 10,000 hours of operation.

Responses to EPA Comments on SCR Catalyst Request For Proposal by DOJ's SCR Consultant

Reference was made in the EPA's comments[49] to a "Request For Proposal for Conceptual SCR Catalyst Design for a Low-Dust and Tail-End SCR System"[50] dated February 2010 by the DOJ's SCR consultant, which was included in Enclosure 15 of the EPA's May 2010 comments. The referenced RFP was "intended to generate conceptual design and SCR performance guaranty information for the retrofit of either a cold-side low-dust or a tail-end SCR system on two different coal-fired electric generating units"[51]. This RFP also

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[47] Ibid Reference number 2, page 26, May 2010*.

[48] Ibid Reference 16, February 2010* as part of Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 160-219, February 2010*.

[49] Ibid Reference number 2, page 13, May 2010*.

[50] Ibid, Enclosure 15, page 3, February 2010*.

[51] Ibid page 3, February 2010*.

specified that "The unit is intended to have a single SCR DeNOx reactor…either in a cold-side low-dust configuration downstream of the air heater and electrostatic precipitator and upstream of a wet limestone forced oxidation FGD scrubber or downstream of the wet forced oxidation FGD scrubber and before the stack. A rotary regenerative gas-gas heater (RGGH) followed by either a natural gas-fired duct burner or a high temperature steam coil ensures the necessary flue gas temperature for the SCR process of 290 °C (554 F)"[52]. The two units were not identified as belonging to Minnkota and Square Butte in the RFP, which the EPA described as "[w]hile the facility in the RFP was not identified as MRYS, the flue gas characteristics in the RFP were based on relevant actual flue gas parameters found at MRYS, including recent stack test information for Unit 1 and Unit 2 and the 1983 Markowski data on particulate matter concentrations and compositions data for Unit 2. Furthermore, it was clearly stated in the RFP that the majority of the sulfates within the particulate matter are expected to be sodium and potassium sulfates"[53]. There were numerous omissions, inaccuracies, and system details related to the referenced Evonik RFP that should be noted:

1. Minnkota's existing wet flue gas desulfurization system on Unit 2 currently uses natural oxidation chemistry with lime (and flyash until December 31, 2010) reagent, not forced oxidation using limestone[54] as a reagent. Use of lime instead of limestone will cause a difference in the amount of reagent consumption and carbon dioxide released (from the limestone reacting with sulfur). The RFP was inaccurate in describing the wet flue gas desulfurization systems, which could alter the catalyst suppliers understanding of flue gas conditions and constituents.

2. Natural gas-fired duct burner or high temperature steam coil was mentioned as the source of heat addition to achieve final reactor flue gas temperature. This departs from EPA's comments[55] (which we have rejected) that only steam should be assumed as the source of flue gas reheat addition in the MRYS NO_X BACT Analysis study cases involving hypothetical applications of SCR technology.

3. On-line catalyst cleaning was not required unless otherwise requested by the catalyst supplier[56]. With no successful SCR experience with North Dakota lignite fired boiler applications, and significant fouling and plugging demonstrated in the Coyote pilot-scale SCR slipstream testing, the catalyst suppliers may look at biomass-fired boiler experience for determining needs for on-line catalyst cleaning. It should be noted that biomass-fired boilers typically have lower sulfur emissions than coal-fired boilers, so the reaction of sulfur

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[52] Ibid, page 3, February 2010*.

[53] Ibid Reference number 2, page 23, May 2010*.

[54] Ibid Reference number 2, Enclosure 15, page 3, February 2010*.

[55] Ibid, page 22, May 2010.

[56] Ibid Reference number 2, Enclosure 15, page 3, February 2010*.

oxides in combination with sodium and potassium may not be a significant fouling issue for biomass-fired boilers compared to what is prevalent with North Dakota lignite fired boiler applications.

4. SCR grade aqueous ammonia was specified as the intended reagent[57]. This departs from EPA's recent comments that only anhydrous ammonia should be assumed as the reagent in the MRYS NO_X BACT Analysis study cases involving hypothetical applications of SCR technology. See our comments herein which reject the EPA's assumption regarding anhydrous ammonia.

5. SCR reactor flue gas bypass was not required unless otherwise requested by the catalyst supplier[58]. This approach appears to allow a catalyst supplier unfamiliar with Minnkota's boiler fireside cleaning practices (not described in the RFP) to ignore the expected contamination and poisoning of catalyst from passage of moisture and entrained ash liberated from heat transfer surfaces during frequent boiler cleaning outages. It also fails to protect the catalyst from moisture condensation that will mobilize the soluble sodium and potassium salts during frequent and possible prolonged startup periods when temperatures can be below dewpoint. The mobilized sodium and potassium will cause poisoning of catalyst sites. With no successful pilot- or full-scale SCR experience with North Dakota lignite fired boiler applications, it is a curious approach to leave it up to the catalyst suppliers to determine whether SCR flue gas bypass is needed on North Dakota lignite fired boiler applications. We believe that SCR reactor flue gas isolation dampers (and catalyst warming systems for boiler outages) would be necessary if such technology were applied to MRYS boilers.

6. Flue gas, flyash, and reagent compositions were specified[59], but coal analyses were not included in the original RFP issued by the DOJ's SCR consultant. We believe this purposely hides the true character of the fuel burned from the catalyst suppliers, so that they may not fully understand the importance of fuel associated impurities on the formation of gas phase species from flame vaporized sodium and potassium that condense to produce aerosols during gas cooling as well as the importance of the non-volatile impurity fraction on the fly ash characteristics in the flue gas stream. This omission of fuel property and composition data from the RFP appears to be intentional so as to obscure the nature of the challenges presented by catalyst exposure to flues gases created from North Dakota lignite burned in cyclone-fired boilers. This omission would tend to result in budgetary designs which undersize initial catalyst volumes, underestimate ammonia slip or overestimate catalyst lifespans. Futhermore, catalyst vendors not provided with site-specific data would be inclined to offer initial catalyst replacement warranties because of this obvious lack of detailed coal and ash analysis and flue gas constituent information.

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[57] Ibid page 3 and page 8, February 2010*.

[58] Ibid page 3, February 2010*.

[59] Ibid pages 4-8, February 2010*.

8. The RFP issued by the DOJ's SCR consultant significantly underestimates the number of forced and scheduled boiler outages (by a factor of three to four times)[60]. Maintenance practices such as routine boiler fireside cleaning outages to remove severe accumulations of ash and slag deposits that are characteristic of firing North Dakota lignite were not mentioned. This lack of boiler outage data in the RFP appears to be intentional so as to obscure the nature of the challenges presented by catalyst exposure to fluctuating temperatures of flues gases created from North Dakota lignite burned in cyclone-fired boilers. This omission would tend to result in budgetary designs which undersize catalyst volumes or overestimate catalyst lifespans due to possible lack of perceived need for reactor flue gas bypasses or catalyst on-line cleaning equipment.

9. Possible need for, or inclusion of, reactor warming systems for catalyst protection during outages were not disclosed or mentioned. We believe that SCR reactor catalyst warming systems (and flue gas isolation dampers) would be necessary if such technology were applied to MRYS boilers because of the potential to mobilize soluble sodium or potassium accumulated on the catalyst.

10. The RFP also specified that each boiler should have only a single reactor, and stated that "The module arrangement within the SCR reactor will be determined as close to square as permissible by the proposed number of catalyst modules". The RFP also included "The type, configuration and chemical composition of the catalyst shall be selected based on the catalyst supplier's sole discretion"[61].

It is important to note that the size of any SCR reactor is dependent upon not only the arrangement of the catalyst modules within the reactor but the number of reactors needed to provide the desired flue gas space velocity and satisfy layout and size limitations involving the flue gas inlet and outlet ductwork and gas-gas heat exchanger(s). It is curious that the referenced RFP specified many design factors involving the maximum module size, and minimum catalyst element height dimensions as part of the "... module design shall comply at least with the following minimum design criteria, requirements and/or limitations"[62] but failed to recognize or mention the maximum allowable size of the reactor because of GGH size limitations. This is discussed further in a subsequent section of these responses.

While the DOJ's SCR consultant's RFP was more specific in certain aspects of reactor design and catalyst configuration than the performance-based information given to the vendors by Burns & McDonnell and Minnkota with Steve Benson of the University of North Dakota in 2009, there are other key differences. The previous effort involving Minnkota provided a design basis to the catalyst vendors including a very detailed characterization of the coal and ash composition, along with particulate components in the flue gas stream

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[60] Ibid page 4, February 2010*.
[61] Ibid page 8, February 2010*.
[62] Ibid page 8, February 2010*.

with actual aerosol data for the flue gas desulfurization system absorbers' inlets and outlets, and at the inlet to Unit 2's electrostatic precipitator, based on values measured in 2009. This flue gas characterization was different than the one provided by the DOJ's SCR consultant. Sodium and potassium were only mentioned once in the DOJ's SCR consultant's RFP when discussing sulfate particulates in the flue gas streams. Mass loadings of sulfate compounds in the RFP appear to be lower than actual detailed analysis has demonstrated[63]. It appears that the DOJ's SCR consultant used the lower levels of particulate measured by Markowski.

Apparently, the scope of the referenced RFP was subsequently altered, presumably by the DOJ's SCR consultant, for at least one of the catalyst vendors. This RFP modification added a "high pressure drop" option that incorporates smaller catalyst flue gas path opening spacing (pitch) compared to the base design. This alteration is believed to have been done via email correspondence between March 4th and March 24th; it was not documented in the original RFP dated February 2010 which was issued on March 3, 2010 or in the non-confidential business information documents submitted to the NDDH with the RFP by the EPA.

Responses to EPA's Submittals of SCR Catalyst Vendor's Responses to DOJ's SCR Consultant's Request For Proposal

It is difficult to understand how the catalyst suppliers, when requested to respond to the subject RFP, can provide proposals that include complete and realistic design information and guarantees for catalyst lifetime when they are not advised of certain design, operating and maintenance conditions, some of which are not commonly seen in typical coal-fired boiler SCR applications. Proposals in response to the DOJ's SCR consultant's Request For Proposal (Evonik RFP) were submitted by three catalyst vendors (CERAM, Johnson Mathey Catalysts (JMC), and Haldor Topsoe). According to the EPA in their May 2010 comments "[u]pon request from two catalyst vendors (CERAM and JMC), a typical coal composition of Center lignite was provided"[64]. These catalyst proposals were subsequently submitted to the NDDH as "confidential business information" by the EPA separately from the EPA's May 2010 comments[65].

Two of these proposals were by the same vendors (CERAM and Haldor Topsoe) that Burns & McDonnell, Minnkota, and Steve Benson of the University of North Dakota, had engaged to provide preliminary catalyst conceptual design and pricing information in 2009 for hypothetical LD and TESCR applications at MRYS. These two vendors were not instructed to consider the very detailed site-specific boiler information, the actual coal and ash analyses, or the 2009 flue gas aerosol data (all of which are part of the public record on the NDDH's website) for characterizing the fuel and flue gas composition upstream of the Unit 2's electrostatic

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[63] Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 279-280, February 2010*

[64] Ibid Reference 2, page 23, May 2010.

[65] See Reference number 19, June 2010*.

precipitator, flue gas desulfurization system absorber inlet and outlet provided previously by Minnkota and their consultants. The intentional omission of fuel and ash composition data from the Evonik RFP as initially issued obscured the nature of the challenges presented by catalyst exposure to flues gases created from North Dakota lignite burned in cyclone-fired boilers, and caused at least one of the catalyst vendors (Haldor Topsoe) to misunderstand the fuel burned in the requested applications. This misunderstanding will be elaborated on later in this document.

The prices requested from catalyst vendors by the DOJ consultant's RFP are current in 2010 dollars for procurement only. This is not consistent with the premise that the hypothetical SCR cases in the November 2009 Supplemental NOx BACT Analysis studies for MRYS Unit 1 and Unit 2 were based on the use of catalyst replacement costs estimated for 2006. Catalyst purchase prices requested from vendors do not include all costs involved in planning and executing the replacement activities, including storage, installation and removal labor, handling and transportation equipment charges, mobilization and demobilization, profit, or disposal costs.

CERAM

CERAM provided budgetary catalyst designs and pricing, dated March 31, 2010, in response to the referenced Evonik RFP and subsequent RFP alterations. CERAM offered catalyst performance guarantees including NOx removal efficiency, maximum ammonia slip, initial pressure drop, sulfur dioxide (SO_2) to sulfur trioxide (SO_3) conversion rate, initial and subsequent catalyst lifetimes with pricing, expected exchange cycle diagram (not guaranteed), and "fill-in technical data" for the base and optional high pressure drop catalyst cases for a low-dust SCR on Unit A (representing MRYS Unit 1) and a tail end SCR on Unit B (representing MRYS Unit 2)[66].

Although the EPA claims that CERAM was one of the catalyst vendors that was subsequently provided with "a typical coal composition of Center lignite"[67], the EPA did not produce any emails from Hans Hartenstein or any telephone call records documenting the submittal of RFP information supplied, nor any written and/or verbal instructions given to CERAM regarding the initial Evonik RFP or the subsequent optional high pressure drop catalyst cases.

On April 8, 2010, CERAM contacted Minnkota by telephone to advise them of the Evonik RFP for unnamed but similar sized coal-fired units as Units 1 and 2 at Young Station. CERAM has subsequently issued a

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[66] Ibid Reference number 19 a., March 2010*.

[67] Ibid Reference number 2, page 23, May 2010.

letter[68] to Minnkota explaining their offer of initial ("Test A") and end of life ("Test B") catalyst guarantees for NOx reduction, ammonia slip, SO_2 to SO_3 conversion rate, and pressure drop as part of its proposal in response to the Evonik RFP. This was in contrast to the SCR catalyst proposal that CERAM submitted to Minnkota on October 13, 2009 in which they only provided initial Test A performance guarantees. CERAM believes that additional field testing information, including a pilot test program that would involve flue gas exposure of one to several catalyst elements under conditions that would replicate the actual SCR system for several thousand hours, would be required before they would be able to provide any life guarantees for SCR catalyst at MRYS.

In their June 11th letter to Minnkota, CERAM explained that "although the requests from Evonik and Minnkota were similar, there were distinct differences in the RFP documents"[69]. The key differences were[70]:

- The range of fuel analysis provided by Evonik was not as detailed as that provided by Minnkota, and considered a lower maximum range of key constituents that can contribute to catalyst poisoning. For example the Evonik specification listed the maximum sodium content to be significantly less than the Minnkota specification. Sodium is a significant catalyst poison that must be considered for the purpose of guarantees. CERAM must consider the full range of potential coals when supplying catalyst performance guarantees.
- Minnkota submitted with the RFP the entire study performed by Microbeam Technologies, Inc (MTI) titled *Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD.* This study included detailed flue gas characterization including details on particle size distribution, particle concentrations, and soluble sodium constituents in the flue gas.
- Minnkota submitted with the RFP the final report titled *Impact of Lignite Properties on Powerspan's NOx Oxidation System.* The report outlined the impacts of the North Dakota Lignite flue gas and fly ash on Powerspan's multi-pollutant control system called electrocatalytic oxidation (ECO) technology, specifically the sodium-rich aerosols and small ash particles which accumulated and became bonded of the surface of the silica electrodes used in this technology.

Further, "CERAM would not have included end of life (Test B) performance guarantees in their budgetary proposal to Evonik had their RFP included the same level of detail that was provided in the [2009] Minnkota RFP documents, but would have again recommended a catalyst pilot test program to characterize the impacts of firing North Dakota Lignite coal upstream of SCR catalyst"[71].

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[68] See Reference number 20, June 2010*.

[69] Ibid, page 1, June 2010*.

[70] Ibid pages 1 and 2, June 2010*.

[71] Ibid, page 2, June 2010*.

These comments from CERAM confirm the importance of accurately and completely characterizing fuel, ash, flue gas, and particulate streams in order to properly assess the design requirements and offer performance guarantees for SCR catalyst. We believe the Evonik RFP and CERAM catalyst proposal in response to said RFP do not properly describe the situation nor accurately represent the volume of catalyst required for the hypothetical application of low-dust SCR on MRYS Unit 1 and tail end SCR on MRYS Unit 2. We recommend that the NDDH ignore the CERAM proposal in response to Evonik's RFP, based on the above discussion.

Haldor Topsoe

Haldor Topsoe, Inc. (HTI) provided budgetary catalyst designs and pricing, dated March 20, 2010[72], in response to the referenced Evonik RFP. HTI offered catalyst performance guarantees including NOx removal efficiency, ammonia slip, initial pressure drop, sulfur dioxide (SO_2) to sulfur trioxide (SO_3) conversion rate, initial catalyst lifetimes and expected exchange cycle diagram (not guaranteed), and pricing with "fill-in technical data" for the 90% and 93% catalyst cases of NOx removal efficiencies for a low-dust SCR on Unit A (supposedly representing MRYS Unit 1[73]) and a tail end SCR on Unit B (representing MRYS Unit 2). The EPA did not produce any emails from Hans Hartenstein or any telephone call records documenting the submittal of RFP information supplied, nor any written and/or verbal instructions given to Haldor Topsoe regarding the Evonik RFP.

Followup by Burns & McDonnell with HTI in June 2010 regarding their proposal to Evonik revealed that it was based on HTI's assumption that the unnamed units in the original Evonik RFP issued by the DOJ's SCR consultant were firing eastern bituminous coal, not North Dakota lignite[74]. We believe this confusion was the direct result of the Evonik RFP lacking any description, coal and ash analysis data or sufficient operating data that identified this application as pertaining to North Dakota lignite-fired boilers. Thus, the catalyst formulation that HTI proposed, which impacts catalyst volumes, pricing, and lifespan estimates, was not selected for specific compatibility with, and recognition of, the nature of the challenges presented by catalyst exposure to flues gases created from North Dakota lignite burned in cyclone-fired boilers. It follows that the proposal and guarantees offered by Haldor Topsoe to the Evonik RFP are inaccurate and invalid relative to the subject boilers at Milton R. Young Station. We recommend that the NDDH ignore the HTI proposal in response to Evonik's RFP, based on the above discussion.

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[72] See Reference number 19 b., March 2010*.

[73] Ibid Reference number 2, page 23, May 2010.

[74] See Reference number 21, July 2010*.

Johnson Mathey

Johnson Mathey Catalysts LLC. (JMC) provided budgetary catalyst designs and pricing, dated March 12, 2010, in response to the referenced DOJ's SCR consultant's Request for Proposal. JMC offered catalyst performance guarantees including NOx removal efficiency, ammonia slip, initial pressure drop, sulfur dioxide (SO_2) to sulfur trioxide (SO_3) conversion rate, initial catalyst lifetimes and expected exchange cycle diagram (not identified as part of the initial lifetime guarantee), and pricing with "fill-in technical data" for only the 90% catalyst cases of NOx removal efficiencies for a low-dust SCR on Unit A (representing MRYS Unit 1) and a tail end SCR on Unit B (representing MRYS Unit 2)[75].

Although the EPA claims that JMC was one of the catalyst vendors that was subsequently provided with "a typical coal composition of Center lignite", the EPA did not produce any emails from Hans Hartenstein or any telephone call records documenting the submittal of RFP information supplied, nor any written and/or verbal instructions given to Johnson Mathey regarding the Evonik RFP. There was no text write-up included with JMC's quote or proposal, no inclusion or mention of any coal analysis requested, received, or reviewed, nor was there any written confirmation provided in the JMC proposal that the catalyst vendor recognized that these unnamed units burn North Dakota lignite. Without inclusion of any identification or discussion about the specific applications in JMC's proposal in response to Evonik's RFP, it is unknown how this vendor considered compatibility with, and recognition of, the nature of the challenges presented by catalyst exposure to flue gases created from North Dakota lignite burned in cyclone-fired boilers at MRYS. We recommend that the NDDH view the JMC proposal in response to Evonik's RFP with skepticism, based on the above discussion.

Responses to DOJ's SCR Consultant's Report

We believe the arguments and comments presented in a April 2010 report[76] submitted by the EPA from the DOJ's SCR consultant regarding the NDDH's April 10, 2010 BACT Determination for Minnkota's M.R. Young Station contain significant statements that are incorrect, incomplete, speculative and misleading. We offer responses that supplement the detailed information previously provided, and not repeated in their entirety here, that relate to the design basis for the costs determination presented by Burns & McDonnell (B&McD) for the hypothetical application of retrofits of low-dust selective catalytic reduction systems (LDSCR) or tail-end selective catalytic reduction systems (TESCR) to control NOx emissions for MRYS. The following comments address pertinent major issues rather than a point-by-point rebuttal of Mr. Hartenstein's April 2010 report. These include:

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[75] See Reference number 19 c., March 2010*.

[76] See Reference number 22, April 2010*.

- Responses to General Comments by DOJ's SCR Consultant
- SCR Reactors, Gas-Gas Heat Exchangers, and General Equipment Arrangements
- SCR Catalyst Exchange Frequency
- Microbeam Technologies Report on MRYS Unit 2's Measured Flue Gas Particulate Emissions
- Responses on individual comments to NDDH's January 2010 request[77]

Responses to General Comments by DOJ's SCR Consultant

SCR Reactors, Gas-Gas Heat Exchangers, and General SCR Equipment Arrangements

We disagree with Hans Hartenstein's negative portrayal of the SCR reactor and gas-gas heat exchanger equipment and ductwork arrangement developed for the conceptual design and cost estimate for hypothetical applications of LDSCR and TESCR technologies at MRYS as "the most costly and unnecessarily complex possible design one could have designed"[78]. The April 2010 "expert" report by Mr. Hartenstein ignores the significant retrofit challenges posed by the site topography with existing and new major air pollution control equipment under construction that are placed in close proximity to active flyash storage silos, scrubber buildings, coal storage areas and coal handling conveyors, plant roadways, and other buildings and structures in the immediate vicinity where low-dust and tail end SCRs and their related ancillary equipment could be located.

Two main SCR reactors, with associated flue gas reheating equipment, ductwork, and ancillary equipment developed for hypothetical LD and TESCR applications at MRYS, were included in the conceptual design and total installed capital cost estimate used in the November 2009 Supplemental NOx BACT Analysis Study report for MRYS Unit 2[79]. A single SCR reactor/GGH "tower" equipment arrangement was developed by the same SCR system supplier (Babcock Power Environmental) who is performing the South Oak Creek LDSCR reactor design and associated equipment arrangement. The technical reasons for this selection are explained below.

The significant reason [not mentioned or acknowledged by the DOJ's SCR consultant] for not having a single LD or TESCR reactor to handle the total flue gas flow from Unit 2's boiler is the size limitation of the rotary regenerative GGH's. The practical limitation came from the size of the single main SCR GGH – in Unit 2's case, this could require a rotary regenerative GGH with a rotor larger than the largest one ever built, in excess of 60 feet in diameter. Unit 2 has two existing wet FGD absorbers arranged in a parallel configuration, with

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[77] Ibid Reference number 15, January 11, 2010*.

[78] Ibid Reference number 22, page10, April 2010*.

[79] Ibid Reference number 9, November, 2009*.

each capable of handling slightly more than 50% of the maximum flue gas mass flow. With Unit 1's boiler having a maximum flue gas flow rate of approximately 60% of Unit 2's boiler, a single main SCR GGH design could effectively be used in all three locations – one for Unit 1 and two for Unit 2. This approach would avoid having the dubious distinction of purchasing and maintaining the first rotary regenerative GGH of a size not proven in utility powerplant or similar service. This arrangement also allows more site locations to consider for possible placement of the SCR reactor/GGH "tower", and commonality of subsystem equipment for design, procurement, installation, operation and maintenance between Unit 1 and Unit 2 boilers.

Other technical reasons for this SCR arrangement include ductwork sizes and being able to route flue gas to and from the two existing Unit 2 desulfurization system absorber inlet and outlet ducts independently. A single flue gas duct sized to handle the entire design volume of Unit 2's mass flow is 30 feet in diameter where it enters the new chimney's inlet breeching. Such large ductwork requires significant space for routing between the GGHs and the FGD scrubber absorber vessels, while considering such factors as pressure drop, flow patterns, structural supports and foundations, construction of new ductwork while the existing plant is operation, maintenance access to existing FGD scrubbers and new SCR reactors, including isolation and bypass dampers, rework of existing fiberglass reinforced plastic (FRP) and steel ductwork and tie-ins of such ductwork for rerouting the flue gas paths between the electrostatic precipitator outlet and the new chimney. Using a design approach compatible with the two existing FGD absorber vessels allowed the use of smaller ductwork. The twin reactor design allowed the flexibility to isolate each scrubber and SCR pair without compromising the other pair in case of problems with the scrubber tower, induced draft fan or booster fan, or SCR subsystem associated with that particular flue gas flow path. As previously stated in response to the EPA's comments, the objective was not to minimize capital cost but to create a conceptual design that considers many factors (i.e. be constructable, operable, reliable, maintainable, and meet performance requirements over the expected life of the equipment).

We also disagree with the DOJ's SCR consultant's comments that the use of heat exchangers for flue gas reheating associated with tail-end SCRs is "completely unnecessary"[80]. The September, 2009 Fuel Tech document[81] provided by Minnkota to the NDDH referenced by Hans Hartenstein in his April 2010 report included the following:

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[80] Ibid Reference number 22, page7, April 2010*.

[81] Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 328-329, February 2010*.

Flue Gas Heating & FGD GGH Options

For Tail End systems, it is important for the flue gas temperature entering the SCR GGH to be above the water dewpoint. This will prevent condensation and potential corrosion within the GGH. There are a few methods for raising the FGD outlet temperature:

- **FGD GGH: Regenerative type heat exchangers have been used in Europe for this application. When FGD systems were deployed in German powerplants, heat exchangers were needed to raise flue gas temperatures to >72°C for plume buoyancy. These same exchangers were integrated into Tail End SCR systems. Some corrosion issues have been documented. Some solutions that have been used include alloy elements, plastic elements, and enameled elements.**
- **FGD Heat Pipes: Another type of heat exchanger is the heat pipe technology, such as that marketed by Hitachi. Hitachi has installed this type of exchanger in Japanese plants.**
- **Flue Gas Heating with Duct Burners: Direct gas firing in the duct would eliminate the need for a heat exchanger. In contrast to the use of duct burners for maintaining flue gas temperature to the inlet of the SCR catalyst, continuous gas firing would be needed for controlling the flue gas temperature at the inlet to the SCR GGH.**
- **Heat Exchange Loop at the SCR GGH: Another method includes the use of a slipstream from the SCR GGH outlet back to the inlet to raise the inlet flue gas temperature. This alternative is shown below in red:**

What Hans Hartenstein failed to mention in his argument "Employing FGD-GGHs for flue gas drying upstream of the SCR-GGH is the most complicated and most costly possible arrangement. Again, B&McD doesn't offer any rationale as to why this selection was made over the other options described in the Fuel Tech document..."[82] was the recognition of the point that Fuel Tech made following the text section above:

> **The latter two methods would affect the overall mass balance of the Tail End system, primarily due to the increased natural gas consumption by the duct burners.**
>
> **A cost-benefit comparison of these alternatives should be prepared specifically for the MRYS installation.**

In developing the conceptual design of the hypothetical applications of LDSCR and TESCR technologies at MRYS, Burns & McDonnell initially relied on technical advice and preliminary mass/heat balance calculations provided by SCR consultants experienced in conventional, LD and TESCR SCR process design (formerly Tackticks, LLC, now part of Fuel Tech, Inc.). The experience and qualifications of the SCR consultants engaged by Burns & McDonnell in this effort, and issues associated with FGD GGHs on TESCR applications for utility boilers, were previously described in September 2008[83].

The configuration of the TESCR flue gas reheating heat exchangers developed for the hypothetical applications at MRYS located the main SCR rotary GGH immediately downstream of the FGD absorber flue gas outlet FGD heat exchanger. The intent of such an arrangement was to allow acid mist carryover ($H_2 SO_4$)

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[82] Ibid Reference number 22, page 8, April 2010*.

[83] See Appendix A of Reference number 23 f., September 22, 2008*.

from the FGD outlet to condense within the FGD heat exchanger where it could be removed by suitable on-line cleaning, not in the main SCR GGH. Hans Hartenstein's report also failed to recognize that during a cold startup, when there is insufficient heat available from the utility boiler to supply a flue gas reheat steam heat exchanger but when coal is being fired in the boiler, there will be some acid condensation in the main SCR GGH for the TESCR configuration he describes. The European TESCR GGH arrangement may tolerate this situation, but they don't burn North Dakota lignite that has a significant amount of sodium-rich aerosol particles in the flue gas downstream of the FGD absorber outlet. These particles are shown to be sticky in nature (as documented in the Powerspan pilot test at MRYS Unit 1 previously reported[84]) and would be expected to accumulate on heat transfer surfaces without on-line cleaning, and require periodic outages for deposit removal[85].

The FGD GGHs proposed in the hypothetical applications at MRYS proposed by an SCR system supplier were assumed to include materials of construction and added on-line cleaning equipment that would tolerate the expected flue gas conditions. BMcD has previously discussed concerns with the potential use of rotary regenerative GGHs for FGD outlet flue gas reheating upstream of the main TESCR GGH in the hypothetical applications at MRYS[86]. The text from Fuel Tech's document included above was general in nature and was offered very near the end of the SCR cost estimate study project. The level of detail developed by Burns & McDonnell involving flue gas reheating equipment and arrangements for the SCR cost estimate study was sufficient for use in a NOx BACT analysis for MRYS boilers.

SCR Catalyst Exchange Frequency

We disagree with Hans Hartenstein's position that the NDDH's BACT Determination and November 2009 MRYS Supplemental NOx BACT Analysis Study reports relied upon "...completely arbitrarily selected catalyst exchange frequencies resulting from unknown and unsupported catalyst deactivation assumptions (B&McD's "Scenario B")" [87] for hypothetical applications of LDSCR and TESCR technologies at MRYS. Details of SCR catalyst deactivation mechanisms from sodium aerosols, and various examples of rapid deactivation after exposure to alkali-rich aerosols, have been previously described[88]:

- Catalyst activity decreased by 52% after about 1140 hours of operation caused by biomass derived alkali rich aerosols (Zheng and others, 2005).

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[84] Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 277-280, February 2010* and Reference number 23, Supplemental Information for Consideration, February/March 2009*.

[85] See pages 3 and 4 of Appendix A of Reference number 23 f., September 22, 2008*.

[86] See Reference number 23h., page 42, and Reference number 23 i., February/March 2009.

[87] Ibid Reference number 22, page10, April 2010*.

[88] Ibid Reference number 23 f., pages 11-13, November, 2008.

- Catalytic activity dropped by over 40% in testing ranging from 100 to 3000 hours due to increased levels of sodium and potassium aerosols accumulated in the SCR catalyst derived from the ultra fine particles in three biomass and peat fired 100 MW-scale combustion systems (Kling and others, 2007).
- Catalyst deactivation rate was about 18% per 1000 hours at a stoker-fired utility boiler firing a blend of biomass and Powder River Basin coal (PRB) (Strege and others, 2008).
- Relative reactivity decreased to 20%, or 80% deactivation after 1400 hours for a pulverized wood-fired boiler due to build up of potassium in the catalyst from the presence of highly reactive alkali (potassium and sodium) aerosols in the flue gas (Khodayari, 2001).
- Deactivation rate of about 1% per day of the relative activity was seen with operation of full-length monolith catalysts installed at a straw-fired power plant when the power plant ran continuously (Zheng and others, 2008).
- Avedore's Unit 2 power boiler which required SCR catalyst to be rejuvenated nine times and replaced once within the first 30,000 hours of operation, which included periods with and without biomass cofiring. Based on the publicly-available data, actual catalyst maintenance activities were much more significant than the above numbers imply, because they represent catalyst impairment resulting from exposure equivalent to approximately 1000 hours of estimated biomass co-firing operation between catalyst rejuvenation or replacement activities.
- Severe, rapid catalyst blinding and plugging due to sodium and potassium rich species from the only known example of simulating SCR catalyst exposure to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler (Coyote pilot-scale SCR test[89]). This experience demonstrated the generation of alkali-sulfate compounds that plugged every micropore of the test catalyst when examined under a scanning electron microscope. This catalyst blinding and plugging was so severe that the catalyst vendor who supplied it was unwilling to analyze it for deactivation.

There is sufficient evidence from demonstrated catalyst exposures to alkali-rich flue gas, including those cited above, and catalyst vendor responses to Minnkota's 2009 Request for Proposal, which indicate that even in hypothetical low-dust and tail-end SCR applications considered for MRYS, there is the high potential for rapid deactivation and fouling of catalyst exposed to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler.

We reject the DOJ's SCR consultant's apparent attempt to link Burns & McDonnell's BACT determination recommendation for MRYS with an implication that it was tainted by a working relationship with "a consultant dedicated to SNCR for developing all of this technical SCR and catalyst information most critical

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[89] See Reference number 24, October 2005.

for the overall cost estimate"[90]. Burns & McDonnell engaged the referenced consultant in the second half of 2008 prior to the purchase of the referenced consulting firm (formerly Tackticks, LLC) by the current owner (Fuel Tech, Inc.). We sought help in this effort primarily because of the significant experience of the consultant's principal (Volker Rummenhohl) involving conventional, low-dust and tail end SCR process design, commissioning, and operations and maintenance performance, not because the parent company's primary business of selective non-catalytic reduction (SNCR) technology happened to coincide with Burns & McDonnell's BACT determination for MRYS. The change in the referenced SCR consulting practice's ownership occurred after the establishment of Burns & McDonnell's BACT recommendation for MRYS, and was simply coincidental and not a relevant factor in technical arguments in favor of SNCR and against SCR being applied to the boilers at MRYS.

The effectiveness of catalyst to reduce NOx emissions long-term in the hypothetical low-dust and tail end SCR applications at Young Station will be a function of a combination of factors. The most significant impacts previously presented (and not repeated in detail here) will be to reduce catalyst effectiveness resulting from fine aerosol of highly-concentrated alkali particles combining with sulfur and ammonia within the catalyst, causing rapid blinding and possible accumulation (plugging) in addition to chemical poisoning (deactivation)[91]. CERAM was not involved with the Coyote pilot-scale SCR testing, so it is not known how much influence their personal awareness of the character of the Coyote test's fine particles and their tendency to penetrate catalyst pores and stick to catalyst surfaces had on their proposal and conceptual catalyst design for MRYS.

We believe that there is enough uncertainty expressed by catalyst vendors when presented with a comprehensive set of documents with details of specific coal and flue gas constituents, along with empirical evidence in the form of the Coyote pilot-scale SCR test results and MRYS Unit 1 pilot-scale Powerspan barrier reactor test results, to alter their willingness to guarantee catalyst life in the cases of hypothetical low-dust and tail end SCR applications at MRYS without having completed a successful long-term pilot test on these boilers burning North Dakota Lignite[92]. There are no current SCR applications in the world that are directly comparable to MRYS with cyclone boilers burning North Dakota lignite coal.

As previously stated, "[i]t is extremely imprudent to apply SCR to a utility boiler with such differences in firing type and fuel burned compared to those situations that have been proven successful without first performing extensive pilot testing and achieving acceptable results, followed by confirming the feasibility of the full-scale design. One cannot look just at the bulk flyash loading and average concentrations of the trace

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[90] Ibid Reference number 22, page11, April 2010*.

[91] Ibid Reference numbers 7, 9, and 16, including Reference number 23 g., pages18 and 19*.

[92] Ibid Reference number 24, October 2005, and Ibid Reference number 23 g., November 2008*.

elements and other poisons in the fuel to decide whether SCR technology will work. It is incorrect to make a blanket statement that implies it is always feasible to install TESCR"[93].

Catalyst is rarely replaced because the user knows precisely when it has reached the end of its design life; it is usually replaced during a scheduled outage when the opportunity is available. Because of the high potential for rapid deactivation and fouling of catalyst exposed to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler causing significant uncertainty in catalyst life expectancy at MRYS, Burns & McDonnell estimated catalyst replacement frequencies and costs for Scenario "B" assuming that the MRYS boilers would be able to sustain typical baseload operation near maximum continuous ratings while achieving 30-day rolling average NOx emission rates at 0.05 lb/mmBtu on a year-round operating basis only if frequent, extended outages coinciding with scheduled boiler fireside cleanings were performed for catalyst maintenance. While these frequencies and conditions of SCR catalyst maintenance in the cases of hypothetical low-dust and tail end SCR applications at MRYS are more pessimistic than the DOJ's SCR consultant's opinions based on his experience with other boilers and fuels not similar to cyclone boilers burning North Dakota lignite and not requiring such high NOx emissions reduction as analyzed for MRYS, such catalyst maintenance activity frequencies are certainly possible when considering the unfavorable Coyote pilot-scale SCR test results and MRYS Unit 1 pilot-scale Powerspan technology test results and other biomass-related SCR catalyst deactivation data.

As for the DOJ's SCR consultant's April 2010 comparison of heat input and flue gas mass flow data[94], the design numbers cited as given to the two catalyst vendors involved with Minnkota's LDSCR and TESCR RFP in 2009 were improperly portrayed by Mr. Hartenstein. The ones listed in the consultant's comparison of the referenced April 2010 report are actually from the SCR Vendor Query issued by B&McD in April 2007. These earlier numbers were calculated separately from the 2009 SCR Cost Study, and were only provided in abbreviated form in the 2009 Minnkota LDSCR and TESCR RFP as a convenient reference. The two catalyst vendors were given preliminary mass balances of flue gas flows and constituents in August 2009 (the spreadsheets of March 11, 2009 as calculated by Fuel Tech). The numbers shown in the DOJ's SCR consultant's April 2010 report also do not accurately reflect values given to the responsive SCR system supplier (Babcock Power) in March 2009[95]. Values given to Babcock Power by Burns & McDonnell in March 2009 shown by the DOJ's SCR consultant in a summary table[96] were taken from the preliminary mass balance spreadsheets as calculated by Fuel Tech dated March 11, 2009 for flue gas flows and constituents at the electrostatic precipitator outlet for the low-dust SCR cases, and the flue gas desulfurization system outlet

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[93] Ibid Reference number 23 g., November 2008*.

[94] Ibid Reference number 22, pages19 and 22, April 2010*.

[95] Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence, pages 40-43, February, 2010.

[96] Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence, page 43, February, 2010.

for the tail end SCR cases, assuming two reactors per boiler. It is obvious that Mr. Hartenstein has incorrectly portrayed this preliminary design basis assumed by the catalyst vendors.

We provided Fuel Tech with appropriate and available information regarding inputs to be assumed for the LDSCR and TESCR preliminary design basis of the hypothetical applications for MRYS. Maximum and normal full load boiler gross heat input rates, coal analyses, boiler outlet oxygen concentration (wet basis), and air inleakage percentage downstream of the boiler and calculated values of flue gas mass flows and constituents (without sulfur trioxide) were provided to Fuel Tech in January 2009 for their preliminary mass balance calculations. We did not assume any SO_3 concentrations because we did not have values for that parameter at MRYS, and because accurate measurements of this constituent involve significant effort, this is not typically measured in routine stack emissions testing. As the amount of SO_3 in the flue gas depends on interactions of sulfur with other gases and entrained particulate within the boiler and downstream treatment processes, we deferred to the catalyst vendors to assume or determine what they felt was an appropriate SO_3 concentration.

It should be pointed out that it is common engineering practice to design flue gas handling equipment based upon maximum expected values (i.e. short-term conditions) but to calculate operating costs of running that equipment based upon values that reflect sustainable averages. We used Haldor Topsoe's LDSCR and TESCR preliminary catalyst and reactor design of the hypothetical applications for MRYS, along with HTI catalyst unit pricing, as inputs to calculations of long-term annual operating costs in the November 2009 Supplemental NOx BACT Analysis Study reports for MRYS. Using current (2009 or 2010) catalyst prices would not be consistent with the 2006 basis assumed for the original NOx BACT Analysis Study reports for MRYS of non-SCR NOx control alternatives. We did not request catalyst proposals from Johnson Mathey Catalysts (JMC, formerly Argillon/Siemens) due to previous lack of responses to our 2007 SCR Vendor Query and 2008 followup.

There are numerous discrepancies contained in the page 22 comparison table of the DOJ's SCR consultant's April 2010 report. The correct values given by B&McD to the SCR system supplier (Babcock Power) and the two catalyst vendors are included in the table below:

B&McD SCR Design Criteria and Values Provided to Vendors

LDSCR MRYS U1		2009 SCR RFI	2007 SCR Vendor Query[97]
Gross heat input	mmBtu/hr	2,955	2,852
Process Location		ESP Outlet	Boiler Outlet
Flue gas mass flow	Lb/h	3,479,112	3,811,000
Volume flow rate	ACFM	1,130,518	2,502,000 (@910°F)
Volume flow rate	Nm3/h, wet	1,232,884	–
SO_2 inlet concen.	Lb/mmBtu	1.93 (calc)	3.0
SO_2 mass flow	Lb/h	5,691(1)	8,970(2)
		Reactor Inlet	–
Flue gas mass flow	Lb/h	3,680,676	–
Volume flow rate	ACFM	1,566,538	–
Volume flow rate	Nm3/h, wet	1,305,184	–
SO_2 inlet concen.	Lb/mmBtu	2.0	–
SO_2 mass flow	Lb/h	5,907	–
TESCR MRYS U2		FGD Outlet	Boiler Outlet
Gross heat input	mmBtu/hr	5,158	4,740
Flue gas mass flow	Lb/h	6,458,832	7,117,000
Volume flow rate	ACFM	1,641,826	4,371,000 (@818°F)
Volume flow rate	Nm3/h, wet	2,361,164	–
SO_2 inlet concen.	Lb/mmBtu	0.096	3.0
SO_2 mass flow	Lb/h	496(1)	15,474(3)
		Reactor Inlet	–
Flue gas mass flow	Lb/h	6,832,108	–
Volume flow rate	ACFM	2,989,916	–
Volume flow rate	Nm3/h, wet	2,497,840	–
SO_2 inlet concen.	Lb/mmBtu	0.01	–
SO_2 mass flow	Lb/h	514	–

Notes:
(1) SO_2 emissions calculated by Fuel Tech are less than the nominal and normal maximum values based upon 7.5% higher than long-term average, and 90th percentile lignite coal sulfur contents, respectively (from the Center mine). Unit 1 SO_2 at ESP outlet should have been stated as 11,368 lb/h or 3.85 lb/mmBtu, based upon 90th percentile as-received coal sulfur content of 1.3% and calculated higher heating value of 6,767 Btu/lb. Unit 2 SO_2 at FGD outlet should have

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[97] See Reference number 23 e., May 2007.

been stated as 992 lb/h or 0.19 lb/mmBtu, based upon 90th percentile as-received coal sulfur content of 1.3% and calculated higher heating value of 6,767 Btu/lb and 95% removal by wet FGD. See Reference number 23 e., May 2007.
(2) Expected Boiler Outlet Maximum 30-day average SO_3 was 135 lb/hr for U1, based upon assuming 1.5% conversion of the boiler outlet SO_2, 2,990 mmBtu/hr heat input, 1% sulfur in lignite coal with 6,578 Btu/lb higher heating value.
(3) Expected Boiler Outlet Maximum 30-day average SO_3 for U2 of 236 lb/hr, based upon assuming 1.5% conversion of the boiler outlet SO_2, 5,158 mmBtu/hr heat input, 1% sulfur in lignite coal with 6,578 Btu/lb higher heating value.

Upon review of the SCR process design values provided in the table above, we noticed that SO_2 emissions in the preliminary mass balance spreadsheets given to the SCR system supplier and the two catalyst vendors were inadvertently underestimated by a substantial margin. Underestimating SO_2 emissions could cause an underprediction of SO_2 to SO_3 conversion by the catalyst vendors, and lead to overprediction of catalyst life. Burns & McDonnell did not attempt to correct or advise the vendors of these discrepancies because they were found after proposal submittals. Both catalyst vendors appear to have calculated SO_2 emissions rather than using the values provided in Fuel Tech's March 2009 LDSCR and TESCR preliminary design basis spreadsheets.

SCR Design Criteria and Values Provided by Vendors

MRYS U1		CERAM	Haldor Topsoe
Gross heat input	mmBtu/hr	(1)	2,852
Process Location		LDSCR Reactor Inlet	LDSCR Reactor Inlet
Flue gas mass flow	Lb/h	3,684,000 (2)	3,811,000
Volume flow rate	ACFM	(1)	(1)
Volume flow rate	Nm3/h, wet	(1)	(1)
SO_2 inlet concen.	Lb/mmBtu	(1) [4.00] (3)	(1) [3.15] (4)
SO_2 mass flow	Lb/h	(1) [11,826] (3)	8,970 (4)
MRYS U2		TESCR Reactor Inlet	LDSCR Reactor Inlet
Gross heat input	mmBtu/hr	(1)	4,740
Flue gas mass flow	Lb/h	6,838,286 (2)	7,117,000
Volume flow rate	ACFM	(1)	(1)
Volume flow rate	Nm3/h, wet	(1)	(1)
SO_2 inlet concen.	Lb/mmBtu	(1) [0.20] (3)	(1) [3.26] (4)
SO_2 mass flow	Lb/h	(1) [1030] (3)	15,474 (4)

Notes:
(1) Value not included in vendor quote.
(2) Calculated by multiplying vendor mass flow in kg/h by 2.2046 lb/kg. Unconfirmed by the vendor.
(3) SO_2 mass rate calculated by multiplying vendor SO_2 concentration in mg/Nm^3 by Fuel Tech's Nm3/h volume flow rate at reactor inlet, then multiplied by 2.2046 lb/kg and divided by 1,000,000 mg/kg. SO_2 inlet concentration in lb/mmBtu calculated by dividing lb/h mass rate by assumed gross heat input rate of 2,955 mmBtu/h for Unit 1 and 5,158 mmBtu/h for Unit 2. Unconfirmed by the vendor.

(4) SO_2 mass rate at LDSCR reactor inlet should have been stated as 10,980 lb/h for Unit 1 and 18,249 lb/h for Unit 2 assuming 3.85 lb SO_2/mmBtu, based upon 90th percentile as-received coal sulfur content of 1.3% and calculated higher heating value of 6,767 Btu/lb. SO_2 inlet concentration in lb/mmBtu calculated by dividing lb/h mass rate by stated gross heat input rate of 2,852 mmBtu/h for Unit 1 and 4,740 mmBtu/h for Unit 2. Unconfirmed by the vendor.

Because of the numerous instances where values contained in the page 22 comparison table of the DOJ's SCR consultant's April 2010 report do not agree with the values provided by Burns & McDonnell in August 2009, we recommend that the NDDH reject the arguments presented by Mr. Hartenstein involving this information.

We disagree with Mr. Hartenstein's mischaracterization of Burns & McDonnell's January 2010 letters[98] that the two catalyst vendors engaged in the 2009 Minnkota LDSCR and TESCR RFP were "offered" pilot scale testing in order to be able to guarantee initial catalyst life. The intention of Burns & McDonnell's letter was to properly capture the substantive caveat these catalyst vendors included in their confidential proposals without having to redact their proposals. We were unaware at the time that Burns & McDonnell issued their proposal clarification letters that the vendors would be subsequently asked by others and agree to redact their confidential proposals to allow public disclosure.

We wish to point out the three catalyst vendors, cited by Mr. Hartenstein as responsive to his June 2008 request to provide commercial guarantees for catalyst life for a TESCR at MRYS without requiring pilot testing, were not provided a detailed flue gas, coal, and ash analysis or detailed design basis when they made those responses. Two of those three catalyst suppliers were provided such details in August 2009 via Minnkota's LDSCR and TESCR RFP and subsequently declined to guarantee catalyst life unless pilot testing were successfully completed. These two catalyst vendors, with significant global catalyst experience on coal-fired boilers, when provided with detailed measured aerosol particulate data as part of a request to consider a new SCR application of North Dakota lignite fired in MRYS cyclone boilers, indicated that they would require successful pilot testing before being willing to offer catalyst life guarantees. We conclude that the catalyst vendors carefully examined the information provided and referenced for review, including fuel, ash, and aerosol data from MRYS, and recognized the difficulties in predicting the ability of the catalyst to maintain performance under such conditions without having actual experience with such combinations of sulfur, ammonia, and ultrafine particulate enriched in sodium and other known catalyst poisons and blinding agents.

Mr. Hartenstein incorrectly assumes that actual measured particulate mass rates from stack tests should be used as the basis in preliminary LDSCR and TESCR process designs. The preliminary design approach taken

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[98] Ibid Reference number 16, pages 377-380, February 2010.

by Burns & McDonnell for Minnkota's hypothetical applications of LDSCR and TESCR technologies for MRYS was to assume the permissible limit for particulate mass per unit of heat input emissions from the ESPs (0.03 lb/mmBtu) as required in Minnkota's April 2006 Consent Decree[99] for MRYS Unit 1 and Unit 2 with wet FGD systems. Electrostatic precipitator hourly average outlet mass particulate outlet emissions were assumed as 0.03 lb/mmBtu x 2,955 mmBtu/hr = 88.7 lb/hr for Unit 1 and 0.03 lb/mmBtu x 5,158 mmBtu/hr = 155 lb/hr for Unit 2.

MRYS U1		CERAM	B&McD / Fuel Tech
Process Location		LDSCR Reactor Inlet	LDSCR Reactor Inlet
Particulate mass flow	Lb/h	37.0(1) x 2 = 74	89 / 35 x 2 = 70(2)(3)
MRYS U2		CERAM	B&McD / Fuel Tech
Process Location		TESCR Reactor Inlet	LDSCR Reactor Inlet
Particulate mass flow	Lb/h	80.0(1) x 2 = 160	155 / 77 x 2 = 154 (2)(3)

Notes:
(1) Particulate emission rate is per reactor assuming two reactors per Unit, so correct total is double the amount CERAM noted in their proposals.
(2) Calculated by multiplying design maximum average boiler heat input rate (million Btu per hour) by the maximum average particulate loading (pound per million Btu) to give lb/h particulate emission rates.. The Fuel Tech March 11, 2009 preliminary mass balance spreadsheets list 35 lb/hr x 2 for Unit 1 and 77 lb/hr x 2 for Unit 2 at ESP outlets.
(3) Value not included in vendor quote.

Upon review of the SCR process design values provided in the table above, we notice that average hourly mass particulate emissions in the preliminary mass balance spreadsheets given to the two catalyst vendors for Unit 1 were inadvertently underestimated by approximately 17 percent (37 x 2 = 74 lb/h instead of 89 lb/h). CERAM appears to have misstated the mass particulate emissions in their initial and updated proposals in response to Minnkota's August 2009 LDSCR and TESCR RFP by a factor of two, but have assured Burns & McDonnell that the smaller values shown in the table above were used in their catalyst design calculations on a per reactor basis as provided in the Fuel Tech LDSCR and TESCR preliminary design basis spreadsheets (dated March 11, 2009). Average hourly mass particulate emissions given to Babcock Power (responsive SCR system supplier) were inadvertently underestimated by approximately 21 percent for Unit 1 (35 x 2 = 70 lb/h instead of 89 lb/h).

<u>Microbeam Technologies report on MRYS Unit 2's measured flue gas particulate emissions</u>

We reject many statements made by Mr. Hartenstein in his April 2010 report regarding the MRYS Unit 2 aerosol particulate testing performed in March 2009 and the Microbeam Technology July 2009 report summarizing the results of the analyses of the samples obtained from these tests.

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[99] Ibid Reference number 8, pages 24 and 25, April 2006.

Mr. Hartenstein's premise that "it is conceivable that the higher particulate concentrations found during the MTI testing compared to the stack testing results since 2005 can be attributed to higher than design flue gas velocities and excessive droplet carryover from the FGD absorber"[100] is unsubstantiated. Many of the reasons postulated by the DOJ's SCR consultant are not proven to be valid for the MRYS case. There could be other valid reasons why particulate loadings at the Unit 2 FGD absorber outlets measured in 2009 are higher than those measured at the stack in 2008. The primary reason is that the stack and aerosol tests were not done simultaneously and thus were performed in different time periods under different firing/load, fuel, ash, and particulate collection conditions. Comparisons of the sort presented by Mr. Hartenstein are speculative and not particularly useful when discussing the details of aerosol particulate emissions reported from Minnkota's Unit 2 boiler.

The penetration of fine particulate through dry ESPs and wet scrubbers has been presented in previous responses[101]. The DOJ's SCR consultant incorrectly implies that Minnkota's Unit 2 FGD absorbers (two units in parallel) do not have wall rings to enhance sulfur and particulate removal efficiencies. In fact, Minnkota's existing scrubbers do have wall rings and high efficiency outlet mist eliminators. Particulate carryover from MRYS wet scrubbers was measured (at one of the absorber's outlet ports) with the flue gas bypass dampers closed, simulating conditions similar to those that will exist in 2011 and beyond after current ductwork modifications and new chimney under construction are completed in late 2010.

Mr. Hartenstein reviewed the work conducted by Kling and others (2007) who conducted research which found significant catalyst deactivation due to the accumulation of alkali elements in a hot side application. Kling and others (2007) found a correlation between the ultrafine particles and alkali (sodium and potassium) accumulation in the SCR catalysts that were exposed to flue gas derived from firing various types of biomass feedstocks. The following is a quote from the Kling paper

"The study has shown a linear correlation between exposure time in the boilers and alkali concentration (mainly potassium) on the samples. The results ***imply*** *that mainly alkali in ultra fine particles (<100 nm) in the flue gas increased the alkali accumulation on the catalyst samples. Low correlation was found between particles larger than 100 nm and the catalyst deactivation."*

Mr. Hartenstein elaborated on the results and conclusions drawn by Kling and others (2007) by making the following statement.

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[100] Ibid Reference number 22, page 26, April 2010.

[101] See Reference number 23 h., pages 18-22, February 2009.

Based on very extensive work and testing done by Kling et. al.[25], only the sodium and potassium bearing aerosols of the size fraction of less than 0.1 µm are of critical importance for catalyst deactivation while Kling found that the ones larger than 0.1 µm in size can be considered largely irrelevant for catalyst deactivation.

The work was not that extensive and nowhere in the referenced paper did Kling and others (2007) indicate that the larger particles are "largely irrelevant for catalyst deactivation" as elaborated by Mr. Hartenstein. Kling and others (2007) did not report that the particles larger than 0.1 µm were unimportant. They just did not find a good correlation. The dataset that they had was not sufficient to make good correlation. Kling and other (2007) indicated that they are uncertain in their correlations made between the impactor mass in the various size fractions and alkali accumulation and qualify the correlations made with the following statement:

> *"The uncertainty in the correlation between the impactor measurements and the alkali accumulation on the catalyst samples were however large. Only one or two impactor measurement of flue gas composition, each with about 20 min sampling time, has been conducted for each catalyst exposure season—in total up to 3000 h."*

Kling and others (2007) conducted testing in a high dust location and could not specifically separate the impacts of the ultrafine sized particles from the larger particles. Figure 1 shows the mass size distribution of the ash particles collected from the flue gas when firing various biomass material. Note that the highest abundance of particles on a mass basis is between 0.1 µm and 1 µm, not at the 0.1 µm (100 nm).

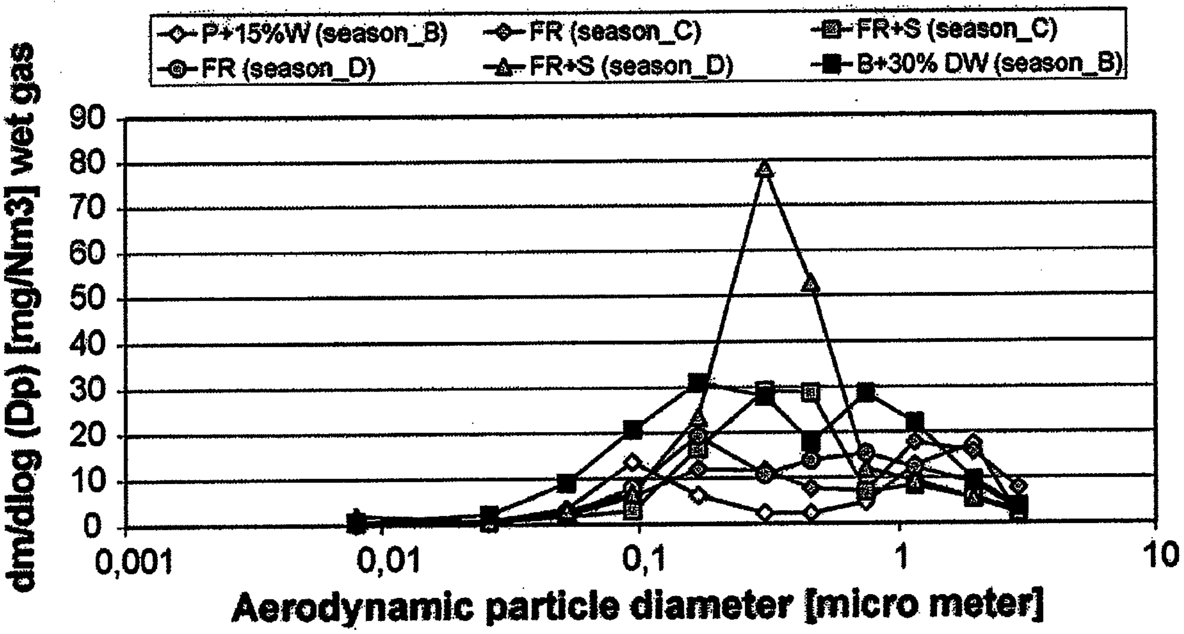

Figure 1. Mass size distribution of ash materials collected from flue gas from biomass fired system (Kling and others, 2007).

The abundance of the sodium, potassium, calcium, chlorine, and phosphorus were plotted as a function of size for the ash materials collected from the flue gas is shown in Figure 2. The results show that there is a significant variation in the abundance of the components as a function of size and the highest concentrations were found between 0.1 and 1.0 µm. The deactivation of catalyst is shown in Figure 3 indicating range in the degree reduction in catalyst activity.

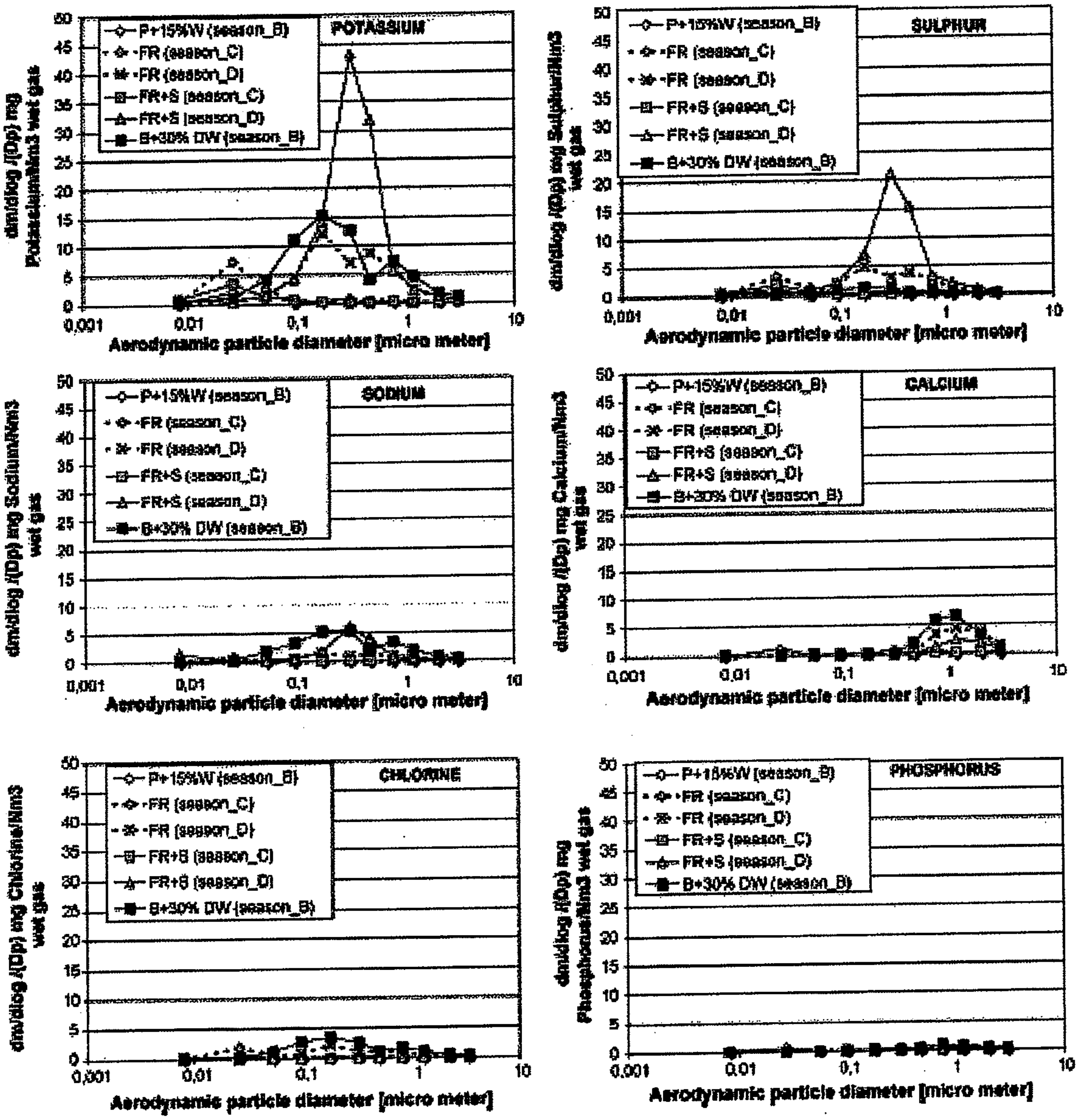

Figure 2. Fly ash mass size distribution (mg/N m3) for potassium, sodium, chlorine and sulphur, lead, zinc, phosphorus and calcium: P, peat; W, wood; FR, forest residues; B, bark; DW, demolition wood (Kling and others, 2007).

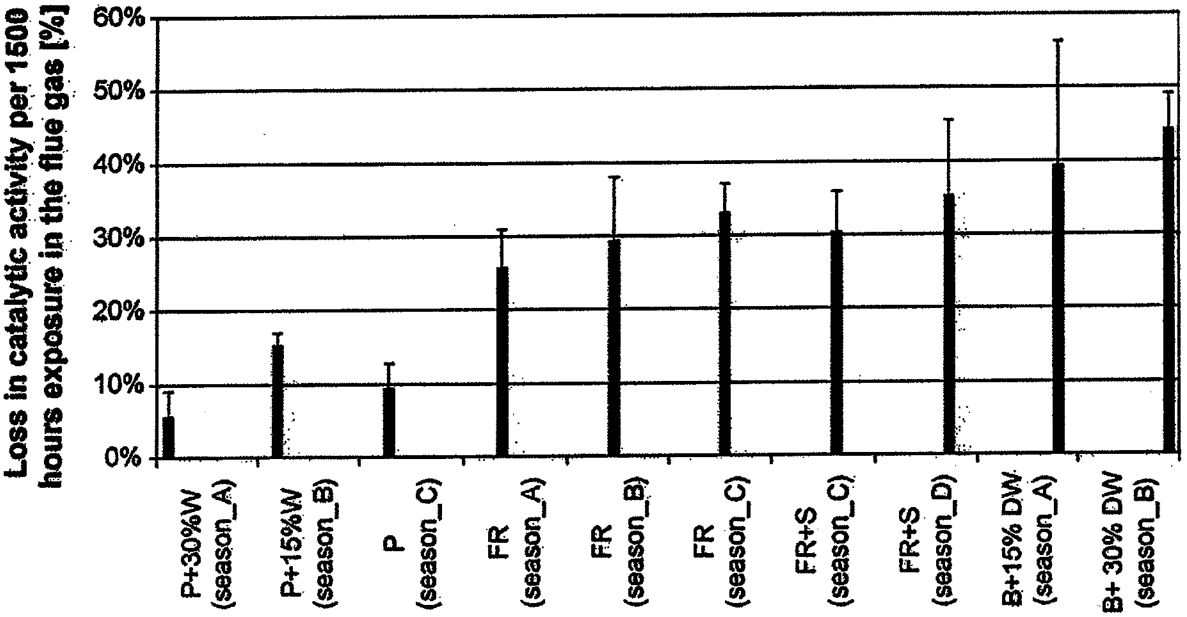

Figure 3. Catalyst deactivation per 1500 hours for various flue gases produced from biomass (Kling and others, 2007).

The impact of the intermediate or fine mode (0.5 to 1μm) of particulate materials on accumulation in the SCR catalyst and catalyst deactivation cannot be ruled out as suggested by Hartenstein. Mr. Hartenstein ignored past peer reviewed literature on the impacts of intermediate fine particulate mode (0.5 to 1μm) on catalyst performance. Of specific interest is a study of SCR catalyst deactivation when exposed to flue gas derived from a biomass grate fired system conducted by Zheng and others, 2005. They found significant catalyst deactivation for ash particles just under 1 μm in diameter. The mass size distribution of the ash produced from grate-fired biomass fired system contained mostly the fine or intermediate mode of particles (0.5 to 1μm) as illustrated in Figure 4. They used a Berner-type low pressure impactor that could aerodynamically classify particle from 0.028 to 12.8 μm. The Berner-type impactor is similar to Dekati impactor used by UND in the Microbeam study (Laumb and others, 2009). The reason for the lack of ultrafines is likely due to lower combustion temperatures and the bed burning environment found in a grate fired system. These intermediate mode or fine particles in the 0.5 to 1μm range were found to have a significant impact on the reactivity of the SCR catalyst as illustrated in Figure 5 where the reactivity dropped by 52% in about 1140 hours of exposure. This is evidence that the deactivation of SCR catalyst is not limited to only the ultrafine particles but the larger 0.5 to 1μm particles are equally or more important.

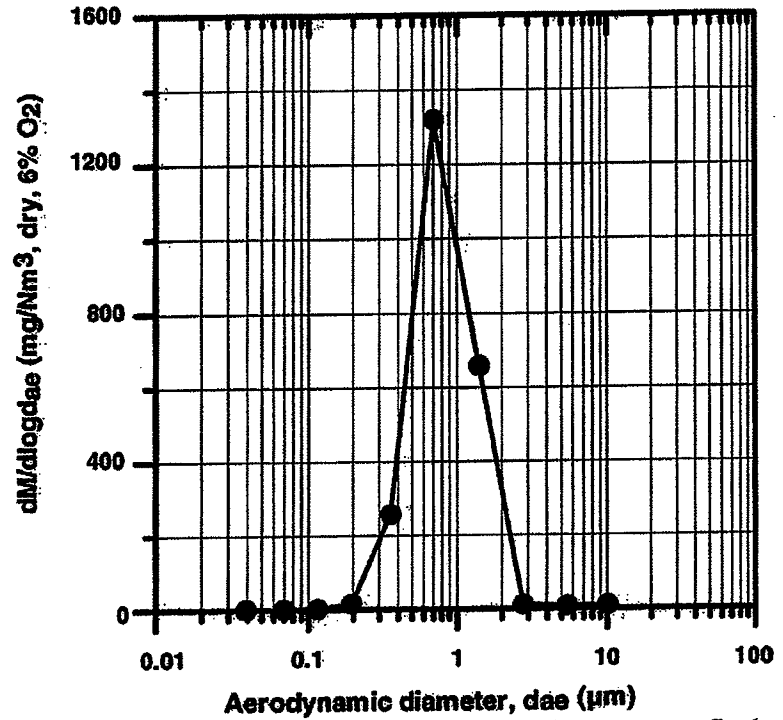

Figure 4. Size distribution of particles collected from a grate fired biomass system (Zheng and others, 2005).

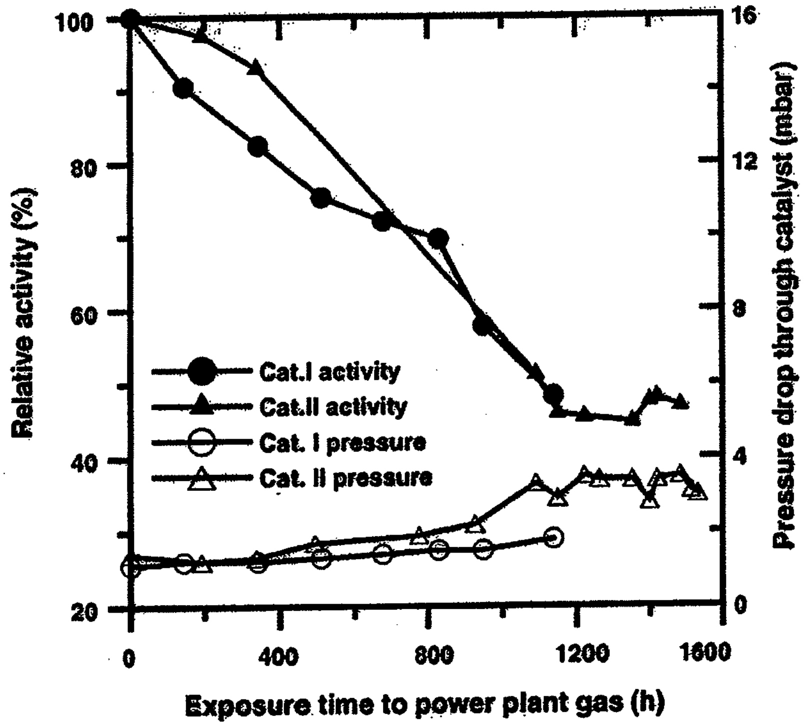

Figure 5. The activities of SCR catalysts and pressure drops over catalysts as a function of exposure time to power plant flue gas (Zheng and others, 2005).

The mass size distribution of the particles produced in the grate fired system (Figure 4) is slightly larger than that found for the exit of the MRY Unit 2 scrubber as shown in Figure 6. This is evidence that the particles in the size range of 0.5 to 1 μm exiting the MRY 2 scrubber cannot be ignored as suggested by Hartenstein and have the potential to impact catalyst performance.

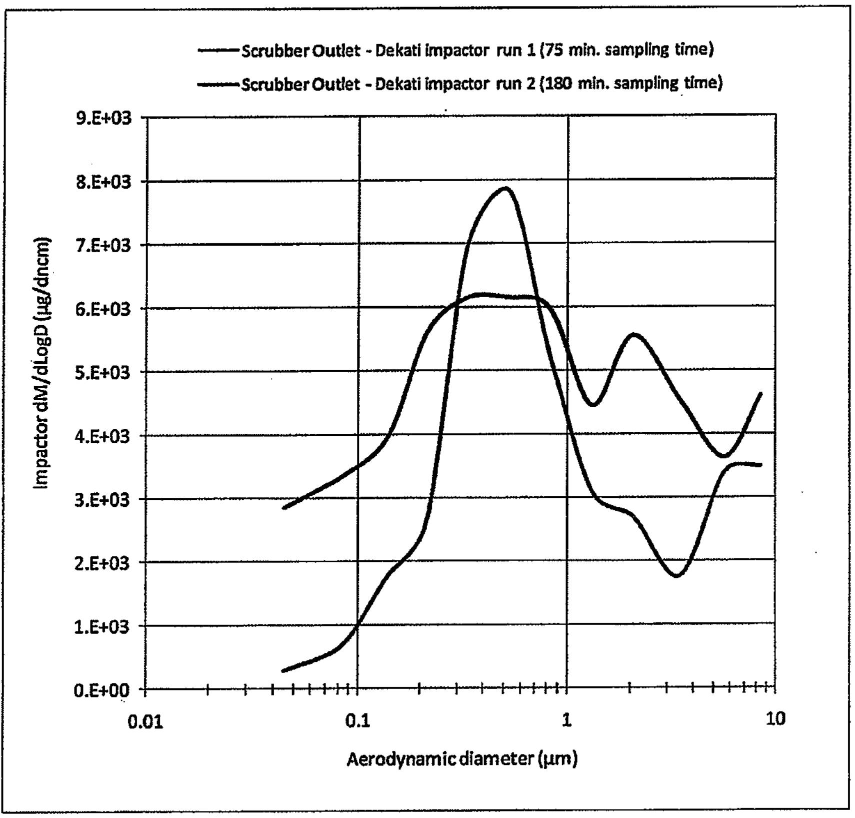

Figure 6. Mass size distribution for the ash collected downstream of the scrubber (Laumb and others, 2009).

Hartenstein appears to be relying heavily on the work by Markowski and others (1983) in his April 2010 report[102] and with reference to his March 2010 SCR catalyst vendor inquiry. This earlier work must be used with caution and puts into question the validity of Hartenstein's March 2010 SCR catalyst vendor inquiry. The Markowski and others (1983) work is consistent with the sampling effort at MRY Unit 2 scrubber summarized in the 2009 Microbeam report (Laumb and other, 2009) in that the concentration of the fine particle emissions at the scrubber exit for one of the tests was 8800 μg/m^3 at a coal ash content of 8.41% and the work of Laumb and others (2009) was 10,000 μg/m^3 at an ash content 7.8%. The referenced 2009 Microbeam report indicated an average ash content in lignite of 8.41 % ash, which is typical of the ash content of lignite fired at the plant of 9.5%. Future projections for fuel quality range from 8.4 to 9.5% on an

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[102] Ibid Reference number 22, page 34, April 2010.

as-received basis as illustrated in Figure 7. North Dakota lignite coals having higher ash contents of between 12 and 19% were fired when much of the earlier testing was conducted by Markowski and others (1981). These higher ash lignites will produce lower levels of less than 1 μm particulate as compared to the lower ash coal because of the abundance and form of the inorganic components in the North Dakota lignite described in detail in Appendix C of the report by Laumb and others (2009). For the high ash coals, Markowski and others (1983) measured the levels of particulate at the scrubber outlet to be 2500 $\mu g/m^3$; these coals are currently not fired without blending with lower ash coal to decrease the ash content because of challenges with cyclone performance. Fuel properties are managed to maintain an ash level and base-to-acid ratio that allows optimum performance of the cyclone fired combustion system. Relying on the particulate measurements made by Markowski and others (1983) on the high ash lignite as it appears that Hartenstein did in his 2010 SCR vendor inquiry does not represent the current and future fuels fired at the plant.

In addition, Hartenstein's comment "Appendix C [of the Microbeam report, July 2010] is merely a regurgitation of mostly irrelevant information"[103] indicates that he does not consider the forms and abundance of the inorganic components in North Dakota lignites as being important. This is a **major oversight** of Hartenstein in that the forms and abundance of the inorganic species in lignite have played a major role in the design as well as the feasibility of technologies that utilize North Dakota lignites. For example, the size of pulverized coal-fired boilers is much larger for high sodium lignite boilers than for subbituminous or bituminous fired systems. The larger size of the boiler allows for more cooling of the products of combustion to minimize fouling and slagging of the upper furnace waterwalls and convective pass superheater/reheater tubes. Further, pilot testing of Powerspan's barrier discharge reactor used for multipollutant technology at MRYS was found to be severely impacted by sodium aerosols.

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[103] Ibid Reference number 22, page 34, April 2010.

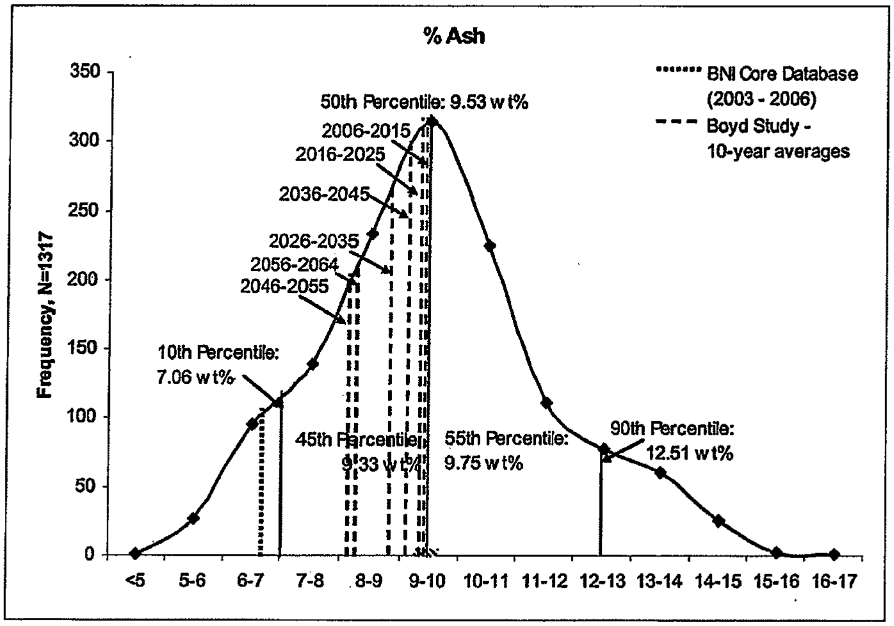

Figure 7. Ash content of lignite fired at MRYS and future projected blend based on core database.

Responses to DOJ's SCR Consultant's Individual Comments to NDDH's January 2010 Request

Responses to Comments to NDDH Request #1

We recommend that the NDDH ignore the majority of the DOJ's SCR consultant's comments for this item because they do not address the questions raised by the NDDH's request. Comments about the SCR system supplier that Burns & McDonnell selected for the Minnkota budgetary proposal of the hypothetical LD and TESCR system attempt to portray the vendor as inexperienced in low-dust SCR applications. Burns & McDonnell mentioned the SCR system supplier in the December 2009 response[104] primarily because of the relevance to the vendor's recent involvement on the WE Energies South Oak Creek LDSCR project, which initially began (conceptually) as a tail end SCR approach.

Much of the commenter's discussion focused on Burns & McDonnell's approach of using natural gas for flue gas reheating. Reasons for this selection were documented in the December 11, 2009 response to the NDDH[105]. For Minnkota's 2009 capital cost estimate and supplemental BACT analysis of the hypothetical LD and TESCR systems, a system using recirculated hot air applying electric resistance heaters was assumed for heating the closed SCR reactor and catalyst to avoid moisture condensation during boiler outages. This electric heat/air recirculation system was expected to operate during startups and shutdowns along with the natural gas-fired main reheat burner system to maintain flue gas temperature control.

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[104] Ibid Reference number 13, page 2, December 2009.

[105] Ibid, pages 3-7, December 2009.

Responses to Comments to NDDH Request #2

Reasons for this selection were documented in the February 11, 2010 response to the NDDH. See additional discussion regarding use of urea versus anhydrous ammonia under item 2 of the section "Responses to EPA Comments on SCR Annual Cost Estimates and Methods" on page 12 herein.

Responses to Comments to NDDH Request #3

Reasons for the catalyst replacement duration outage assumptions were summarized in the February 11, 2010 response to the NDDH. Because of the nature of scheduled boiler cleaning outages taking place during all seasons of the year, it should be noted that ambient weather conditions can also have significant impacts beyond catalyst reactor interior design, access, and replacement catalyst handling system design assumptions involving catalyst replacement duration. We know of no examples of SCR catalyst being replaced at existing installations in the middle of winter as severe as often experienced in North Dakota, which can frequently see subzero ambient temperatures, - winds of 30 miles per hour and greater, with significant snow accumulations. The low-dust and tail end SCR reactors were assumed to not be totally enclosed inside a heated building for the purposes of Minnkota's 2009 capital cost estimate and supplemental BACT analysis of the hypothetical LD and TESCR systems. See additional discussion under item 3 of the section "Responses to EPA Comments on SCR Annual Cost Estimates and Methods" on page 12 herein regarding the number of additional outage hours not being solely a matter of catalyst replacement duration and frequency.

Responses to Comments to NDDH Request #4

We recommend that the NDDH ignore the majority of the DOJ's SCR consultant's comments for this item because they do not address the questions raised by the NDDH's request. Explanation of the estimated indirect capital costs was summarized in the November 2009 Supplemental NOx BACT Analysis Study reports, December 11, 2009 and February 11, 2010 responses, and December 21, 2009 presentation to the NDDH, with additional discussion presented earlier in this response document.

Much of the commenter's discussion focused on Burns & McDonnell's project schedule for completion of hypothetical LD and TESCR systems for MRYS Unit 2 by year-end 2016 and by year-end 2017 for Unit 1. This schedule assumed that extensive slip-stream pilot-scale catalyst testing would be required and nearly completed before SCR system selection could be confirmed and design finished. There are also significant additional challenges that would be faced in retrofitting low-dust and tail end SCRs at MRYS involving:

- scheduling of placement of major equipment structural foundations to avoid winter weather;
- large rotary regenerative flue gas-gas reheating and induced draft fan equipment design, procurement, and field assembly/erection;

- design, procurement, field assembly/erection of modifications to existing/replacement of sections of large fiberglass-reinforced flue gas ductwork;
- coal storage and handling modifications and installations;
- flyash storage and handling modifications and installations.

None of the schedule examples cited by Mr. Hartenstein involved low-dust or tail end SCRs. The amount of time claimed to be required to execute retrofit SCR projects does not mention whether extensive slip-stream pilot-scale catalyst testing programs, with design and procurement of SCR system equipment of suitable scale and ability to simulate full-scale operation was required, nor the time to perform long-term testing, analyze the test catalyst, and report the results.

Responses to Comments to NDDH Request #5

We recommend that the NDDH ignore the DOJ's SCR consultant's comment for this item because it does not reflect or consider the assumption that the cost effectiveness analysis in the November 2009 Supplemental NOx BACT Analysis Study reports used the power industry's natural gas unit cost forecasts from 2006, in order to be consistent with the cost effectiveness analysis performed and reported in October 2006 for the non-SCR alternatives that involve consumption of natural gas.

Responses to Comments to NDDH Request #6

We recommend that the NDDH ignore the DOJ's SCR consultant's comments for this item. The comments do not reflect or consider the reasons for the preliminary design basis and assumptions involved with [estimating the capital and operating/maintenance costs for] retrofitting low-dust and tail end SCRs at MRYS that have been presented earlier in this document.

Responses to Comments to NDDH Request #7

Discussion of the SCR system supplier's and catalyst vendors' proposals were summarized in the February 11, 2010 response to the NDDH, with additional responses as provided elsewhere in this document.

Responses to Comments to NDDH Request #8

The flue gas-gas reheating equipment temperatures have not been finalized because the process calculations used as a basis of the system design in hypothetical applications of low-dust and tail end SCRs at MRYS are preliminary. The assumptions were summarized in the February 11, 2010 response to the NDDH.

Responses to Comments to NDDH Request #9

Many comments presented by the DOJ's SCR consultant regarding the WE Energies South Oak Creek Units 5, 6, 7, and 8 and PSE&G's Mercer Units 1 and 2 cold-side LDSCR retrofits contain significant errors and other statements that are incorrect and misleading:

- South Oak Creek LDSCRs are not designed for 90% NOx removal efficiencies. Confirmation from the SCR system supplier (Babcock Power)[106] indicates design inlet NOx emissions ranged between 0.15 and 0.22 lb/mmBtu and guaranteed outlet emissions of 0.07 lb/mmBtu. This results in nominal SCR system overall NOx removal efficiencies between 53% and 68%. Even if the worst case amount of untreated gas leakage across the GGH to the reactor inlet is factored in (up to 5%, which is much greater than the 1% leakage guaranteed by the GGH vendor without seal air usage), and a performance margin below 0.07 lb/mmBtu outlet emissions (to 0.065 lb/mmBtu) were applied, the actual reactor NOx removal efficiencies could be around 75%. This is substantially less than the amount claimed by the DOJ's SCR consultant.
- Mercer LDSCRs were not designed for 90% NOx removal efficiencies. The SCR system supplier (Babcock Power) that subsequently worked on the project believes the nominal SCR system overall NOx removal efficiency was 85%[107].
- Mercer boilers are not cyclone-fired as claimed. They are twin-furnace wet bottom (slagging) pulverized coal-fired boilers with high uncontrolled NOx emissions, but which have been previously retrofitted with amine-enhanced selective non-catalytic reduction (AESNCR™) technology[108].

We believe it is inappropriate to compare the capital costs associated with the low-dust SCR installation at Mercer Station, or at South Oak Creek Station, against those developed for the hypothetical applications of low-dust and tail end SCR technologies at MRYS. This is primarily because:

- Control cost effectiveness of alternatives in a BACT analysis is calculated prospectively, i.e. before the selected alternative has been chosen and implemented. This request involves comparing an actual cost amount against an estimated number, which while the latter is sufficient for the purposes of performing a BACT analysis for control cost effectiveness, is not based on similar assumptions of implementation. The Mercer project has been completed and (presumably) all project capital costs should be known. While the South Oak Creek Station LDSCR projects are not completely constructed, we believe all major equipment has been procured and construction contracts substantially underway. The forecast capital costs for South Oak Creek Station LDSCR projects' completion should be fairly close to what will be the actual final amount. The capital costs estimated by Burns & McDonnell for the hypothetical applications of low-dust and tail end SCR technologies at

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[106] Telephone conference call between R. Blakley and C. Weilert of B&McD with M. Gialanella, J. Waller, and C. Erickson of Babcock Power on July 22, 2010.
[107] Ibid July 22, 2010.
[108] See Reference number 26.

MRYS are not based on completed final designs and firm bid equipment quotes and installation bids for the SCR systems and auxiliaries. Because actual equipment procurement contracts are often higher in monetary amount than the initial budgetary quotes, the latter not being a "not-to-exceed" amount, we believe that the previous and current response to this NDDH request issue is suitable and sufficient.

- Mercer LDSCRs were implemented due to a Consent Decree (and subsequent amendment) that required installation of "state-of-the-art controls", including SCR technology, and achieving and maintaining NOx emission rates at Mercer Unit 1 and Unit 2 no greater than 0.100 lb/mmBtu based on 90-day rolling average emission rates[109]. This was not a case where a BACT analysis and a BACT determination were required for nitrogen oxide emissions controls, which is what applies to MRYS.

Responses to Comments to NDDH Request #10

Explanation for the selection of natural gas for a flue gas reheat source was provided in the December 11, 2009 response to the NDDH, and the discussion of the determination that Minnkota's units are boiler-limited was documented in the February 11, 2010 response to the NDDH.

Responses to Comments to NDDH Request #11 a

We reject the DOJ's SCR consultant's comments that "B&McD coarsely overestimated the TESCR, for which HTI didn't offer any specific deactivation rate and exchange frequency"[110]. Clarification of the catalyst volume for MRYS Unit 2 reactors was documented in the February 11, 2010 response to the NDDH. Haldor Topsoe's October 2009 proposal primarily focused on catalyst volume, pitch, and composition for reactors sized for a low dust SCR on each MRYS boiler located just downstream of the ESP. Burns & McDonnell assumed the volume of catalyst for a hypothetical application of low dust SCR on each MRYS boiler was also the same for a tail end SCR configuration, based upon statements in Haldor Topsoe's confidential October 12, 2009 proposal. However, the commenter ignores these statements in HTI's proposal. We recommend that the NDDH ignore the DOJ's SCR consultant's comments for this item. The comments do not reflect or consider the reasons stated in HTI's October 2009 proposal[111] for the preliminary design basis and assumptions involved with [estimating the capital and operating/maintenance costs for] retrofitting low-dust and tail end SCRs at MRYS that have been presented earlier in this document and in the November 2009 Supplemental NOx BACT Analysis Study reports.

Responses to Comments to NDDH Request #11 b

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[109]

[110] Ibid Reference number 22, page 39, April 2010.

[111] Ibid Reference number 5, Appendix D.

Many comments presented by the DOJ's SCR consultant regarding the flue gas reheating equipment process design and impacts using steam on unit electrical energy output for cold-side LDSCR and tail end SCR retrofits contain significant statements that are incorrect and misleading:

- No actual examples are provided by Mr. Hartenstein involving the use of natural gas for flue gas reheating of LD and TESCRs in Europe, which he has repeatedly claimed are typically reheated using steam. Assumptions and comparisons of flue gas reheating equipment process design and impacts using steam on unit electrical energy output are expected to be different than the process design using natural gas, otherwise, why would the EPA and the DOJ's SCR consultant so vigorously argue about Minnkota's choice to use natural gas and its influence on the control cost effectiveness numbers calculated by Burns & McDonnell in the November 2009 Supplemental NOx BACT Analysis Study reports.
- The majority of the commenter's arguments involve the estimated amount of reduction in unit electrical energy outputs from using steam for flue gas reheating in hypothetical applications of low-dust and tail end SCR technologies at MRYS, including using the uncorrected GGH temperature gradient for MRYS Unit 1's LDSCR. We disagree with the commenter's statement that the amount of reduction in unit electrical energy outputs from using steam for flue gas reheating should be the same between LD and TESCRs for the same temperature gradient across the SCR GGH for each unit. This ignores the reality that flue gas is saturated with water at the FGD absorber outlets, which requires more heat to raise the flue gas the same amount of temperature rise as a LDSCR case. While the flue gas temperature is slightly above saturation (increased by the FGD GGH in Minnkota's cases) before entering the SCR GGH in the TESCR cases and so does not necessitate adding the latent heat of water vaporization by the SCR GGH, the higher moisture content of the flue gas from the scrubber will still require more heat to raise its temperature versus a LDSCR case. The amount of SCR flue gas-gas heat exchanger heat transfer and supplemental heat required was calculated by B&McD's SCR process design consultant for each of the four cases (MRYS U1 LD and TESCRs, U2 LD and TESCRs). This was described in the December 11, 2009 response to the NDDH. Unit 1's LDSCR case was subsequently revised in February 2010 and submitted in the February 11, 2010 response and revised February 2010 Unit 1 Supplemental NOx BACT Analysis Study report.
- We also dispute the commenter's statement that SCR operating temperatures and SCR flue gas-gas heat exchanger temperature gradients should be the same for LD versus TESCRs at MRYS. This ignores the reality that flue gas upstream of the FGD absorbers includes many times more sulfur dioxide and is expected to have more sulfur trioxide concentrations than downstream of the scrubber outlets. Acid dewpoint temperatures of the flue gas will be higher before the scrubbers than after. This is the reason why the LDSCR reactor temperatures need to be higher. It was because of the expected commonality of the SCR GGH equipment that the temperature gradients were selected to be

the same for all cases (corrected) of hypothetical applications of low-dust and tail end SCR technologies at MRYS.

- We disagree with the commenter's assumptions involving diverting steam for flue gas reheat not causing an increase in unit heat rate (lower heat to electricity conversion efficiency). Steam used for flue gas reheating must be at sufficient pressure, whether saturated or superheated, to provide a heat source with temperature high enough to be at or above the desired reactor inlet temperature, due to the inefficiency of the steam-to-gas heat exchanger used in the example that the DOJ's SCR consultant provided. Any steam withdrawn from a subcritical boiler's steam drum reduces the amount that is available to go through the superheater sections prior to the main steam piping supplying the steam turbine inlet. While there are other potential uses for this diverted steam, the point of the December 11, 2009 response[112] was to explain that steam that would normally flow from the boiler to the steam turbine so that the energy it contains would produce electrical power from the main generator would be reduced in mass flow, and thus gross unit output (MW_g) will decrease. Steam used for dilution air heating or feedwater heating is normally supplied from the steam turbine by extraction, but it does add to the generator's electrical output before being extracted. So there is a heat rate penalty (loss of efficiency in converting heat to electricity) if high pressure steam in any form is used for flue gas reheating.
- We believe there is a possibility that a flue gas reheat steam coil, placed after the main SCR GGH, could become fouled with deposits. This may occur due to pass-through of particulate and moisture during cold unit startups when coal is first being fired and the scrubber is operating (outlet gas is saturated). A period of time before sufficient heat is available from the GGHs and recirculated gas to raise all the metal SCR ductwork in temperature so there will be no acid or vapor condensation could exist when the deposits could form. We doubt that any of the European boilers with TESCRs using steam coils for flue gas reheating have particulate with such sticky characteristics as could occur at MRYS.
- Minnkota and Burns &McDonnell were not asked to calculate control cost effectiveness or substantiate potential impacts on operating costs from steam usage for flue gas reheat associated with LD and TESCRs more than two years ago. The Supplemental MRYS NOx BACT Analysis Study reports were submitted in November, 2009, less than four months after receiving the request letter from the NDDH dated July 15, 2009. A letter request from the NDDH regarding the use of steam from the main boilers for flue gas reheat NDDH's was dated November 25, 2009 and a response was submitted on December 11, 2009. A response to a subsequent letter from the NDDH dated January 11, 2010 was provided on February 12, 2010 that answered the question involving an apparent

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[112] Ibid Reference number 13, page 4, December 2009.

discrepancy in reheat for MRYS Unit 1's low-dust SCR case in the November 2009 Supplemental MRYS NOx BACT Analysis Study.

- The units at MRYS are boiler-limited. The higher the hourly fuel firing rate, the faster the boilers' fireside surfaces foul with ash and slag deposits. Minnkota has determined through years of experience how to sustain operation at outputs close to maximum continuous ratings before having to shutdown and remove the fireside deposits. Even if they were not boiler-limited, sustained firing of additional fuel for producing the same gross megawatt output as without steam usage for flue gas reheat would create an increase in annual tons of NOx and other emissions, compared with not using steam and not firing harder, even if emissions are controlled at lower lb/mmBtu rates.

Responses to EPA's SCR Cost Analysis

We believe that the EPA's attempt to recalculate the control cost effectiveness analysis improperly oversteps the detailed, site-specific basis and rigorous cost estimating approach that has been provided by Burns & McDonnell and submitted by Minnkota for use by the North Dakota Department of Health's Air Quality Division as the basis for their preliminary determination of Best Available Control Technology for the control of nitrogen oxides emissions from the cyclone boilers firing North Dakota lignite at the Milton R. Young Station. The EPA's interpretation and denials of the valid use of documented assumptions are not consistent within the NSR Manual and its Appendix B for the hypothetical SCR cases in the November 2009 Supplemental NOx BACT Analysis studies for MRYS Unit 1 and Unit 2. The NSR Manual specifically mentions the use of a levelizing cost approach for estimating annual control costs of alternatives in a BACT analysis. The EPA's approach ignores the disclaimer included in its own OAQPS Control Cost Manual chapter for SCR that states it should not be used to estimate costs regarding cases of tail end [and low-dust] SCRs requiring flue gas reheat equipment. The EPA's claims that anhydrous ammonia must be assumed as the only allowed reagent and that use of regenerated catalyst should be assumed are unsubstantiated and unproven.

Summary of Responses to EPA and DOJ's SCR Consultant's Comments

SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT/BART Analysis Study reports and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports and subsequent responses. We disagree with the EPA's conclusions that the "there is a presumption that SCR is both technically and economically feasible at MRYS" simply because "SCR has been successfully applied worldwide to such a wide variety of sources" [113]. We believe that the EPA has incorrectly interpreted the NSR Manual and improperly compared NOx control costs of hypothetically-applied low dust and tail end SCRs on MRYS cyclone boilers firing North Dakota lignite to other emission sources of dissimilar type and ignored the other mitigating circumstances that the NDDH considered before issuing their revised preliminary BACT Determination for the M.R. Young Unit 1 and Unit 2 boilers.

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[113] Ibid, Reference number 2, page 29, May 2010*.

Responses to May 2010 National Park Service Comments

We believe that the NPS's attempt to recalculate the control cost effectiveness analysis improperly oversteps the detailed, site-specific basis and rigorous cost estimating approach that has been provided by Burns & McDonnell and submitted by Minnkota for use by the North Dakota Department of Health's Air Quality Division as the basis for their preliminary determination of Best Available Control Technology for the control of nitrogen oxides emissions from the cyclone boilers firing North Dakota lignite at the Milton R. Young Station. The NPS's approach ignores the disclaimer included in the EPA's OAQPS Control Cost Manual chapter for SCRs that it should not be used to estimate costs regarding cases of low-dust and tail end SCRs requiring flue gas reheat equipment. There are other assumptions made by the NPS for their control cost analysis that we disagree with, essentially for the same reasons as stated in our responses to the EPA's May 2010 comments. It should also be noted that MRYS NO_X BACT Analysis alternatives' control costs were estimated prospectively with calendar year 2006 basis, including those involving hypothetical applications of low-dust and tail end SCR technologies. We reject the NPS's NOx control costs effectiveness analysis for MRYS for many reasons not repeated here, particularly because it makes numerous assumptions that are inconsistent with the MRYS NO_X BACT Analyses for non-SCR alternatives and does not consider or address incremental control costs in accordance with the NSR Manual.

We also disagree with the National Park's Service calculations of baseline NO_X emissions and annual reductions claimed to be in accordance with the EPA's NSR Manual. The NSR Manual states "Annual "potential" emission projections are calculated using the source's maximum design capacity and full year round operation (8760 hours)....[and] emissions estimates used for the purpose or calculating and comparing cost effectiveness of a control option are based on a different approach"[114]...For cost-effectiveness analysis, the NSR Manual also states: "Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in developing a realistic upper-bound case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"[115].

On an annual basis, historical data for MRYS Unit 1 and Unit 2 boilers used in the NOx BACT analyses are considered a valid representation of the annual NO_X tons to be assumed for the pre-control annual baselines for the purpose of calculating cost effectiveness of control options. It is unrealistic to assume that these boilers would be capable of operating at the maximum hourly heat input ratings continuously with allowable annual average unit emission rates for 8,760 hours per year for the estimation of control cost effectiveness of

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[114] Ibid Reference number 10, page B.23, October 1990.

[115] Ibid, page B.37, October 1990.

NO_X control options. It should be recognized that the NO_X control cost analysis for MRYS Unit 1 and Unit 2 boilers has a different annual pre-control and post-control basis than what is used for visibility impairment impact analysis for BART.

The fact that the estimated site-specific total installed capital costs of the hypothetical applications of SCRs in Minnkota's Supplemental NO_X BACT Analysis studies do not correspond with NPS's assumptions and use of cost ratios to develop their estimates is not a result of Burns & McDonnell improperly accounting for design, procurement, and installation conditions. We believe it is a failure on the NPS's part to recognize the limitations of their methods and use of the OAQPS Control Cost Manual with respect to accurately estimating costs of these technologies on a relevant site-specific basis. NPS has ignored the previously-stated disclaimer not to use the referenced EPA OAQPS Control Cost Manual report because of its inadequacies.

The NPS believes that NDDH should have considered Regenerative Selective Catalytic Reduction technology for potential application at MRYS on Unit 1 and Unit 2 boilers. We disagree that this form of low-dust cold-side SCR system is applicable and suitable for NO_X emissions control of the units Minnkota operates.

The system supplier (Babcock Power Inc.) markets RSCR® technology to reduce NOx emissions from relatively small biomass (wood)-fired and industrial boilers, waste-to-energy furnaces, and other process applications which lack sufficient space for conventional hot-side high dust SCR and/or need to avoid exposure of the catalyst to untreated emissions[116]. Typical installations have been on wood-fired boilers between 15 and 54 MW equivalent output, reducing NO_X emissions from 0.25-0.28 lb/mmBtu to below 0.065-0.075 lb/mmBtu, for 70-85% control. There have been no known installations on small, medium, or large-scale utility coal-fired boilers. Even though they are called "tail-end" SCR, typical inlet flue gas temperatures are 200-350°F. As far as we can discern, they have not been applied downstream of any boilers with wet or dry flue gas desulfurization systems. Particulate and gaseous emissions from MRYS cyclone boilers firing North Dakota lignite contain sulfur compounds and very fine sodium aerosols, which have been previously described in detail and provided by Minnkota to NDDH. Babcock Power did not suggest to Burns & McDonnell that such a system be considered as an alternate approach for Minnkota when BPI was asked to provide conceptual designs and indicative pricing for MRYS low-dust and tail-end SCRs. Likewise, there is no publicly-available information discovered that indicates that Babcock Power, supplying the low-dust SCRs at South Oak Creek plant Units 5-8 for Wisconsin Electric Power Company, suggested RSCR® technology be applied on these referenced medium-sized coal-fired utility boilers. There is insufficient evidence that RSCR® technology is applicable and suitable for NO_X emissions control of the MRYS Unit 1 and Unit 2

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[116] See Reference number 28, September, 2008.

boilers. Further consideration of RSCR® technology for the MRYS NOx BACT and BART analyses is unwarranted.

Responses to January 2010 National Parks Conservation Association Comments

We reject the NPCA's arguments[117] regarding NDDH's Regional Haze State Implementation Plan (RH SIP) for control of NOx emissions for MRYS for many reasons previously provided and not repeated in their entirety here. A summary of the pertinent major reasons include:

- We continue to agree with NDDH that hot side, high dust SCRs (HDSCRs) are technically infeasible at MRYS. The NPCA fails to recognize that technical issues which include demonstrated failure of the pilot-scale SCR slip stream test at Coyote station, excessive boiler flue gas temperatures and severe flue gas characteristics preclude the successful application of HD SCRs at MRYS. Catalyst vendors require flue gas temperatures to be within a range that their catalyst can withstand and perform effectively for extended periods. Without assurances from SCR system suppliers, i.e. boiler original equipment manufacturers, that the MRYS boiler's extreme flue gas temperature range can be successfully resolved without impacting the required lignite drying systems' performance and reliability, and how much that will cost, there is great uncertainty that hot-side, high dust SCR can be successfully applied and operated even without the added questions of catalyst deactivation, fouling, plugging, and other problems. BACT and BART do not mean "experimental development of air pollution control technologies' design that must be performed as a prerequisite for determining the probable success or potential failure of the subject technology to work successfully".
- NPCA's statements that catalyst vendors bear the risk of failure[118] is misleading – the utility implementing the SCR project pays for potential risk of the vendor to fail to deliver a product usable in the SCR installation by spending sums of money much greater than the initial catalyst cost. The owner of the plant ultimately assumes the business and environmental compliance risks to operate and maintain such air pollution control systems long after the contractural guarantees and warranty periods expire, which are much shorter than the expected remaining life of the equipment or plant.
- NPCA's statements that the catalyst used at the Coyote station pilot-scale SCR slip stream test are incorrect that "while it was *supposedly cleaned* [emphasis added] between tests"...it is undisputed that it was not new or fresh catalyst"[119]. EERC used the same pilot-scale slip stream test apparatus with the same vendor's type, pitch, and formulation of catalyst at the Baldwin station and at Coyote station, but it is indisputable that fresh catalyst was, in fact, used at the Coyote station pilot SCR test.

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[117] Ibid Reference number 4, January 2010*.

[118] Ibid, page 24, January 2010*.

[119] Ibid, page 24; January 2010*.

It is an incorrect interpretation of EERC's technical paper[120], and, along with NPCA's comments regarding pilot SCR test catalyst selection and results of the Coyote and Baldwin pilot-scale slip stream SCR tests, does not accurately reflect subsequent responses on this issue previously submitted to the NDDH and EPA[121].

- NPCA's comments on sodium, catalyst vendor guarantees, and control cost details[122] do not accurately reflect subsequent responses on this issue previously submitted to the NDDH and EPA[123].

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[120] See Reference number 24, October 2005.

[121] See Reference number 23, 2007-2009 and Reference number 16, February and April, 2010*.

[122] Ibid Reference number 4, pages 24-27, January 2010.

[123] Ibid Reference number 238, 2007-2010*.

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: Comments on Preliminary BACT Determination*, dated May 12, 2010.

2. United States Environmental Protection Agency Region 8 letter from Andrew M. Gaydosh to Mr. Terry O'Clair, Director, Division of Air Quality, North Dakota Department of Health, *Re: EPA's Comments on the North Dakota Department of Health's April 2010 Draft BACT Determination for NOx for the Milton R. Young Station,* date stamped May 10, 2010, with enclosures, including a "Request for Proposal for Conceptual SCR Catalyst Design for a Low-Dust and Tail-End System, February 2010" as part of Enclosure 15.

3. National Park Service Policy, Planning and Permit Review Branch from John Bunyak, Chief, Terry L. O'Clair, P.E., Director, Division of Air Quality, North Dakota Department of Health, Environmental Health Section, *Re: NPS comments regarding the proposed [North Dakota Department of Health's April 2010 Draft] Best Available Control Technology (BACT) Determinations [for NOx] for the Milton R. Young Station (MRYS),* dated May 10, 2010.

4. National Parks Conservation Association letter to Terry L. O'Clair, Director, Division of Air Quality, North Dakota Department of Health, *Re: Comments on North Dakota's Regional Haze State Implementation Plan,* dated January 8, 2010.

5. North Dakota Department of Health, Environmental Health Section, Division of Air Quality, *"Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2"*, posted at the NDDH website http://www.ndhealth.gov/aq/Dockets/Minnkota/BACT%20April%202010/BACT%20Analysis/BACT%20Analysis%2004-10.pdf , dated April, 2010. Includes redacted catalyst vendor proposals posted at the NDDH website under Appendix D of the Minnkota Power Cooperative – Preliminary BACT Determination (April 2010) in the public notices> http://www.ndhealth.gov/AQ/Dockets/Minnkota/BACT%20April%202010/Appendix%20D/Haldor%20and%20CERAM%20Statements.pdf.
   This followed *"ND Department of Health, Division of Air Quality Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, June 2008, released for public comment June 3, 2008"*.

6. North Dakota Department of Health, Environmental Health Section, Division of Air Quality, "Final Regional Haze State Implementation Plan Revision", and related documents pertaining to Department BART Determinations in Appendix B.4 for M.R. Young, and Minnkota SCR Technical Feasibility in Appendix B.6, posted at the NDDH website http://www.ndhealth.gov/AQ/RegionalHaze/ , dated November 25, 2009.

7. *"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"*, included with the *"BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc. Final Report, October 2006"*.

8. 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.

9. *"NO$_X$ Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009*; and a separate *NO$_X$ BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009"*, November 12, 2009.

10. 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: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

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

12. 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 Cost Estimate*, dated November 25, 2009.

13. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility"*, December 11, 2009.

14. Burns & McDonnell presentation to North Dakota Department of Health, Air Quality Division "*Milton R. Young Supplemental NOx BACT Analysis Study Review with SCR Cost Estimate Study Summary*" December 21, 2009.

15. 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: SCR Cost Estimate,* January 11, 2010.

16. "*Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility"*, February 11, 2010; and March 31, 2010 correction to revised CERAM catalyst budgetary proposal dated October 13, 2009. (There was a typographical error in the fill-in data sheets regarding the fly ash concentration in the catalyst design for the Unit 1 low dust arrangement; all other aspects of the proposal remained unchanged). This document was submitted to the NDDH and claimed as confidential in accordance with Air Pollution Control Rules for the State of North Dakota at 33-15-01-16. See February 2010 response, page 2, for additional details.

17. EPA Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual – Sixth Edition (EPA/452/B-02-001), January 2002, Section 1 and Section 4.2 Chapter 2.

18. *"Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies"*, J. Edward Cichanowicz, Prepared for Utility Air Regulatory Group, June 2007.

19. United States Environmental Protection Agency Region 8 June 2010 emails with attachments to Tom Bachman, Division of Air Quality, North Dakota Department of Health:
a. CERAM Environmental, Inc. June 4, 2010 email from Greg Holscher to Jeff Kodish, USEPA, with attachment: SCR Catalyst Budgetary Proposal Support for Low Dust and Tail End Study, CERAM Proposal No. GH100315-2 (Confidential), dated March 31, 2010.
b. Haldor Topsoe, Inc. June 17, 2010 email from Nathan White to Jeff Kodish, USEPA, with attachment: Haldor Topsoe Low Dust and Tail End Systems.pdf (confidential quotation, 10-6089-R1), and Haldor Topsoe Catalyst Management Plan.pdf (confidential), dated March 20, 2010.
c. Johnson Mathey Catalysts LLC June 16, 2010 email from Cindy Khalaf to Jeff Kodish, USEPA, with attachment: Budgetary Proposal JMC for LDSCR and TESCR.pdf (confidential proposal 71779), dated March 12, 2010.

20. CERAM Environmental, Inc. letter by Noel Rosha to Luther Kvernen, Minnkota Power Cooperative, Inc., Re: Milton R. Young Station SCR Performance Guarantees, June 11, 2010. (See attachments)

21. Haldor Topsoe, Inc. letter by Wayne Jones to Robert Blakley, Burns & McDonnell., Re: Evonik RFP SCR Performance Guarantees, July 27, 2010. (See attachments)

22. *"Report of Hans Hartenstein: On North Dakota Department of Health's April 10, 2010 BACT Determination for Minnkota's M. R. Young Station, Expert Report of Hans Hartenstein, On Behalf Of The United States Department Of Justice"*, dated April 2010.

23. a. *"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 (re: U.S. EPA Region 8 letter January 8, 2007); and
b. *"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 (re: NDDH letter February 1, 2007 including U.S. EPA Region 8 letter January 26, 2007); and
c. Burns & McDonnell and Energy & Environmental Research Center (EERC) presentation, *"Summary of Responses to EPA/DOH Questions on Minnkota Power's NOx BACT Analysis for Milton R. Young Units 1 & 2, to North Dakota Department of Health, Environmental Health Section, Division of Air Quality, and United States Environmental Protection Agency, May 23, 2007"*); and
d. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Comment and Response To EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station"* November, 2007 (re: U.S. EPA Region 8 letter October 4, 2007); and
e. *"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"; and
f. *"Comments and Responses to NDDH Regarding U.S. EPA Region 8's July 31, 2008 Comments and Plains Justice July 30, 2008 Comments on NDDH Preliminary NOx BACT Determination for Milton R. Young Station (MRYS)"* September 22, 2008 (re: U.S. EPA Region 8 letter July 31, 2008); and
g. Burns & McDonnell, University of North Dakota, and Fuel Tech, *"Responses to Hans Hartenstein's October 2008 Remarks to September 22, 2008 Comments and Responses on NDDH Preliminary NOx BACT Determination for Milton R. Young Station (MRYS)"*, November 17, 2008 (re: U.S. EPA Region 8 letter October 17, 2008); and
h. *"Supplemental Information for Consideration Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCR or LDSCR Retrofit"*, February 20, 2009 revised March 2, 2009; and
i. Burns & McDonnell and Energy & Environmental Research Center (EERC) presentation to NDDH *"Supplemental Information for Consideration Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCR or LDSCR Retrofit"* March 2, 2009.

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

25. Kling, A.; Andersson, C.; Myringer, A.; Eskilsson, D.; Jaras, S.G., *Alkali Deactivation of High-Dust SCR Catalysts Used for NOx Reduction Exposed to Flue Gas from 100-MW-Scale Biofuel and Peat Fired Boilers: Influence of Flue Gas Composition.* Applied Catalysis B: Environmental 2007, 69, 240-251.

26. *"First Commercial Installation of Amine Enhanced Fuel Lean Gas Reburn on Units 1 and 2 at Public Service Electric & Gas Mercer Station"*, Andres. F. Gomez, Alexander S. Dainoff, John H. O'Leary, and Robert A. Schrecengost; White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlled NOx Emissions, Institute of Clean Air Companies, Inc., May 2000.

27. "PSEG Fossil L.L.C. Fact Sheet", available at >http://www.epa.gov/compliance/resources/cases/civil/caa/pseglic-fcsht-061130.html accessed on 12/17/2009.

28. "Babcock Power Inc. Overview for WPCA/Duke Seminar", Craig Peterson and Tony Licata, Babcock Power Inc., September 4, 2008, downloaded June 9, 2010 from Worldwide Pollution Control Association's website at: http://wpca.info/pdf/presentations/Duke_Sept2008/WPCA_Duke_2008_Cofiring_Biomass_Tony_Licata.pdf.

ATTACHMENTS:

1. CERAM Environmental, Inc. letter by Noel Rosha to Luther Kvernen, Minnkota Power Cooperative, Inc., Re: Milton R. Young Station SCR Performance Guarantees, June 11, 2010.

2. Haldor Topsoe, Inc. letter by Wayne Jones to Robert Blakley, Burns & McDonnell., Re: Evonik RFP SCR Performance Guarantees, July 27, 2010.

CERAM
ENVIRONMENTAL, INC.
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Porzellanfabrik Frauenthal GmbH

Minnkota Power Cooperative, Inc.
Attn. Mr. Luther Kvernen
1822 Mill Road
PO Box 13200
Grand Forks, ND 58208-3200

June 11, 2010

Milton R. Young Station SCR Performance Guarantees

Dear Mr. Kvernen:

On March 31, 2010 CERAM Environmental, Inc. (CERAM) submitted a budgetary proposal (CERAM Proposal GH100315-2) to Evonik Energy Services, LLC (Evonik) to support a conceptual design study project regarding both a low dust and/or tail end SCR application for *unnamed* coal fired units similar to the size of the Milton R. Young station Units 1 and 2. Subsequently we received a request from Evonik that portions of our March 31, 2010 budgetary proposal be released from confidentiality in order to submit the information to the North Dakota Department of Health (NDDH).

As part of our budgetary proposal (GH100315-2) we offered both initial (Test A) and end of life (Test B) catalyst guarantees for NOx reduction, ammonia slip, SO_2 to SO_3 conversion rate, and pressure drop. This is in contrast to the SCR catalyst proposal we submitted to Minnkota on October 13, 2009 (CERAM Proposal NR090911-2) in which we only provided initial Test A performance guarantees, and recommended a catalyst pilot testing program to characterize the M.R. Young fuel impacts on SCR catalyst in order to provide end of life guarantees.

Please note that although the requests from Evonik and Minnkota were similar, there were distinct differences in the RFP documents. The key differences are as follows:

- The range of fuel analysis provided by Evonik was not as detailed as that provided by Minnkota, and considered a lower maximum range of key constituents that can contribute to catalyst poisoning. For example the Evonik specification listed the maximum sodium content to be significantly less than the Minnkota specification. Sodium is a significant catalyst poison that must be considered for the purpose of guarantees. CERAM must consider the full range of potential coals when supplying catalyst performance guarantees.
- Minnkota submitted with the RFP the entire study performed by Microbeam Technologies, Inc (MTI) titled *Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD.* This study included detailed flue gas characterization including details on particle size distribution, particle concentrations, and soluble sodium constituents in the flue gas.

- Minnkota submitted with the RFP the final report titled *Impact of Lignite Properties on Powerspan's NOx Oxidation System*. The report outlined the impacts of the North Dakota Lignite flue gas and fly ash on Powerspan's multi-pollutant control system called electrocatalytic oxidation (ECO) technology, specifically the sodium-rich aerosols and small ash particles which accumulated and became bonded of the surface of the silica electrodes used in this technology.

CERAM would not have included end of life (Test B) performance guarantees in our budgetary proposal to Evonik had their RFP included the same level of detail that was provided in the Minnkota RFP documents, but would have again recommended a catalyst pilot test program to characterize the impacts of firing North Dakota Lignite coal upstream of SCR catalyst. Should you have any questions or need further information please contact me via e-mail (noel.rosha@ceram-usa.com) or at 913-239-9896.

Yours sincerely,
CERAM Environmental, Inc.

Noel Rosha
Senior Applications Engineer

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July 27, 2010

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9400 Ward Parkway
Kansas City, MO 64114

Dear Robert:

This letter is in response to questions raised by Burns and McDonnell and EPA concerning HTI's recent catalyst Quotation 10-6089 and 10-6089-R1 to Evonik Industries.

In February 2010, HTI received a Request for Quotation from Hans Hartenstein of Evonik Industries. The RFQ was for the supply of SCR catalyst for a coal fired unit. The proposal requested a quote for both a low-dust SCR and a tail-end SCR. The RFQ was given to one of newer associates to review and to provide the requested quotations.

The RFQ provided very little detail about the unit. No unit name or operating company was provided. No proximate or ultimate fuel analysis was provided; nor was there any ash analysis provided. In the RFQ, no mention was made that in fact this unit was firing North Dakota lignite. Actually very little operating data was provided. This included limited information with regard to flue gas chemical makeup. In retrospect, HTI should have requested additional detailed information about the proposed fuel from Evonik.

The quotation that was provided was based on a typical low arsenic eastern bituminous coal. No consideration was made for the fuel being anything else other than eastern bituminous. The typical guarantees that we provide for eastern bituminous fired boilers were provided in this quotation. These guarantees would not have been provided if HTI had known that the fuel fired on this unit is North Dakota lignite.

HTI currently has one of the first SCR's on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NOx removal effects, ammonia slip, SO_2 Oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC applications in the world. All of these are new and very challenging projects which push the technology to the next level.

HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees.

If you have any questions, please do not hesitate to call me at 281-228-5136.

Sincerely,

HALDOR TOPSOE, INC.

Wayne S. Jones
Sales Manager, Power Generation
SCR/DeNOx Catalyst & Technology

WSJ/gad/33/Jul2010

Findings of Fact
for
Best Available Control Technology
Determination
for
Control of Nitrogen Oxides
for
M.R. Young Station
Units 1 and 2

November, 2010

ND Department of Health
Division of Air Quality
918 E. Divide Ave, 2nd Floor
Bismarck, ND 58501

The North Dakota Department of Health (Department) makes this BACT Determination for M.R. Young Station Units 1 and 2 (MRYS) pursuant to the provisions of a Consent Decree entered by the United States District Court for the District of North Dakota for Civil Action No. 1:06-CV-034, United States of America and the State of North Dakota versus Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative.

Having considered the comments made and other information entered into the record, and hereby incorporating its two Preliminary Determinations and its Responses to Comments in these proceedings, the Department makes the following **Findings and Conclusions:**

I. Introduction

A. Background

Minnkota Power Cooperative (Minnkota) operates the MRYS near Center, North Dakota. Unit 1 of the station is owned by Minnkota Power Cooperative and has a gross rating of approximately 257 MWe. Existing air pollution controls on Unit 1 consist of a cold-side electrostatic precipitator. Unit 2, which is owned by Square Butte Electric Cooperative, has a rating of approximately 477 MWe gross. Existing air pollution controls on Unit 2 consist of a cold-side electrostatic precipitator and a lime/flyash wet scrubber for sulfur dioxide control. Unit 1 went online in 1970 while Unit 2 began operations in 1977. Both units are fired on lignite obtained from BNI Coal Ltd's Center Mine which is adjacent to the station.

The United States of America – on behalf of the Environmental Protection Agency (EPA) – and the State of North Dakota filed a Complaint alleging, among other things, that Minnkota had failed to obtain the necessary permits and install the controls necessary under the Clean Air Act to reduce its nitrogen oxide (NO_x) emissions. The parties entered into a Consent Decree to settle the alleged violations, which was approved and entered by the court on July 27, 2006. Under the terms of the Consent Decree, the Department must make a NO_x Best Available Control Technology Determination (BACT Determination) for both units at MRYS.

B. Consent Decree's Requirements for NO_x BACT Analysis and Determination

The Consent Decree requires Minnkota to submit to the Department for review and approval a NO_x Top-Down Best Available Control Technology Analysis (BACT Analysis) for the two existing units at MRYS. Minnkota must complete its BACT Analysis in accordance with the provisions of Chapter B of EPA's "New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting," (Draft October 1990) ("NSR Manual")[1]. The Consent Decree lists the technologies Minnkota must evaluate as part of its BACT Analysis, including selective catalytic reduction (SCR), selective non-catalytic reduction (SNCR), over-fire air (OFA), and rich reagent injection (RRI). The BACT Analysis must address both a normal operating scenario and a startup scenario, specify the technology to be installed, and recommend an emission rate on 30-day rolling average basis, that is BACT for each of the units and for each scenario evaluated. Throughout the process Minnkota is required to submit any additional, pertinent information requested by the Department or the EPA.

After Minnkota completes its BACT Analysis, the Department must review the BACT Analysis and develop a BACT Determination in compliance with applicable federal and state statutes, rules and guidance. In making its BACT Determination, the Department must consult with EPA. The BACT Determination must include for each unit the specific control technologies to be installed and a specific Phase II 30-Day Rolling Average NO_x Emission Rate limitation (lbs/MMBtu).

C. History of BACT Analysis and Determination

On October 9, 2006, the Department received Minnkota's BACT Analysis and concluded that Minnkota had included all of the items required by the Consent Decree.

In June 2008, the Department provided for public comment a Preliminary BACT Determination that SCR, including high dust SCR (HDSCR), low dust SCR (LDSCR), and tail-end SCR (TESCR), was not technically feasible for the MRYS[10]. Based on the comments received during that public comment period, the Department reconsidered the technical feasibility of LDSCR and TESCR[2].

In November 2008, the Department confirmed that HDSCR was not technically feasible; however, it determined that LDSCR and TESCR had a good possibility of successful operation. Based on this determination, the Department asked Minnkota to prepare a cost estimate and complete the BACT Analysis for LDSCR and TESCR. This analysis was submitted in November 2009 and was revised in February 2010.

In April 2010, the Department provided for public comment a second Preliminary BACT Determination[11] that confirmed that SCR (HDSCR, LDSCR, and TESCR) was not BACT for MRYS. In its second Preliminary BACT Determination, the Department reconfirmed that HDSCR was not technically feasible and that there were serious concerns about the technical feasibility of LDSCR and TESCR. Since the Department's November 2008 conclusion that LDSCR and TESCR are technically feasible, additional information has been obtained that contradicts that conclusion. First, the Department learned that, contrary to earlier information provided to the Department, Haldor Topsoe, Incorporated (HTI) and CERAM Environmental, Incorporated (CERAM), both potential vendors for SCR catalyst, would not provide a catalyst life guarantee for LDSCR or TESCR. Second, HTI and CERAM both indicated that an SCR designer must look at the full range of flue gas characteristics. Catalyst deactivation can occur rapidly, so worst case flue gas characteristics are important and must be evaluated. The Department's 2008 analysis only evaluated one concentration of sodium and potassium in the flue gas. This concentration did not account for worst case conditions. Third, the vendors indicated that the flue gas characteristics may be worse than the biomass boilers the Department evaluated where TESCR has been applied.

II. Overview of Applicable Law

A. Definition of Best Available Control Technology

An emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under the Clean Air Act which would be emitted from any proposed major stationary source or major modification which the Department, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60 and 61. If the Department determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results. N.D. Admin. Code § 33-15-15-01.2

B. Steps for Conducting a BACT Analysis Using the "Top-Down" Approach

- **Step 1: Identify All Control Technologies**

- **List is comprehensive**

All "available" control technologies must be listed in Step 1. For purposes of Step 1, "available" means "those air pollution control technologies or techniques with a practical potential for application to the emissions unit and the regulated pollutant under evaluation." (Section III.A page B.5).

Potentially applicable control technologies are divided into three categories:

- *Inherently Lower-Emitting Processes/Practices*, including the use of materials and production processes and work practices that prevent emissions and result in lower "production-specific" emissions; and

- *Add-on Controls*, such as scrubbers, fabric filters, thermal oxidizers and other devices that control and reduce emissions after they are produced.

- *Combinations of Inherently Lower Emitting Processes and Add-on Controls*. For example, the application of combustion and post-combustion controls to reduce NO_x emissions at a gas-fired turbine. (Section IV.A page B.10)

A proper BACT analysis requires consideration of "potentially applicable control techniques from all three categories." Unlike other types of control technologies, add-on controls "should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream." Accordingly, "candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review." (Section IV.A page B.10).

- **Step 2: Eliminate Technically Infeasible Options**
  - A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review.

In Step 2, "technically infeasible" options are eliminated from the list created in Step 1. The NSR Manual[1] provides guidance for determining whether a control option is technically feasible. Control options that are "demonstrated" – or "installed and operated successfully on the type of source under review" – are technically feasible. To be technically feasible, an undemonstrated control technology must be both "available" and "applicable." A technology is considered "available" if it can be acquired "through commercial channels or is otherwise available within the common sense meaning of the term." An available technology is "applicable" if the technology "can reasonably be installed and operated on the source type under consideration." (Section IV.B. page B.17).

Regarding "availability" the NSR Manual[1] states:

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. 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 a pilot scale testing stages of development would not be considered available for BACT review. (Section IV.B page B.18)

With respect to "applicability" the NSR Manual[1] states:

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 an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary. (Section IV.B page B.18-19)

The NSR Manual[1] further notes that:

In practice, decisions about technical feasibility are within the purview of the review authority. Further, a presumption of technical feasibility may be made by the review authority based solely on technology transfer. For example, in the case of add-on controls, decisions of this type would be made by comparing the physical and chemical characteristics of the exhaust gas stream from the unit under review to those of the unit from which the technology is to be transferred. 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. (Section IV.B page B.19)

- **Step 3: Rank Remaining Control Technologies By Control Effectiveness**

  Should include:

  - control effectiveness (percent pollutant removed);
  - expected emission rate (tons per year);
  - expected emission reduction (tons per year);
  - energy impacts (Btu, kW-hr);
  - environmental impacts (other media and the emissions of toxic and hazardous air emissions); and
  - economic impacts (total cost effectiveness and incremental cost effectiveness).

- **Step 4: Evaluate Most Effective Controls and Document Results**

  - Case-by-case consideration of energy, environmental, and economic impacts.
  - If most effective option is not selected as BACT, evaluate next most effective control option.

- **Step 5: Select BACT**

  - Most effective option not rejected is BACT and establish emission limit or work practice standard.

III. Determination on SCR

The following discussion is applicable to both units at MRYS, due to the similarities between them. This document focuses on the technical feasibility – specifically, the availability and applicability – of SCR (including HDSCR, LDSCR, and TESCR) and the cost effectiveness of those control technologies. These are the issues that have been raised by the parties to the Consent Decree and in the public comments. For other aspects of the BACT Determination, the Department relies on its 2008 Preliminary BACT Determination and its response to comments received on that document, which are incorporated herein by reference.

A. Technical Feasibility of LDSCR and TESCR for MRYS

LDSCR and TESCR are evaluated together since the flue gas characteristics at each location would not vary significantly and both vendors from which Minnkota had sought proposals (HTI and CERAM) indicated they would not provide a guarantee for either location. With regard to the technical feasibility of these control technologies, the Department makes the following findings and conclusions:

1. There has never been a full scale SCR – of any type – installed on a facility that burns North Dakota lignite.

2. To determine technical feasibility of LDSCR and TESCR, one must compare the flue gas characteristics of MRYS to the flue gas characteristics of other source types to which these control technologies have been applied previously.

3. The lignite combusted at MRYS contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels. Core samples for 2007-2010 indicated a sodium oxide (Na_2O) concentration in the ash as high as 13.4% and a potassium oxide (K_2O) concentration as high as 6.9% (Appendix A-2, 4/23/07 submittal). During combustion of this fuel in the cyclone furnaces at MRYS, a significant portion of these organically associated elements are either vaporized or form small particles that leave the boiler in the flue gas. Soluble sodium and potassium are catalyst poisons even in dry conditions in the SCR[3]. The soluble sodium and potassium can also form sulfates that can blind and plug the catalyst pores and plug the catalyst channels.

4. The flue gas characteristics of MRYS are significantly different from other boilers where SCR has been applied. The high soluble sodium content (catalyst poison) and the sticky nature of the ash are characteristics that are different from facilities where SCR has been successfully applied. Minnkota has supplied a significant amount of material that clearly shows the difference.

5. CERAM stated it is unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS. In its proposal[3] to Minnkota, CERAM stated that, "The high levels of Na_2O in the ash for the North Dakota lignite are not commonly found in sub-bituminous and bituminous coals which are fired with SCR systems." CERAM[3] also stated, "The levels of K_20 in the North Dakota lignite ash are in the high end range found in

many biomass fuels, such as wood and switch grass. However, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications."

6. HTI[4] stated, "... the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions."

7. Regarding North Dakota lignite, Sargent and Lundy (S&L) stated, "There are attributes of this fuel in a tail-end SCR environment that are not well understood today and need more investigation to predict its performance to make it a commercially available technology." S&L also stated, "Some important unanswered questions pose a significant risk for an SCR design engineer for tail-end SCR[9]."

8. The State of Louisiana determined that SCR was not feasible for the Red River Environmental Products, LLC, activated carbon plant that uses lignite[8]. This determination was based on a finding that the sodium sulfate in the flue gas could cause rapid deactivation of the catalyst and the lack of operating or empirical data.

9. EPA has considered cyclone (and more generally slag tap) furnaces that burn lignite from North Dakota, South Dakota, and Montana to be a separate source category for NO_x emission limits in 40 CFR 60 Subparts D and Da. This was due to the high sodium content of the lignite (43 FR 9276). Not until EPA established a fuel and furnace type neutral standard was all subcategorization eliminated.

10. In its justification for the fuel and furnace type neutral standard, EPA determined that "there is considerable experience in the industry to show that use of SCR on lignite is technically feasible." To support this determination, EPA stated that SCR was shown to work on Gulf Coast lignite, Texas lignite, and European brown coals, and that performance guarantees can be obtained from catalyst suppliers (71 FR 9870). The Department does not find EPA's justification for the fuel and furnace type neutral standard persuasive to show that SCR is technically feasible at MRYS and disagrees with EPA's statements made in that justification. First, the Department believes that there is not considerable experience in the industry to show the use of SCR for a North Dakota lignite-fired unit is technically feasible. CERAM has stated "CERAM is unaware of any SCR application experience in the industry with this level and form of sodium in the ash." Second, Minnkota has clearly demonstrated that the ash from MRYS is different from Gulf Coast lignite, Texas lignite and European brown coals where SCR has been applied. CERAM and HTI both have indicated that they have offered catalyst life guarantees for other lignite fired units, including Texas lignite; however, they have refused to provide a catalyst life guarantee for MRYS which burns North Dakota lignite. In addition, it is not clear what criteria EPA used to determine that SCR was technically feasible for NSPS purposes or the BART Guidelines. Under the PSD program, technical feasibility determinations are based on the flue gas characteristics of the source evaluated. The Department is not aware of any analysis of the flue gas characteristics of North Dakota lignite by EPA which was considered when the subpart Da standards were revised or the BART Guidelines were developed.

11. Both HTI and CERAM indicated in their October 2009 proposals they will not provide a guarantee for the catalyst life without successful pilot scale testing being done. HTI indicated that SCR may not be a viable option for MRYS and that pilot testing would be necessary to show whether SCR is a viable option. S&L also recommended that pilot testing be conducted to answer questions about the effects of the soluble alkalis and ash characteristics including the size, stickiness and abrasiveness qualities of the ash. An SCR that is guaranteed to work successfully is not available for MRYS.

12. Both HTI and CERAM indicated that refusal to provide a catalyst guarantee is extremely rare. They both indicated they have offered guarantees for other types of lignite (including Texas lignite), European brown coals, and biomass. Both companies indicated they were not aware of any SCR being installed in the United States without a catalyst life guarantee.

13. In a letter to Burns and McDonnell (July 27, 2010), HTI stated:

"HTI currently has one of the first SCR's on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NO_x removal effects, ammonia slip, SO_2 oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC applications in the world. All of these are new and very challenging projects which push the technology to the next level.

HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees."

14. EPA has indicated that BACT is intended as a "technology forcing" requirement. HTI has indicated they have "forced" the technology (SCR) at other facilities and provided guarantees. Apparently, the use of SCR at MRYS forces the technology beyond an acceptable risk for the company. The same is apparently true for CERAM. Both companies have indicated that their decision not to provide a guarantee was not influenced by Minnkota or Burns and McDonnell. It was a business decision based on the risk involved.

15. The Department of Justice, through its contractor Evonik Energy Services, LLL (Evonik) provided a Request for Proposals (RFP) to HTI and CERAM supposedly based on the flue gas characteristics of MRYS. Both companies indicated they would provide catalyst life guarantees to Evonik based on the RFP. HTI and CERAM have provided letters explaining this seeming contradiction. Both have indicated that Evonik did not provide a fuel analysis, ash analyses, the range of fuel and ash characteristics that could be encountered, details on the soluble constituents in the flue gas and the fact that it was North Dakota lignite. HTI believed the RFP was for a facility burning eastern subbituminous coal. HTI indicated they would not have provided a guarantee if it had known that the fuel was North Dakota lignite. CERAM has indicated it would not have provided a guarantee if the Evonik RFP had provided the same level of detail as the Minnkota RFP. The RFP by Evonik and subsequent proposals by CERAM and HTI proved nothing and have no value.

16. CERAM and HTI have indicated that up to one year of pilot scale testing is required before they would consider a guarantee. This is consistent with S&L's recommendation of one year of operation of a pilot scale test. S&L indicated that the overall pilot scale test program duration would be 18-24 months based on one year of operation. The additional time is for design, mobilization, setup and evaluation of the data.

17. Estimates of the cost of pilot scale testing range up to two million dollars.[9]

18. MRYS, and cyclone boilers burning North Dakota lignite, is a new and dissimilar source category from other sources that have successfully applied SCR.

19. Minnkota is not required under BACT to assume the high risk associated with the failure of a technology that has never been used on a North Dakota lignite-fired unit or source with similar flue gas characteristics.

20. Minnkota is not required to experience resource penalties or extended trials to learn how to apply SCR to MRYS – a new and dissimilar source type.

21. LDSCR and TESCR for MRYS are in the pilot stage of development. Technologies in the pilot scale testing phase of development need not be considered as available control technologies.

22. Based on the lack of vendor guarantees and need for pilot testing, LDSCR and TESCR for MRYS cannot be obtained through commercial channels and is not otherwise available within the common sense meaning of the word. Thus, LDSCR and TESCR for MRYS are not "available" for purposes of Step 2 of the BACT Analysis.

23. LDSCR and TESCR have not been, and will not soon be, deployed on the same or a similar source. MRYS's flue gas characteristics are significantly different from other sources that have applied LDSCR and TESCR and these unique characteristics present significant challenges to successful application of those control technologies for MRYS. Thus, LDSCR and TESCR cannot reasonably be installed at MRYS and are therefore not "applicable" for MRYS for purposes of Step 2 of the BACT Analysis.

24. Because LDSCR and TESCR are neither "available" nor "applicable" to MRYS, these control technologies are technically infeasible for MRYS.

B. Technical Feasibility of HDSCR

With regard to the technical feasibility of these control technologies, the Department makes the following findings and conclusions:

1. In the November 2008 technical feasibility analysis[2], the Department evaluated HDSCR and determined it was not technically feasible. This was consistent with the Department's June 2008 Preliminary BACT Determination[10].

2. Microbeam Technologies, Inc. (Microbeam) conducted particulate emissions testing at MRYS in March of 2009. The results indicate that most of the particulate matter emissions from each boiler are removed by the electrostatic precipitator (ESP). Microbeam's results indicated a particulate matter removal efficiency of 99.76%. Microbeam's results also indicate the amount of $Na_2O + K_2O$ is approximately 50-90 times greater entering the ESP than exiting the ESP. The results are similar for $Na_2O + K_2O$ entering the ESP versus exiting the wet scrubber. Because a HDSCR will be placed before the ESP, the loading of $Na_2O + K_2O$ on a HDSCR would be approximately 50-90 times higher than a LDSCR or TESCR.

3. The Department has reviewed the Microbeam Technologies report[5] and reached the same conclusions regarding technical feasibility. The empirical data shows a very strong indication that HDSCR will not achieve a successful catalyst life. The amount of sodium and potassium in the flue gas is so high that it is very unlikely that 10,000 hours of catalyst life could be achieved. The testing by Kling[6] found deactivation rates up to 52% in 1500 hours for a fuel made up of tree bark and 30% demolition waste. The Microbeam[5] results suggest a similar rate for MRYS. Zheng[7] found a deactivation rate of 0.4% per day using 20-30 mg/Nm^3 of potassium sulfate with a mass mean diameter of 0.55 micrometers. The 0.4% deactivation rate per day is equivalent to 6000 hours to 100% deactivation. The Microbeam[5] results indicate a higher potassium sulfate equivalent loading of aerosols less than 0.55 μm at MRYS. Both HTI and CERAM indicated change out of the SCR catalyst at 50% deactivation, not 100% deactivation.

4. The flue gas temperature problems associated with HDSCR still remain. The temperature problem is another potential fatal flaw to the successful use of HDSCR at MRYS. An extensive engineering study must be conducted to determine if this problem can be resolved. Babcock and Wilcox estimated the cost of the study at $275,000-$400,000 and would take 20-24 weeks to complete.

5. Minnkota was unable to get a catalyst life guarantee for LDSCR and TESCR. It is very unlikely that a guarantee would be offered for HDSCR when the loading of catalyst deactivation compounds is 50-90 times higher than LDSCR or TESCR.

6. In 2007, Minnkota solicited information from SCR and catalyst vendors. Although some vendor responses indicated a high degree of confidence about the successful use of HDSCR at MRYS, all vendor responses indicated the need for pilot scale testing to determine if there were fatal flaws for using HDSCR. Two of the companies that expressed confidence in the use of HDSCR at MRYS were HTI and CERAM. Each company has since refused to offer a catalyst life guarantee for LDSCR or TESCR. It appears a catalyst life guarantee for HDSCR cannot be obtained.

7. As discussed in Subsection III(A), SCR – including HDSCR – has not been applied to a ND lignite-fired unit or a source with similar flue gas characteristics to MRYS. MRYS is a new and dissimilar source type category from other sources that have successfully applied SCR.

8. Minnkota is not required to undergo the expensive and lengthy time delays that would be required in order to learn how to apply HDSCR technology to MRYS – a new and dissimilar source type.

9. HDSCR for MRYS is in the pilot stage of development. Technologies in the pilot scale testing phase of development need not be considered as available control technologies.

10. Based on the lack of vendor guarantees and need for pilot testing, HDSCR for MRYS cannot be obtained through commercial channels and is not otherwise available within the common sense meaning of the word. Thus, HDSCR for MRYS is not "available" for purposes of Step 2 of the BACT Analysis.

11. HDSCR has not been, and will not soon be, deployed on the same or a similar source. MRYS's flue gas characteristics are significantly different from other sources that have applied HDSCR and these unique characteristics present significant challenges to successful application of this control technology for MRYS. In addition, the flue gas temperature problem may not be solvable (a complex study is required). Thus, HDSCR cannot reasonably be installed at MRYS and is therefore not "applicable" for MRYS for purposes of Step 2 of the BACT Analysis.

12. Because HDSCR is neither "available" nor "applicable" to MRYS, this control technology is technically infeasible for MRYS.

C. Cost Effectiveness of SC

Because the Department has determined that SCR is not technically feasible, there is no need to complete the remaining steps of the top-down process. Thus, the Department declines to address the cost effectiveness of SCR for MRYS.

VI. BACT Selection

HDSCR, LDSCR and TESCR are not technically feasible. The next most effective technology is selective non-catalytic reduction (SNCR). When coupled with advanced separated overfire air (ASOFA), the expected removal efficiency is approximately 58%. BACT is represented by SNCR + ASOFA and BACT is the following limits:

Unit 1 - 0.36 lb/10^6 on a 30-day rolling average basis except during periods of startup. During startup, NO_x emissions shall not exceed 2070.2 lb/hr on a 24-hour rolling average basis.

Unit 2 - 0.35 lb/10^6 Btu on a 30-day rolling average basis except during periods of startup. During startup, NO_x emissions shall not exceed 3995.6 lb/hr on a 24-hour rolling average basis.

For purposes of this BACT determination, startup is defined as:

The 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 is greater than or equal to 2500 x 10^6 Btu/hr for Unit 1 and 4800 x 10^6 Btu for Unit 2. For purposes of determining compliance, startup cannot exceed 61 hours for Unit 1 and 115 hours for Unit 2.

References
Findings of Fact

1. U.S. EPA; New Source Review Workshop Manual; October 1990.

2. NDDH; Selective Catalytic Reduction (SCR) Technical Feasibility for M.R. Young Station; November 2008.

3. CERAM Environmental, Inc.; SCR Catalyst Budgetary Proposals and Recommendations for Milton R. Young Station Units 1 and 2 - Confidential; October 13, 2009.

4. Haldor Topsoe, Inc.; SCR DeNO$_x$ Catalyst Specification for Burns and McDonnell & Minnkota Power, Milton R. Young Station Units 1 & 2 – Confidential; October 12, 2009.

5. Microbeam Technologies, Inc.; Final Report: Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD; July 1, 2009.

6. Kling, Asa; Andersson, Chester; Myringer, Ase; Eskilsson, David; Jaras, Sven G; Alkali deactivation of higher dust SCR catalysts used for NO$_x$ reduction exposed to flue gas from 100 MW – scale biofuel and peat fired boilers: Influence of flue gas composition; Applied Catalysis; 2007.

7. Zheng, Yuanjing; Jensen, Anker Dega; Johnsson, Jan Erik; Thogerson, Jaokim Reimer; Deactivation of V_205 - WO_3 – $Ti0_2$ SCR catalyst at biomass fired power plants; Elucidation of mechanisms by lab – and pilot-scale experiment; Applied Catalysts; 2008.

8. Louisiana DEQ; Preliminary Determination Summary, Red River Products, LLC, Agency Interest No.: 152139, Armisted, Red River Parish, Louisiana, PSD-LA-727; November 21, 2007.

9. Sargent and Lundy, LLC; Application of Tail-end SCR Technology to North Dakota Lignite Fuels; PowerPoint Presentation, March 11, 2009.

10. ND Department of Health; Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2; June 2008.

11. ND Department of Health; Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2; April 2010.

Response to Public Comments
EPA Comments
5/10/10

I. SCR is Cost Effective Based upon NDDH's Inflated Cost Estimates

Comment 1: – NDDH failed to conduct an adequate comparison of the average cost effectiveness of SCR at MRYS with other sources.

Response: Disagree – The NDDH reviewed all BACT determinations for coal-fired power plants contained in the RACT/BACT/LAER Clearinghouse from 2005 to the present. This review was not limited to sources in nearby states as erroneously stated by EPA. Unfortunately, cost information for SCR was not available for most of the facilities. Older determinations were not considered because of the rapid increase in SCR cost since 2004.[1] So, the Department also reviewed cost estimates for SCR in BART analyses from states as far away as Oregon and Alaska. The BART estimates from western states were chosen because of availability and local cost considerations (e.g., labor costs, transportation costs, etc.) which are expected to be similar to those in North Dakota.

Comment 2: – The draft BACT determination is also deficient because it compared the calculated cost effectiveness of LDSCR at MRYS with the average of the costs of controls from within the small group selected by NDDH, instead of comparing costs with individual costs at other facilities.

Response: Disagree – The NDDH compared both the average cost and the highest individual costs for the limited data that was available for BACT determinations. In the MRYS determination, the NDDH states "The cost effectiveness of SCR at M.R. Young Station is higher than any other facility in Table 7" (note – the reference to Table 7 is incorrect, it should be Table 8; Table 7 lists CO_2 emissions). The NDDH reviewed every BACT determination for coal-fired power plants from 2005 to the present. Very little information was available on the cost of SCR and what information was available was probably not verified by the reviewing agency. The Department expanded its review to available BART information.

Comment 3: The requirement in the Clean Air Act is for the "Best" available controls, not the average available controls.

Response: The NDDH agrees that the Best Available Control Technology is required. Minnkota evaluated SCR + ASOFA with a control efficiency of 93.8%. This is the highest removal efficiency found in any BACT or BART analysis for a coal-fired boiler using SCR. This technology is anything but average. The average cost for BACT for sources reviewed was evaluated because of the huge discrepancy in the projected BACT cost effectiveness (from \$1,511/ton to \$4,037/ton – both for new facilities, both pulverized coal-fired units with similar baseline emissions). The average indicates the high end of the range may not be valid. The cost effectiveness at the end is approximately \$1,400/ton higher than the next highest BACT analysis.

Comment 4: WDEQ considers \$4,156/ton and incremental cost of \$10,303/ton to be reasonable. **Response**: The NDDH does not consider an incremental cost of \$10,303/ton to be reasonable. As pointed out in the analysis, several other states also do not consider it reasonable. EPA in their analysis for the Deseret Power Plant[2] states "The incremental cost of \$10,540 per ton of SO_2 to install a wet scrubber rather than a dry scrubber is **too high to justify the expenditure.**" The analysis goes on to state "Limestone injection and wet FGD is eliminated as a BACT control option, based on economic impacts of wet FGD (**unacceptably high incremental SO_2 removal costs**) ..." As indicated earlier, the unacceptably high incremental SO_2 removal cost was \$10,540 per ton. In the response to comments on the Deseret Power Plant[3], EPA provided information on other PSD BACT determinations where incremental costs were considered excessive. These included:

Facility	**State**	**Pollutant**	**Incremental Cost (\$/ton)**
Longleaf Energy Station	GA	SO_2	8,964
Cargill's Blair Corn Million	NE	SO_2	5,900
ADM Columbus Corn Milling	NE	NO_x	5,600
MDU/Westmoreland Gascoyne 175	ND	NO_x	14,339
Red Rail Energy	ND	SO_2	10,252
Wygen 3	WY	PM	14,609

Based on the average of the two catalyst replacement scenarios, the incremental cost effectiveness of LDSCR + ASOFA was \$9,207/ton for Unit 1 and \$10,872/ton for Unit 2. For TESCR + ASOFA, the incremental cost effectiveness was \$10,872/ton and \$12,578/ton for Units 1 and 2, respectively. The NDDH considers these incremental cost effectiveness values to be excessive.

Comment 5: Wisconsin Public Service Company's Weston 4 plant had a cost effectiveness of \$6,116/ton but was not considered by the NDDH.

Response: The Wisconsin Public Services Company's BACT determination was not considered because the estimated removal efficiency of SCR was 53.3% and other concerns (see Response to Comment 7). As the NSR Manual[4] points out, underestimating the control efficiency can inflate the cost effectiveness (and incremental cost effectiveness) of the control technology.

Comment 6: The baseline emission rate in the Sherco #2 is 0.20 $lb/10^6$ Btu and SCR at MRYS can expect to have a higher removal efficiency than Sherco #2.

Response: Minnkota used a 90% removal efficiency for SCR with an expected emission rate of 0.05 $lb/10^6$ Btu (including ASOFA). The expected emission rate at Sherco #2 with combustion optimization and SCR is 0.08 $lb/10^6$ Btu. The SCR was expected to reduce emissions only 47%. Had the Sherco #2 analysis used an expected emission rate of 0.05 $lb/10^6$ Btu, the cost effectiveness would have been $2,841/ton, a difference of $1,759/ton. As shown by the Dry Fork BACT analysis[5], an emission rate of 0.05 lb/10^6 Btu is achievable for a much lower baseline emission rate than that at MRYS. The NDDH believes that when comparing the cost effectiveness of a technology to cost borne by other facilities, a comparison must be made of the expected efficiency and expected emission rate to have a common basis of comparison. As indicated in the draft BACT analysis, using low efficiencies (i.e., higher controlled emission rates) leads to inflated cost effectiveness estimates.

Comment 7: The commenter provided several examples of documents where costs for NO_x control were presumed to be cost effective including refineries, State guidance document, EPA letters to State Agencies, survey results, consent decrees, Laramie Cement Plant BACT analysis, RBLC documents and EAB ruling.

Response: The NSR Manual[4] states "In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying the control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT" (emphasis added). The NSR Manual[4] goes on to say "Where the cost effectiveness of a control alternative for the specific source being reviewed is within the range of normal costs for that control alternative, the alternative may also be eligible for elimination in limited circumstances. This may occur, for example, where a control alternative has not been required as BACT (or its application as BACT has been extremely limited) and there is a clear demarcation between recent BACT control costs in that source category and the control costs for sources in that source category which have been driven by other constraining factors (e.g., need to meet a PSD increment or a NAAQS)" (emphasis added).

Coal-fired boilers are a different type of source than a refinery, cement plant, chemical plant, combustion turbine, etc. The RBLC classifies these sources separately. NSPS and MACT standards regulate these type of sources separately and they are listed as separate source categories in the definition of major stationary source in the PSD regulations. The NDDH believes that costs for controls on a coal-fired power plant should be compared to costs at other coal-fired power plants.

The commenter inappropriately provided data on many other source categories other than coal-fired boilers. Of the 14 facilities the commenter indicated in the RBLC with a higher cost effectiveness only two were coal-fired boilers. The Weston Power Plant #4 was reviewed by the NDDH prior to the draft BACT determination. The RBLC indicated a cost effectiveness of $6,116/ton; however, the efficiency of the SCR was only listed at 53.3%. This low efficiency could lead to an inflated cost effectiveness. Other issues with the analysis were that the baseline emission rate was set at the NSPS limit, not actual expected emission rate, and the annual capacity factor was only 85%. The NSR Manual[4] (Section IV.D.2.b) states "The NSPS/NESHAP requirements or the application of controls, including other controls necessary to comply with state or local air pollution regulations, are not considered in calculating the baseline emissions." The MRYS analysis set the baseline at the actual emission rate and used a capacity factor of 97.3% for Unit 1 and 98.9% for Unit 2. Had 90% removal efficiency, 95% availability and a baseline emission rate of 0.30 lb/10^6 Btu (typical for pulverized units) been used in the Weston economic analysis, the cost effectiveness of SCR would have been as low as $1,621/ton. When comparing cost effectiveness of similar sources, the NDDH believes you have to make an apples-to-apples comparison.

The Keystone Cogeneration Systems, Inc. facility, which commenter also listed, is no longer in the RBLC. The Comprehensive Report provided by the commenter for this facility indicates this is probably not a BACT determination. The report suggests it is a case-by-case determination, perhaps LAER. The Comprehensive Report also indicates SNCR can be used to achieve the NO_x emission limit at a cost effectiveness of $3,980/ton. Since this is apparently not a BACT determination, the cost effectiveness is not a fair comparison to MRYS.

The commenter also suggested that 90% removal by SCR in the BART analysis for Sherco #2 is not available and the cost comparison is appropriate. The BART analysis for Sherco #2 indicates that SOFA+ SCR will only achieve an emission rate of 0.08 $lb/10^6$ Btu. The NDDH believes 0.05 $lb/10^6$ Btu may be achievable (Wygen 3 and Dry Fork Power plants are expected to achieve this rate). In the BART analysis for Leland Olds Unit 1, the NDDH used an 80% removal efficiency and an expected emission rate of 0.057 $lb/10^6$ Btu. Had 0.05 $lb/10^6$ Btu been used as the expected emission rate (75% reduction), the cost effectiveness would have been as low as $2,841/ton.

The NSR Manual[4] states that a comparison of the expected costs should be made to cost previously borne by other sources of the same type. Guidance documents from States and EPA do not necessarily reflect costs borne by the same source type or category. The only true comparison is from BACT determinations for the same source category that were actually constructed.

Comment 8: 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 all support the position that SCR is technically feasible and cost effective.

Response: The NSR Manual[4] states "Technical feasibility of technology transfer control candidates generally is assessed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control has been applied previously." The NDDH has not found any analysis of the flue gas characteristic of North Dakota lignite in the record for the CAIR, BART or NSPS rules. The commenter did not provide any such analysis to support the technical feasibility claim for North Dakota lignite in these rules. The flue gas characteristics of a cyclone-fired boiler combusting North Dakota lignite is different from other coal-fired combustors. CERAM Environmental, Inc. has stated in their proposal to Minnkota that they are unaware of any SCR application experience in the industry with the level and form of sodium in the MRYS ash. Haldor Topsoe, Inc. has stated in their proposal that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x emissions. Both vendors would not supply a catalyst life guarantee without successful pilot-scale testing. The pilot testing would be used to determine if SCR can be successfully applied at the MRYS.

The costs for SCR in the CAIR, BART Guideline and NSPS are general cost estimates based on high dust SCR. These estimates do not account for site specific circumstances and are not applicable to low dust and tail end SCR because of the additional cost for reheating the flue gas. Again, these rules did not review the flue gas characteristics of North Dakota lignite which will affect the design and operation of an SCR system. The comparison of SCR costs estimated in the preparation of CAIR, the NSPS and the BART Guideline is inappropriate.

Comment 9: The cost estimate provided by Minnkota must be considered cost effective.

Response: The NDDH did not say that the cost effectiveness was excessive. The draft BACT determination said the cost effectiveness was high. This high cost effectiveness, high incremental cost, additional pollutants emitted and a major question about technical feasibility of SCR to MRYS were all factors in rejecting SCR as BACT. The NDDH still considers the cost effectiveness and incremental cost effectiveness to be high – as high as those for any other BACT source with similar emission limits (or efficiencies), availability, and calculation of baseline emissions where SCR was required. However, the NDDH's final determination is that SCR (HDSCR, LDSCR and TESCR) is not considered technically feasible for MRYS. Therefore, the costs for SCR are irrelevant.

Comment 10: The commenter provided information that other reasons were involved in the rejection of an emission limit of 0.043 lb/10^6 Btu at Wygen 2 and SNCR at 0.05 lb/10^6 Btu at an ADM facility in Nebraska.

Response: The NDDH agrees that other factors contributed to the rejection of the listed emission rates at these two facilities. However, other facilities where a technology or emission rate were rejected include:

Facility	Incremental Cost
River Hill Power Company	$ 5,000/ton
Long Leaf Generating Station	$ 8,964/ton
Cargill, Inc – Blair Plant	$ 5,900/ton
Sandy Creek Station	$ 5,000/ton
Red Trail Energy	$ 10,252/ton
Spiritwood Station	$ 12,902/ton

The commenter claims that EPA had other reasons for rejecting wet scrubbing at Deseret Power[2]. In their statement of basis EPA stated "The incremental cost of $10,540 per ton of SO_2 to install a wet scrubber rather than a dry scrubber is too high to justify the expenditure." The statement of basis[2] also states "limestone injection + wet FGD is eliminated as a BACT control option based on economic impacts of wet FGD (unacceptably high incremental SO_2 removal costs)..." Although EPA may have had other reasons for rejecting wet FGD, the statement of basis suggests EPA considered $10,540/ton incremental cost to be excessive for wet FGD. Excessive costs are valid reasons for rejecting a technology. EPA implies that SO_2 control costs should not be compared to NO_x control costs. In the Response to Comments on the Deseret Power Plant (p.30), EPA Region 8 also made a comparison of costs for SO_2 removal to costs for NO_x and PM_{10} removal. The NDDH has never made a distinction between these pollutants for cost comparisons in a BACT determination. This is also true for MRYS.

II. NDDH Draft BACT Determination Failed to Follow EPA's NSR Workshop Manual

Comment 1: NDDH was and is required to conduct its BACT determination in accordance with the NSR Manual and OAQPS Control Cost Manual.

Response: The NSR Manual[4] (Section IV.D.2.a) states "The basis for equipment cost estimates also should be documented, either with data supplied by an equipment vendor (i.e., budget estimates or bids) or by a referenced source [such as the OAQPS Control Cost Manual (Fourth Edition)]" (emphasis added). It goes on to state "Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control Cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis."

"Total cost estimates of options developed for BACT analyses should be on the order of plus or minus 30 percent accuracy. If more accurate cost data are available (such as specific bid estimates), these should be used. However, these types of costs may not be available at the time permit applications are being prepared. Costs should also be site specific" (emphasis added).

The first citation above suggests that cost estimates should be from equipment vendor data or by an estimating source, not necessarily the OAQPS Control Cost Manual[6]. The second citation seems to conflict with the first by requiring costs be based on the OAQPS Control Cost Manual. The third citation indicates costs should be site specific. The OAQPS Manual provides a generic methodology for calculating SCR costs but is not site specific.

The OAPQS Manual[6], Section 2.4 for SCR, states "The cost estimating methodology presented here provides a tool to estimate study-level costs for **high-dust SCR systems**. Actual selection of the most cost effective option should be based on a detailed engineering study and cost quotations from the system suppliers" (emphasis added). It also states "This report is based on the high-dust SCR system because it is the most common design. A low-dust configuration would cost somewhat less because the required catalyst volume is smaller and ash hoppers on the SCR reactor are not required. The cost methodology is valid for a low-dust SCR system because the cost reductions are expected to be within the range of uncertainty for study-level costs. The costs for the tail end arrangement, however, cannot be estimated from this report because they are significantly higher than the high-dust SCR systems due to flue gas reheating requirements" (emphasis added).

The NDDH believes the OAQPS Cost Manual[6] was not intended for making BACT determinations for LDSCR and TESCR. The Cost Manual clearly states that selection of the most cost effective option study be based on a detailed (i.e., site specific) engineering analysis with vendor quotes. It is also clear the OAQPS Manual cannot be used to estimate TESCR. Although the manual states that it can be used for LDSCR, a closer examination suggests it cannot be used for such purpose. In Section 2.2.3 of the manual for Low Dust SCR it is stated "Flue gas temperatures generally do not decrease to the point where reheating is required. However, an increase in the size of the economizer bypass duct may be required to maintain the flue gas temperature within the optimum range." Minnkota's evaluation of LDSCR has found that flue gas reheating will be necessary. Since the manual did not anticipate reheating the flue gas for LDSCR, the manual cannot be used for cost estimating for the same reason it cannot be for TESCR (i.e. reheat costs). Based on the statements in the OAQPS Manual[6] that a detailed engineering study should be used to determine the most cost effective option (i.e. BACT) and LDSCR/TESCR cannot be estimated by using the manual, Minnkota has selected a methodology for the capital cost estimate consistent with Current Capital Cost and Cost-Effectiveness of Power Emissions Control Technologies[7]" by Cichanowicz. Since the cost estimate is site specific, with vendor quotes and uses a referenced source, the methodology is acceptable for this BACT determination.

A. Inflated Capital Cost Estimates and Cost Methods

Comment 2: MRYS cost estimate is significantly higher than other sources which range from \$100-\$200/kw including two projects in North Dakota which had estimated costs of \$117/kw to \$132/kw.

Response: The three projects in North Dakota which had final applications and were subject to public comment were the Gascoyne 175 plant, Gascoyne 500 plant and the Spiritwood Station. The Gascoyne 175 SCR capital cost was estimated at \$177/kw, Gascoyne 500 at \$134/kw and the Spiritwood Station was approximately \$235/kw. The Gascoyne 175 cost references the 1990 OAQPS Cost Manual for its basis and the Spiritwood Station references the 2002 OAQPS Cost Manual[6]. The Gascoyne 500 estimate follows the procedures of the OAQPS Cost Manual; however, it does not include costs for reheating the flue gas. As indicated in the Response to Comment 11, the OAQPS Cost Manual is not appropriate for estimating the cost of low-dust SCR. The NDDH did not object to these cost estimates since they were obviously conservative and the incremental cost between SCR and SNCR was obviously excessive. Only the Spiritwood Station was built, without SCR.

The commenter provided information that the projected cost of LDSCR at WE Energies South Oak Creek Units 5-8 was approximately \$168/kw; however, in Footnote 34, the commenter also indicates that information submitted to the Public Service Commission of Wisconsin indicates a higher cost. The commenter does not provide the revised estimated cost. Without a detailed cost estimate to evaluate, it is impossible to tell the differences between MRYS estimate and the South Oak Creek estimate. Since the BACT determination is based on a site specific cost estimate, the information for the South Oak Creek estimate is of little value. The commenter also indicates that the PSE&G retrofitted the Mercer Station Units 1 and 2 with cold-side SCRs with a capital cost of approximately \$185/kw. Again, no details were provided.

III. Minnkota's Cost Estimate

Comment: EPA objected to Minnkota's cost estimate for several reasons. These included:

1) Use of a levelized cost
2) Failure to use the EPA Air Pollution Control Cost Manual.

3) Inclusion of startup expenses, cost escalation, allowance for funds during construction (AFDC) and owner's costs. EPA also objected to the amount included for these items.
4) Inflated Annual Cost Estimates & Cost Methods
    a) Annual Maintenance costs
    b) Annual Reagent costs
    c) Annual Electricity costs
    d) Catalyst Replacement costs
    e) Natural gas for flue gas reheating

Response:

1) Use of a levelized cost – EPA's objection to the use of a levelized annual cost is without merit. The NSR Manual[4], Appendix B, Section II, page b.4 states "The permit application should use the levelized annual cost approach for consistency in BACT cost analyses." Use of a levelized cost estimate is consistent with the NSR Manual.

2) Failure to use the EPA Air Pollution Control Cost Manual - The Control Cost Manual cannot be used for estimating the cost of TESCR and LDSCR (see Response to Comment II.1).

3) Inclusion of startup expenses, cost escalation, allowance for funds during construction (AFDC), owner's costs and owner's contingency funds.

    Since the Control Cost Manual[6] cannot be used for estimating the cost of TESCR and LDSCR because it would underestimate both the capital and annual operating costs, Minnkota has developed a site specific cost estimate with a procedure that varies somewhat from the Control Cost Manual[6]. The Department has reviewed the BART analyses prepared by five different consultants to determine if the listed items were included (Note that BART cost estimates are governed by the same guidance as BACT cost estimates). The five consultants included TRC, BARR Engineering, Co, CH_2M Hill, HDR Engineering, Inc., and Black & Veatch. One of the consultants included startup costs in their estimate for SCR. In addition, the cost estimate sheet in the NSR Manual[4], Appendix B, page b.5 includes startup costs at rate of 2% of the total direct investment (direct capital cost). Minnkota used 2% of direct capital costs. The inclusion of startup costs appears appropriate.

    Cost escalation is driven by general inflation, changes in technology but mostly by supply and demand imbalances for a good or service. To illustrate this point, the consumer price index increased approximately 18% from the beginning of 2003 to the end of 2008. During this same time period, structural steel prices increased (escalated) by over 150%. Escalation is usually included in the contingency funds which can be from 10-25%. However, any estimate for a project in the 2003-2008 time period that used a lot of steel (such as an SCR) may have been underestimated if a 10-25% contingency fund was used. Minnkota has included an escalation cost in their estimate. The estimate is based on 2006 dollars; however, the project would not be completed until 2016-2017. It is unknown whether escalation will be so severe that contingency funds will not cover it. With the implementation of the new Transport Rule and the Regional Haze requirements, the demand for SCRs and the contractors who build these units will greatly increase. Escalation of SCR equipment costs and the erection of such units is likely. Inclusion of some escalation costs, beyond contingency funds, appears to be appropriate.

Allowance for Fund during Construction (AFDC) is for the cost of borrowing money until a project is placed into operation. The review of the BART analyses indicated that one of the five consultants included AFDC as a specific line item for their SCR cost estimate. The Control Cost Manual[6] in Table 2.5 assumes that the AFDC for an SCR is zero. However, there is no explanation for this assumption. An assumption that there will be no interest on money during construction is not credible. In addition to the Control Cost Manual[6], EPA also provides the CUECOST model which can be used for estimating the cost of SCR. This model includes a specific line item for AFDC which has a default value of 10.80% per year. As described earlier, the Control Cost Manual[6] cannot be used for estimating the cost of TESCR and LDSCR. Minnkota has estimated the indirect cost of TESCR and LDSCR consistent with the Cichanowicz[7] document which includes financing during construction or AFDC. Inclusion of AFDC is reasonable.

Owner's costs will consist of, but is not limited to, legal assistance, permitting, owner's project management, owner's site mobilization, O&M staff training, construction insurance, auxiliary power, taxes and consultant fees. Again, one of the five consultants reviewed included a specific line item for owner's costs. One other consultant listed several of the items identified above as owner's costs as separate line items in their estimate. The methodology in Cichanowicz's paper[7] also includes owner's costs. The NSR Manual[4], Appendix B, page b.7 states "Indirect, or "fixed", annual costs are those whose values are relatively independent of the exhaust or material flowrate and, in fact, would be incurred even if the control system were shutdown. They include such categories as overhead, property taxes, insurance and capital recovery." Several items mentioned (i.e. overhead, property taxes and insurance) are owner's costs. The inclusion of owners cost is appropriate and consistent with the NSR Manual.[4]

Minnkota's owners cost includes an owner's contingency amount. The total owner's cost is approximately 17% of the total direct capital cost. Cichanowicz[7] lists a range of owner's cost at 5-10% of the capital cost. The Cichanowicz paper discusses the high rate of increase in the cost of materials and labor. Data is provided to show these increases from 2003 to 2007 including steel, concrete and various labor professions. All of these had escalation rates well above the increase in the consumer price index. It is reasonable to expect that the owner's cost may increase more than the consumer price index. Including escalation for the owner's cost items appears reasonable.

4) EPA believes cost estimations for various items are inflated.

   a) Annual Maintenance Costs – EPA believes a factor 1.5% of total capital investment (as stated in the Cost Control Manual) for annual maintenance costs should be used. Minnkota used 3% for their estimate. Minnkota has argued that additional maintenance will be required for the gas-to-gas heat exchangers

(GGH). Minnkota has also indicated the harsh North Dakota winters will make maintenance more difficult.

The rotary GGHs will provide additional maintenance challenges beyond a normal high dust SCR. Since EPA's 1.5% factor for maintenance is for a high dust SCR, the NDDH believes 3.0% is inappropriate because of the additional equipment that must be maintained. The NDDH also agrees that the harsh North Dakota winters will make maintenance more difficult than an average SCR on which the Control Cost Manual[6] is based. The maintenance factor of 3% appears to be reasonable.

b) Annual Reagent Costs – EPA has argued that anhydrous ammonia would be cheaper. Minnkota has argued that there is no evidence presented by EPA to support their claim that anhydrous ammonia is the cheapest reagent available to MRYS. Minnkota has also argued that health and safety concerns must also be considered.

EPA provided no evidence to support their claim that anhydrous ammonia delivered to MRYS would be cheaper than urea. The NDDH will not second guess Minnkota when it comes to health and safety matters on the MRYS plant site. The safe handling of anhydrous ammonia during the cold North Dakota winters can present many challenges. The use of urea as the SCR reagent is justified.

c) Annual electricity costs (loss of electrical sales due to extended outages). EPA believes Minnkota's estimate of the time for outages to replace the catalyst is unreasonably high. Minnkota has argued that outages for other reasons (other than catalyst replacement) that are associated with the SCR will occur. This includes forced outages for boiler tube leaks that must be repaired shortly after discovery to prevent severe fouling of a LDSCR. Also, failure of the GGHs will cause additional boiler outage. Forced outages could occur for booster fans and other auxiliary equipment associated with SCR system.

The NDDH believes it is appropriate to include these other forced outages in the cost estimate for SCR. Failure to recognize that equipment failures/malfunctions other than the catalyst replacement would cause outages would lead to an underestimation of the cost of operating the SCR.

Minnkota has indicated they used a unit availability reduction of 2.2% associated with the advanced separated overfire air system (ASOFA). These outages could be due to problematic cyclone slag tapping, excessive heat transfer surface fouling, increases in boiler tube leaks and operation of the air-staged cyclone combustion. Prediction of whether the ASOFA system will cause the outage time estimated by Minnkota is extremely difficult. EPA has provided no specific evidence to show that the prediction is incorrect. Without specific evidence to the contrary, the rate is considered reasonable.

d) Catalyst Replacement Costs – EPA has indicated that the replacement cost of catalyst was significantly higher than the bids Minnkota received and substantially higher than Mr. Hartenstein received with his Request for Proposals (RFP).

EPA has not defined what significantly means. A review of the bids indicates virtually no difference to less than a 30% difference. Minnkota has previously indicated they included transportation, handling, storage, installation and taxes in their estimate. Based on the addition of these items, the \$7,500/m^3 used by Minnkota does not appear to be significantly higher for the replacement costs. Regarding the costs Mr. Hartenstein received for his RFP, these costs are considered irrelevant because of the faulty RFP (see Response to Comment IV).

Regarding the use of regenerated replacement catalyst, there is no evidence to prove that catalyst used at the MRYS can be regenerated. This is obvious since it has never been used at MRYS. The flue gas characteristics may preclude the use of regenerated catalyst. Until there is evidence to support the use of regenerated catalyst, Minnkota is justified in providing a catalyst replacement cost based on new catalyst.

e) Use of natural gas for reheating the flue gas - EPA has indicated that it questions whether natural gas needs to be used for reheat instead of steam.

Minnkota has indicated that the units at the MRYS are boiler limited. This is obvious since the changes that lead to the Consent Decree were boiler related and not generator related. Using steam would require the derating of the units (see December 12, 2009 Response to NDDH request). Minnkota has estimated the total derate for MRYS would be 13-16 MWe. Additional arguments against using steam are unsatisfactory results previously using steam for flue gas reheat associated with the Unit 2 scrubber (Minnkota actually abandoned the system and now uses flue gas bypass for reheating), a detailed study is required to determine the performance impacts from the modifications needed to use steam for reheat, and the cost of high pressure steam piping and the structural work needed to handle the thermal growth and load stresses.

The NDDH has discussed the use of steam for reheat with Basin Electric Power Cooperative. Because of the extremely cold North Dakota winters, Basin Electric indicated it was a bad idea because of the potential for problems and the difficulty of fixing those problems in the winter months. The NDDH believes the use of natural gas instead of steam is justified for MRYS.

IV. EPA Corrected Cost Analysis

Comment: EPA has prepared its own cost estimate for LDSCR and TESCR based on the responses to Mr. Hartenstein's RFP and use of the factors in Control Cost Manual.[4] The results show a much lower cost for LDSCR and TESCR.

Response: EPA's cost estimate is based on at least three faulty premises that will affect the cost estimate. These include 1) a faulty RFP by Mr. Hartenstein, 2) Failure to estimate levelized annual cost, and 3) Use of the Control Cost Manual.

The RFP submitted by Mr. Hartenstein was fatally flawed. The RFP flaws include, but are not limited to:

a) The RFP did not mention the fuel was North Dakota lignite.
b) The RFP did not indicate that the sodium in the flue gas was soluble sodium. Soluble sodium is a potent catalyst poison.
c) The concentration of the flue gas constituents (e.g. sodium and potassium) was at the low end of the expected range of these constituents. Both CERAM and Haldor Topsoe have indicated to the Department that the full range of flue gas constituents encountered must be provided to prepare a proper catalyst design. From the data provided, Haldor Topsoe assumed the fuel was eastern bituminous coal.
d) The RFP failed to provide sufficient information on the sticky nature of the ash.
e) The RFP was not sufficiently detailed on particle sizing, particulate concentration and soluble sodium constituents in the flue gas. Both CERAM and Haldor Topsoe have indicated that they would not have provided a catalyst life guarantee to Mr. Hartenstein had the information in his RFP been as detailed as the Minnkota RFP. It is apparent that the catalyst design would also have been different for these vendors.

2) EPA failed to calculate a levelized cost as required by the NSR Manual[4], Appendix B, Section II which states "The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis."

3) The Control Cost Manual[6] cannot be used for estimating the cost of TESCR and LDSCR (see Response to Comment II.1). The Control Cost Manual states "The cost-estimating methodology, presented here provides a tool to estimate study-level costs for <u>high-dust SCR systems</u>" (emphasis added). Actual selection of the most cost-effective option should be based on a detailed engineering study and cost quotations from the system suppliers. Minnkota has prepared such a cost estimate.

National Parks
Conservation Association
2010 Comments

Comment 1: The NSPS limit of 0.11 lb/10^6 Btu (revised in 2008) should have been considered in the BACT determination.

Response: The limit stated by the commentor is for reconstructed sources. The limit for modified sources is 0.15 lb/10^6 Btu (40 CFR 60.44 Da(e)(3)).

The MRYS is not subject to the NSPS standards for NO_x. The definition of "BACT" indicates the BACT emission limit cannot be any less stringent than an applicable standard under the NSPS. Since there is no applicable standard for MRYS, this portion of the BACT definition is not relevant.

Although EPA has established a limit of 0.15 lb/ 10^6 Btu for all modified coal-fired boilers, there is no evidence to suggest than EPA considered the flue gas characteristics of cyclone boiler combusting North Dakota lignite. EPA cited experience with Gulf Coast lignite, Texas lignite and European brown coals; however, there was no direct discussion of North Dakota lignite (71 FR 9870)[12]. CERAM has indicated there is no experience in the world with the level and form of sodium found in North Dakota lignite[9]. Therefore, EPA's citation to other lignite's is not applicable. EPA then suggested SCR is not required to achieve 0.15 lb/10^6 Btu. This may be true for other pulverized units, but not for cyclone-fired units. Without a detailed evaluation of the flue gas characteristics of a cyclone-fired unit combusting North Dakota lignite, EPA has not demonstrated that the NSPS is achievable for this type of boiler.

Comment 2: The NO_x BACT analysis for MR Young must be considered in the context of the far-reaching impacts of the facility's NO_x emissions on air quality, visibility, public lands and public health under step five of the top-down approach.

Response: North Dakota is in compliance with all of the National Ambient Air Quality Standards. EPA has determined that emissions from North Dakota do no significantly contribute to any non-attainment areas for ozone or $PM_{2.5}$ (75 FR 31290-31306 and 75 FR 45255-45269), The NDDH has evaluated the impact on visibility in the Class I areas if SCR is installed instead of SNCR at MRYS[8]. The improvement in visibility (0.01 deciviews for Unit 1 and 0.02 deciviews for Unit 2 average for the 20% worst days) by using SCR is insignificant. All other impacts are also expected to be insignificant except for the increase in emissions due to using SCR. The SCR will increase CO_2 emissions by 150,000 – 200,000 tons per year due to the need to reheat the flue gas and increased electricity use.

NDDH's Technical Feasbility Analysis is Legally and Technically Deficient

Comment 3: There is no valid technical or other constraints that make SCR installation technically infeasible. A difference in gas stream characteristics does not by itself imply that the difference is significant enough to impact successful operation of the control technology.

Response: Determination of technical feasibility is based on the flue gas characteristics of the source and the potential for successful operation of the control technology evaluated. CERAM Environmental, Inc. has indicated that they are unaware of any SCR experience in the industry with the level and form of sodium in MRYS flue gas[9]. Haldor Topsoe[10] has stated that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions.

These statements indicate there is a significant difference in the flue gas characteristics at MRYS versus other coal and biomass fired boilers that could impact operation of an SCR and technical feasibility. The difference is so great that SCR may not be a workable solution for NO_x control. The lack of vendor guarantees is also strong evidence that SCR is not technically feasible.

Comment 4: Pilot scale testing would not require extended time delays or resource penalties. Pilot scale testing in this case is a means to optimize SCR design to a specific situation prior to more expensive full-scale installation.

Response: CERAM Environmental has indicated that they prefer 5,000 hours of pilot scale testing[9]. Haldor Topsoe has indicated that a 9-12 month pilot scale test is required. Taking into account time to design, fabricate and install the pilot-scale reactor, 5,000 hours of operation, decommissioning and evaluating the data, one to two years would be required for a pilot-scale test. Sargent and Lundy estimated the cost to be 1.5-2 million dollars[13]. This is a significant time delay and cost for MRYS.

Haldor Topsoe has indicated that physical deactivation could be severe enough to make SCR a non-viable option for controlling NO_x emissions[10]. It is clear that pilot-scale testing would be required to prove SCR is a viable option for controlling NO_x emissions and not just for optimizing the design of SCR. CERAM Environmental has pointed out that they are not aware of any SCR experience for flue gas characteristics similar to that at MRYS[9]. Pilot-scale testing would be used to determine if the catalyst deactivation rate is so severe that SCR cannot be successfully applied at MRYS.

Comment 5: To dismiss SCR on the grounds that there is a risk to Minnkota would be contrary to the technology-forcing function of the BACT process that was intended by Congress.

Response: Haldor Topsoe, in a letter to Burns & McDonnell[14], states "HTI does not avoid challenging applications, but we do review the technical as well as the financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees." Haldor Topsoe would not provide a performance guarantee. This indicates the risk of failure of SCR at MRYS is too high for them. This is also apparently true for CERAM Environmental since they refused to provide a guarantee. The NDDH believes the risk of failure is also too high and LDSCR and TESCR are not technically feasible at this time.

NDDH Fails to Accurately Calculate Cost Effectiveness of SCR

Comment 6: NDDH inappropriately compared only regionally - limited BART determinations rather than generally accepted BACT determinations.

Response: The NDDH compared the cost of SCR at MRYS to both BACT and BART analyses. Every BACT determination in the RBLC for the last five years was reviewed and cost data obtained from Missouri, Arkansas, Wyoming and Nevada. These are not regional analyses. BART data was obtained from sources as far as Oregon, Nebraska and Alaska. Again, these are not regional to North Dakota.

Comment 7: A 30-year service life should have been used in the economic analysis.

Response: EPA's Air Pollution Control Cost Manual[6] states that an economic life time of 20 years is assumed for a SCR system (p. 2-48). The Department reviewed several BART analyses which indicated the estimated life of SCR ranged from 11-20 years. Minnkota's use of 20 years is consistent with other economic analysis.

Comment 8: Labor and maintenance costs were estimated at 3% of installed capital costs. The Control Cost Manual indicates they are 1.5% of the total capital investment. Thus these costs are overestimated.

Response: The Cost Control Manual[6] states that it cannot be used to estimate the cost of TESCR. For the same reason (i.e. reheating the flue gas), LDSCR cannot be estimated from the Control Cost Manual. The higher cost used by Minnkota is expected due to maintenance activities that will be more frequent (e.g. catalyst changement) than a typical SCR installation and more difficult because of the cold North Dakota climate. Additional equipment for flue gas reheat will also need maintenance and will increase these costs. The estimate of 3% appears appropriate.

Comment 9: Levelization of costs escalates costs. Cost effectiveness analyses do not include escalation.

Response: Appendix B, Section II of the NSR Manual[4] states "The permit applicant should use the levelized annual cost approach for consistency in BACT cost analysis." The commenter assertion that levelization is not allowed is incorrect.

Comment 10: A cost for catalyst of $7,500 per cubic meter is excessive and catalyst regeneration must be considered.

Response: The cost of the catalyst quoted in the Confidential Vendor Proposals is substantially higher than $\$3,500/m^3$. Minnkota has added shipping, handling, storage, labor, mobilization, disposal costs and taxes to the cost of the catalyst. Based on the vendor proposals, $\$7,500/m^3$ is reasonable.

Catalyst regeneration has not been demonstrated for a catalyst exposed to flue gas characteristics similar to the MRYS. Therefore, the cost of regenerated catalyst in the cost estimate is inappropriate.

Comment 11: The costs for foundations and supports needs to be justified.

Response: The costs of foundations are directly affected by the soil type encountered at the specific site. Minnkota has provided a site specific analysis for foundations and supports. A site specific estimate is preferred to a general estimate.

Comment 12: The indirect costs include owner's costs which are not included in the Control Cost Manual.

Response: The Control Cost Manual cannot be used for estimating the cost of TESCR or LDSCR (see Response to Comment 8). Minnkota has used a cost estimating methodology which is consistent with those by Cichanowicz[7]. This methodology includes owner's cost at a rate of 5-10%. (Also see Response to EPA 2010 Comment III).

Comment 13: The commenter had concerns about the costs associated with electrical equipment, SCR installation and maintenance, contingency expenses and capital cost of the SCR system and auxiliaries.

Response: The commentor provided no details or examples to support his concerns. Since there are no details, a detailed response cannot be made. The NDDH believes Minnkota's estimate is within the required range of ± 30%.

Comment 14: Several states have established cost effectiveness thresholds based on pollutant controlled, not bound by the emitting source categories.

Response: The NSR Manual, Section IV.D.2. C., states "In essence, if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the <u>same source category</u> in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT" (emphasis added). The NSR Manual[4] also discusses this issue further and terminology specific to "that source category" and for "the type of facility". It is clear that a comparison must be made for the source category reviewed, not dissimilar source types. Cost comparisons must also be made to costs borne by the same source category. Guidance from other states is irrelevant until applied to a source similar to MRYS that actually bears that cost.

Comment 15: U.S. EPA determined that \$10,000/ton control cost ceiling was for NO_x and SO_2 in attainment areas, equivalent to over \$13,000/ton today.

Response: The EPA document referenced by the commenter addresses costs at refineries and is listed as an upper bound. The NSR Manual[4], Section IV.D.2.(p.B-32) states "To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionally high when compared to the cost of control for that particular pollutant and source in recent BACT determinations" (emphasis added).

The NDDH is not aware of EPA ever establishing a brightline cost effectiveness cutoff for BACT. As noted in the NSR Manual, any cutoff would be established by recent BACT determinations and costs actually borne by similar sources.

Comment 16: Several air districts in California have set cost effectiveness thresholds for NO_x including $9,700/ton, $17,000/ton and $17,500/ton.

Response: See response to Comments 14 and 15. The San Joaquin Valley District noted that their definition of BACT is the most stringent limitation or control technology that is:

- Achieved in practice by such a source category and Class of source
- Required by the SIP.

The most stringent limitation that is achieved in practice is considered to be LAER (lowest achievable emission rate) in most of the United States. LAER is not the same as BACT in North Dakota.

Most of California is nonattainment for ozone. Controlling NO_x emissions is vital to achieving or maintaining compliance with the ozone NAAQS. Therefore, California has very stringent emission limits for NO_x in their SIP that may be more stringent than BACT elsewhere. This can be seen from the BACT guidance for the San Joaquin Air District which lists a BACT cost effectiveness for SO_2 at $3,900/ton.

Guidance documents do not meet the requirement to compare costs at the source under review to recent BACT determinations. The NDDH does not consider $9,700 - 17,500/ton to be cost effective for NO_x controls in North Dakota.

Comment 17: The commentor provided data on several determinations which he indicates show BACT costs well over that estimated at MRYS.

Response: Of all the summaries provided, only one BACT determination was for a coal-fired power plant. The rest were gas turbines, refineries, cement plants or other types of sources. As indicated in the Response to Comments 14 and 15, costs must be compared to recent BACT determinations for the same source category.

The Weston Power Plant BACT determination was reviewed. When an apples-to-apples comparison in done, the BACT cost of SCR at the Western Plant is actually considerably lower than at MRYS (see Response to EPA's 2010 Comment 7).

Comment 18: The BACT analysis gave undue influence to the incremental cost.

Response: The NSR Manual[4], Section IV.D.2.b, states "the cost-effectiveness calculations can be conducted on an average, or incremental basis." It also states "The incremental cost should be examined in combination with the average cost effectiveness in order to justify elimination of a control plan." The NDDH provided both the cost effectiveness and the incremental cost for the two dominant control operations. The cost effectiveness of SCR is considered high and the incremental cost between SNCR and SCR is considered very high. Other BACT determinations have rejected control options based on incremental cost where the cost effectiveness was much lower than at MRYS including:

Facility	Cost Effectiveness ($/ton)	State
Longleaf Generating Station (SO_2)	724	GA
Hardin Plant (SO_2)	1,395	MT
Red Trail Energy (NO_x)	2,609	ND
Intermountain Power (PM_{10})	≈37	UT
Dry Fork (NO_x @ 0.040)	2,004	WY
Dry Fork (SO_2 – WFGD)	1,595	WY
WYGEN Z (NO_x @ 0.060)	4,156	WY
WYGEN 3 (PM_{10})	134	WY

Minnkota's estimate of cost effectiveness for LDSCR/TESCR ranged from $3,586/ton to $6,426/ton.

The NDDH considered the cost effectiveness of SCR, the incremental cost between SCR and SNCR, the additional pollutants emitted by using SCR and the uncertainty regarding the technical feasibility of SCR. When all factors are considered together, SNCR is BACT.

National Park Services
Comments
2010

Comment 1: NDDH errored by using historical emissions for baseline emissions.

Response: The NSR Manual[4], Section IV.D.2.b, states "In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source" (emphasis added). Minnkota calculated baseline emissions based on a maximum emission rate and maximum expected utilization. The historical data for these specific units suggests a lower baseline than calculated from maximum values. The Department's approach is consistent with the NSR Manual.

Comment 2: Minnkota incorrectly included major costs for "allowance for Funds During Construction, Escalation, Owner's Cost and a levelization factor which are not allowed by the cost manual."

Response: The Control Cost Manual[6] cannot be used for estimating the cost of TESCR or LDSCR because it does not account for reheat of the flue gas. Minnkota has provided a site specific cost analysis. Minnkota used a procedure similar to that outlined in the paper Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies[7] by Cichanowicz. This methodology includes an Owner's Cost and Financing during construction. The NSR Manual[4], Appendix B, Section II, states "The permit applicant should use the levelized annual cost approach for consistency in BACT cost analyses". Therefore, levelized cost approach with an escalation factor is appropriate (See Response to EPA's 2010 Comment III).

Comment 3: The commentor provided his estimate of the cost of TESCR and ASOFA for both units of MRYS using the Control Cost Manual[6].

Response: As indicated in Section 2.4 (p2-41) of the Control Cost Manual, the cost of TESCR cannot be estimated from the document because the costs are significantly higher than high dust SCR systems due to flue gas reheating requirements. Therefore, the cost estimate supplied by the commenter is inappropriate, especially for O&M costs.

The NDDH also believes that Control Cost Manual is extremely out-of-date for such cost estimates. The costs presented are in 1998 dollars (Section 2.4, p. 2-40). ERG, Inc. evaluated the cost of SCR for PGE Boardman plant as part of BART determination. ERG[10] has indicated that SCR installed costs have escalated rapidly since 2004 (p.4). The commentor also used an inappropriately high baseline emission rate that has never been achieved in the history of the facility. Continuous emission monitoring data indicates the maximum annual emission rate for Unit 1 was 9,220 tons/yr (2 year average of 8,840 tons/yr). The maximum single year for Unit 2 was 17,727 tons (2 year average of 15,507 tons/hr). The commentor baseline is 31% higher than the historical highest single year for Unit 1 and 34% higher than the historical highest year for Unit 2. The underestimating of the O&M costs and the inappropriate baseline emission rate lead to an underestimate of the costs effectiveness of TESCR + ASOFA.

Comment 4: The Wyoming DEQ has determined that incremental costs of $10,303 and $11,102 respectively were reasonable.

Response: While Wyoming may have determined that an incremental cost of up to $11,102 per ton is acceptable, other states such as Georgia, Nebraska, Pennsylvania, the U.S. EPA Region 8 and North Dakota have determined that it is not reasonable.

Comment 5: The NDDH should have primarily considered sources where SCR was accepted as BART.

Response: The NDDH provided the cost data from BART analysis for comparison purposes. A BART determination must take into account the amount of visibility improvement, a BACT determination does not. Each state is free to weigh the visibility impact factor as much as they choose. Some states may give great weight to visibility improvement with little weight to cost. Other states may be vice versa. Therefore, a BART determination cannot be compared to a BACT determination. However, the cost effectiveness can be compared and indicate that the cost of SCR at MRYS is at the high end of the cost scale.

Comment 6: The NDDH used a heat input of 3200 x 10^6 Btu/hr, 100% utilization and 0.86 lb/10^6 Btu, in conducting its BART analysis for Unit 1. Absent any constraints in a permit, those values should also be used for the BACT analysis which yields an NO_x emission rate of 12,054 tons per year for the uncontrolled situation.

Response: The commenter is incorrect. In its BART evaluation for Unit 1, the NDDH used a baseline emission rate of 9032 tons per year. This is very similar to the BACT analysis which used 8518 tons/per year. As noted in the response to Comment 3, the maximum measured annual emission rate was 9220 tons per year in 2001. Emissions have decreased steadily since then. The difference between the BART baseline is due to the review of two different five-year periods for this unit, one for BART and a more recent one for BACT. Use of 3200 x 10^6 Btu/hr, 100% utilization and an emission rate of 0.86 lb/10^6 Btu does not represent realistic upper bound operating conditions for this unit as required by the NSR Manual[4].

Comment 7: In the absence of permit constraints, the baseline emissions should be based on a heat input of 6300 x 10^6 Btu/hr, 100% utilization and an emission rate of 0.86 lb/10^6 Btu which yields an uncontrolled emission rate of 23,271 tons per year. This operating data was used in the BART analysis.

Response: The commenter is incorrect. In its BART determination, the NDDH used a baseline emission rate of 15,507 tons per year. This is similar to the 14,858 tons per year baseline used in the BACT analyses. As noted in the response to Comment 3, the maximum measured emission rate is 17,727 tons per year in 2000 and emissions have been decreasing since then. Use of the suggested operating parameters for determining baseline emissions for Unit 2 does not represent realistic upper bound conditions for Unit 2.

Comment 8: The commentor provided his estimate of costs for Unit 1 and Unit 2 TESCR with his assumptions. These are located in Appendix B and are based on the OAQPS Manual[6].

Response: The Cost Control Manual[6] cannot be used for estimating the cost of TESCR (see SCR Section 2.4, p.2-40). With respect to the commenter's assumptions:

a) Catalyst Cost = \$3,000/m^3 – The confidential proposals submitted by vendors have a much higher catalyst cost. Based on this vendor's proposals, the \$7,500/m^3 appears to be reasonable when shipping, handling, storage, installation and disposal costs are included.

b) Operating Life of Catalyst = 16,000 hours – No vendor has provided a guarantee for the life of the catalyst. Pilot scale testing will be required to determine an appropriate life of the catalyst. Using 16,000 hours is speculation and may significantly overestimate the life and underestimate the operation and maintenance costs.

c) Natural Gas = \$5/mcf – The EIA "has estimated that he cost of natural gas for commercial operations will vary from \$8.92 - \$12.12 per decatherm for the period 2010 – 2030. The cost for industrial sources is from \$5.02 - \$8.21 per decatherm. For a levelized annual cost analysis, as required by the NSR Manual[4], a cost of \$5 per decatherm is too low. Minnkota used \$8 per decatherm which appears to be reasonable.

d) Baseline Emission Based on 100% Utilization – See Response to Comments 1, 6 and 7.

e) Escalation and Owner's Costs are not allowed – See Response to Comment 2.

Basin Electric Power Cooperative
Comments
2010

Comment 1: Basin Electric supports the conclusion that SCR does not represent BACT for the MRYS. This is based on their own investigation of SCR for Leland Olds Unit 2 which indicated extensive pilot scale testing was necessary to predict the performance of SCR on a cyclone boiler firing North Dakota lignite. Basin Electric found it particularly significant that two vendors that had previously indicated they would provide a guarantee for a boiler firing North Dakota lignite now refuse to provide such a guarantee for LDSCR and TESCR at MRYS.

Response: No response necessary

Ottertail Power Company
Comments
2010

Comment 1: Ottertail supports the conclusion that SCR does not represent BACT for the MRYS.

Response: No response necessary

Environmental Groups

Comment I: NDDH consistently misapplies the "technically feasible" analysis set forth in the NSR Manual and thus, the review of the BACT analysis is flawed.

Response: The NSR Manual, Section IV.A, Step 1, states:

"The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower-polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. <u>Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit undergoing BACT review</u>" (emphasis added).

The NSR Manual, Section IV.B, Step 2, states:

"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 application 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."

The Department has evaluated the pollutant bearing gas stream of the M.R. Young Station (MRYS) and compared it to other power plant gas streams where SCR has been successfully applied. The results indicate the sodium concentration in the flue gas would be at least 9 times higher in the MRYS flue gas than other cyclone boilers. In addition, the sodium is in a soluble form. The soluble form of sodium is a potent catalyst poison and can cause plugging and blinding of the catalyst. For the four main catalyst poisons, the MRYS flue gas would contain approximately twice as much of these poisons as Texas lignite or Wyoming subbituminous coal-fired units.

As stated in the NSR Manual (Section IV.B):

"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 consideration (emphasis added).

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 an existing source with similar gas stream characteristics is generally sufficient basis for concluding technical feasibility barring a demonstration to the contrary" (emphasis added).

Although SCR has been applied to various coal-fired boilers, the Department has found no evidence that SCR has been applied to a flue gas with as high a sodium (Na) concentration as the MRYS flue gas. CERAM Environmental has indicated they are not aware of any SCR application experience in the industry with the level and form of sodium in the M.R. Young Station ash. EPA's consultant, Mr. Roger Christman from ERG, Inc., indicated he was not aware of any facility with this high of sodium loading where SCR had been applied. This confirms the flue gas characteristics are dissimilar from other sources where the technology has been applied. Because the sodium in the flue gas is a catalyst poison and can cause plugging and blinding of the catalyst, the Department believes currently available catalysts for an SCR system may not be successful when applied to the MRYS flue gas. As explained in the Department's June 2008 "Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2" (hereafter preliminary determination), successful application of SCR technology does not mean operation of the system for a few thousand hours before changeout of the catalyst. The Department established a minimum of 10,000 hours between changeouts before SCR can be determined to be "successfully applied" to MRYS. There is very little evidence to support the thought that available catalysts will last at least 10,000 hours before the BACT limit is exceeded or ammonia slip becomes excessive. Haldor Topsoe has stated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x emissions. Pilot testing is required to determine whether SCR technology is a viable option to control NO_x emissions, establish design parameters for an SCR system and to determine the catalyst life. Both Haldor Topsoe and CERAM have offered catalyst life guarantees for Texas lignite, European brown coals and biomass; yet, both have refused to offer a guarantee for North Dakota lignite at MRYS. Therefore, existing SCR technology is not available or applicable for the MRYS.

Comment II: NDDH and Minnkota have not adequately supported the decision to disregard fuel switching/blending as technically feasible.

A. Lack of railroad access to M.R. Young does not make fuel switching/blending infeasible.

Response: The Department did not say that the lack of railroad access made fuel switching/blending infeasible. This fact was pointed out to show the changes that would be necessary to bring in other types of coal. In fact, the Department pointed out that burning PRB coal is technically feasible (see p. 14 of preliminary determination). The trucking of PRB coal to blend with Center lignite would be extremely expensive and as pointed out have no effect on emissions (see discussion under Response to Comment 2.B and 2.C).

B. Using the annual average NO_x emission rate is not acceptable for labeling fuel switching/blending as technically infeasible.

Response: The Department did not say fuel switching was infeasible (see p. 14 of the preliminary determination). The Department compared the annual average emission rate of the Big Stone Station in South Dakota to that of the MRYS. The Big Stone Station is equipped with a cyclone boiler of similar design to MRYS and was originally designed to burn lignite from the Peerless Mine near Gascoyne, North Dakota. Since the Big Stone boiler is of similar design, a comparison of annual average uncontrolled emission rates provides a legitimate comparison of very similar units, one burning subbituminous coal and the other burning lignite. Based on the design, the 30-day rolling averages are expected to be proportional to the annual averages.

The use of the Acid Rain database as a whole for comparison, as suggested by the commentors, is clearly erroneous. The database contains units that are not cyclone units (higher emitters) and includes sources which have NO_x controls installed. A legitimate estimate of the effect of PRB on NO_x emissions must be made considering only cyclone boilers without NO_x controls.

C. The combustion of PRB would result in lower NO_x emissions.

Response: Based on actual operating data from the Big Stone Station, burning of PRB alone would not lower uncontrolled emissions of NO_x and may actually increase emissions on a lb/10^6 Btu basis. Blending even 50% PRB with lignite would only reduce the amount of sodium in the MRYS flue gas by a factor of 2. It would still be 4-5 times more than a cyclone burning PRB. This still would make SCR infeasible. Only a near total switch to PRB would make SCR feasible.

The commentor tries to use AP-42 emission factors to establish that Montana PRB would provide lower baseline uncontrolled emission rates. However, actual continuous emissions monitoring data from Big Stone and MRYS show that subbituminous coal would have higher emissions on a lb/10^6 Btu basis. AP-42, Introduction, Figure 1 shows that CEM data is the most reliable data available. The CEMs at Big Stone and MRYS are all certified to their accuracy under the Acid Rain Program. The data has been checked and quality assured before being entered into EPA Acid Rain database. AP-42 states "Average emission factors differ significantly from source-to-source and, therefore, emission factors do not provide adequate estimates of the average emission rate for a specific source. The extent of between-source variability that exists, even among similar individual sources, can be large depending on process, control systems, and pollutants." This can be seen by calculating the emission rates using the AP-42 emission factors and comparing them to the emission rates measured by the CEMs. AP-42 would predict an emission rate of approximately 1.05 $lb/10^6$ Btu for a cyclone boiler burning PRB coal and 1.13 $lb/10^6$ Btu for a cyclone boiler burning lignite. However, actual CEM data for Big Stone and MRYS show emission rates of 0.83 $lb/10^6$ Btu, 0.85 $lb/10^6$ Btu and 0.79 $lb/10^6$ Btu (2 units at MRYS). EPA, in AP-42 cautions "Data from source-specific emissions tests or continuous emissions monitors are usually preferred for estimating a source's emissions because those data provide the best representation of the tested source's emissions." AP-42, in this case, is inaccurate for both Big Stone and MRYS.

Comment III: The BACT Determination does not adhere to the guidelines set forth in the Consent Decree.

Response: The Consent Decree states that the BACT determination must be "in accordance with applicable federal and state statutes, regulations, and guidance." The commentors claims that Sierra Club, et al. v. U.S. Environmental Protection Agency and Prairie State Generating Company LLC (hereafter Prairie State) cannot be applied retroactively and should be interpreted very narrowly. The decision in Prairie State is simply an interpretation of existing statute, regulations and guidance. The decision clarifies the issue of redesigning a plant which EPA has not required as part of the BACT determination. Since EPA, historically, has not required the redesign of source, any further interpretation of EPA guidance should be available to Minnkota.

The changes necessary at Prairie State Generating are described in the following: "But to convert the design from that of a mine-mouth plant to one that burned coal obtained from a distance would require that the plant undergo significant modification - concretely, the half-mile long conveyor belt, and its interface with the mine and the plant, would be superfluous and instead there would have to be a railspur and facilities for unloading coal from rail cars and feeding it into the plant." These are the same changes Minnkota would have to make to MRYS. MRYS was designed and has operated as a mine-mouth power plant for 40 years using only coal from BNI's Center Mine. Switching from Center Mine lignite to rail car delivered coal would make the existing truck delivery, crushers, conveyors and stackers superfluous. Minnkota would have to not only build a railroad spur but also approximately 10 miles of track. In addition, a railcar unloading facility and a transport system to get the coal to boilers would have to be built. Minnkota would not only have to redesign an existing facility but would have to also reconstruct it. The required actions at MRYS are almost identical to those at Prairie State Generating; therefore, the decision should be applied to MRYS.

Comment IV: Other reviewing authorities, including EPA and the Texas Commission on Environmental Quality, have found SCR to be technically feasible for lignite.

Response: There has never been a BACT determination for a cyclone boiler that combusts North Dakota lignite made either by the Department or EPA. Texas lignite does not have similar flue gas characteristics to North Dakota lignite when considering the application of SCR. As shown in the Department's preliminary determination (see p. 21-27), ash from Texas lignite is much lower in sodium and other catalyst deactivating chemicals. A determination of both availability and applicability are based on the flue gas characteristics of the source under review. Both CERAM and Haldor Topsoe have offered catalyst life guarantees for facilities that combust Texas lignite; however, they have refused to offer a guarantee for the MRYS. Any comparison on Texas lignite to North Dakota lignite for SCR is inappropriate and any BACT determinations for Texas lignite are irrelevant.

The State of Louisiana recently (5/28/08) determined that SCR was technically infeasible for an activated carbon plant that utilizes lignite. This determination indicated the flue gas characteristics of lignite would preclude the successful application of the technology.

Comment VI: NDDH and Minnkota have not considered engineering solutions that facilitate the use of SCR, rendering the BACT top-down analysis complete.

1. Fuel blending/switching in conjunction with SCR.

Response: This issue is addressed in the response to Comments II and III .

2. Injection of fluxing agent to increase melting of the solid combustion byproducts, creating less flyash to be portioned and reinjected into the exhaust gas to poison the catalysts.

Response: The use of fluxing agents would not prevent the melting of sodium particles that are carried in the flue gas, it may actually enhance it. The sodium becomes a fume which is not captured in the slag. Sodium is the main cause of catalyst deactivation and fluxing agents will not reduce the amount of sodium reaching the catalyst of an SCR system.

3. Sootblowing and screens to minimize fly ash and prevent plugging of catalysts.

Response: Sootblowing may remove surface deposits of ash; however, it will not remove the sticky sodium and potassium deposits that penetrate into the pores of the catalyst and cause deactivation. Screens are effective in removing larger ash particles such as popcorn ash but will be ineffective in removing the submicron sodium and potassium aerosols.

4. Catalyst improvement by surface and edge coating . . .

Response: Edge coating of the catalyst may reduce erosion, however, it will not reduce catalyst deactivation or channel plugging. The testing that was conducted in Florida appears to be at a plant that fired PRB subbituminous coal. PRB coal is much lower in sodium and other catalyst deactivation substances (Na_2O, K_2O, etc.). The results of that testing would not be directly applicable to a unit burning North Dakota lignite. Additional pilot testing would be necessary to determine if the surface coating was effective in reducing the deactivation rate for North Dakota lignite.

5. Conventional Coal Cleaning - Wet process

Response: While conventional coal cleaning will remove ash, sulfur and perhaps mercury, there is no evidence supplied to indicate that conventional coal cleaning will remove the organically associated sodium or other catalyst poisons in North Dakota lignite. Pilot testing would be required to determine if this technology would be effective.

6. Coal Cleaning and Drying

Response: Coal drying is already in use at MRYS. MRYS is equipped with a cyclone drying system. Removing moisture from the coal does not remove the sodium, potassium and other deactivation substances. Coal cleaning using air jigs will have little effect on these substances. The results of testing coal drying at the Coal Creek Station suggest only a 2.8 to 5% reduction in heat input rate. This would be insufficient to offset the sodium in the coal which is 275-1400%+ more than other coals. The Department has addressed K-fuels® in the preliminary determination. K-fuels® has been recently rejected as BACT for four other projects that burn lignite[15]. There is no additional evidence supplied by the commentor that K-fuels® would be appropriate as BACT.

7. Coal Beneficiation - Coal Creek

Response: The effect of the coal beneficiation systems developed at the Coal Creek Station on SCR catalyst deactivation substances has not been demonstrated. The 2.8-5% heat input reduction rate from the drying process would have only a minor effect, if any, on the catalyst deactivation rate. The air jigging process will not remove the chemically bound sodium in the lignite.

Comment VI: NDDH has not reviewed add-on controls nor a combination of controls that may overcome the challenges associated using SCR and have proved more efficient reduction of NO_x than SNCR.

1. Deep Staging - Rich Reagent Injection - SNCR system or Advanced Layered Technology Approach (ALTA)

Response: This technology has been addressed extensively by Minnkota (Appendix A, Sections A.1.3.3, A.1.4.1.2 and A.1.4.1.3). There are insurmountable problems in controlling the air/fuel mixture at each cyclone so that an area devoid of oxygen is established for Rich Reagent Injection (RRI) to work properly. Because of the variability of the fuel, some cyclones may be devoid of oxygen while others will have surplus oxygen. This surplus oxygen will oxidize the urea from the RRI process and form more NO_x.

2. Deep Staging - Overfire Air (OFA) - Continuous Corrosion Monitoring, Combustion Control - Oxygen Injection

Response: The information about this technology appears to be taken from a Power Engineering article from November 2006. The article indicates the technology is only in the pilot scale testing phase and no results from the testing are available. The testing is being conducted on high-volatile bituminous coal. Since this technology is only in the pilot scale phase of development and has only been tested on high-volatile bituminous coal, it is not considered available for lignite applications.

3. Gas Reburning with Low NO_x Burners

Response: The testing at Wisconsin Power and Light's Nelson Dewey Plant was with coal reburning only. There were no low NO_x burners as implied by the comment. The test was conducted on subbituminous and bituminous coal. Minnkota has addressed this testing in their BACT assessment (Appendix A, Sections A.1.2.7.2 and 1.2.7.3). The tests using low NO_x burners occurred at Cherokee Station in Colorado which are not cyclone fired units. Lignite (coal) reburn with advanced separated overfire air (ASOFA) was considered as a technically feasible option. Low NO_x burners are not applicable to a cyclone fired unit.

4. Amine-Enhanced Gas Injection (AEGI)

Response:

AEGI is a category of NO_x controls including Amine Enhanced Fuel Lean Gas Reburn (AEFLGR) which has been installed at Public Service Electric and Gas Mercer Station in New Jersey. Minnkota addressed this technology (Appendix A, Section A.1.4.2.1). The commentor suggests that this technology was eliminated without an analysis of the flue gas characteristics. FLGR is a "process-type control alternative" since it prevents the formation of NO_x rather than removing it after the NO_x is formed. The NSR Manual states "For process-type control alternatives the decision of whether or not it is applicable to the source in question would have to be based on an assessment of the similarities and differences between the proposed source and other sources to which the process technique has been applied previously." Since it has not been demonstrated on or applied to a cyclone boiler, its effectiveness has not been demonstrated. FLGR plus SNCR was eliminated based on that analysis and because it provided less NO_x reduction than ASOFA + SNCR. The commentor has provided no evidence to dispute those findings.

5. Flue Gas Recirculation (FGR)

Response: FGR was addressed by Minnkota in their BACT assessment (Appendix A, Section A.1.2.5). The commentor claims that the Department inappropriately dismissed this methodology based on the premise that it would be ineffective in reducing NO_x emissions. MRYS Unit 1 was originally equipped with FGR but it was ultimately removed. Initial stack testing at MRYS Unit 1 shortly after startup indicated NO_x emission rates of 0.91-1.09 $lb/10^6$ Btu. The current baseline emission rate is 0.85 $lb/10^6$ Btu (annual average). Adjusting the baseline emission rate to a short-term average as measured by stack testing would yield comparable emission rates. Based on actual operating data, FGR has not and probably will not reduce NO_x emissions at Unit 1. Unit 2 is equipped with FGR.

6. Hybrid Selective Reduction

Response: The commentor is apparently referring to an SNCR/SCR hybrid system. This technology was not considered because SCR was considered to be technically infeasible. This technology would be no more effective than SNCR since SCR is infeasible. Therefore, it is an inferior option that is technically infeasible.

7. Oxyfuels or Oxygen Enhanced Combustion

Response: Minnkota addressed oxygen-enhanced combustion (Appendix A, Section A.1.2.4). The Department addressed it on p. 60 of the preliminary determination. This technology was eliminated because it was determined to be inferior to other control techniques. The commentor has provided no evidence to dispute that assertion.

8. Regenerative Activated Coke Technology (ReACT)

Response: The Regenerative Activated Coke Technology (ReACT) is an integrated emissions control technology intended for installation downstream of a particulate control device. The process consists of an absorber, regenerator and product recovery. The process is capable of removing sulfur dioxide, nitrogen oxides, mercury and particulate matter. The process has been available in Germany and Japan; however, it has only recently been tested on U.S. bituminous and subbituminous coals. The testing was conducted at the Valmy Generating Station in northern Nevada in 2007. A paper titled "ReACT Process Demonstration at Valmy Generating Station" (Dene, C.; Gilbert, J.; Jackson, K. and Miyagawa, S.) presented the results of the testing. For NO_x, the testing indicated a removal efficiency of 38.35 to 40.6 percent. The paper also presents data from testing at the Isogo #1 boiler in Japan. Those results indicate a 10-50 percent removal efficiency.

The ReACT process has not been tested on a North Dakota lignite-fired boiler. The amount of NO_x removal for lignite is unknown; however, the Valmy and Isogo #1 testing indicates the technology would be inferior to ASOFA plus SNCR (10-50% versus 58%). Only pilot scale testing will indicate whether this technology can be successfully applied to a unit firing North Dakota lignite. Since it is an inferior option and is considered unavailable, it is not considered further in the BACT determination.

9. Chemical Oxidation/Chemical Reduction

Response: Although these systems were not evaluated by Minnkota, they were evaluated at the Coal Creek Station and Stanton Station as part of the Regional Haze BART program and at the Spiritwood Generating Station as part of a BACT assessment[15]. At Coal Creek the cost effectiveness was $11,610/ton, at Stanton was $23,217/ton and Spiritwood Generating Station it was $6,534/ton. Each of these analyses showed the cost was excessive especially when compared to other technology including SNCR. Non-air quality concerns with this technology include high electricity consumption and the production of nitrates in the FGD waste product. The production of nitrates may require a wastewater treatment system. In addition to the environmental and energy impacts, there is very limited operating experience for this technology. The $LoTo_x$ technology has only been demonstrated at industrial plants with small boilers compared to MRYS boilers. Whether this technology can be adapted to large power plants would require extensive testing. Based on the high cost, energy and adverse environmental impacts, and the limited application of the technology, the Department eliminates this technology from consideration.

10. Mitsui Babcock (now Doosan Babcock Energy) NO_x Star™

Response: This technology was evaluated by Minnkota (Appendix A, Section A.1.3.2) and by the Department (p. 61 of preliminary determination). The commentor provided no evidence disputing the findings of the Department.

11. Mitsui Babcock Combined Non-Catalytic NO_x Reduction System

Response: This technology combines SNCR, low-NO_x burners, deep furnace staging, boosted overfire air, and coal and gas reburn. All of these technologies have been addressed separately or in some combination by Minnkota. Low NO_x burners are not installed on cyclone fired boilers and are technically infeasible. Therefore, the Mitsui Babcock CNCR system, which relies on low NO_x burners in combination with all of the other technologies in the control system, must also be deemed technically infeasible.

12. RJM Layered System

Response: The RJM layered system consists of burner modification, overfire air, NO_x (combustion) tempering, SNCR, and the RJM-AC™ system. Combustion tempering was evaluated by Minnkota (Appendix A, Section A.1.2.6) and it was concluded that water injection would be difficult for lignite-fired cyclone boilers due to the high moisture content of lignite and the need to readily ignite and sustain combustion and molten slag formation in the cyclone furnaces. The technology was deemed technically infeasible. The RJM-AC™ system is based on Rich Reagent Injection (RRI) technology. Minnkota evaluated RRI (Appendix A, Section A.1.3.3) and determined it was technically infeasible due to the variable heat content of the lignite combusted which creates the inability to control the oxygen levels to near zero at the reagent injection point.

Since two of the RJM-LT layers are technically infeasible for MRYS, the entire technology must be deemed technically infeasible. The combustion modifications, overfire air and SCNR layers of RJM-LT have been proposed as BACT.

Comment VII: The startup and shutdown (SU/SD) periods at Minnkota are excessive and do not reflect the reported plant design at Minnkota.

Response: Minnkota has established the length of startups and shutdowns based on actual operating data. The length of time for unit startup or shutdown is irrelevant to the BACT limit established for such periods. The limit is written as a lb/hr limit on a 24-hour rolling average. The BACT determination does include a definition for startup as suggested by the commentor. The definition of startup includes a heat input level as a cut-off for startup which is directly proportional to the output level as suggested by the commentor. In addition, the BACT limited startup to a maximum of 61 hours for Unit 1 and 115 hours for Unit 2. Minnkota has indicated the Smart Process will be installed on Unit 2, although it does not affect the length of startup or shutdown.

Comment VIII: The exclusion of SU/SD from the "30-day rolling average" and establishment of a separate SU/SD limit violates the Consent Decree.

Response: The Department agrees that shutdowns cannot be excluded from the 30-day rolling average and the BACT determination will be adjusted accordingly. However, the Consent Decree states in Paragraph 66 "NDDH's BACT Determination shall also address specific NO_x emission limitations during Unit Startups." The separate limits for startup and exclusion from the 30-day rolling average are appropriate.

Comment IX: The Control Efficiency proposed by NDDH and Minnkota does not represent BACT.

Response: The removal efficiency required by Minnkota is 58% for both units, not 41% as stated by the commentor (p. 63 of preliminary determination). The discussion from p. 66 to p. 68 pertains to startup and shutdown of the boiler, not normal operation. This pertains to the use of SNCR, not SCR as the commentor implies. The temperature range of NO_x reduction with ammonia and urea is for SNCR which does not use a catalyst as with SCR. Because SCR uses a catalyst, lower temperatures provide optimum NO_x reduction. When a boiler is starting up and shutting down, the flue gas temperature will not be in the optimal range and the normal BACT limits cannot be met.

The Emerson Smart Processor does not increase the flue gas temperature. The EPA Air Pollution Control Cost Manual states "At lower load profiles, the temperature within the boiler is lower. Variations in the flue gas temperature make design and operation of an SNCR system more difficult."

The Department never claimed that 95% reduction of NO_x can be achieved with an SNCR system. In fact, for retrofits it is less than 50% and on new facilities it is generally less than 60%. Figure 1.3 shows theoretical NO_x reduction which is never achieved in practice.

The Department and Minnkota has considered the other technologies in Comment VI (see Appendix A of Minnkota's assessment and p. 57-62 of the Department's preliminary determination). Each of these technologies have been rejected for various reasons. The commenter provided no reason why the rejection of these technologies was incorrect.

Heating of the flue gas during startup or shutdown would be impractical and not cost effective because of the large volume. There is no natural gas available and generation of heat for the flue gas would produce additional air pollutants including NO_x, CO, CO_2 and perhaps SO_2 and particulate matter.

Comment X: The proposed NO_x emission limit associated with the proposed BACT is not consistent with other emission rates achieved across the United States

Response: The commentor compares the proposed BACT with those of other sources without consideration to the type of boiler. The Choctaw Generating Station is a circulating fluidized bed boiler with no NO_x controls. The Stanton Station Units 1 and 10 are wall-fired and tangentially fired respectively, again with no NO_x control. The MRYS boilers are cyclone boilers with much higher uncontrolled NO_x emission rates, 0.85 lb/10^6 Btu and 0.79 lb/10^6 Btu (annual average) respectively. In order to do a fair comparison, the comparison must consider the type of boiler (i.e. cyclone). The comparisons provided by the commentor are inappropriate.

EPA

I. NDDH's Analysis of Technical Feasibility of Tail-End and Low Dust SCR at MRYS is Incorrect and Based on Incomplete Information

Response: EPA in footnote 6 attempts to equate the evaluation of low dust or tail-end SCR at the Gascoyne 500 Generating Station with that at the MRYS. The Gascoyne 500 Station was proposed as two circulating fluidized bed (CFB) boilers which use a dry scrubber and baghouse to control SO_2 and particulate emissions. MRYS Unit 1 is equipped with an electrostatic precipitator (ESP) and Unit 2 is equipped with a spray tower scrubber for SO_2 control and ESP for particulate. The comparison is faulty because it does not consider the type of boiler and the type of particulate control devices. Due to higher operating temperatures, a cyclone boiler produces more submicron aerosols of sodium and potassium which are concentrated in the fly ash which is not expected from the CFB. The baghouse at Gascoyne 500 will be approximately five times more effective in removing these submicron particles (Air and Waste Management Association; Air Pollution Engineering Manual). EPA did not provide any data to show the loading of catalyst deactivation chemical would be similar.

EPA also insinuates that the Department made a definitive interpretation that low dust or tail-end SCR was technically feasible for Gascoyne 500 and this determination should apply to MRYS. In its analysis, the Department stated "However, the Department is not certain that this technology (tail-end SCR) will work with a North Dakota lignite-fired unit because it has not been used before. For these reasons, the Department retained, with reservations, it as a technologically feasible control option." (Note - this technology was ultimately eliminated based on its high cost). In the BACT analysis prepared by Westmoreland they discuss the difficulties in getting the technology to work and state "Due to the presence of alkali constituents, especially Na, in lignite-fired flue gas, SCR has not been installed or demonstrated to be technically feasible on a lignite-fired boiler." Regarding low dust SCR, Westmoreland stated "Given the concern for catalyst poisoning and fouling with a high dust SCR, it may [emphasis added] be possible to design a low dust SCR system to control NO_x emissions downstream of the particulate control device." In this case, the particulate control device is a baghouse which is expected to be five times more efficient in removing the submicron catalyst deactivation chemicals. Westmoreland and the Department never said that a low dust system could be made to work. Westmoreland stated "Low dust SCR has not been used to control NO_x emissions from a CFB boiler. The low dust SCR configuration described above would be a first-of-its-kind design, and it is likely that Westmoreland would incur significant engineering and testing to ensure the viability of a low dust SCR control system on a lignite-fired CFB boiler." It is obvious that pilot scale testing would be required to determine the viability of a low dust SCR (both Haldor and CERAM will not provide a guarantee to Minnkota without pilot scale testing). The Westmoreland BACT analysis was prepared and submitted in June 2006 which is prior to Minnkota's BACT analysis (October 2006).

EPA's comparison of the MRYS BACT to the Gascoyne 500 BACT is inappropriate because of the different type of boilers, the different type of particulate control devices, the lignite is from a different mine and Minnkota conducted a much more thorough analysis.

Coyote Station Pilot Testing

The Coyote Station pilot testing does show a difference between subbituminous coal and North Dakota lignite. The EERC has described the blinding and plugging (deactivation) at the Coyote Station as extremely rapid and severe as compared to testing at the Columbia and Baldwin Stations which burn subbituminous coal. The pilot testing indicates that an SCR system designed for a plant that burns subbituminous coal may not be appropriate for a plant that burns North Dakota lignite. Additional research and testing on the effects of the flue gas constituents are required to determine if TESCR and LDSCR are a viable option for controlling NO_x emissions (Haldor Topsoe has indicated that the potential exists that the physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x).

MRYS Unit 1 Sampling

The testing at MRYS 1 shows that some of the sodium aerosols will escape capture by the electrostatic precipitator. Minnkota has indicated that the sodium aerosols will have a mean diameter of 0.1 microns. The spray tower at MRYS Unit 2 is designed for SO_2 control, not particulate control. A spray tower designed for particulate control will generally have a very low removal efficiency for particles of this size. Wark and Warner (Air Pollution Control) and the Air and Waste Management Association (Air Pollution Engineering Manual) indicate less than 10% removal efficiency of these size particles. EPA's Air Pollution Control Technology Fact Sheet (EPA-452/F-03-016) states that spray tower scrubbers are not suited for fine particulate control. It goes on to state they are relatively inefficient in removing fine PM. EPA's Module 6: Air Pollutants and Control Techniques - Particulate Matter - Control Techniques indicates an average efficiency of less than 40% for 0.1 micron particles for a unit specifically designed to remove particulate matter. The scrubber at MRYS Unit 2 is designed for SO_2 control and is expected to be less efficient than average for particulate matter. EPA has provided no references to assert that the spray tower will be highly effective in removing aerosols with a mean diameter of 0.1 microns. Testing by Markowski[25] and Microbeam Technologies, Inc.[19] have confirmed that the wet scrubber is relatively ineffective in removing the submicron particles. Both CERAM Environmental and Haldor Topsoe, Inc. found the loading and form of the aerosols and particles in the flue gas at MRYs to be so significant that they would not provide a catalyst life guarantee for LDSCR or TESCR.

Minn-Dak Farmers Coop. Experience

The experience at Minn-Dak was intended to show that the submicron sodium aerosols will not be completely removed by particulate control devices and a fraction will be emitted. Minn-Dak is equipped with a venturi scrubber which is specifically designed for particulate control. For 1 micron particles, a venturi scrubber is expected to be more efficient than an ESP (Wark & Warner, Air Pollution Its Origin and Control). Wark & Warner further indicate that an ESP is expected to have less than a 10% efficiency for removal of 0.1 micron particles. The Minn-Dak experience verifies that the submicron sodium particles will not be captured even by a high efficiency wet scrubber designed to control particulate matter.

SCR System and Catalyst Vendor Responses on TESCR

Vendor guarantees alone do not prove that a technology will work (NSR Manual, Section I.V.B, p. B20). The Department considers vendor guarantees to be of little value unless there is a binding contract. No such guarantees exist for MRYS. In 2008, EPA provided emails which suggested that a catalyst life guarantee could be obtained from catalyst vendors. However, Minnkota requested proposals from CERAM Environmental and Haldor Topsoe, Inc. for LDSCR and TESCR in 2009. Both vendors indicated they would not provide a guarantee without pilot scale testing. After reviewing detailed information about the flue gas characteristics at MRYS, CERAM and HTI apparently decided the financial risk was too great to provide a guarantee.

Minnkota and its consultants provided information on a recent SCR test program in the southeast United States which caused the catalyst vendors to significantly modify and/or completely withdraw the guarantees they had offered prior to the testing. Minnkota indicates there has never been any tail-end SCR applied to any type of boiler burning lignite, whether in Europe or North America. In addition, Minnkota indicates no tail-end SCRs have been installed on any coal-fired utility boiler anywhere in the world since 1991. The fact that no tail-end SCR has been applied to a lignite-fired boiler and none have been constructed since 1991 on any type of coal-fired boiler leads the Department to question the amount of study and evaluation that was conducted by the vendors prior to making a so-called guarantee.

Conclusion of TESCR and LDSCR Technical Feasibility

LDSCR and TESCR are evaluated together since the flue gas characteristics at each location would not vary significantly and both vendors from which Minnkota had sought proposals (HTI and CERAM) both indicated they would not provide a guarantee for either location.

The NSR Manual states in Step 1:

> "Add-on controls on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review."

The flue gas characteristics of the MRYS are significantly different from other boilers where SCR has been applied. Minnkota has supplied a significant amount of material which clearly shows the difference. CERAM stated in their proposal to Minnkota that "The high levels of Na_2O in the ash for the North Dakota lignite are not commonly found in sub-bituminous and bituminous coals which are fired with SCR systems. CERAM is unaware of any SCR application experience in the industry with this level and form of sodium in the ash." HTI[4] has stated "… the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions." Regarding North Dakota lignite, Sargent and Lundy (S&L) has stated "There are attributes of this fuel in a tail-end SCR environment that are not well understood today and need more investigation to predict its performance to make it a commercially available technology[13]." S&L also stated "Some important unanswered questions pose a significant risk for an SCR design engineer for tail-end SCR." Both HTI and CERAM have indicated in their October 2009 proposals they will not provide a guarantee for the catalyst life without successful pilot scale testing being done.

The NSR Manual states "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. 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 state;
- research and patenting;
- bench scale or laboratory testing;
- pilot scale testing;
- licensing and commercial demonstration; and commercial sales.

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. 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" (emphasis added).

The MYRS is a new and dissimilar source category from other facilities where SCR has been successfully applied. The U.S. Environmental Protection Agency (EPA) has considered cyclone (and more generally slag tap) furnaces that burn lignite from North Dakota, South Dakota and Montana to be a separate source category for NO_x emission limits in 40 CFR 60 Subparts D and Da. This was due to the high sodium content of the lignite (43 FR 9276). Not until EPA established a fuel and furnace type neutral standard was all subcategorization eliminated. The Department is not aware of any analysis of the flue gas characteristics of North Dakota lignite by EPA which was considered when the subpart Da standards were revised. EPA states:

> "EPA disagrees that lignite-fired steam-generating units would not be able to achieve the amended NSPS. While there are no existing lignite-fired electric utility steam-generating units with SCR in the United States, there is considerable experience in the industry to show that use of SCR on lignite is technically feasible. EPA has concluded that the primary reason that no pulverized lignite-fired units are equipped with SCR is because no new pulverized lignite unit has been built in the United States since 1986.
>
> The Electric Power Research Institute testing of SCR catalyst in a slipstream at the Martin Lake Power showed acceptable results from Gulf Coast lignite. In addition, two recent

> permit applications for pulverized lignite-fired utility units in Texas (Twin Oaks 3 and Oak Grove facilities) propose to use SCR to control NO_x emissions to 0.07 and 0.10 lb/MMBtu, respectively. Finally, technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. EPA has concluded that SCR can be used on lignite boilers in the United States and catalyst suppliers have indicated that they will offer performance guarantees on these applications."
>
> "In addition, the use of SCR is not required to comply with the amended NO_x standard. The existing Big Brown facility in Texas burns pulverized Gulf Coast lignite and is able to achieve 0.15 lb NO_x/MMBtu with combustion controls alone. EPA has concluded that new lignite-fired units would either be able to achieve the amended standards without the use of any backend controls or could use SNCR to comply. Existing units at 0.15 lb/MMBtu would only need 30 percent NO_x reduction to comply with the amended NO_x standard. This level of control has been demonstrated for existing pulverized coal (PC) units retrofit with SNCR, and new units could achieve even better results.
>
> Fluidized bed combustion and gasification are also options for new lignite units. The proposed permits for the Westmoreland and South Heart facilities in North Dakota both propose to burn Fort Union lignite in fluidized beds and use SNCR to achieve a NO_x emissions limits of 0.09 lb/MMBtu. With regard to size, Foster Wheeler recently designed a 460 MW supercritical fluidized bed." (71 FR 9870)

Several of EPA's statements are erroneous for North Dakota lignite. There is <u>not</u> considerable experience in the industry to show the use of SCR for North Dakota lignite fired unit is technically feasible. CERAM has stated they are unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS. CERAM[3] also stated "the levels of K_20 in the North Dakota lignite ash are in the high end range found in many biomass fuels, such as wood and switch grass. However, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications." S&L has indicated that unanswered questions about the flue gas characteristics and their effect on an SCR pose a significant risk. EPA's own consultant indicated he was not aware of any facility with as high of sodium loading as MRYs where SCR had been applied.[16]

EPA also indicated that SCR was shown to work on Gulf Coast lignite, Texas lignite and European brown coals. EPA concluded that SCR can be used on lignite boilers and that performance guarantees can be obtained from catalyst suppliers. Minnkota has clearly demonstrated that the ash from MRYS is different from Gulf Coast lignite, Texas lignite and European brown coals where SCR has been applied. CERAM[26] and HTI[27] both have indicated that they have offered catalyst life guarantees for other lignite fired units, including Texas lignite; however, they have refused to provide a catalyst life guarantee for MRYS which burns North Dakota lignite. The criteria EPA used to determine that SCR was technically feasible for NSPS purposes, is unclear. Under the PSD program, technical feasibility determinations are based on the flue gas characteristics of the source evaluated. EPA's second thought in their justification for the fuel and furnace type neutral standard was that a fluidized bed combustion unit could be used to meet the limits. The MRYS consists of existing cyclone fired units combusting North Dakota lignite and must be evaluated on this basis.

As CERAM pointed out, the flue gas characteristics of MRYS are different from other facilities where SCR has been applied. HTI has indicated that these fuel gas characteristics may cause so severe catalyst deactivation that SCR may not be a viable option for controlling NO_x emissions. These statements clearly indicate that the MRYS, and cyclone boilers burning North Dakota lignite, is a dissimilar source category from other sources that have successfully applied SCR.

Both CERAM and HTI believe pilot scale testing must be conducted prior to providing any guarantees for catalyst life. S&L has also recommended that pilot testing be conducted to answer questions about the effects of the soluble alkalis and ash characteristics including the size, stickiness and abrasiveness qualities of the ash.

There has never been a full scale SCR installed on a facility that burns North Dakota lignite. The high soluble sodium content (catalyst poison) and the sticky nature of the ash are characteristics that are different from facilities where SCR has been successfully applied. CERAM and HTI have supplied guarantees for catalyst at other lignite-fired facilities but would not provide one for MRYS. They have indicated they are not aware of any SCR being installed in the United States without a catalyst life guarantee. An SCR that is guaranteed to work successfully is not available for the MRYS.

The NSR Manual[1] states that technologies in the pilot scale testing phase of development need not be considered as available control technologies. Both CERAM and HTI have indicated that pilot scale testing is needed and would not provide a catalyst life guarantee. HTI has indicated that SCR may not be a viable option for MRYS. Pilot testing would be necessary to show whether SCR is a viable option. Minnkota is not required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is Minnkota required to experience extended trials to learn how to apply SCR to MRYS which is a new and dissimilar source type. CERAM and HTI have indicated that up to one year of pilot scale testing is required before they would consider a guarantee. This is consistent with Sargent and Lundy's (S&L) recommendation of one year of operation of a pilot scale test. S&L indicated that the overall pilot scale test program duration would be 18-24 months based on one year of operation. The additional time is for design, mobilization, setup and evaluation of the data. Estimates of the cost of pilot scale testing have ranged up to two million dollars (S&L Presentation March 11, 2009). This level of resource penalties and time delays are not required by BACT. Therefore, SCR is not an available technology for the MRYS.

The NSR Manual states "Technical feasibility of technology transfer control candidates generally is addressed based on an evaluation of pollutant-bearing gas stream characteristics for the proposed source and other source types to which the control had been applied previously." (Section IV.B, p.B.21)

"A demonstration of technical infeasibility is based on a technical assessment considering physical, chemical and engineering principles and/or empirical data showing that he technology would not work on the emissions unit under review, or that unresolvable technical difficulties would preclude the successful deployment of the technique." (Section IV.B, p.B.20)

"Generally, decisions about technical feasibility will be based on chemical and engineering analysis in conjunction with information about vendor guarantees." (Section IV.B, p.B.20)

The lignite combusted at MRYS contains high quantities of soluble sodium and potassium which can cause catalyst reaction site poisoning, blinding, and plugging of catalyst pores and channels. Core samples for 2007-2010 indicated a sodium oxide (Na_2O) concentration in the ash as high as 13.4% and a potassium oxide (K_2O) concentration as high as 6.9% (Appendix A-2, 4/23/07 submittal). During combustion of this fuel, a significant portion of these organically associated elements are either vaporized or form small particles that leave the boiler in the flue gas. Soluble sodium and potassium are catalyst poisons even in dry conditions in the SCR. The sodium and potassium can also form sulfates that plug the catalyst pores and channels. HTI has stated for LDSCR and TESCR that physical deactivation due to catalyst binding and plugging could be severe enough to make SCR a non-viable option for controlling NO_x emissions. CERAM has stated that the levels of K_2O in the North Dakota lignite ash are at the high end of the range found in many biomass fuels; however, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications. The potential clearly exists that LDSCR and TESCR cannot be successfully applied at MRYS.

The NSR Manual states that decisions about technical feasibility will be based on chemical, and engineering analysis in conjunction with information about vendor guarantees. Both HTI and CERAM refused to provide catalyst life guarantees for MRYS. Both companies have indicated that refusal to provide a catalyst guarantee is extremely rare. They both indicated they have offered guarantees for other types of lignite (including Texas lignite), European brown coals and biomass. Both companies indicated they were not aware of any SCR being installed in the United States without a catalyst life guarantee. In a letter to Burns and McDonnell (July 27, 2010), HTI stated:

> "HTI currently has one of the first SCR's on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NO_x removal effects, ammonia slip, SO_2 oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC applications in the world. All of these are new and very challenging projects which push the technology to the next level.
>
> HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees."

Apparently, the risk of failure at MRYS was too great for HTI since they would not supply a catalyst life guarantee. SCR is not applicable to MRYS.

EPA has indicated that BACT is intended as a "technology forcing" requirement. HTI has indicated they have "forced" the technology (SCR) at other facilities and provided guarantees. Apparently, the use of SCR at MRYS forces the technology beyond an acceptable risk for the company. The same is apparently true for CERAM. Both companies have indicated that their decision not to provide a guarantee was not influenced by Minnkota or Burns and McDonnell. It was a business decision based on the risk involved.

The Department of Justice, through their contractor Evonik Energy Services, LLL (Evonik) provided a Request for Proposals (RFP) to HTI and CERAM supposedly based on the flue gas characteristics of MRYS. Both companies indicated they would provide catalyst life guarantees to Evonik based on the RFP. HTI and CERAM have provided letters explaining this seeming contradiction. Both have indicated that Evonik did not provide a fuel analysis, ash analyses, the range of fuel and ash characteristics that could be encountered , details on the soluble constituents in the flue gas and the fact that it was North Dakota lignite. HTI believed the RFP was for a facility burning eastern subbituminous coal. HTI indicated they would not have provided a guarantee if it had known that the fuel was North Dakota lignite. CERAM has indicated it would not have provided a guarantee if the Evonik RFP had provided the same level of detail as the Minnkota RFP. The RFP by Evonik and subsequent proposals by CERAM and HTI proved nothing and have no value.

The chemical constituents in the flue gas at MRYS are known to cause chemical poisoning of SCR catalyst, blinding of the catalyst and pluggage. The risk of failure of an SCR system at MRYS was so great that two catalyst vendors, HTI and CERAM, independently determined that they could not provide a catalyst life guarantee. Minnkota is not required under BACT to assume the high risk associated with the failure of a technology that has never been used on North Dakota lignite-fired unit. Therefore, the technology is currently not applicable to MRYS.

In order for a technology to be technically feasible it must both be available and applicable to the sources under review. Since LDSCR and TESCR are neither available or applicable to MRYS, the technology is not technically feasible for a lignite source. This is not the first BACT determination that deemed SCR was not technically feasible for a lignite source. The State of Louisiana determined that SCR was not feasible for the Red River Environmental Products, LLC activated carbon plant that uses lignite. This determination was based on a finding that the sodium sulfate in the flue could cause rapid deactivation of the catalyst and the lack of operating or empirical data.

Both CERAM[26] and HTI[27] have stated that they are not aware of an SCR being installed in the United States without a catalyst life guarantee. Minnkota is not required under BACT to assume the high risk associated with the failure of an SCR system.

Comment II: NDDH's Technical Feasibility Analysis of High Dust SCR is Incorrect and Based Upon Flawed Data

Response:

- HDSCR Catalyst Plugging and Deactivation

The NSR Manual[4], page B.20, states "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."

The Department asked EPA's consultant, Mr. Roger Christmann, if he was aware of any installation in the world where SCR had been applied to a facility with as high of sodium loading as at MRYS. Mr. Christmann indicated no.[16] CERAM Environmental, Inc., in their proposal for LDSCR and TESCR, has indicated that they are not aware of any SCR experience in the industry with the level and form of sodium in the flue gas at MRYS. Haldor Topsoe in their proposal for LDSCR has indicated that catalyst deactivation at MRYS could be so severe that LDSCR may not be a viable NO_x control. The concentration of the catalyst deactivation constituents at a HDSCR location would be as much as 90 times that at a LDSCR location. This indicates there has never been a design established for a flue gas with the chemical characteristics found at MRYS.

Simple mathematics prepared by the Department shows that the flue gas at MRYS is much higher in sodium and other catalyst deactivation chemicals than other power plant flue gases. EPA tries to dismiss this by ratioing the loading of PRB to bituminous without indicating the actual loading. The Department showed the actual loading (lb/dscf and lb/wscf) as well as the ratio to other facilities. When you start out with a very small loading, as is the case with bituminous coal, a large ratio for subbituminous coal also gives you small loading. EPA seems to ignore the fact that the sodium at MRYS is the soluble form (organically associated) which is a more potent catalyst deactivation chemical than the insoluble (inorganically associated) form found in other coals. As EPA's own consultant points out, SCR has never been applied to a sodium loading as high as MRYS.

Minnkota and its consultants have documented very well the effect of soluble sodium on an SCR catalyst. Although the Coyote testing did not provide any deactivation rate data for high soluble sodium North Dakota lignite, it did show that an SCR design for subbituminous coal may not work successfully with North Dakota lignite. As Sargent and Lundy pointed out, there is no known solution for the soluble alkalis such as the soluble sodium and potassium found in North Dakota lignite[17]. EPA ignores the chemical differences between Texas lignite and North Dakota lignite. With respect to the catalyst vendor guarantees provided in 2007 to Minnkota, all vendors indicated that pilot scale testing was either required or should be done prior to applying high dust SCR technology to a North Dakota lignite-fired boiler. The so called "guarantees" that SCR can be applied to MRYS are somewhat meaningless because there was no consequence for making an incorrect statement at that point in time. Only when a contract is signed between the source and vendor is there any consequence to the statement that SCR will work at the MRYS. This is apparent from the proposals CERAM Environmental and Haldor Topsoe made for TESCR and LDSCR in 2009. Each company refused to provide a guarantee without pilot testing. It can be inferred the same would be true for HDSCR.

The NSR Manual[4], page B.20, states "However, EPA does not consider a vendor guarantee alone to be sufficient justification that a control option will work." The NSR Manual[4] goes on to state "Generally, decisions about technical feasibility will be based on chemical and engineering analyses (as discussed above) in conjunction with information about vendor guarantees." Minnkota has provided information that indicates the potential for greatly reduced catalyst life due to the chemical characteristics of the flue gas. Although two vendors in 2007 indicated a catalyst life for HDSCR which the Department would consider as a "successful application" of SCR technology at MRYS, others did not give such an indication. All vendors indicated the flue gas temperature problems (too hot or too cold) must be resolved for the application of HDSCR to be successful. No solution to this problem has been found at this time. All vendors indicated that pilot scale testing should be conducted. Two of the companies that indicated in 2007 that they would provide a guarantee for HDSCR at MRYS have refused in 2009 to provide a guarantee for LDSCR or TESCR. A HDSCR will encounter much higher concentrations of catalyst deactivation chemicals. Although Texas has determined that SCR is technically feasible for Texas lignite, the chemical constituents of North Dakota lignite that affect the feasibility of SCR are quite different. CERAM and Haldor Topsoe have both offered catalyst life guarantees for Texas lignite; however, they have refused to offer a guarantee for the MRYS. The State of Louisiana recently determined that SCR was not technically feasible for an activated carbon plant because of the flue gas characteristics of the Gulf Coast lignite used in the process. The NSR Manual[4], pages B.19 - 20, indicates that an add-on control technology is only technically feasible if it can lead to "successful operation" or "successful deployment." The Department has indicated that anything less than 10,000 hours of catalyst life would not be successful operation of the SCR system and thus be technically infeasible. Based on the analysis of the chemical characteristics of the flue gas at MRYS, Minnkota has demonstrated that the flue gas characteristics of MRYS are different from other coal-fired boilers where SCR has been applied. CERAM has stated for LDSCR and TESCR that they are unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS[9]. It can be surmised that this is also true for HDSCR. The MRYS is a dissimilar source.

The NSR Manual[4] states "A source would not be required to experience 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" (Chapter B, Section IV.B). Minnkota is not required to conduct extensive and expensive feasibility analyses for modifying the boiler to correct temperature problems that make HDSCR infeasible.

EPA has indicated that catalyst regeneration is a viable option (that is currently used in practice) for restoring catalyst life either in-situ, on-site, or off-site water washing. EPA cites a PowerPoint presentation at the 2007 NO_x Round Table and Expo by Reinhold Environmental Limited as evidence that this technique is available. DOJ's consultant, Mr. Hans Hartenstein, also made a presentation at the referenced Expo. In Mr. Hartinstein's presentation the following statement is made "Regeneration = Removal of catalyst poisons plus restoration of catalytically active ingredients - can typically not be done in-situ or on-site, but should be done off-site to ensure required close process control." EPA may be referring to "rejuvenation" of a catalyst for which Mr. Hartenstein states "Removal of catalyst poisons without the need for replenishing catalytically active compounds - can **sometimes** [emphasis added] be done in-situ, but is most commonly done either on-site or off-site." These statements were also made by Ehrnschwender and Holsccher at the February 2008 Expo (Considerations for Catalyst Deactivation and Regeneration When Firing Biomass). Minnkota and its consultants have addressed this issue by stating "Regarding the contention of Hartenstein, there is extremely limited experience with in-situ catalyst cleaning on coal-fired units. ENBW in Germany developed this technique, but it has never had a commercial success. It has also never been used for blinded or chemically poisoned catalyst, but only for mechanically plugged catalyst."[18] There is no evidence regarding the effectiveness of washing to rejuvenate an SCR catalyst on the MRYS. Pilot scale testing would be necessary to determine the feasibility of this catalyst management technique.

Microbeam Technologies, Inc. (Microbeam) conducted particulate emissions testing at the MRYS in March of 2009[19]. The results indicate that most of the particulate matter emissions from each boiler is removed by the electrostatic precipitator (ESP). Microbeam's results indicated a particulate matter removal efficiency of 99.76%. Microbeam's results also indicate the amount of $Na_2O + K_2O$ is approximately 50-90 times greater entering the ESP than exiting the ESP. The results are similar for $Na_2O + K_2O$ entering the ESP versus exiting the wet scrubber. The loading of $Na_2O + K_2O$ on a HDSCR would be approximately 50-90 times higher than a LDSCR or TESCR. In the November 2008 technical feasibility analysis, the Department evaluated HDSCR and determined it was not technically feasible. The Department has reviewed the Microbeam Technologies report and reached the same conclusions regarding technical feasibility. The amount of sodium and potassium in the flue gas is so high that it is very unlikely that 10,000 hours of catalyst life could be achieved. The testing by Kling et. al. found deactivation rates up to 52% in 1,500 hours for a fuel made up of tree bark and 20% demolition waste. The Microbeam[19] results suggest a similar rate for MRYS. Zheng et. al. found a deactivation rate of 0.4% per day using 20-30 mg/Nm^3 of potassium sulfate with a mass mean diameter of 0.55 micrometers (u.m.). The 0.4% deactivation rate per day is equivalent to 6,000 hours to 100% deactivation. The Microbeam results indicate a higher potassium sulfate equivalent loading of aerosols less than 0.55 μm at MRYS. Both HTI and CERAM indicated changeout of the SCR catalyst at 50% deactivation[9,10]. This empirical data suggests that catalyst changeout for a HDSCR at MRYS will have to occur much more frequently than 10,000 hours per changeout.

Therefore, a commercial design of HDSCR for high soluble sodium North Dakota lignite is not available. Experience with subbituminous coal or bituminous coal is not applicable. Based on the guidance in the NSR Manual, HDSCR must be determined not to be technically feasible.

- MRYS Temperature Variation Issue Related to HDSCR

The resolution of the temperature problem would require a technical feasibility analysis of a "very complex nature" (Steve Moorman 7/18/07 email) to determine if boiler modifications could bring furnace exit gas temperatures into the range needed for compatibility with the operation of HDSCR. Modifications outside of the boiler may solve the temperature problem; however, a study would be required. Babcock and Wilcox estimated the cost of the study at $275,000 - $400,000 and would take 20-24 weeks to complete. Minnkota is not required to undergo expensive and lengthy time delays in order to learn how to apply SCR technology. The temperature problem is another potentially fatal road block to the successful use of HDSCR. EPA's statement that the technical issues with the temperature issue can be resolved appears to be premature.

EPA's Conclusion on HDSCR

When considering application of HDSCR to a cyclone boiler burning North Dakota lignite, the MRYS is considered a new source type. EPA has recognized cyclone boilers, and more generally slag tap furnaces, that burn lignite from North Dakota, South Dakota and Montana as a separate source category for NO_x emissions in the New Source Performance Standards, Subparts D and Da. This separate category was established primarily based on the use of high sodium lignite. Not until EPA went to a fuel and furnace neutral standard was this category replaced. The replacement of this category was apparently done without an evaluation of the flue gas characteristics of North Dakota lignite. The NSR Manual states "Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit undergoing BACT review." (NSR Manual, Chapter B, Section IV.A).

Minnkota was unable to obtain a catalyst life guarantee for LDSCR and TESCR. It follows that a guarantee is also not available for HDSCR which will have worse flue gas conditions for the SCR catalyst. Empirical data suggest the catalyst will have to be replaced much more frequently than every 10,000 hours of operation. The temperature problem may be unresolveable. Therefore, HDSCR is not available or applicable and is technically infeasible.

Comment III: The NDDH BACT Determination Incorrectly Applies the Concept of Pilot Testing in EPA's NSR Manual to Conclude that SCR is not Technically Feasible.

Response: EPA states that "For determining whether a control option is available, EPA's NSR Manual does not describe the comparison of gas stream characteristics between the source under review and other sources."

Whether MRYS is a new or dissimilar source is based on the flue gas characteristics. Chapter B, Section IV.A, p. B.10, Identify Alternative Emission Control Techniques (Step 1) states "The top-down BACT analysis should consider potentially applicable control techniques from all three categories. Lower polluting processes should be considered based on demonstrations made on the basis of manufacturing identical or similar products from identical or similar raw materials or fuels. Add-on controls, on the other hand, should be considered based on the physical and chemical characteristics of the pollutant-bearing emission stream. Thus, candidate add-on controls may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emissions unit undergoing BACT review" (emphasis added). Clearly, identification of "potentially available" control options under Step 1 must take into account the flue gas characteristics. There has never been SCR technology applied to a boiler that combusts North Dakota lignite. EPA has recognized, in the past, cyclone boilers, such as those at Minnkota, that burn lignite from North Dakota is a separate source category for NO_x emission limits under the New Source Performance Standards, Subpart D and Da. Minnkota has shown that the flue gas characteristics at MRYS are different from that at any other coal-fired power plant where SCR has been installed. Mr. Roger Christmann, EPA's consultant, stated that he was not aware of any power plant where SCR had been applied with as high of sodium loading as MRYS[16]. CERAM Environmental has stated that it is unaware of any SCR application experience in the industry with the level and form of sodium in the MRYS ash[9]. Haldor Topsoe has stated that SCR (HDSCR, LDSCR and TESCR) may not be a viable option for controlling NO_x emissions due to catalyst pluggage and blinding[10]. MRYS is a new and dissimilar source from any source category where SCR has been applied successfully.

SCR technology designed for other coal-fired power plants may not be applicable to a North Dakota lignite-fired unit and there is no commercially available design. The experience at other coal-fired boilers is not applicable. Pilot scale testing would be necessary to show whether SCR can work successfully. As Sargent and Lundy (S&L)[13] pointed out, there are no known solutions for the catalyst surface masking and catalyst deactivation caused by the soluble alkalis (Na_2O and K_2O) found in North Dakota lignite. S&L indicated that some thresholds or limits are yet to be defined for SCR involving ash with greater than 2% Na_2O and greater than 1% K_2O. The Na_2O in the ash at MRYS can be as high as 13% and K_2O as high as 7%. S&L has also stated "there are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance." Any pilot scale testing would be used to obtain data on the soluble alkalis and ash characteristics and compare the findings with experience on Power River Basin Coal to determine if SCR can be applied successfully to a unit firing ND lignite.

The pilot scale testing would not be for optimizing an existing available control technology. It would be for determining whether SCR is a viable control option, researching solutions to the high concentration of soluble alkalis and the possibility of designing an SCR system for a new and dissimilar source category.

Comment IV: The NDDH BACT Determination Frustrates the Technology Forcing Function of the BACT that was Intended by Congress.

Response: MRYS is a different source category based on its flue gas characteristics. The Department has taken the position that the flue gas characteristics at the MRYS will preclude the successful application of existing SCR technology.

Haldor Topsoe has stated in a July 27, 2010 letter to Burns and McDonnell the following: "HTI currently has one of the first SCRs on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NO_x removal effects, ammonia slip, SO_2 oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC application in the world. All of these are new and very challenging projects which push the technology to the next level. HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees."

Clearly Haldor Topsoe believes that "forcing" SCR technology for MRYS presents an unacceptable risk for their company since they would not provide a catalyst guarantee for LDSCR or TESCR. CERAM Environmental also would not provide a guarantee[9]. Again, apparently the risk of failure was too great.

Decisions regarding technical feasibility are based on the flue gas characteristics, not whether it has been applied to a coal-fired boiler or some other general source category. We believe Congress never intended forcing a technology on a source when there is a low probability of successful deployment of that technology.

Comment V: Other Comments on the NDDH BACT Determination.

Comment 1: EPA does not agree with the statement "Information from Sargent and Lundy indicates that not enough information is available to determine whether SCR technology can be successfully adapted to units burning North Dakota lignite."

Response: Sargent and Lundy[17] indicates that there are no known solutions to the surface masking from soluble alkalis (Slide 49) and no known solution to the catalyst deactivation by soluble alkalis (Slide 52). In addition, S&L states that "There are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance (Slide 82)." Without knowing the performance of an SCR, one cannot say it can be successfully adapted to North Dakota lignite.

Comment 2: EPA believes control of popcorn ash is not a significant problem.

Response: The Department agrees that recent experience indicates that popcorn ash can be adequately controlled.

Comment 3: EPA believes coal cleaning needs to be addressed.

Response: The issue of coal cleaning for NO_x reduction was addressed by Minnkota in their analysis (see p. 3-10 and 3-11). There is no evidence that coal cleaning will reduce the boiler NO_x emissions.

EPA suggested in their comments that coal cleaning could remove the soluble sodium and potassium elements in the coal. The sodium and potassium are organically bound within the coal particles. Physical coal cleaning can remove only matter that is physically distinct from the coal, such as small dirt particles, rocks and pyritic sulfur. Physical cleaning cannot remove contaminants that are chemically combined with coal. It also cannot remove nitrogen from the coal (Noyes, Robert; Pollution Prevention Technology Handbook, 1993).

Chemical cleaning of the lignite may remove some of the chemically bound sodium and potassium. EPA did not site any examples of facilities that are removing chemically bound sodium or potassium. The Department has not found any coal cleaning plants that remove the organically associated sodium and potassium from coal. Therefore, the technology is not commercially available and therefore, technically infeasible.

Comment 4: EPA would like the email from Mr. Brad Plummer included in the record.

Response: Agreed.

Comment VI: Docket Information for the TXU Oak Grove NSR Permit is Evidence that the Utility Industry and Other State Agencies Believe that SCR is Technically Feasible & can be Applied to New Fuel Types & Boiler Types.

Response: The NSR manual[4] states "A demonstration of technical infeasibility should be clearly documented and should show, based on physical, chemical, and engineering principles, that technical difficulties would preclude the successful use of the control option on the emissions unit under review" (Chapter B, Section II.A). The flue gas characteristics of Texas lignite are significantly different from North Dakota lignite. North Dakota lignite ash contains much more sodium and potassium and it is in the soluble form. This soluble form penetrates deeply into the pores of the catalyst and causes premature failure of the catalyst. Minnkota has provided sufficient evidence that the flue gas characteristics could preclude successful application of SCR technology. Both Haldor Topsoe[27] and CERAM[26] have indicated they have offered guarantees for Texas lignite. However, they have refused to provide a guarantee for North Dakota lignite. Any comparisons of North Dakota lignite to Texas lignite for application of SCR is inappropriate.

Regarding other state's BACT determinations, the State of Louisiana recently determined that SCR was not technically feasible at an activated carbon plant (Red River Environmental Products, LLC) that uses Gulf Coast lignite as a feedstock. This determination was based on a conclusion that the flue gas characteristics (i.e. alkali metals, especially sodium) would deactivate the catalyst and preclude successful deployment of SCR technology. EPA did not object to Louisiana's BACT determination.

Comment VII: B&McD 114 Response Documents.

Response: No response necessary.

Comment VIII: Docket Information for the Clean Air Interstate Rule (CAIR), Best Available Retrofit Technology, and New Source Performance Standards (NSPS) States that EPA Determined that SCR is Technically Feasible for Lignite-Fired Utility Boilers.

Response: The MYRS is a new and dissimilar source category from other facilities where SCR has been successfully applied. The U.S. Environmental Protection Agency (EPA) has considered cyclone (and more generally slag tap) furnaces that burn lignite from North Dakota, South Dakota and Montana to be a separate source category for NO_x emission limits in 40 CFR 60 Subparts D and Da. This was due to the high sodium content of the lignite.[24] Not until EPA established a fuel and furnace type neutral standard was all subcategorization eliminated. The Department is not aware of any analysis of the flue gas characteristics of North Dakota lignite by EPA which was considered when the subpart Da standards were revised. EPA states:

> "EPA disagrees that lignite-fired steam-generating units would not be able to achieve the amended NSPS. While there are no existing lignite-fired electric utility steam-generating units with SCR in the United States, there is considerable experience in the industry to show that use of SCR on lignite is technically feasible. EPA has concluded that the primary reason that no pulverized lignite-fired units are equipped with SCR is because no new pulverized lignite unit has been built in the United States since 1986.
>
> The Electric Power Research Institute testing of SCR catalyst in a slipstream at the Martin Lake Power showed acceptable results from Gulf Coast lignite. In addition, two recent permit applications for pulverized lignite-fired utility units in Texas (Twin Oaks 3 and Oak

> Grove facilities) propose to use SCR to control NO_x emissions to 0.07 and 0.10 lb/MMBtu, respectively. Finally, technology suppliers report that SCR has been successfully used on lignite and brown coal boilers in Europe. EPA has concluded that SCR can be used on lignite boilers in the United States and catalyst suppliers have indicated that they will offer performance guarantees on these applications."
>
> "In addition, the use of SCR is not required to comply with the amended NO_x standard. The existing Big Brown facility in Texas burns pulverized Gulf Coast lignite and is able to achieve 0.15 lb NO_x/MMBtu with combustion controls alone. EPA has concluded that new lignite-fired units would either be able to achieve the amended standards without the use of any backend controls or could use SNCR to comply. Existing units at 0.15 lb/MMBtu would only need 30 percent NO_x reduction to comply with the amended NO_x standard. This level of control has been demonstrated for existing pulverized coal (PC) units retrofit with SNCR, and new units could achieve even better results.
>
> Fluidized bed combustion and gasification are also options for new lignite units. The proposed permits for the Westmoreland and South Heart facilities in North Dakota both propose to burn Fort Union lignite in fluidized beds and use SNCR to achieve a NO_x emissions limits of 0.09 lb/MMBtu. With regard to size, Foster Wheeler recently designed a 460 MW supercritical fluidized bed." (71 FR 9870)

Several of EPA's statements are erroneous for North Dakota lignite. There is not considerable experience in the industry to show the use of SCR for North Dakota lignite fired unit is technically feasible. CERAM[9] has stated they are unaware of any SCR application experience in the industry with the level and form of sodium in the ash at MRYS. CERAM also stated "the levels of K_20 in the North Dakota lignite ash are in the high end range found in many biomass fuels, such as wood and switch grass. However, the levels of Na_2O are much greater than that found in biomass or coal-fired SCR applications." S&L[13] has indicated that unanswered questions about the flue gas characteristics and their effect on an SCR pose a significant risk.

EPA also indicated that SCR was shown to work on Gulf Coast lignite, Texas lignite and European brown coals. EPA concluded that SCR can be used on lignite boilers and that performance guarantees can be obtained from catalyst suppliers. Minnkota has clearly demonstrated that the ash from MRYS is different from Gulf Coast lignite, Texas lignite and European brown coals where SCR has been applied. CERAM[26] and HTI[27] both have indicated that they have offered catalyst life guarantees for other lignite fired units, including Texas lignite; however, they have refused to provide a catalyst life guarantee for MRYS which burns North Dakota lignite. The criteria EPA used to determine that SCR was technically feasible for NSPS purposes, is unclear. Under the PSD program, technical feasibility determinations are based on the flue gas characteristics of the source evaluated. EPA's second thought in their justification for the fuel and furnace type neutral standard was that a fluidized bed combustion unit could be used to meet the limits. The MRYS consists of existing cyclone fired units combusting North Dakota lignite and must be evaluated on this basis.

The decision of technical feasibility of add-on controls under the PSD BACT process is based on the flue gas characteristics of the source under review. EPA has provided no technical analysis of the flue gas characteristics of North Dakota lignite, which is different from other lignites, to show its reasoning that SCR is technically feasible under the CAIR rule, BART Guidelines and NSPS. EPA's criteria for determining technical feasibility under these rules is unclear. Without such an analysis, the decisions under the cited rules and guidelines are immaterial. It should be noted that the CAIR rule did not include North Dakota sources and has been vacated by the Circuit Court of Appeals for the District of Columbia. MRYS is not subject to the BART Guidelines or the NO_x standards under the NSPS.

All information provided by EPA will be included in the record.

Comment IX: Hans Hartenstein Expert Report on "Feasibility of SCR Technology for NO_x Control Technology for the Milton R. Young Station, Center, North Dakota.

Response: The expert report is based on several premises that are incorrect. These include:

Premise 1: Sodium is not a poison to catalyst at SCR operating temperatures. Moisture is needed to carry soluble sodium into catalyst pores before it can poison the catalyst.

Response: Soluble sodium has been found to be an SCR catalyst poison at normal SCR operating temperatures (Haldor Topsoe[10], Zheng et.al.[21], Kling et.al.[20], Guo,[23] Baxter[22]). CERAM Environmental has indicated in their Confidential Proposal for LDSCR and TESCR that soluble sodium will cause SCR deactivation even in dry conditions. This is consistent with the findings of Kling et.al.[20] and Zheng et.al.[21] that submicron aerosols of sodium migrate into the catalyst pores, most likely by surface diffusion, and deactivate the catalyst.

Premise 2: Vendors will supply guarantees for HSDSCR, LDSCR and TESCR.

Response: The Confidential Proposals for LDSCR and TESCR by CERAM Environmental and Haldor Topsoe indicated they would not provide a guarantee without pilot scale testing. This is in contrast to Hartenstein's statements that these companies assured him they would provide guarantees. It is virtually assured these companies would not provide a guarantee for HDSCR without pilot scale testing.

Premise 3: There is other experience with coal-fired power plants that can be utilized for designing an SCR for M.R. Young Station.

Response: CERAM Environmental, in their Confidential Proposal for LDSCR and TESCR, has indicated they are not aware of any SCR application experience in the industry with the level and form of sodium in the M.R. Young ash. Haldor Topsoe has indicated that the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a nonviable option for controlling NO_x emissions. S&L has indicated there are attributes of North Dakota lignite in an SCR environment that are not well understood and need investigation to predict its performance. These statements indicate that there is not enough experience with the flue gas characteristics at the MRYS to assure SCR can be applied successfully. This is also one of the reasons CERAM and HTI would not supply a catalyst life guarantee.

Premise 4: Sodium and other catalyst poisons will be removed by the wet scrubber prior to TESCR.

Response: Testing by Markowski[25] and Microbeam Technologies, Inc.[19] indicate that the wet scrubber on Unit 2 at the MRYS will not effectively remove the submicron aerosols that will cause SCR catalyst deactivation. A significant amount of sodium and potassium aerosols will be in the flue gas after the wet scrubber.

Premise 5: The same catalyst was used on the pilot scale testing at Baldwin Station and Coyote Station.

Response: Minnkota has indicated that fresh catalyst was used in the Coyote testing.

Premise 6: Temperature problems are no reason to reject SCR as technically infeasible since they can be easily fixed.

Response: High temperature will sinter the catalyst and deactivate it. All vendors indicated the high temperature problem must be resolved before HDSCR can be successfully applied. Babcock and Wilcox indicates that a study of the temperature problem would be very complex, cost $275,000 - $400,000, and take 20-24 weeks to complete. Minnkota is not required to undergo costly studies or extended delays in order to adapt a technology to their facility.

The faulty premises of Mr. Hartenstein's report has failed to demonstrate that HDSCR, LDSCR or TESCR is technically feasible for the MRYS.

References

1. ERG; Technical Memorandum #2, Estimation of Costs and Impacts of NO_x Control Technologies Applied to PGE Boardman Plant; June 26, 2008.

2. U.S. EPA; Final Statement of Basis for Draft Permit No. PSD-OU-002-04.00, Deseret Power Electric Cooperative Bonanza Power Plant; August 30, 2007.

3. U.S. EPA; Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construct, Permit No. PSD-OU-0002-04.00; August 30, 2007.

4. U.S. EPA; New Source Review Workshop Manual; October, 1990.

5. Wyoming Department of Environmental Quality; Permit Application Analysis, NSR-AP-3546; February 5, 2007.

6. U.S. EPA; EPA Air Pollution Control Cost Manual Sixth Edition; EPA/452/B-02-001; January 2002.

7. Cichanowicz; Edward; Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies; June 2007.

8. NDDH; North Dakota State Implementation Plan for Regional Haze; February 24, 2010.

9. CERAM Environmental, Inc.; SCR Catalyst Budgetary Proposal and Recommendations for Milton R. Young Station Units 1 and 2 – Confidential; October 13, 2009.

10. Haldor Topsoe, Inc.; SCR $DeNo_x$ Catalyst Specification for Burns and McDonnell & Minnkota Power, Milton R. Young Station Units 1 & 2 – Confidential; October 12, 2007.

11. Energy Information Administration; Annual Energy Outlook 2010; December 2009.

12. U.S. EPA, Federal Register; February 27, 2006.

13. Sargent & Lundy, LLC; Application of Tail-end SCR Technology to North Dakota Lignite Fuels; March 11, 2009.

14. Haldor Topsoe, Inc.; Letter to Robert Blakely from Wayne S. Jones; July 27, 2010.

15. NDDH; Best Available Control Technology Determinations: Red Trail Energy; May 2004; Montana Dakota Utilities/Westmoreland Power Inc.; March 2005; Westmoreland Power, Inc.; May 2007; Great River Energy; July 2007.

16. Meeting with EPA Region 8, NDDH and Mr. Roger Christmann; January 11, 2007,

17. Sargent and Lundy, LLC; Application of SCR Technology to North Dakota Lignite Fuels (Power Point Presentation); May 2007

18. Minnkota Power Coop.; Comments and Responses to NDDH Regarding U.S. EPA Region 8's July 31, 2009 Comments and Plains Justice July 30, 2008 Comments on NDDH Preliminary NO_x BACT Determinations for Milton R. Young Station (MRYS); September 22, 2008.

19. Microbeam Technologies, Inc.; Final Report; Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD; July 1, 2009.

20. Kling, Asa; Anderson, Chester; Mryinger, Ase; Eskilsson, David; Jaras, Sven G; Alkali deactivation of higher dust SCR catalysts used for NO_x reduction exposed to flue gas from 100 MW-scale biofuel and peat-fired boilers: Influence of flue gas composition; Applied Catalysis; 2007.

21. Zheng, Yuanjing; Jensen, Anker Dega; Johnsson, Jan Erik; Thogersen, Jaokim Reimer; Deactivation of V_2O_5-WO_3-TiO_2 SCR catalysis at biomass-fired power plants; Elucidation of mechanisms by lab – pilot-scale experiments; applied catalysis; 2008.

22. Baxter, Larry; Biomass Impacts on SCR Catalyst Performance; October 2005.

23. Guo, Xianyu; Poisoning and Sulfation on Vanadia SCR Catalyst; August 2006.

24. U.S. EPA; Federal Register; March 7, 1978; 43 FR 9276

25. Markowski, Gregory R; Downs, Jerry Li, Woffinden, George J.; Sulfate Aerosols from Western Low-Rank Coal-Fired Boiler with FGD: Summary of Tests at Coal Creek, Clay Boswell, Milton R. Young, and San Miquel Stations; May 31, 1983.

26. Personal Conversation with Noel Rosha, CERAM Environmental, Inc.; September 17, 2010.

27. Personal Conversation with Wayne Jones, Haldor Topsoe, Inc.; September 15, 2010.

MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

RESPONSES TO NDDH REQUEST
NOx BACT ANALYSIS STUDY
MILTON R. YOUNG STATION UNIT 1 and UNIT 2
REGARDING SCR ECONOMIC FEASIBILITY

December 11, 2009

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide more detailed and comprehensive cost data following their reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental reports[2] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station ("MRYS"). A detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[3], are attached. Responses to the use of steam from the main boilers for reheat of the flue gas are provided. A comparison of control costs from relevant recent BACT Determinations versus the estimated control costs of hypothetical applications of low-dust and tail end SCR technologies at MRYS included with the November 2009 Supplemental Reports is also provided.

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced NO_X BACT Analysis Study[4] 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)[5]. The November 2009 NO_X BACT Analysis Study Supplemental Reports were generated in response to the NDDH's request[6] to see Steps 3 and

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[1] See Reference number 1, November 25, 2009.

[2] See Reference number 2, November 12, 2009.

[3] See Reference number 3, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

[4] See Reference number 4, October 2006.

[5] See Reference number 5, April 24, 2006.

[6] Ibid Reference number 3, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

4 of the BACT analysis process[7] be performed and include low-dust and tail end SCR alternatives.

Detailed NOx BACT Analysis Study Supplemental reports' Capital and Operating & Maintenance Cost Summary:

NDDH Request: "A detailed breakdown of capital costs and operation and maintenance costs for the bulleted items on page 4-16 should be provided."[8]

BMcD Response:

The referenced "bulleted items on page 4-16" of the November 2009 NOx BACT Analysis Study Supplemental reports are intended to represent the major components (physical assets) that were identified as being required to install and operate low-dust and tail end SCRs if they were considered technically feasible for application at MRYS. Preliminary SCR Cost Estimates used as inputs to the November 2009 NO_X BACT Analysis Study Supplemental Reports were not developed based upon a direct match to each of the bulleted items included in the reports. Thus it is not possible to provide a cost breakdown in that format. In lieu of a breakout directly corresponding to the bulleted items, Burns & McDonnell has modified our cost estimate spreadsheets for the four "shared facilities" as well as the four "stand alone" hypothetical applications of SCR technologies analyzed, to reflect the cost tabulation format used in the "SCR Chapter" of the "EPA Air Pollution Control Cost Manual – Sixth Edition" (Section 4.2; Chapter 2).

Please see the attached "Shared Facilities Total Capital Investment" and "Stand Alone Total Capital Investment" cost estimate tables that follow the outline of Table 2.5 in the SCR Chapter of EPA's Control Cost Manual[9] for these hypothetical applications of SCR technologies analyzed. Note that this SCR Chapter of the EPA Control Cost Manual is intended for estimating costs of high dust SCRs, as it states on page 2-41 that "costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher

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[7] See Reference number 8, October 1990.

[8] Ibid Reference number 1, November 25, 2009.

[9] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-44, January 2002.

than the high-dust SCR systems due to flue gas heating requirements"[10]. The SCR Chapter of the Control Cost Manual also states that "the cost methodology is valid for a low-dust SCR system because the cost reductions are expected to be within the range of uncertainty for study-level costs"[11]. We also suggest that the SCR Cost Manual is not suitable for estimating the costs for the cold-side low-dust SCR arrangement analyzed in the Supplemental NOx BACT reports for MRYS because of the flue gas reheating required.

Also see attached tables of estimated "Shared Facilities Total Annual Costs" and "Stand Alone Total Annual Costs" that include the items described in pages 2-44 through 2-49 of the SCR Chapter of EPA's Control Cost Manual[12] for an SCR application. As previously mentioned, the equations in the SCR Cost Manual's cost methodology were not used for estimating annual costs of electrical power consumption, reagent usage, and catalyst replacements. Note that budgetary vendor quotes were the primary source of information used to calculate these estimated annual costs of the hypothetical applications of SCR technologies analyzed.

Use of Steam from the main boilers for reheat of flue gas (for low-dust and tail end SCR alternatives):

NDDH Request: "The use of steam from the main boilers for the flue gas reheat should also be addressed."

BMcD Response:

Natural gas-fired flue gas reheat is shown in the SCR Chapter of EPA's Control Cost Manual for an SCR application of a tail end SCR example[13], so the use of such reheat systems is not unique to Minnkota's study. MPC selected natural gas firing and rejected the use of steam for flue gas reheating for the evaluation of hypothetical applications of low-dust and tail end SCR technologies at MRYS. For the SCR cost estimate study by Burns & McDonnell, it was necessary to establish the scope conceptual design basis for estimating the costs associated with installation and operation and maintenance of the hypothetical applications of low-dust and tail

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[10] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-41, January 2002.

[11] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-41, January 2002.

[12] Ibid Reference number 9, Section 4.2, Chapter 2, pages 2-44 – 2-49, January 2002.

[13] Ibid Reference number 9, Section 4.2, Chapter 2, page 2-21, January 2002.

end SCR technologies. Minnkota's selection of natural gas-fired flue gas reheating for these conceptual designs and cost estimates was made in order to avoid additional loss of unit electrical energy generation output capacity.

A preliminary high level conceptual review of the MRYS Unit 1 steam cycle was done by Minnkota to investigate the feasibility of using steam to achieve the estimated heat duty (31.1 million BTU/hr to raise flue gas temperature from 555°F to 580°F for one reactor) required for the hypothetical application of low dust SCR technology. This preliminary review indicated that using steam for this service appeared to be feasible but would result in a unit electrical output capacity derate of 4-5 MW. This is because the high-temperature/high-pressure main steam extracted from the boiler for flue gas reheat system would not pass through any stages of the high/intermediate/low pressure steam turbines, so less net electrical energy would be produced.

The value of lost electrical generating capacity was not calculated, but the steady-state long term operation impact is believed to be approximately 50% or more of the total auxiliary electricity demand estimated in the November 2009 NO_X BACT Analysis Study Supplemental Reports' Table C.4-3[14] for the hypothetical application of SCR technologies at MRYS.

The preliminary concept assumed that main boiler steam (high pressure, high temperature, around 1000°F, 2500 psig) would be diverted from the steam turbine's inlet piping, and be routed for supply to the flue gas heating system. This would involve the heating steam supplied being condensed using heating coils inserted into the flue gas ductwork. The condensate liquid would then be returned to the boiler feedwater treatment system for reuse. The 4-5 MW Unit 1 derate for a hypothetical application of low-dust SCR technology does not include additional downtime due to tube leaks or other maintenance issues associated with the flue gas reheat steam system. Higher induced draft booster fan discharge pressure requirement for pressure drop is not included. Use of steam for cleaning the in-duct steam coils' exterior surfaces or the gas-to-gas heat exchanger online during operation using soot blowing is also not included in this estimate of the potential unit derate. The time required to modify the main steam piping and other steam turbine and boiler feedwater treatment system components in the steam cycle power generation

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[14] Ibid Reference 2, page 4-27.

and balance-of-plant systems and boiler flue gas systems to accommodate such suggested changes would be lengthy. The duration of an outage to implement such modifications, and value of lost electrical generating capacity, would be significant.

A similar preliminary high level conceptual review of the MRYS Unit 2's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (2 reactors, 48.1 MMBTU/hr each to raise flue gas temperature from 535°F to 580°F) required for a hypothetical application of low-dust SCR technology was not performed. Although sizing was not evaluated for MRYS Unit 2, using a scaling factor (ratio of 477 MW divided by 257 MW nameplate capacity ratings) to estimate Unit 2's derate compared with Unit 1's estimated derate could be applied for an approximation. This would yield a potential Unit 2 electrical generating output capacity derate on the order of magnitude of 8 to 10 MW for a hypothetical application of low-dust SCR technology. Similar impacts and issues as described for Unit 1 would be expected for Unit 2.

A similar preliminary high level conceptual review of the MRYS Unit 1's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (1 reactor, 60.3 MMBTU/hr each to raise flue gas temperature from 520°F to 563°F) required for a hypothetical application of tail end SCR technology was not performed. Although sizing was not evaluated for this case, using a scaling factor (ratio of 60.3 divided by 31.1 heat duties) to estimate Unit 1's derate compared with Unit 1's estimated derate for a hypothetical application of low-dust SCR technology could be applied for an approximation. This would yield a potential Unit 1 electrical generating output capacity derate on the order of magnitude of 8 to 10 MW for a hypothetical application of tail end SCR technology. Similar impacts and issues as previously described for Unit 1 would be expected.

A similar preliminary high level conceptual review of the MRYS Unit 2's steam cycle to investigate the feasibility of using steam to achieve the estimated heat duty (2 reactors, 50.8 MMBTU/hr each to raise flue gas temperature from 520°F to 563°F) required for a hypothetical application of tail end SCR technology was not performed. Although sizing was not evaluated for MRYS Unit 2, using a scaling factor (ratio of 101.6 divided by 31.1 heat duties) to estimate

Unit 2's derate compared with Unit 1's estimated derate could be applied for an approximation. This would yield a potential Unit 2 electrical generating output capacity derate on the order of magnitude of 13 to 16 MW for a hypothetical application of tail end SCR technology. Similar impacts and issues as described for Unit 1 would be expected for Unit 2.

These estimates of lost electrical generation outputs come from boiler main steam usage, larger induced draft fan power requirements, and potential additional downtime associated with the flue gas reheating systems. Because the MRYS units' electrical energy generation output capacity is limited by the steam energy production capacity of each boiler ("boiler limited"), there is not "free capacity margin" available to offset the megawatt losses. Minnkota also cannot increase boiler hourly heat inputs (coal firing rates) in order to compensate for the decrease in output because the increased emissions from higher firing rates are not permitted.

Additional arguments that support the decision to select natural gas firing and reject the use of steam for flue gas reheating involving hypothetical applications of low-dust and tail end SCR technologies at MRYS:

- Minnkota's previous experience with the use of steam for Unit 2's flue gas desulfurization system absorber outlet flue gas reheat (for stack plume buoyancy) was not positive and the technique was abandoned in favor of reheat via scrubber flue gas bypass. The Consent Decree does not allow Minnkota to continue the use of unscrubbed flue gas for reheating the stack gas[15].
- Boiler-turbine steam systems are complex and sensitive to steam inputs, extractions, and outlet conditions. There was insufficient time available during the SCR cost estimate study to perform a comprehensive analysis of potential performance impacts from the modifications related to the use of steam for flue gas reheat.
- High pressure/high temperature steam piping is expensive to procure and install, and requires special design to accommodate thermal growth and significant weight and dynamic loads without overstress. There was insufficient time available during the SCR cost estimate study to perform a comprehensive analysis of potential hanger supports,

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[15] Ibid Reference number 5, April 24, 2006.

pipe sizing and routing from the main steam source to the multiple points of use and return of condensate to the boiler plant.

- The deposits removed during cleaning of the in-duct steam coils fouled by particulate, aerosols, and ash products emitted from the boilers and also removed from the gas-gas heat exchanger upstream of the flue gas reheater will be entrained in the flue gas stream entering the SCR reactor. This will require a "large particle ash screen" that creates more pressure drop than the direct-fired duct burner.

Comparison of Average and Incremental Control Costs for MRYS NOx BACT (for low-dust and tail end SCR alternatives) versus recent BACT determinations:

NDDH Request: "It should be documented that the costs of SCR at the M.R. Young Station are significantly beyond the range of recent costs normally associated with BACT for coal-fired power plants (or BACT control costs in general) for the control of nitrogen oxides (NSR Manual Chapter B, Section IV.D.2.C)."

BMcD Response:

A review of available information on "costs normally associated with BACT" for control of NOx emissions from coal-fired power plants indicates that very little documentation is published. Although both the EPA's RACT BACT LAER Clearinghouse (RBLC) [http://cfpub.epa.gov/rblc/htm/bl02.cfm] and the EPA's "National Coal-Fired Utility Projects Spreadsheet" [available via http://www.epa.gov/ttn/catc/products.html#misc] include an assigned database field for entry of "Control Cost Effectiveness" in units of $/ton, neither of these sources contains much information. The assigned field where the data should be entered is blank in the vast majority of cases entered in these databases.

This dearth of data on BACT cost effectiveness was encountered by EPA Region 8 during its preparation of the "Response to Public Comments" for the Draft PSD Permit for Deseret Power Electric Cooperative's proposed 110 MW waste coal fired unit addition to the Bonanza Power Plant[16]. In seeking to defend the cost basis for its rejection of a control technology as BACT, EPA Region 8 was able to identify only 13 cases (total for all pollutants) in which control cost effectiveness data were identified in recent permit actions involving BACT.

Burns & McDonnell reviewed the cases identified by EPA Region 8 in their response for the Deseret BACT case to determine if any data on "the cost associated with BACT" was available for cases involving NOx control for coal-fired boilers. Of the 13 cases for all pollutants identified by EPA Region 8, only one case involved the rejection of the "top" NOx control

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[16] See Reference number 10, pages 29-33.

technology as BACT due to what was identified as “excessive cost”. This was the case of MDU’s proposed Gascoyne project in North Dakota. The inability of EPA Region 8 to identify more cases in which the permit record clearly establishes the level of NOx control costs illustrates the difficulty of this task.

Burns & McDonnell was able to identify only two other cases, both also in North Dakota, in which the permit record shows that the “top” NOx control technology for a coal-fired boiler was rejected as having an excessive “control cost effectiveness”. The relevant data for these cases is tabulated below, and compared to similar information as stated in the Supplemental NO_X BACT reports prepared for MRYS Units 1 and 2.

Previous Coal-Fired Boiler NO_X BACT Determinations Based on Cost Effectiveness

State	Utility	Plant Name	Technology Considered Technically Feasible but Rejected as BACT by State Agency	Average Control Cost of Rejected Technology	Average Control Cost of Technology Accepted as BACT	Technology Recommended as BACT
ND	MDU	Gascoyne	SCR	$7545/ton	$2926/ton	SNCR
ND	South Heart Coal LLC	South Heart	SCR	$7640/ton	$1690/ton	SNCR
ND	GRE	Spiritwood	SCR	$7640/ton	$1843/ton	SNCR

As shown in the table above, for coal-fired boilers the "average cost effectiveness of BACT for NOx" as established in previous permit actions ranges from $1690/ton to $2926/ton. By comparison, the estimated cost for NOx control using SCR, which was rejected as BACT due to excessive costs in these previous cases, ranged from 2.6 to 4.5 times the control cost of the technology established as BACT using the "top down" process.

As shown in the table above, for coal-fired boilers the "average cost effectiveness of BACT for NOx" as established in previous permit actions ranges from $1690/ton to $2926/ton. By comparison, the estimated cost for NOx control using SCR, which was rejected as BACT due to excessive costs in these previous cases, ranged from 2.6 to 4.5 times the control cost of the technology established as BACT using the "top down" process.

Control Cost Data from MRYS Units 1 & 2 Supplemental NOx BACT Reports

"Top" Technology Recommended to be Rejected as BACT	Average Control Cost of "Top" Technology	Average Control Cost of Technology Recommended as BACT	Technology Recommended as BACT
MRYS Unit 1 Low-Dust or Tail End SCR with ASOFA	\$3,396/ton to \$5,969/ton	\$1,265/ton	MRYS Unit 1 SNCR with ASOFA
MRYS Unit 2 Low-Dust or Tail End SCR with ASOFA	\$3,859/ton to \$6,597/ton	\$1,240/ton	MRYS Unit 2 SNCR with ASOFA

In the case of MRYS Units 1 and 2, and taking the range of control costs for SCR (TESCR and LDSCR) with ASOFA as presented in the Supplemental NO_X BACT reports (shown above), the ratio between the cost of the technology proposed for rejection on a cost basis to the cost of the technology proposed as BACT for the MRYS units is quite similar to that seen in previous permit actions. For Unit 1, the cost ratio ranges from 2.7 to 4.7. For Unit 2, the cost ratio ranges from 3.1 to 5.3. Thus it appears that the same rationale that was used to reject SCR technology as being "excessively costly on a \$/ton control cost basis" in the case of these other three North Dakota BACT determinations should also apply to the case of MRYS.

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 Cost Estimate*, dated November 25, 2009.

2. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

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: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

4. "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.

5. 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.

6. 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.

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

9. EPA Air Pollution Control Cost Manual – Sixth Edition (EPA/452/B-02-001), January 2002.

10. *Response to Public Comments on Draft Air Pollution Control Prevention of Significant Deterioration (PSD) Permit to Construct [Permit No. PSD-OU-0002-04.00]*, U.S. EPA Region 8, August 30, 2007.

ATTACHMENTS

1. "Shared Facilities Total Capital Investment" and "Stand Alone Total Capital Investment" cost estimate tables for Low-Dust and Tail End Selective Catalytic Reduction alternatives, as supporting information regarding Unit 1 and Unit 2 at Milton R. Young Station, November, 2009, Reference number 2, NO_X Best Available Control Technology Analysis Study – Supplemental Reports for Minnkota Power Cooperative, Inc., dated December 7, 2009.

2. "Shared Facilities Total Annual Costs" and "Stand Alone Total Annual Costs" tables for Low-Dust and Tail End Selective Catalytic Reduction alternatives, as supporting information regarding Unit 1 and Unit 2 at Milton R. Young Station, November, 2009, Reference number 2, NO_X Best Available Control Technology Analysis Study – Supplemental Reports for Minnkota Power Cooperative, Inc., dated December 7, 2009.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Shared Facilities

DIRECT CAPITAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Purchased Capital Equipment					
(a) SCR System Equipment					
Capital Cost of SCR System	$ 29,738,389	$ 52,565,778	$ 38,796,814	$ 70,418,628	Note 1
Capital Cost of Spare Catalyst					Note 2
(b) Auxiliaries/Balance of Plant	$ 23,756,987	$ 40,894,045	$ 33,414,080	$ 52,307,775	Note 3
(c) Instruments and controls					Note 4
(d) Taxes					Note 5
(e) Freight					Note 6
PURCHASED CAPITAL EQUIPMENT COSTS - TOTAL	$ 53,495,376	$ 93,459,823	$ 72,210,894	$122,726,403	Note 7
(2) Construction Costs					
(a) Foundations and supports	$ 15,097,939	$ 28,304,959	$ 20,041,826	$ 39,631,284	Note 8
(b) Urea storage building					Note 9
(c) Electrical	$ 6,901,578	$ 13,809,256	$ 7,690,294	$ 15,296,131	Note 10
(d) Mechanical/Piping	$ 2,411,613	$ 4,718,286	$ 2,513,213	$ 4,995,255	Note 11
(e) Insulation	$ 3,195,016	$ 4,686,967	$ 5,350,536	$ 7,143,550	Note 12
(f) Painting					Note 13
DIRECT CAPITAL CONSTRUCTION COSTS - TOTAL	$ 27,606,146	$ 51,519,468	$ 35,595,868	$ 67,066,221	Note 14
DIRECT CAPITAL COSTS - TOTAL	$ 81,101,522	$144,979,291	$107,806,762	$189,792,624	Note 15
INDIRECT CAPITAL COSTS					
(3) Indirect Installation Costs					
(a) Engineering & Field Support	$ 12,165,228	$ 21,746,894	$ 16,171,014	$ 28,468,894	Note 16
(b) Construction Mgt & Indirects	$ 3,244,061	$ 5,799,172	$ 4,312,270	$ 7,591,705	Note 17
(c) Startup Expenses	$ 1,582,000	$ 2,938,000	$ 1,582,000	$ 2,938,000	Note 18
(d) Scope Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 19
(4) Other Indirect Costs					
(a) Pricing Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 20
INDIRECT INSTALLATION COSTS - TOTAL	$ 41,964,276	$ 73,619,274	$ 55,137,991	$ 95,302,199	Note 21
(5) Cost Escalation during Project	$ 26,772,124	$ 40,212,687	$ 35,491,483	$ 52,726,778	Note 22
(6) Interest During Construction	$ 17,441,200	$ 30,047,900	$ 23,097,900	$ 39,221,000	Note 23
(7) Natural Gas Pipeline - Installed	$ 2,362,500	$ 4,387,500	$ 2,362,500	$ 4,387,500	Note 24
(8) Owner's Costs - Other	$ 13,632,335	$ 24,182,077	$ 16,920,540	$ 29,632,862	Note 25
TOTAL CAPITAL INVESTMENT	**$183,273,957**	**$317,428,728**	**$240,817,176**	**$411,062,963**	Note 26

Shared Facilities (SF) represents estimated costs if SCR equipment is retrofitted to both boilers concurrently. This table follows outline of Table 2.5 of EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44.

Note 1: Includes costs for SCR equipment including initial catalyst, flue gas heat recovery equipment, and flue gas reheat burner equipment as well mechanical setting of this equipment.

Note 2: Does not include spare catalyst in purchased SCR equipment costs.

Note 3: Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion, flue gas reheat gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment.

Note 4: Instrumentation and controls are included in Electrical Construction costs (see Note 10).

Note 5: Sales taxes for engineered equipment and permanent materials is not included; Taxes are included for consumable materials.

Note 6: Delivery expenses are included in equipment costs.

Note 7: Sum of SCR, Auxiliaries/Balance of Plant, and Instruments/Controls equipment costs; taxes and freight.

Note 8: Includes site excavation, structural steel, concrete, and architectural construction costs. Includes SCR bypass ducts and isolation dampers, and interconnecting ductwork construction costs.

Note 9: Estimated separately as shown in Table 4.5 SF in Supplemental BACT Control and Cost Effectiveness Analysis.

Note 10: Instrumentation and Controls, additional plant electrical distribution equipment are included in Electrical construction costs.

Note 11: Mechanical/Piping includes material and installation of all piping not provided with engineered equipment.

Note 12: Insulation includes ductwork and piping insulation.

Note 13: Painting included in structural and architectural construction costs.

Note 14: Sum of Direct Capital Construction Costs.

Note 15: Sum of Total Purchased Capital Equipment and Total Direct Capital Construction Costs; considered to be equivalent to "A" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 16: Sum of Engineering and Field Support Costs.

Note 17: Sum of Construction Management and Construction Indirects.

Note 18: Startup Costs include costs for startup engineering support.

Note 19: Scope contingency is to account for potential changes in the project scope resulting from engineering, equipment, and/or construction work which were not identified or included.

Note 20: Pricing contingency is to account for potential changes in project costs resulting from wages, productivities, equipment and/or materials costs being higher than anticipated. Note: this does not intend to cover pricing increases over time, i.e. Escalation. Considered to be equivalent to "C" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 21: Sum of Indirect Capital Installation Costs; considered to be equivalent to "D", Total Plant Costs in EPA OAQPS SCR Cost Manual Table 2.5.

Note 22: Escalation is a result of anticipated increases in costs that are due to higher costs over time.

Note 23: Interest During Construction (or Allowance for Funds During Construction) are considered to be equivalent to "E" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 24: Natural gas pipeline construction cost was assumed as an owner cost.

Note 25: Other Owner Costs include Owner personnel, insurance, pilot testing, Owner Contingency and Spare Parts.

Note 26: Total Capital Investment (TCI) is equivalent to Installed Capital Cost for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Table 4-5SF, page 4-18. The installed capital cost of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, are not included in these numbers. See Table 4-5SF.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Capital Investment for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Stand Alone

DIRECT CAPITAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Purchased Capital Equipment					
(a) SCR System Equipment					
Capital Cost of SCR System	$ 29,738,389	$ 52,565,778	$ 38,796,814	$ 70,418,628	Note 1
Capital Cost of Spare Catalyst					Note 2
(b) Auxiliaries/Balance of Plant	$ 34,665,617	$ 46,348,360	$ 44,322,710	$ 57,762,090	Note 3
(c) Instruments and controls					Note 4
(d) Taxes					Note 5
(e) Freight					Note 6
PURCHASED CAPITAL EQUIPMENT COSTS - TOTAL	$ 64,404,006	$ 98,914,138	$ 83,119,524	$128,180,718	Note 7
(2) Construction Costs					
(a) Foundations and supports	$ 20,120,339	$ 30,816,159	$ 25,024,641	$ 42,122,692	Note 8
(b) Urea storage building					Note 9
(c) Electrical	$ 8,399,220	$ 14,558,077	$ 9,489,326	$ 19,195,648	Note 10
(d) Mechanical/Piping	$ 4,299,227	$ 5,662,093	$ 4,400,827	$ 5,939,062	Note 11
(e) Insulation	$ 3,288,333	$ 4,733,626	$ 5,443,853	$ 7,190,209	Note 12
(f) Painting					Note 13
DIRECT CAPITAL CONSTRUCTION COSTS - TOTAL	$ 36,107,120	$ 55,769,955	$ 44,358,647	$ 71,447,611	Note 14
DIRECT CAPITAL COSTS - TOTAL	$100,511,125	$154,684,093	$127,478,171	$199,628,329	Note 15
INDIRECT CAPITAL COSTS					
(3) Indirect Installation Costs					
(a) Engineering & Field Support	$ 15,076,669	$ 23,202,614	$ 19,121,726	$ 29,944,249	Note 16
(b) Construction Mgt & Indirects	$ 4,020,445	$ 6,187,364	$ 5,099,127	$ 7,985,133	Note 17
(c) Startup Expenses	$ 1,582,000	$ 2,938,000	$ 1,582,000	$ 2,938,000	Note 18
(d) Scope Contingency	$ 15,436,040	$ 22,988,134	$ 19,529,462	$ 29,593,180	Note 19
(4) Other Indirect Costs					
(a) Pricing Contingency	$ 12,486,493	$ 21,567,604	$ 16,536,353	$ 28,151,800	Note 20
INDIRECT INSTALLATION COSTS - TOTAL	$ 51,551,194	$ 78,304,245	$ 64,861,776	$100,053,742	Note 21
(5) Cost Escalation during Project	$ 30,170,164	$ 42,869,269	$ 42,013,593	$ 55,436,089	Note 22
(6) Interest During Construction	$ 21,561,300	$ 32,027,100	$ 27,278,800	$ 41,228,900	Note 23
(7) Natural Gas Pipeline - Installed	$ 6,750,000	$ 6,750,000	$ 6,750,000	$ 6,750,000	Note 24
(8) Owner's Costs - Other	$ 23,114,224	$ 27,867,439	$ 26,204,034	$ 33,248,637	Note 25
TOTAL CAPITAL INVESTMENT	**$236,658,008**	**$342,502,146**	**$294,586,374**	**$436,345,697**	Note 26

Stand Alone (SA) represents estimated costs if SCR equipment is retrofitted to both boilers independently. This table follows outline of Table 2.5 of EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44.

Note 1: Includes costs for SCR equipment including initial catalyst, flue gas heat recovery equipment, and flue gas reheat burner equipment as well mechanical setting of this equipment.

Note 2: Does not include spare catalyst in purchased SCR equipment costs.

Note 3: Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion, flue gas reheat gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment.

Note 4: Instrumentation and controls are included in Electrical Construction costs (see Note 10).

Note 5: Sales taxes for engineered equipment and permanent materials is not included; Taxes are included for consumable materials.

Note 6: Delivery expenses are included in equipment costs.

Note 7: Sum of SCR, Auxiliaries/Balance of Plant, and Instruments/Controls equipment costs; taxes and freight.

Note 8: Includes site excavation, structural steel, concrete, and architectural construction costs. Includes SCR bypass ducts and isolation dampers, and interconnecting ductwork construction costs.

Note 9: Estimated separately as shown in Table 4.5 SA in Supplemental BACT Control and Cost Effectiveness Analysis.

Note 10: Instrumentation and Controls, additional plant electrical distribution equipment are included in Electrical construction costs.

Note 11: Mechanical/Piping includes material and installation of all piping not provided with engineered equipment.

Note 12: Insulation includes ductwork and piping insulation.

Note 13: Painting included in structural and architectural construction costs.

Note 14: Sum of Direct Capital Construction Costs.

Note 15: Sum of Total Purchased Capital Equipment and Total Direct Capital Construction Costs; considered to be equivalent to "A" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 16: Sum of Engineering and Field Support Costs.

Note 17: Sum of Construction Management and Construction Indirects.

Note 18: Startup Costs include costs for startup engineering support.

Note 19: Scope contingency is to account for potential changes in the project scope resulting from engineering, equipment, and/or construction work which were not identified or included.

Note 20: Pricing contingency is to account for potential changes in project costs resulting from wages, productivities, equipment and/or materials costs being higher than anticipated. Note: this does not intend to cover pricing increases over time, i.e. Escalation. Considered to be equivalent to "C" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 21: Sum of Indirect Capital Installation Costs; considered to be equivalent to "D", Total Plant Costs in EPA OAQPS SCR Cost Manual Table 2.5.

Note 22: Escalation is a result of anticipated increases in costs that are due to higher costs over time.

Note 23: Interest During Construction (or Allowance for Funds During Construction) are considered to be equivalent to "E" in EPA OAQPS SCR Cost Manual Table 2.5.

Note 24: Natural gas pipeline construction cost was assumed as an owner cost.

Note 25: Other Owner Costs include Owner personnel, insurance, pilot testing, Owner Contingency and Spare Parts.

Note 26: Total Capital Investment (TCI) is equivalent to Installed Capital Cost for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Table 4-5SA, page 4-17. The installed capital cost of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, are not included in these numbers. See Table 4-5SA.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Annual Costs for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Shared Facilities

DIRECT ANNUAL COSTS	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**	**Notes**
(1) Annual Maintenance Costs	$ 4,189,181	$ 7,514,611	$ 5,444,530	$ 9,608,381	Note 1
(2) Annual Reagent Costs					Note 2
Scenario A	$ 2,710,313	$ 4,171,528	$ 2,709,417	$ 4,170,150	
Scenario B	$ 2,725,539	$ 4,204,613	$ 2,724,643	$ 4,204,613	
(3) Annual Electricity Costs					Note 3
Scenario A	$ 5,929,642	$ 9,730,376	$ 6,011,088	$ 9,740,159	
Scenario B	$ 11,939,901	$ 24,539,279	$ 11,982,549	$ 25,083,883	
(4) Annual Water Costs					Note 4
(5) Catalyst Replacement Costs					Note 5
Scenario A	$ 709,951	$ 958,131	$ 709,951	$ 963,350	Note 6
Scenario B	$ 4,387,500	$ 10,260,000	$ 4,387,500	$ 10,260,000	Note 7
(6) Natural Gas for F.G. Reheating & Urea-to-Ammonia Conversion sys.					Note 8
Scenario A	$ 2,136,238	$ 6,064,108	$ 3,931,511	$ 6,416,128	
Scenario B	$ 1,944,698	$ 5,296,499	$ 3,580,852	$ 5,574,558	Note 9
(7) Operating labor for SCR equipment and urea-to-ammonia eqpmnt					Note 10
DIRECT Annual COSTS - TOTAL					Note 11
Scenario A	$ 15,675,326	$ 28,438,754	$ 18,806,498	$ 30,898,167	
Scenario B	$ 25,186,819	$ 51,815,002	$ 28,120,074	$ 54,731,434	
INDIRECT Annual COSTS					
(8) Annual Costs from Capital Recovery	$ 12,174,396	$ 21,838,601	$ 15,822,632	$ 27,923,414	Note 12
(9) Administrative overhead, insurance and property taxes for SCRs and aux.					Note 13
INDIRECT Annual COSTS - TOTAL	$ 12,174,396	$ 21,838,601	$ 15,822,632	$ 27,923,414	
TOTAL ANNUAL COSTS					Note 14
Scenario A	$ 27,849,722	$ 50,277,355	$ 34,629,130	$ 58,821,580	
Scenario B	$ 37,361,215	$ 73,653,603	$ 43,942,706	$ 82,654,848	
LEVELIZED TOTAL ANNUALIZED COSTS					Note 15
Scenario A	$ 31,748,616	$ 57,350,872	$ 39,306,834	$ 66,506,822	
Scenario B	$ 43,625,884	$ 86,541,448	$ 50,936,958	$ 96,268,092	

Shared Facilities (SF) represents estimated costs if SCR equipment is retrofitted to both boilers concurrently.
This table includes values that are identified in the EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44 through 2-49 but use calculated and vendor-quoted values instead of the formulas provided in the OAQPS manual
Total Annual Costs consist of direct costs, indirect costs, and recovery credits (if any). Direct Annual Costs and variable and semi-variable costs that are proportional to the quantity of flue gas processed by the control system. Indirect Annual Costs are fixed costs incurred independent of control operation, and include capital recovery costs, insurance, administrative charges, and overhead (payroll and plant).
Note 1: Annual maintenance was assumed to be 3% of installed capital cost of the SCR equipment and auxiliary equipment related to the SCR systems, not including catalyst replacement costs. Maint. costs for ASOFA are included.
Note 2: Annual reagent costs are for "Scenario A" and "Scenario B" operation and related chemical usage based on receiving 50% aqueous urea solution, assumed to be $379.29 per ton in 2006$.
Note 3: Annual electricity costs are for "Scenario A" and "Scenario B" operation and related electricity consumption and lost generation, assumed to be $35/MW-hr in 2006$. See Tables C.4-1 through C.4-4 in the November 2009 NOx BACT Analysis Study Supplemental Reports for details.
Note 4: Annual water costs were not calculated, but may be more than zero, if concentrated liquid urea liquor (70% concentration) is purchased, which must be diluted to 50% concentration for storage.
Note 5: Annual catalyst replacement costs are for "Scenario A" and "Scenario B" operation, and are assumed to be based on $7,500 per cubic meter in 2006$.
Note 6: Annual catalyst replacement costs for "Scenario A" are assumed to be based one layer per reactor every two years (approx. 16,000 operating hours), and follows the EPA OAQPS SCR Cost Manual for annualizing the purchase cost using Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 assuming 6% per year annual interest rate. Tail end SCRs were assumed to have 10 layers replaced during the 20-year economic evaluation period, and 12 layers for Low-dust SCRs, but the annual catalyst replacement costs for U2 used in the November 2009 NOx BACT Analysis Study Supplemental Report underestimate the cost per layer due to assuming regular depth layers instead of deep layers recommended by vendor.
Note 7: Annual catalyst replacement costs for "Scenario B" are assumed to be based three layers per reactor every year (approx. 2,667 operating hours) for U1 and four layers per reactor per year (approx. 2,000 operating hours) for U2. There were no adjustments for annualizing the purchase cost (Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 of the EPA OAQPS SCR Cost Manual were not used). U1 Low-dust and Tail end SCRs were assumed to have 60 layers replaced during the 20-year economic evaluation period, and 80 layers for U2's Tail end SCRs.
Note 8: Annual costs of natural gas firing for flue gas reheating and urea-to-ammonia conversion system operation for "Scenario A" and "Scenario B" are assumed to be based on $7.98 per million BTU in 2006$.
Note 9: Annual costs of natural gas firing for "Scenario B" are lower than "Scenario A" due to fewer annual hours of operation resulting from additional catalyst replacements.
Note 10: Annual costs of operating labor for SCR equipment, flue gas reheating, and urea-to-ammonia systems were assumed to be zero, but this may underestimate actual requirements.
Note 11: Total Direct Annual Costs are the sum of maintenance, reagent, electricity, catalyst replacements, and natural gas for Scenario A and Scenario B operations. This may underestimate actual requirements.
Note 12: Annual Costs from capital recovery are the same for Scenario A and Scenario B operations. See Appendix C in the 2006 NOx BACT Analysis Study reports for details. The capital recovery factor used to calculate the annual costs is 0.087185. Capital recovery costs for ASOFA are included.
Note 13: Annual costs of increases in administrative overhead, insurance premiums, and property taxes for SCR equipment and related auxiliaries were assumed to be zero, but this may underestimate actual requirements.
Note 14: Total Annual Costs are the sum of increases in Direct Costs and Indirect Costs for SCR equipment and related auxiliaries. These values may underestimate actual requirements.
Note 15: Levelized Total Annualized Costs are TDC multiplied by the levelization factor (1.24873) plus the Total Indirect Annual Costs (capital recovery). See Appendix C in the 2006 NOx BACT Analysis Study Reports for details. These values may underestimate actual requirements.

These numbers are the same Levelized Total Annualized Costs for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Tables 4-6SF, 4-7SF, 4-8SF, and 4-9SF. The capital recovery costs of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, based on the installed capital costs shown in Tables 4-4SF and 4-5SF, are included in these numbers.

Milton R. Young Station Unit 1 and Unit 2
Estimates of Total Annual Costs for
Low Dust and Tail End Selective Catalytic Reduction Alternatives
Best Available Control Technology - Supplemental Analysis

Stand Alone

DIRECT ANNUAL COSTS	Low Dust U1	Low Dust U2	Tail End U1	Tail End U2	Notes
(1) Annual Maintenance Costs	$ 5,422,167	$ 8,123,552	$ 6,685,918	$ 10,222,003	Note 1
(2) Annual Reagent Costs					Note 2
Scenario A	$ 2,710,313	$ 4,171,528	$ 2,709,417	$ 4,170,150	
Scenario B	$ 2,725,539	$ 4,204,613	$ 2,724,643	$ 4,204,613	
(3) Annual Electricity Costs					Note 3
Scenario A	$ 5,929,642	$ 9,730,376	$ 6,011,088	$ 9,740,159	
Scenario B	$ 11,939,901	$ 24,539,279	$ 11,982,549	$ 25,083,883	
(4) Annual Water Costs					Note 4
(5) Catalyst Replacement Costs					Note 5
Scenario A	$ 709,951	$ 958,131	$ 709,951	$ 963,350	Note 6
Scenario B	$ 5,850,000	$ 10,260,000	$ 4,387,500	$ 10,260,000	Note 7
(6) Natural Gas for F.G. Reheating & Urea-to-Ammonia Conversion sys.					Note 8
Scenario A	$ 2,136,238	$ 6,064,108	$ 3,931,511	$ 6,416,128	
Scenario B	$ 1,944,698	$ 5,296,499	$ 3,580,852	$ 5,574,558	Note 9
(7) Operating labor for SCR equipment and urea-to-ammonia eqpmnt					Note 10
DIRECT Annual COSTS - TOTAL					Note 11
Scenario A	$ 16,908,311	$ 29,047,696	$ 20,047,886	$ 31,511,788	
Scenario B	$ 27,882,304	$ 52,423,943	$ 29,361,462	$ 55,345,056	
INDIRECT Annual COSTS					
(8) Annual Costs from Capital Recovery	$ 15,757,639	$ 23,608,277	$ 19,430,293	$ 29,706,692	Note 12
(9) Administrative overhead, insurance and property taxes for SCRs and aux.					Note 13
INDIRECT Annual COSTS - TOTAL	$ 15,757,639	$ 23,608,277	$ 19,430,239	$ 29,706,692	
TOTAL ANNUAL COSTS					Note 14
Scenario A	$ 32,665,951	$ 52,655,972	$ 39,478,179	$ 61,218,481	
Scenario B	$ 43,639,944	$ 76,032,220	$ 48,791,755	$ 85,051,748	
LEVELIZED TOTAL ANNUALIZED COSTS					Note 15
Scenario A	$ 36,871,522	$ 59,880,950	$ 44,464,651	$ 69,056,347	
Scenario B	$ 50,575,055	$ 89,071,526	$ 56,094,775	$ 98,817,617	

Stand Alone (SA) represents estimated costs if SCR equipment is retrofitted to both boilers independently.

This table includes values that are identified in the EPA OAQPS SCR Cost Manual, EPA/452/B-02-001 Section 4.2 NOx Controls Post Combustion, page 2-44 through 2-49 but use calculated and vendor-quoted values instead of the formulas provided in the OAQPS manual

Total Annual Costs consist of direct costs, indirect costs, and recovery credits (if any). Direct Annual Costs and variable and semi-variable costs that are proportional to the quantity of flue gas processed by the control system. Indirect Annual Costs are fixed costs incurred independent of control operation, and include capital recovery costs, insurance, administrative charges, and overhead (payroll and plant).

Note 1: Annual maintenance was assumed to be 3% of installed capital cost of the SCR equipment and auxiliary equipment related to the SCR systems, not including catalyst replacement costs. Maint. costs for ASOFA are included.

Note 2: Annual reagent costs are for "Scenario A" and "Scenario B" operation and related chemical usage based on receiving 50% aqueous urea solution, assumed to be $379.29 per ton in 2006$.

Note 3: Annual electricity costs are for "Scenario A" and "Scenario B" operation and related electricity consumption and lost generation, assumed to be $35/MW-hr in 2006$. See Tables C.4-1 through C.4-4 in the November 2009 NOx BACT Analysis Study Supplemental Reports for details.

Note 4: Annual water costs were not calculated, but may be more than zero, if concentrated liquid urea liquor (70% concentration) is purchased, which must be diluted to 50% concentration for storage.

Note 5: Annual catalyst replacement costs are for "Scenario A" and "Scenario B" operation, and are assumed to be based on $7,500 per cubic meter in 2006$.

Note 6: Annual catalyst replacement costs for "Scenario A" are assumed to be based one layer per reactor every two years (approx. 16,000 operating hours), and follows the EPA OAQPS SCR Cost Manual for annualizing the purchase cost using Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 assuming 6% per year annual interest rate. Tail end SCRs were assumed to have 10 layers replaced during the 20-year economic evaluation period, and 12 layers for Low-dust SCRs, but the annual catalyst replacement costs for U2 used in the November 2009 NOx BACT Analysis Study Supplemental Report underestimate the cost per layer due to assuming regular depth layers instead of deep layers recommended by vendor.

Note 7: Annual catalyst replacement costs for "Scenario B" are assumed to be based three layers per reactor every year (approx. 2,667 operating hours) for U1 and four layers per reactor per year (approx. 2,000 operating hours) for U2. There were no adjustments for annualizing the purchase cost (Equations 2.51 and 2.52 on page 2-47 and Equation 2.53 on page 2-48 of the EPA OAQPS SCR Cost Manual were not used). U1 Low-dust and Tail end SCRs were assumed to have 60 layers replaced during the 20-year economic evaluation period, and 80 layers for U2's Tail end SCRs.

Note 8: Annual costs of natural gas firing for flue gas reheating and urea-to-ammonia conversion system operation for "Scenario A" and "Scenario B" are assumed to be based on $7.98 per million BTU in 2006$.

Note 9: Annual costs of natural gas firing for "Scenario B" are lower than "Scenario A" due to fewer annual hours of operation resulting from additional catalyst replacements.

Note 10: Annual costs of operating labor for SCR equipment, flue gas reheating, and urea-to-ammonia systems were assumed to be zero, but this may underestimate actual requirements.

Note 11: Total Direct Annual Costs are the sum of maintenance, reagent, electricity, catalyst replacements, and natural gas for Scenario A and Scenario B operations. This may underestimate actual requirements.

Note 12: Annual Costs from capital recovery are the same for Scenario A and Scenario B operations. See Appendix C in the 2006 NOx BACT Analysis Study reports for details. The capital recovery factor used to calculate the annual costs is 0.087185. Capital recovery costs for ASOFA are included.

Note 13: Annual costs of increases in administrative overhead, insurance premiums, and property taxes for SCR equipment and related auxiliaries were assumed to be zero, but this may underestimate actual requirements.

Note 14: Total Annual Costs are the sum of increases in Direct Costs and Indirect Costs for SCR equipment and related auxiliaries. These values may underestimate actual requirements.

Note 15: Levelized Total Annualized Costs are TDC multiplied by the levelization factor (1.24873) plus the Total Indirect Annual Costs (capital recovery). See Appendix C in the 2006 NOx BACT Analysis Study Reports for details. These values may underestimate actual requirements.

These numbers are the same Levelized Total Annualized Costs for Low-Dust and Tail End SCRs in the November 2009 NOx BACT Supplemental Analysis Tables 4-6SA, 4-7SA, 4-8SA, and 4-9SA. The capital recovery costs of the Urea Storage Tanks and Building, and Advanced Separated Overfire Air (ASOFA) system, based on the installed capital costs shown in Tables 4-4SA and 4-5SA, are included in these numbers.

Burns &
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SINCE 1898

January 6, 2010

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Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Jones:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

Please review this statement and respond in writing to confirm that we have correctly stated your company's position on catalyst life guarantees for the application of SCR systems to MRYS Units 1 & 2 without successful completion of pilot testing.

Sincerely,

Robert D. Blakley

Robert D Blakley, P.E.
Project Engineer

9400 Ward Parkway
Kansas City, Missouri 64114-3319
Tel: 816-333-9400
Fax: 816-333-3690
http://www.burnsmcd.com

Burns & McDonnell
SINCE 1898

January 6, 2010

Mr. Noel Rosha
CERAM Environmental, Inc.
7304 W. 130th St.
Suite 140
Overland Park, Kansas 66213

Minnkota Power Cooperative Milton R. Young Station Units 1 & 2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD Project 31777

Dear Mr. Rosha:

Burns & McDonnell has prepared supplemental reports for the NOx BACT analyses for Milton R. Young Station (MRYS) Units 1 and 2, and these reports have been submitted by Minnkota Power Cooperative to the North Dakota Department of Health. In the text of these reports, we stated that:

> During preparation of the cost estimate, Burns & McDonnell consulted with two SCR catalyst vendors experienced with biomass-fired boiler SCRs and European coal-fired boilers with low-dust and tail end SCR systems. However, neither of these vendors was willing to guarantee a catalyst replacement schedule for cyclone boilers firing North Dakota lignite without results following successful extensive pilot-scale slipstream testing that confirm the deactivation and fouling rates. According to these catalyst suppliers, there is no SCR operating experience in the world found to be directly comparable to the hypothetically applied tail end and low-dust SCR cases on North Dakota lignite-fired cyclone boilers being evaluated. Thus they were unable to offer a guaranteed catalyst replacement schedule based on their experience.

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Fax: (281) 228-5019

January 13, 2010

Mr. Robert D. Blakley, P.E.
Burns & McDonnell
9400 Ward Parkway
Kansas City, Missouri 64114

Minnkota Power Cooperative, Milton R. Young Units 1&2
Investigation of Hypothetical Application of TESCR and LDSCR
BMcD project 31777

Mr. Blakley,

This letter is to confirm that it is my understanding, based on the information currently at hand, that Haldor Topsoe, Inc would consider providing a SCR catalyst life guarantee for either Milton R. Young Unit 1 or Unit 2 for either a tail end (TESCR) or low dust (LDSCR) configuration only following the successful completion of a pilot-scale slipstream test of our SCR catalyst on one of the two MRY units. The issuance of a SCR catalyst life guarantee, if any, would be for only the configuration tested during the pilot-scale testing.

If you have any question please feel free to contact me at 281-228-5136

Sincerely,

Wayne S. Jones
Sales Manager, Power Generation
SCR/DeNOx Catalyst & Technology

Bachman, Tom A.

From: John Graves [jgraves@minnkota.com]
Sent: Thursday, January 14, 2010 11:16 AM
To: O'Clair, Terry L.
Cc: Bachman, Tom A.; David B Sogard
Subject: Catalyst Vendor Guarantees
Attachments: CERAM Jan 06_2010 (signed).pdf

Terry,

Below is an email from CERAM confirming their position on catalyst guarantees for LDSCRs and TESCRs at Milton R Young Station.

John T. Graves, P.E.
Environmental Manager
Minnkota Power Cooperative, Inc.
P.O. Box 13200
Grand Forks, N.D. 58208-3200
Tel: (701) 795-4221
Fax: (701) 795-4214
----- Forwarded by John Graves/Legal/Minnkota on 01/14/2010 11:11 AM -----

From: "Blakley, Robert" <rblakley@burnsmcd.com>

To: John Graves <jgraves@minnkota.com>

Cc: "Weilert, Carl" <cweiler@burnsmcd.com>

Date: 01/13/2010 04:08 PM

Subject: FW: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R.
Young Station Units 1 & 2

From: Noel Rosha [mailto:Noel.Rosha@ceram-usa.com]
Sent: Wednesday, January 13, 2010 3:02 PM
To: Blakley, Robert
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Robert,

CERAM confirms that the attached letter accurately reflects our position regarding catalyst life guarantees for the Milton R. Young Station tail end and low-dust SCR applications.

Best regards,

Noel Rosha, P.E.
Senior Applications Engineer

CERAM Environmental, Inc.
Phone: 913-239-9896
Mobile: 913-638-9672

From: Blakley, Robert [mailto:rblakley@burnsmcd.com]
Sent: Wednesday, January 06, 2010 2:48 PM
To: Noel Rosha
Cc: Weilert, Carl
Subject: RE: Investigation of Hypothetical Application of TESCR and LDSCR, Minnkota Power Cooperative Milton R. Young Station Units 1 & 2

Noel:
Confirming our phone conversation of January 6, 2010.
We are asking for review of our attached letter with written confirmation regarding stating CERAM-USA's catalyst life guarantee being contingent upon successful completion of pilot-scale slipstream testing that confirm catalyst deactivation and fouling rates of the studied hypothetical applications of tail end and low-dust SCRs for Units 1 and 2 at Milton R.
Young Station for Minnkota Power Cooperative.
Robert D. Blakley, P.E.
Associate Project Engineer
(Currently registered and licensed in North Dakota) Burns & McDonnell Energy Group 9400 Ward Parkway
Kansas City, MO 64114
Direct: 816-822-3842
Main: 816-333-9400
Fax: 816-333-3690
rblakley@burnsmcd.com
www.burnsmcd.com
(See attached file: CERAM Jan 06_2010 (signed).pdf)

Bachman, Tom A.

From:	John Graves [jgraves@minnkota.com]
Sent:	Wednesday, March 24, 2010 8:34 AM
To:	Bachman, Tom A.
Subject:	Use of Confidential Information

Tom,

Haldour Topsoe has agreed to the use of their information as you previously described.

John T. Graves, P.E.
Environmental Manager
Minnkota Power Cooperative, Inc.
P.O. Box 13200
Grand Forks, N.D. 58208-3200
Tel: (701) 795-4221
Fax: (701) 795-4214

3.3 Catalyst Specification, Exceptions & Offer

Based on the current data available, including the Microbeam Technologies report dated August 20, 2009, HTI believes that the low dust (after ESP) option is the most viable. HTI feels that deactivation of the catalyst due to alkali poisoning (sodium) will be the biggest challenge. However, with that said, HTI also recognizes that chemical deactivation can generally be managed with the adjustment of catalyst volume and/or guarantee life while the potential exists that physical deactivation due to catalyst blinding and plugging could be severe enough to make SCR a non-viable option for controlling NOx emissions.

The absence of SO_2 downstream of the FGD has been discussed and the effect it might have on physical deactivation of the catalyst due to blinding. Considering that most of the calcium will be removed in the ESP, calcium sulfate formation should be minimal. Also, considering the low operating temperature of the SCR (~600F) chemical poisoning of the catalyst affects the observed activity much more than does physical poisoning (blinding) of the catalyst. The tail-end option should be considered further with actual slip stream or mini reactor testing on an operating unit but at this time HTI feels that with the data currently available that the low dust option is the best option available.

HTI's main concern in relation to the lignite fuel is the content of alkali metals (sodium in the case of ND lignite) which leads to chemical poisoning of the catalyst by reacting with the vanadium active sites. The deactivating effect of sodium (and potassium) will be the same, whether in the form of oxide, sulfate or another salt. The deposition rate of the aerosols could be different, though, depending on whether they are in the form of oxides or sulfates due to differences in mobility.

Bachman, Tom A.

From:	John Graves [jgraves@minnkota.com]
Sent:	Wednesday, March 17, 2010 9:22 AM
To:	Bachman, Tom A.
Subject:	Minnkota BACT - Use of Confidential information

Tom,,

CERAM will allow the use of several paragraphs from their October 13, 2009 proposal in your analysis of our recent BACT submittals. Specifically they will allow the use of the material on Page 3, paragraphs 2, 3 and 5(which continues on page 4) beginning with "The high levels….." and ending with " ...calcium oxide present in the flue gas."

John T. Graves, P.E.
Environmental Manager
Minnkota Power Cooperative, Inc.
P.O. Box 13200
Grand Forks, N.D. 58208-3200
Tel: (701) 795-4221
Fax: (701) 795-4214

CERAM
CATALYSTS + HONEYCOMBS

CERAM Environmental, Inc.
Porzellanfabrik Frauenthal GmbH

Minnkota Power Cooperative
Attn. Mr. Luther Kvernen
Milton R. Young Station Units 1 & 2
1822 Mill Road
Grand Forks, ND 58208-3200

This page is claimed as
CONFIDENTIAL
In accordance with Air Pollution Control Rules
for the State of North Dakota at 33-15-01-16

October 13, 2009

Boiler Type and Fuel Analysis

The levels of K_2O in the ND lignite ash are in the high end range found in many biomass fuels, such as wood and switch grass. However, the levels of Na_2O are much greater than that found in biomass or coal fired SCR applications. Different boiler types will affect deactivation. CERAM's experience with biomass applications that utilize a bubbling fluidized bed (BFB) boiler with the SCR in a high dust arrangement have been successful because we were able to size the catalyst appropriately and take advantage of the lower flame temperature (e.g., less oxidized poisons), available sorbent (e.g., limestone) that can absorb a portion of the catalyst poisons and the fact that a large portion of the ash is entrained. Pulverized coal (PC), stoker and cyclone boilers in the high dust arrangement can lead to an increase in deactivation due to the higher local flame temperatures and areas of incomplete combustion that both can lead to a severe increase in oxidized poisons. Solutions to reduce catalyst deactivation have been to use low dust (e.g., catalyst downstream of a baghouse with sorbent injection) and tail end (e.g., downstream baghouse and scrubber) configurations. However, our experience on low dust and tail end biomass and incinerator applications with similar fuel characteristics have shown that increased deactivation will still occur compared to similar applications firing sub-bituminous and bituminous coals.

The high levels of Na_2O in the ash for the ND lignite are not commonly found in sub-bituminous and bituminous coals which are fired with SCR systems. CERAM is unaware of any SCR application experience in the industry with this level and form of sodium in the ash. Sodium is a well known catalyst poison. In particulate form the effects of sodium can be controlled by maintaining warm and dry conditions on the catalyst at all times during layup. Allowing moist conditions on the catalyst will result in the particulate bound sodium leaching into the pore structure of the catalyst where catalyst poisoning will occur. Small aerosol particles can penetrate and neutralize active catalyst sites even in dry conditions.

Catalyst Deactivation

For this application we can assume that most of the ash will be removed; however catalyst deactivation will still occur due to gaseous constituents in the flue gas and from the small amount of ash that will reach the reactor. Even though this application may be ether a low dust or tail end application it is not a "no dust" application. Deactivation can be caused by exposure to various catalyst poisons and fouling agents, such as alkaline metals, arsenic, sulfate compounds, silica and phosphorous compounds, hydrochloric and hydrofluoric acids, sodium and potassium in the ash, etc., that are formed during the combustion process. Catalyst installed in even low dust and tail end locations are poisoned from the exposure to the flue gas. Some of the potential catalyst poisons that could lead to deactivation of our catalyst are found in the mineral and trace analysis or can be controlled by temperature. The amount of sulfur dioxide, sulfur trioxide and sulfuric acid are a function of temperature, thereby if the temperature is controlled above the acid dew point then no problems should exist. In addition, the amount of lead, mercury, chromium and other metals listed in the trace analysis are typically extremely low and should not be a major influencing factor for a coal fired application. Moreover, the high levels of phosphorous, sodium and potassium found in the mineral analysis will increase deactivation rates. Arsenic poisoning will occur, however the levels for which this can be attributed to are a function of the amount of calcium oxide present in the flue gas.

MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

FOLLOWUP RESPONSES TO PRESENTATION and NDDH REQUEST FOR ADDITIONAL INFORMATION SUPPLEMENTAL NOx BACT ANALYSIS STUDY MILTON R. YOUNG STATION UNIT 1 and UNIT 2 REGARDING SCR ECONOMIC FEASIBILITY

February 11, 2010

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide additional information clarifying the written response submitted December 11, 2009[2] that provided detailed and comprehensive cost data following the NDDH's and U.S. EPA's reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental Reports[3] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station (MRYS).

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced 2006 NO_X BACT Analysis Study[4] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station in accordance with the requirements of a Consent Decree (CD)[5]. Burns & McDonnell also performed the November 2009 Supplemental NO_X BACT Analysis Study and generated the referenced reports for each MRYS boiler in response to the NDDH's request[6] to see Steps 3 and 4 of the BACT analysis process[7] include low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[8].

Information supplementing the previously-provided detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, and their subsequent presentation to NDDH, are attached.

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[1] See Reference number 1, January 11, 2010.

[2] See Reference number 2, December 11, 2009.

[3] See Reference number 3, November 12, 2009.

[4] See Reference number 4, October 2006.

[5] See Reference number 5, April 24, 2006.

[6] See Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

[7] See Reference number 7, October 1990.

[8] Ibid Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

NOx BACT Analysis Study Supplemental Reports:

NDDH Request #1: How were the SCR reactors sized and the catalyst volume determined and what target NOx control efficiency was used to size the catalyst? How was the cost of the catalyst determined?

BMcD Response:
The same SCR system supplier that is providing the low-dust SCR equipment for the WE Energies South Oak Creek project in Wisconsin was asked to provide a budgetary equipment proposal for both low-dust and tail end SCR arrangements for each unit at MRYS. A lignite coal analysis (proximate, ultimate, and coal ash) and process design basis (boiler fuel heat input rates, excess air percentages, flue gas volumetric flows, temperatures and gas species contents) were included with the request. An assumed inlet and outlet NOx concentration was also provided, with a nominal 85% reduction from 0.5 lb/mmBtu requested. This SCR system supplier sized the SCR reactor, the SCR gas-to-gas heat exchange equipment (SCR GGH), and related ductwork. The initial catalyst charge for each reactor was included in the lump-sum equipment price proposal. The SCR system supplier did not disclose the specific volume of catalyst to be provided nor the specific manufacturer or type of catalyst (i.e. honeycomb, plate, etc.). Due to the proprietary nature of this SCR conceptual design and budgetary equipment pricing effort, this work was performed by the SCR system supplier with the understanding that it was confidential. Refer to Burns & McDonnell's response to NDDH Request #7 for additional information.

Two SCR catalyst suppliers provided budgetary replacement catalyst quotes, including catalyst volume, catalyst pitch, catalyst type, and arrangement of catalyst modules, based on preliminary process design provided by an SCR process design consultant. The design used for these catalyst supplier proposals was based on 90% overall NOx reduction across the SCR system. The catalyst suppliers also provided cost proposals for the replacement catalyst. One supplier provided a cost of replacement catalysts in terms of $\$/m^3$. Due to the proprietary nature of this SCR reactor sizing and budgetary catalyst pricing effort, this work was performed by the SCR catalyst suppliers with the understanding that it was confidential. Refer to Burns & McDonnell's response to NDDH Request #7 for additional information.

NDDH Request #2: Anhydrous ammonia appears to be a less expensive reagent than urea for the SCR system due to local availability. A justification must be supplied for electing urea over anhydrous ammonia.

BMcD Response:
Aqueous urea solution was selected because of health and safety issues related to the use of ammonia, including site constraints involving over-the-road transport, on-site unloading and storage. MRYS does not

have rail access, and is adjacent to a lake used for condenser cooling water and process water supplies. Public access to the lake is allowed. Anhydrous ammonia and aqueous ammonia are classified as hazardous chemicals per Clean Air Act Section 112 (r). This requires extensive emergency planning. Transport and handling of ammonia is restricted by the United States Department of Homeland Security and the Department of Transportation through the Rail Security Act. The U.S. EPA has determined that a toxic radius of a spill to be between 5 and 7 miles for anhydrous ammonia and 1 to 2 miles for aqueous ammonia[9].

NDDH Request #3: Support must be provided for the catalyst cleaning/replacement outage periods. This should include an explanation of the method used to estimate the outage time and clarification whether the outage time includes the regular outage period.

BMcD Response:

Burns & McDonnell and Minnkota queried SCR catalyst suppliers, process design consultants, utility construction and maintenance contractors, and utility personnel at U.S. coal-fired plants with operating SCRs to provide input into the estimation of time associated with catalyst installation into the empty (spare) layer of the reactor, and to remove dirty catalyst and install fresh catalyst in its place. The responses indicated that there is a broad range of experiences based on limited amounts of user and vendor data on this issue. The range of experience is due to the site-specific conditions and design-specific features of the reactor catalyst access doors' locations and sizes, module arrangement, hoisting equipment, staging areas and platforms, labor availability and familiarity. The general lack of data is due to the relative newness of many SCR installations currently operating at coal-fired powerplants in the United States that have not accumulated significant operating time and so have not required significant numbers of catalyst changeouts.

Catalyst replacement activities by current coal-fired powerplant users are typically scheduled during major boiler outages that are 18-36 months apart. The SCR catalyst changeout is usually not a schedule-critical activity during such outages. The catalyst changeout time required depends on how many modules are involved, and whether a single shift of personnel or multiple shifts per day are engaged in the work.

For the hypothetical application of low-dust and tail end SCR technologies at MRYS, most of the catalyst changeouts were assumed to coincide with boiler fireside cleaning outages, which are historically approximately 4 days in duration, three or four times per year, depending on the boiler involved. Because of the use of high pressure water to remove boiler deposits during these cleanings, the air exhausted from the boilers through the flue gas ductwork to the chimneys during these times contains moisture and particulate.

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[9] See Reference 8.

Catalyst vendors have advised that this air stream is not suitable for passing through an SCR reactor filled with catalyst. This will require an SCR reactor bypass to be provided for use during these outages.

Before catalyst changeout operations can begin, the large volume of catalyst and supporting structural steel must be cooled down sufficiently to allow personnel to safely enter the reactor to gain access to remove any ash accumulations. The means and equipment required to remove the catalyst depends on the specific reactor design and module arrangements. The specific time and equipment requirements for catalyst changeouts are normally developed after the specific reactor and module details are established.

The SCR Cost Estimate study assumed that reactor isolation dampers and reactor maintenance bypass ductwork dampers would be required to avoid contamination of the catalyst by the air/water/particulate stream, and allow the reactors to be cooled while being isolated from the normal flue gas path to the chimney. The time estimated for catalyst installation into the empty (spare) layer of the reactor was 16 shifts, which, assuming two shifts per day, would be 8 days. The time estimated to remove dirty catalyst and install fresh catalyst in its place was 24 shifts, which, assuming two shifts per day, would be 12 days. The time assumed for reactor cooldown was previously estimated as 48-60 hours, which would elapse during the first half of the boiler cleaning process[10]. After the fresh catalyst is in place, and the reactor access doors closed, the entire volume of fresh and dirty catalyst remaining in the reactor must then be heated to above the moisture dewpoint to avoid possible moisture condensation during boiler startup. This would involve use of the supplemental catalyst outage heating system, not the flue gas reheat system nor flue gas from the boiler. Burns & McDonnell estimated that post catalyst changeout outage time will extend approximately 36-48 hours until the boilers are ready to begin the startup process to return to service.

The November 2009 Supplemental NOx BACT Analysis study assumed 1168 total hours and 1126 total hours of outage time per year associated with MRYS Unit 1's hypothetical application of low-dust and tail end SCR technologies (Scenario "B"), respectively. This is 980 hours and 938 hours of outage time in addition to the 188 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming three catalyst layer changeout outages per year for Unit 1, this works out to be approximately 13 extra days per outage. Unit 2's Scenario "B" assumed 1415 total hours of outage time for either hypothetical application of low-dust and tail end SCR technologies. This is 1234 hours of outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming four catalyst changeout outages per year for Unit 2, this works out to be approximately 13 extra days per outage.

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[10] See Reference 9, March 15, 2007, pages 12-14.

The November 2009 Supplemental NOx BACT Analysis study assumed 401 total hours and 443 total hours of outage time per year associated with MRYS Unit 1's, and 387 total hours and 428 total hours of outage time per year for Unit 2's, hypothetical application of tail end and low-dust SCR technologies (Scenario "A"), respectively. This is 213 or 256 hours of Unit 1 outage time and 206 or 247 hours of Unit 2 outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming one catalyst changeout outage every two years for each Unit 1 and Unit 2, this works out to be approximately between 8.6 and 10.7 extra days per outage, depending on the boiler and SCR technology studied.

The catalyst changeout outage times assumed in the November 2009 Supplemental NOx BACT Analysis study for MRYS Unit 1 and the similar study for MRYS Unit 2 are expected to be extensions to the boiler cleaning outages. Note that the estimated annual number of days for catalyst changeout outages is in addition to outage times included in the Advanced Separated Overfire Air alternative, which is also relative to baseline operation which include downtime for boiler cleanings. We believe the outage durations and frequency are reasonable assumptions to use for the purposes of showing possible economic outcomes that could result from the hypothetical application of low-dust and tail end SCR technologies at MRYS.

NDDH Request #4: The indirect capital costs associated with the project appear to be high. A detailed explanation of the estimation method must be supplied.

BMcD Response:

Burns & McDonnell used standard estimating practices to estimate direct, installation, and indirect capital costs for MRYS Unit 1's and Unit 2's hypothetical application of low-dust and tail end SCR technologies. To establish the context of estimated indirect costs, we note that several major assumptions were used by Burns & McDonnell in developing the capital cost estimates of the hypothetical applications of low-dust and tail end SCRs at Milton R. Young Station. These assumptions include the following:

- A multiple (parallel prime) contracting approach was selected (as opposed to single "turnkey" or Engineer-Procure-Construct contract). Although this approach may increase the project execution risk to the Owner, the execution risk is considered manageable. This contracting approach was recommended because it allows early award of major equipment procurements to allow detailed design engineering to proceed expeditiously to meet the project schedule, and offers the greatest flexibility for the Owner (Minnkota) to be involved in key decisions regarding design.
- Project will be executed to achieve completion in 2016 for Unit 2 and 2017 for Unit 1. It was assumed that the project will be executed with skilled workforce resources sufficient to meet the target project execution schedule while minimizing overtime. No additional overtime is included to accommodate a compressed work schedule.

Indirect Costs:

- Escalation based on historical data and Burns & McDonnell experience was assumed to average 5% per year for equipment, 9% per year for materials and 5% per year for labor. See additional general description of escalation included below.
- Contingency was calculated at 20% overall (10% for pricing and 10% for scope). Contingency was applied to Total Direct Capital Costs plus Indirect Capital Costs such as Engineering and Field Support, Construction Management and related indirects, Startup Expenses, and Cost Escalation during Project Execution. Owner Contingency was estimated at 7%. See additional general description of contingency included below.
- A performance bond is included for all subcontract work at the rate of 1.5% of the estimated project contract costs.
- Sales tax on construction consumables is included. No other tax is included.
- Owner will provide a builder's risk policy for the project. Cost for this is included in the estimate of Owner's costs.
- Interest During Construction (IDC) is included in the Owner's costs at 6% per year, assuming project execution-based monthly expenditures.

Escalation:

An estimate for escalation of project costs has been included in the capital cost estimate. Escalation of construction labor, materials, and indirects was estimated based on historical data and Burns & McDonnell experience.

Escalation of construction labor was estimated to be approximately 5% annually throughout the project. This estimate of escalation was based on the average increase in craft labor costs for the United States combined with known union labor contract costs in the next few years. The average annual escalation of union contracts for skilled and common labor rates over the last ten years in North Dakota has been approximately 5.0% per year.

Escalation of equipment and materials is included in the project estimate at a rate of 5% per year for equipment and 9% per year for materials. Since January 2004, steel pricing experienced rapid escalation equating to a nearly a 100% increase in rebar and structural steel costs, then dropped in late 2008 and early 2009. Within the past 6 months, steel prices have again started to rise. Pipe and electrical commodities have also seen a high overall escalation during this time, followed by a decline in late 2008. Due to this volatility, equipment and material suppliers have been providing pricing with short bid validity.

Contingency:

This project involves a significant amount of retrofit work in the existing plant. The SCR Cost Estimate study did not perform a thorough review of existing conditions and interfaces with the new work. It is anticipated that the scope of work will increase as unknown conditions are discovered during project execution. A contingency of 20% of the overall project costs is included in the project cost. Of this 20%, 10% covers accuracy of the pricing of the equipment and materials (commodities), and 10% covers omissions from the defined project scope. This contingency is not intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) nor major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans).

In addition to the project contingency, an additional owner contingency is included to cover owner general project scope additions. Based upon the amount of preliminary design and project definition completed, a 7% scope contingency to cover such potential changes is included. However, this contingency level depends on the probability of additional scope and is typically determined by the Owner (Minnkota).

NDDH Request #5: Support must be supplied for the cost of natural gas and electricity.

BMcD Response:
Burns & McDonnell used estimated long-term average natural gas unit cost for the economics of conventional and fuel-lean gas reburn alternatives' annual operating costs included in the 2006 NOx BACT Analysis Study reports for MRYS Unit 1 and Unit 2. The annual cost of auxiliary power consumed by air pollution control equipment and the value of electric generator output not able to be sold ("lost") due to inability to produce electricity during outages related to the air pollution control equipment associated with particular control alternatives were also calculated. The long-term average unit costs for natural gas and electricity were provided by Minnkota. Burns & McDonnell's recent review of the forecast power industry's natural gas unit cost forecasts from 2006 confirm that the number used in the original NOx BACT Analysis Study calculations and reports submitted in October 2006 are reasonable, given the uncertainty and variability that is common with such forecasts.

In the November 2009 Supplemental NOx BACT Analysis study reports, Burns & McDonnell assumed the economics of hypothetical application of low-dust and tail end SCR technologies at MRYS should be also based on the same unit costs used for the 2006 NOx BACT Analysis study reports.

NDDH Request #6: More details, including calculations, must be supplied to justify the pressure drops and parasitic loads associated with the SCR configurations.

BMcD Response:

Burns & McDonnell used estimated flue gas pressure drops provided by the SCR supplier for the SCR reactor, and gas-to-gas heat exchangers (GGH), in the development of new induced draft booster fans' performance requirements and the alternatives' economics of hypothetical application of low-dust and tail end SCR technologies at MRYS for Unit 1 and Unit 2 in the November 2009 Supplemental NOx BACT Analysis study reports. The estimated flue gas pressure drops of the flue gas ductwork, which would be incurred upstream and downstream of the low-dust and tail end SCR reactors and GGHs, were calculated using a proprietary spreadsheet.

For low dust SCR cases, new ductwork would be connected downstream of the existing induced draft fans' outlets and a new booster fan for each reactor would follow the GGH outlet after the SCR reactor, discharging to the existing flue gas desulfurization (FGD) system absorber inlet duct[11].

In tail end SCR cases, new duct connections downstream of the existing induced draft fans' outlets would divert flue gas before the FGD absorbers' inlet ducts, through the hot side of the FGD GGH then back to the FGD absorber inlet duct. Additional duct connections downstream of the existing FGD absorbers' outlet ducts would reroute flue gas through the cold side of the FGD GGH, then to the cold side of the main (SCR) GGH upstream of the flue gas reheat section in the SCR reactor. After the reactor, flue gas would pass through the hot side of the main (SCR) GGH, continue to the new induced draft booster fans, and be discharged back to new duct connections near the existing inlets to the chimneys[12].

Horsepower required to drive the fans to produce pressure needed to overcome the cumulative ductwork and SCR equipment pressure losses for full load (maximum continuous rating) and "test block" flue gas flows was calculated from budgetary booster fan equipment quotes, which included preliminary pressure rise versus flow and mechanical efficiency curves, from two fan vendors. The horsepower required for the volumetric gas flow and pressure rise was then converted into electrical kilovolt-amperes (kVA) and kilowatts (kW) in order to calculate auxiliary power loads. An annual average load factor was applied, which was then multiplied by the assumed hours of annual operation to determine the annual megawatt-hours (MW-h) of consumed auxiliary power due to the SCRs' induced draft booster fans.

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[11] See attached sketch for low-dust SCR equipment and ductwork conceptual arrangement.

[12] See attached sketch for tail end SCR equipment and ductwork conceptual arrangement.

The parasitic loads associated with the SCR alternatives studied were determined by identifying known power-consuming auxiliary equipment serving the new air pollution control equipment. Estimates of design horsepower or kVA, based on vendor quotes or similar projects where information is available, were generated. Conversion to kW along with application of an annual average load factor resulted in estimated average annual auxiliary power loads, which were summed together to establish the total parasitic load. Annual megawatt-hours (MW-h) of consumed auxiliary power due to the various SCR cases studied were calculated by multiplying the total parasitic load by the assumed hours of annual operation.

The table below provides the results of these calculations.

Pressure Drop and Fan Power Calculation Results

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) pressure drop, in. w.g.	--	2.7	--	1.87
FGD GGH (cold side) pressure drop, in. w.g.	--	2.7	--	1.87
SCR GGH (cold side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR reactor/catalyst press. drop, in. w.g.	2.0	2.0	2.0	2.0
SCR GGH (hot side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR flue gas ducts/dampers/connections pressure drop, in. w.g.	5.4	6.2	4.5	6.3
Booster Fan Static Pressure Rise / Total Pressure[1] (Inches W.G.)	12.0 / 13.51	19.0 / 21.33	10.0 / 11.50	16.0 / 18.23
Booster Fan Motor Horsepower[2]	5000	7000	3500	5000
Load kVA / Demand kVA[3]	5000 /4500	7000 /6300	3500 /3150	5000 /4500
Quantity of Fans, capacity per fan, each case	One (1) x 100%		Two (2) x 50%	

1- Booster fan static pressure rise is the sum of the duct and SCR equipment pressure drops. Total fan pressure includes fan static pressure rise plus additional pressure rise required to overcome pressure drops within the fan equipment. These numbers do not include additional fan capacity (margin) above the amount required for full load (maximum continuous rating or MCR) operation, which allows for factors that reduce actual performance over sustained periods of running. Static pressure rise and Total pressure numbers are preliminary; final design may require values higher or lower than those shown.

2- Motor horsepower is greater than fan mechanical horsepower, and is based on available size larger than "Test Block" horsepower. Mechanical horsepower takes into account fan mechanical efficiency at the stated operating condition. Fans are sized based on mechanical efficiency and additional capacity (margin) above the MCR condition, referred to as "Test Block". The test block flow margin is 15% per fan, the test block pressure rise margin is 32.25% (1.15^2) above MCR values stated above. Test block fan mechanical efficiency is approximately 0.8. Fan Mechanical Horsepower = flue gas volumetric flow (actual cubic feet per minute) multiplied by pressure rise in inches w.g. divided by (6536 x efficiency). Fan efficiency varies with flow and pressure rise; values based on estimates/vendor quotes for full load (maximum continuous rating or MCR) conditions.

3- Horsepower (motor rating) is approximately equal to Connected Load kVA; Connected Load kVA x Estimated Annual Average Demand factor = Demand Load kVA.

Hypothetical applications of low-dust and tail end SCR technologies included estimates of auxiliary electrical power usage. It is important to note that some alternatives identified between 88 and 109 electricity-consuming items supplying or serving each SCR reactor system. Several pieces of auxiliary equipment with significant electrical power loads were included. These are: sootblowing air compressors with dryers; instrument/service air compressors with dryers; seal air fans for SCR reactor inlet and outlet flue gas isolation dampers; SCR flue gas reheat burner combustion air fans; drive gearboxes for rotary gas/gas heat exchangers; urea-to-ammonia dilution air/combustion air fans; auxiliary equipment service building ventilation/heating/lighting; and urea feed pumps. The instrument/service air and sootblowing air compressors are significant but necessary to supply dry compressed air used by equipment dedicated to control, maintain, and provide catalyst cleaning media for the SCR systems.

NDDH Request #7: All vendor correspondence related to SCR reactor sizing, catalyst volume, NOx control efficiency, catalyst cost, catalyst replacement schedule, and catalyst guarantees should be provided. This includes the original requests submitted to vendors and analyst [catalyst] suppliers by Minnkota and its consultants. This must also include the description of the gas stream that was supplied to the vendors.

BMcD Response:

Information responsive to this request by Minnkota, Burns & McDonnell and the SCR system supplier and SCR process design consultant, catalyst vendors, and flue gas particulate characterization consultant is being submitted (see Enclosures). Documents that include information considered as "trade secrets" per the NDDH's Air Pollution Control rules are being submitted and marked "confidential" (see Enclosures).

Minnkota developed agreements with the catalyst suppliers and flue gas particulate characterization consultant engaged in this effort, and has a general services agreement with Burns & McDonnell, which covers work done by the SCR system supplier and SCR process design consultant. Information provided under Enclosure C is considered non-confidential, and includes information for which no claim is being made for confidentiality, along with an index and summary of the information submitted which is suitable for release to the public. Enclosure D includes documents claimed to contain trade secrets which are requested to be treated as confidential, along with an affidavit stating how and why the information fulfills the conditions of confidentiality per the NDDH's Air Pollution Control rules describing this confidentiality procedure.

NDDH Request #8: Data must be provided for the temperature gradient of the regenerative heat exchanger to justify the reheat calculations. This must be provided for the both LDSCR and TESCR. The 600°F temperature for the reheated flue gas must be justified.

BMcD Response:

The preliminary design temperatures for the hypothetical applications of low-dust and tail end SCR technologies shown in the table below were calculated by the SCR process consultant. The temperature data tabulated below for the Unit 1 low dust (LD) case include corrections identified by the SCR process consultant as described further in the response to NDDH Request #11.b. The SCR system supplier, which provided pricing of SCR equipment, including GGHs for low-dust and tail end SCRs, did not provide estimates of the GGHs' process performance.

SCR Process Design Temperatures

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) inlet temperature, °F	--	335	--	331
FGD GGH (hot side) outlet / FGD Absorber Inlet temperature, °F	--	(1)	--	(1)
FGD GGH (cold side) inlet/ FGD Absorber Outlet temperature, °F	--	142	--	143
FGD GGH (cold side) outlet temperature, °F	--	150	--	151
SCR GGH (cold side) inlet temperature, °F	335	150	331	151
SCR GGH (cold side) outlet temperature, °F	535	520	535	520
Flue Gas Reheat Burner outlet / SCR Ammonia Injection Grid/Reactor inlet temperature, °F	580	563	580	563
SCR GGH (hot side) outlet temperature, °F	380	199	380	197
FGD Absorber Outlet temperature, °F	142	142	143	143

1- The temperature of the FGD GGH hot side outlet (discharges to FGD Absorber Inlet) was not provided by the SCR process consultant. It would be less than 330°F.

As can be seen in the table above, the flue gas is reheated by natural gas to either 580°F for low-dust SCR cases or 563°F for tail end SCR cases. Natural gas heat input rates used in the November 2009 Supplemental NOx BACT Analysis study reports assumed these flue gas temperatures. These preliminary process design temperatures have not been confirmed pending final design by the gas/gas heat exchanger manufacturer. The catalyst vendors recommended that the catalyst be designed for (able to withstand continuous exposure to) 600°F service operating temperature. The capacity of the reheat burner equipment was not specifically provided by the SCR system supplier, but was expected to be capable of raising the flue gas up to the recommended service temperature.

NDDH Request #9: A comparison of the SCR costs at M.R.Young Station versus PSE&G Mercer Station and We Energies Oak Creek Station should be provided or an explanation why such a comparison is not possible or inappropriate. We recognize that each plant has unique characteristics and there will be some design differences from plant-to-plant, but those differences should not necessarily dismiss making general comparison of costs unless there are unique or extenuating circumstances which would preclude a general cost comparison.

BMcD Response:

A BACT analysis is performed on a case-by-case, site-specific basis. It is inappropriate to compare the capital costs associated with the low-dust SCR installation at Mercer Station, or at South Oak Creek Station, against those developed for the hypothetical applications of low-dust and tail end SCR technologies at MRYS. Site conditions, boiler firing type, type and characteristics of fuels burned and resulting flue gas emissions and ash produced, and the limited amount of NOx reduction required for those referenced low-dust SCR cases that were not required to represent BACT, make the comparison not relevant to MRYS.

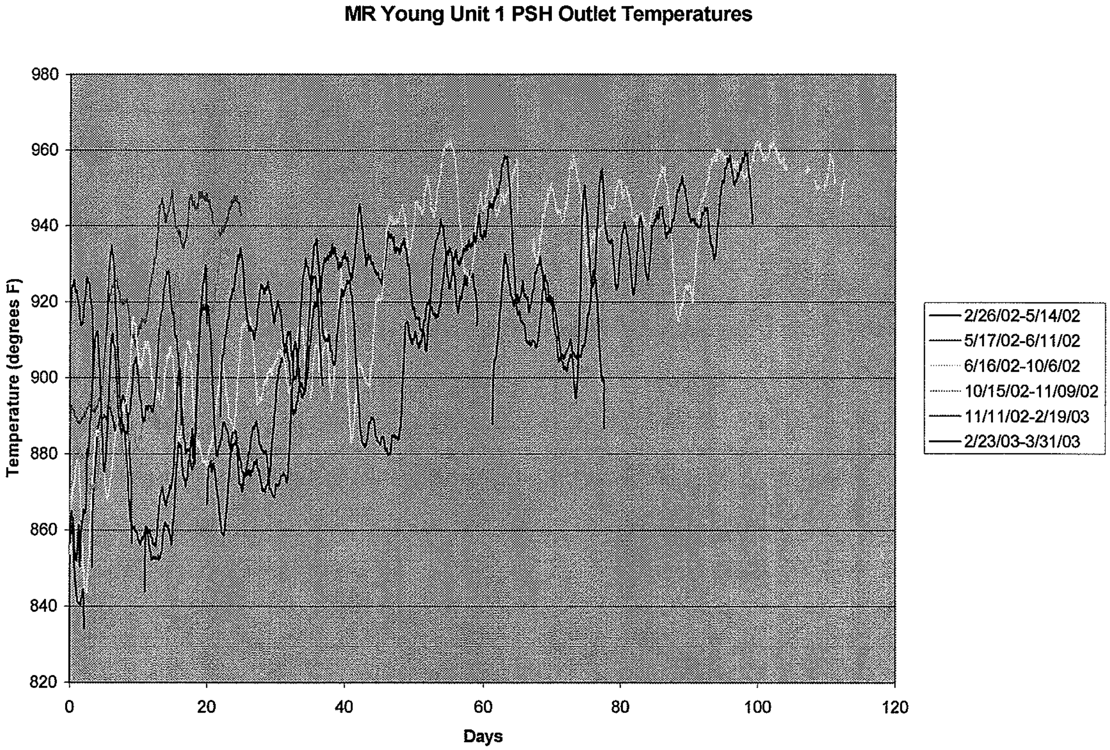
NDDH Request #10: Provide additional clarification and technical justification regarding Minnkota's determination that the units at MRYS are boiler limited and cannot generate additional steam for flue gas reheating purposes.

BMcD Response:

The steam turbine-generators at MRYS have a given output (gross megawatts) based on steam pressures, temperatures and flow rates related to the boilers. Removing high pressure/high temperature steam to use for flue gas reheating will directly cause a reduction in electrical output. This output reduction cannot be compensated for by increased boiler steam generation without unreasonable consequences. The boilers generate steam based upon their fuel heat input (firing) rates and capacities to absorb the heat created from the fuel combustion. The efficiency of converting fuel heat to steam to megawatts (heat rate or Btu per gross kilowatt) is limited by many factors. Fuel characteristics and boiler capacity are factors that impact heat rate (efficiency) that are not easily changed in the positive direction. The current fuel quality coming from the adjacent mine is not within the original design parameters of the boilers.

Because of the firing type (cyclone) and characteristics of North Dakota lignite burned and resulting flue gas emissions and ash produced at MRYS, the amount of fouling of the heat-absorbing surfaces within the boiler system is severe. These fouling conditions cause high exit flue gas temperatures that eventually reach the maximum limit recommended for maintaining the integrity of the air preheaters. This is indicated by the time-temperature graphs previously provided[13] and repeated below. The rate of boiler surface fouling increases significantly as more coal is fired, especially at maximum sustainable firing rates.

Due to the sticky character of the ash deposits, an "arsenal" of sootblower and water lance equipment is employed by Minnkota in an attempt to reduce the rate of fouling accumulations during boiler operations and remove these deposits during frequent boiler outages. These boiler cleaning outages occur every three to four months depending on the specific unit and the fuel quality delivered during the period. If the firing rate is increased to generate more steam for other heating purposes, the frequency of the cleaning outages must be increased. If the accumulated deposits are not removed, the frequency of the cleaning outages must be increased or the firing rates must be reduced and thus reduce the steam and electrical output of the boilers and steam turbine-generators. There is not "excess steam available for flue gas reheating" that would allow Minnkota to avoid reduced annual power generation.



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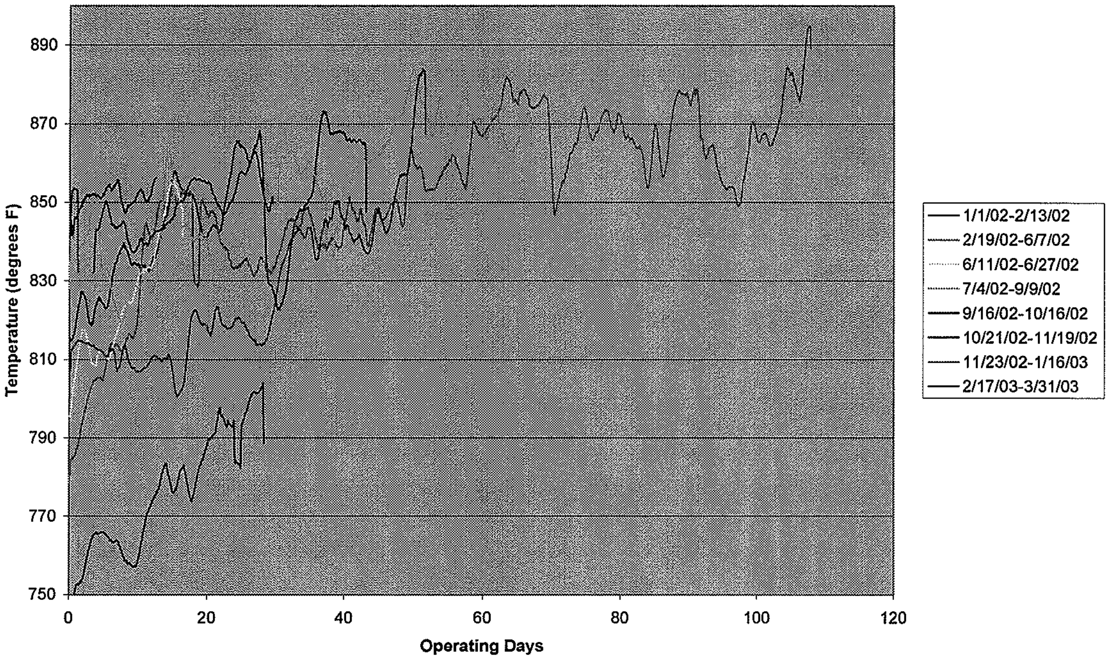
[13] See Reference number 11, April 18, 2007, pages 13-17.

MR Young Unit 2 Economizer Outlet Temperatures



NDDH Request #11: There appear to be several discrepancies in the documents that must be addressed including:

a. **The catalyst volume for Unit 2 (p. 4-23) is listed as 256 m^3 per reactor or 512 m^3 per layer. This is 4-5 times more than Unit 1 yet Unit 2 is not twice as large. Please verify the Unit 2 catalyst volume.**

At page 4-23, the words "per reactor" should be deleted from the sentence describing Unit 2's catalyst volume. This will be shown on an "Errata Sheet" attached to this document.

For Unit 2, the total initial volume was 768 cubic meters for three layers, or 256 cubic meters per layer, based on catalyst vendor input. Subsequent installation of 342 cubic meters for the fourth layer was assumed, also based on catalyst vendor input. Total initial volume plus first fill of spare layer equaling 1110 cubic meters is for two SCR reactors for each case studied for Unit 2. The correct catalyst volumes were used in the annual operating and maintenance cost calculations that are a portion of the levelized total annual costs for NOx control alternatives provided in the referenced November 2009 Supplemental NOx BACT Analysis study reports.

The conceptual design of Unit 1 Low-Dust SCR Reactor, and Tail End SCR Reactor as provided by the catalyst supplier included in each layer a total of 104 catalyst modules (8 x 13 arrangement). There is one SCR reactor for each case studied for Unit 1. The conceptual design of Unit 2 Low-Dust SCR Reactor, and Tail End SCR Reactor included in each layer a total of 91 catalyst modules per reactor (7 x 13 arrangement). There are two SCR reactors for each case studied for Unit 2.

b. **The reheat for Unit 2 for TESCR is listed as 48.11 MMBtu/hr per reactor and for LDSCR is 45.55 MMBtu/hr per reactor. The differential between TESCR and LDSCR is much less than for Unit 1 (60.3 MMBtu/hr and 31 MMBtu/hr). Please explain this difference.**

The preliminary process design calculations were reviewed for the hypothetical applications of low-dust and tail end SCR technologies for Unit 1 and Unit 2. It was determined from this review that the temperature rise for the Unit 1 LDSCR flue gas reheat system was incorrectly assumed to be 25 degrees F instead of 25 degrees C (equivalent to 45 degrees F). The corrected 45 degrees F temperature rise for the Unit 1 LDSCR flue gas reheat system is shown in the table included with the response to NDDH Request #8. The correct natural gas heat input rate for Unit 1's low-dust SCR cases is 54.5 MMBtu/hr (instead of 31 MMBtu/hr).

The discovery of the underestimate of Unit 1's low-dust SCR flue gas reheat fuel requires revision to the MRYS Unit 1 November 2009 Supplemental NOx BACT Analysis study report for "Scenario A" and "Scenario B" cases. A revised version of the referenced November 2009 MRYS Unit 1 Supplemental NOx BACT Analysis Study report document and the December 2009 response document is being submitted with the corrected numbers and recalculated control costs (see Enclosures). The flue gas reheat fuel rates and costs assumed for the hypothetical applications of Unit 1's tail end and Unit 2's low-dust and tail end SCR alternatives included in the November 2009 Supplemental NOx BACT Analysis study reports will not change.

The temperature rise for the Unit 1 TESCR, Unit 2 LDSCR, and Unit 2 TESCR flue gas reheat systems are also shown in the table included with the response to NDDH Request #8. These are all preliminary numbers that would require confirmation after final cold-side outlet design temperatures are established by the FGD and SCR gas/gas heat exchanger manufacturer.

c. The capital costs for the "stand alone" SCR (p.3 of attachments to December 11, 2009 submittal) do not total correctly. Please check the numbers and revise the documents as necessary.

The numbers for "Pricing Contingency" shown in the table that provided "Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives Best Available Control Technology – Supplemental Analysis Stand Alone" cases submitted on December 11, 2009 were incorrect. They should match the "Scope Contingency" numbers above the "Pricing Contingency" line in the table. A revised version of the referenced document is being submitted containing the table with corrected data (see Enclosures).

d. The flue gas reheat burners and fans appear to be included in both "SCR system equipment" and "Auxiliaries" cost estimates (see p.4 of attachments to December 11, 2009 submittal, footnotes 1 and 3). Please check this and revise the documents as necessary.

There are two systems of natural gas-fired burners associated with each alternative studied for hypothetical application of low-dust and tail end SCR technologies in the November 2009 Supplemental NOx BACT Analysis study reports. The "flue gas reheat burner equipment" is correctly included as part of the "Purchased Capital Equipment SCR System Equipment" item (1) (a) under "Direct Capital Costs" denoted by footnote number1 in both tables of "Estimates of Total Capital Investment" for "Shared Facilities" and "Stand Alone" as submitted on December 11, 2009. Item (1) (b) "Auxiliaries/Balance of Plant" of both tables has footnote number 3. This footnote should be revised to read as follows: "Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion ~~flue gas reheat~~ equipment with natural gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment". A revised version of the referenced document with the corrected footnotes is being submitted (see Enclosures).

REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter from Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: SCR Cost Estimate,* January 11, 2010.

2. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009.

3. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

4. "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.

5. 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.

6. 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: Milton R. Young Station BACT Determination,* dated July 15, 2009, and *Re: Request for Time Extension,* dated August 7, 2009.

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

8. Technical Information (brochure) FT-9200-AP involving anhydrous and aqueous ammonia versus urea for SCRs available from Fuel Tech's website www.ftek.com, dated November 17, 2008.

9. 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. [with regard to two documents: 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. *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.]

10. 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. [with regard to two documents: 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.]

ATTACHMENTS

1. Conceptual design sketch, for hypothetical application of Low Dust SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

2. Conceptual design sketch, for hypothetical application of Tail End SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

3. ERRATA Sheet:

   a. Corrections to Reference number 3 of this document "NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 2, Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner" November, 2009; (February, 2010).

ENCLOSURES:

A. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009, revised February, 2010.

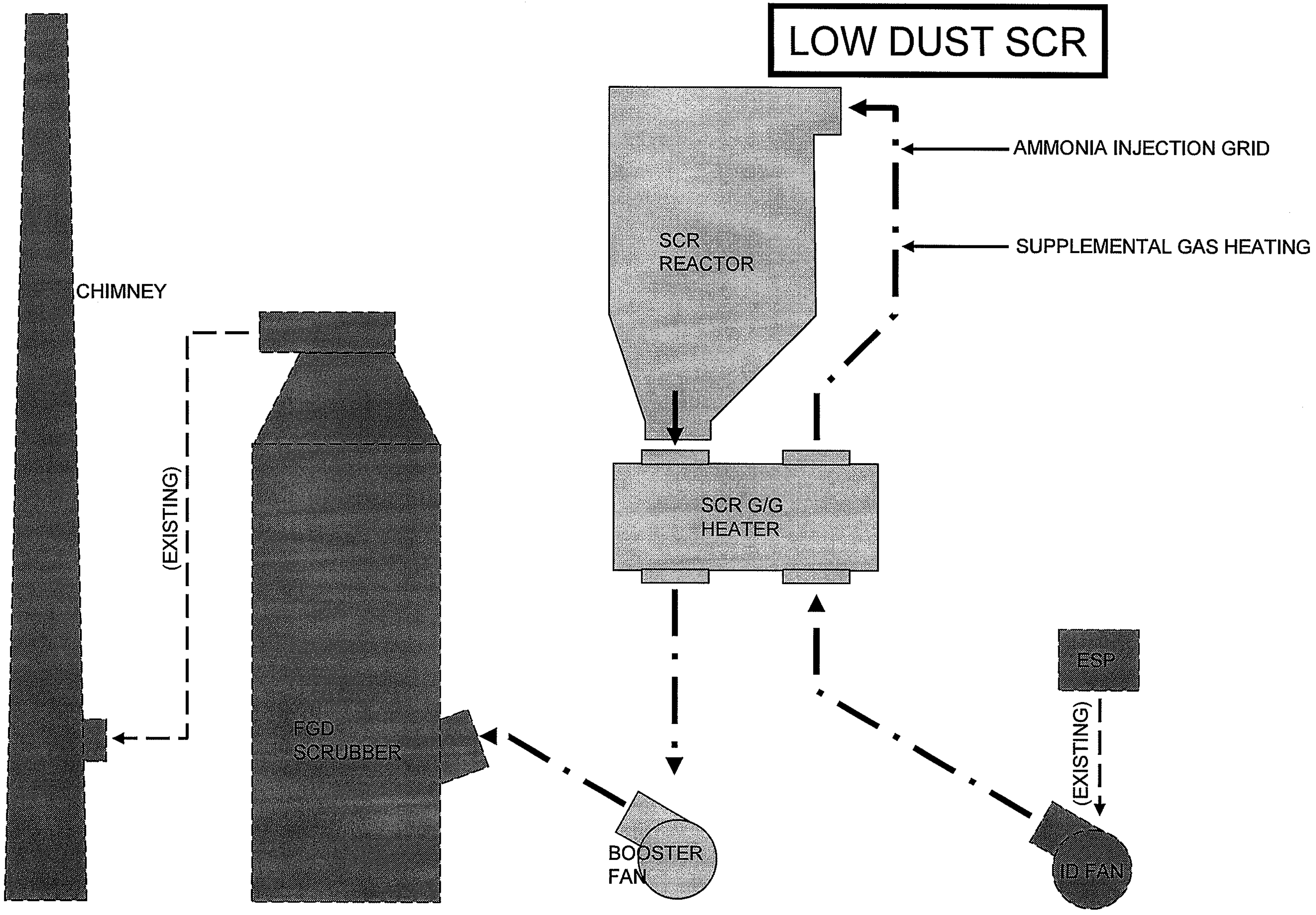
B. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009, revised February, 2010.

C. Non-confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

D. Confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

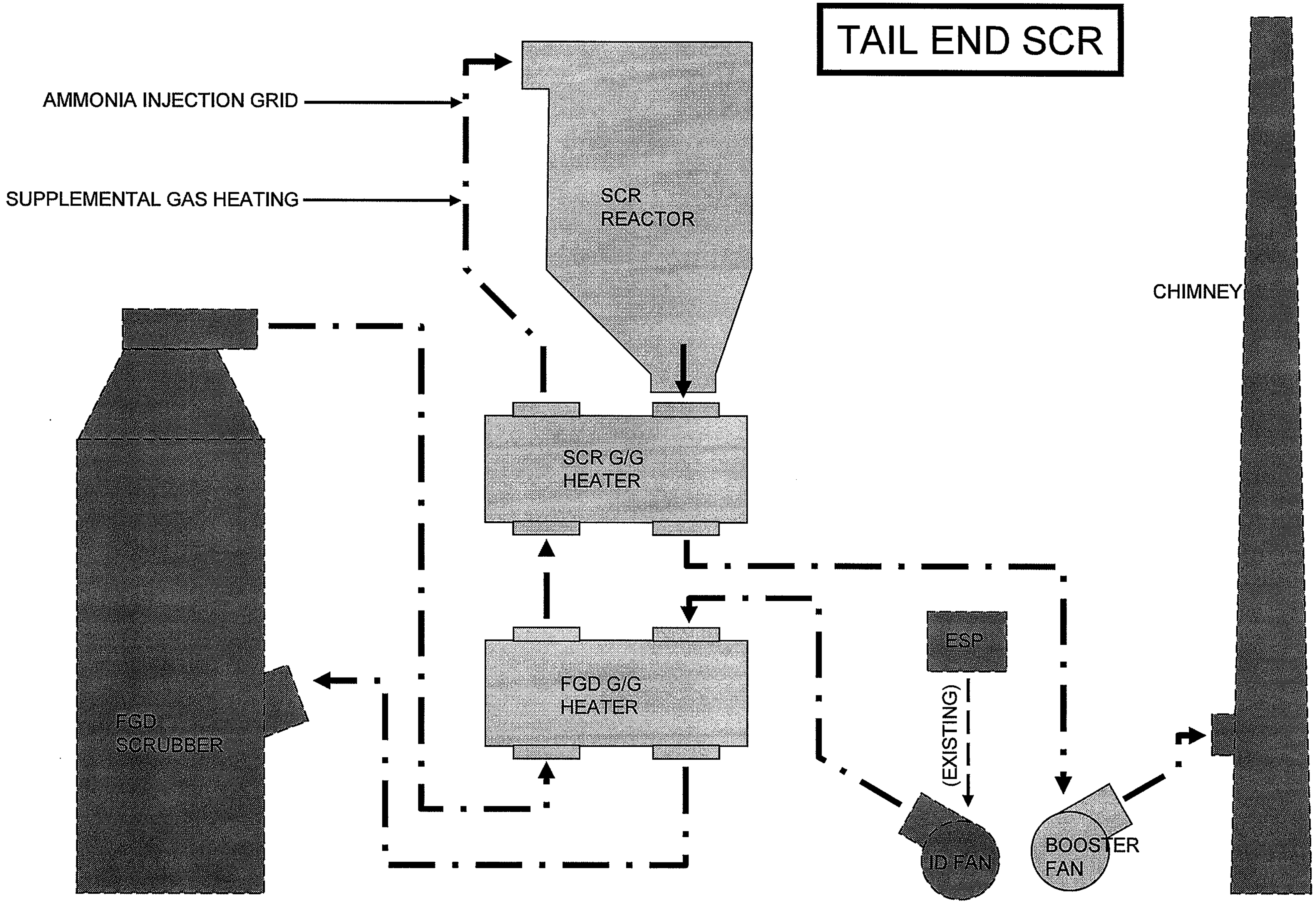
SKETCH SK - FD1

LOW DUST SCR



SKETCH SK – FD2

TAIL END SCR



ERRATA – MRYS Unit 2 Supplemental NOx BACT Analysis Study Report (November 2009)

Unit 2 Supplemental NOx BACT Analysis Study Report November 2009, page 4-23:

The second sentence of the paragraph should be revised to delete the words "per reactor":

> SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 256 cubic meters per layer ~~per reactor~~ for two reactors in parallel. A fourth (bottom) layer at 342 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.

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MAY 10 2010

MAY 2010
Received
Air Quality

Ref: 8ENF-L

Via Email and UPS Overnight

Mr. Terry O'Clair
Director, Division of Air Quality
North Dakota Department of Health
918 E. Divide Avenue
Bismarck, ND 58501-1947

Re: EPA's Comments on the North Dakota Department of Health's April 2010 Draft BACT Determination for NO_x for the Milton R. Young Station

Dear Mr. O'Clair:

This letter transmits the United States Environmental Protection Agency's (EPA's) comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination).

The Draft BACT Determination concludes that low-dust and tail end Selective Catalytic Reduction (SCR) are not cost effective NO_x controls at MRYS. The Draft BACT Determination found that low-dust SCR (LDSCR) would be more cost effective than tail-end SCR (TESCR), and evaluated the cost effectiveness of LDSCR based upon NDDH's conclusion that the average cost effectiveness for LDSCR is \$4,201 per ton for Unit 1 and \$4,822 per ton for Unit 2.[1] NDDH's Draft BACT Determination also concludes that LDSCR was not cost effective because of the incremental costs of these controls.

The Draft BACT Determination is not supported by the record and is not reasonable in light of applicable statutory and regulatory provisions for two reasons. First, the Draft BACT Determination relied upon unreasonable assumptions and factors not authorized by law to determine the cost effectiveness of SCR at MRYS. This resulted in a significant overestimate of

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[1] Since NDDH found that LDSCR was more cost effective than TESCR, these comments are focused on LDCSR, but most of the comments also apply to TESCR.

the cost of these controls. Second, even NDDH's unreasonably inflated cost estimates are on the same order as costs previously borne by other sources and must be considered cost effective.

I. SCR is Cost Effective Based upon NDDH's Inflated Cost Estimates

The Consent Decree that EPA and NDDH entered into with Minnkota requires NDDH to conduct its BACT analysis in accordance with the applicable federal and state statutes, and the provisions of Chapter B of EPA's "New Source Review Workshop Manual---Prevention of Significant Deterioration and Nonattainment Area Permitting," (October 1990) (NSR Manual).[2] The NSR Manual is used nationwide in PSD permitting decisions and provides that, "if the cost of reducing emissions with the top control alternative, expressed in dollars per ton, is on the same order as the cost previously borne by other sources of the same type in applying that control alternative, the alternative should initially be considered economically achievable, and therefore acceptable as BACT."[3] The NSR Manual further provides that "cost estimates used in BACT are typically accurate to ± 20 to 30 percent. Therefore, control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options."[4]

According to the NSR Manual, the economic impacts component of a BACT analysis may include an examination of both the average cost effectiveness and the incremental cost effectiveness of a control option.[5] The Manual defines the "average cost effectiveness" as the "total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate. . ."[6]

NDDH's Draft BACT Determination failed to conduct an adequate comparison of the average cost effectiveness of SCR at MRYS with other sources. NDDH only reviewed the cost effectiveness of a small select group of facilities with SCRs in nearby states, ignoring the costs borne by facilities that installed NO_x controls throughout the country. The Clean Air Act, the PSD regulations, and the NSR Manual do not allow a permitting authority to restrict its comparative review to a subset of the whole of the sources that have undergone BACT review for NO_x. This review should have been nationwide, and the dollars per ton removed of NO_x can be compared to sources undergoing PSD review across the country. Although a permitting authority may consider unique circumstances relating to the location of a facility in determining the total costs of a BACT control technology at that facility, it may not ignore the cost effectiveness determinations from other parts of the country and choose to allow

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[2] *See* http://www.epa.gov/ttn/nsr/gen/wkshpman.pdf.

[3] *See* NSR Manual at B.44.

[4] *Id.*

[5] *See* NSR Manual at B.41.

[6] *Id.* at B.36.

facilities to avoid the installation of BACT level controls by setting unreasonable low cost effectiveness thresholds.

The Draft BACT Determination is also deficient because it compared the calculated cost effectiveness of LDSCR at MRYS with the average of the costs of controls from the facilities within the small group selected by NDDH, instead of comparing the MRYS costs with individual costs at the other facilities. NDDH's comparison of the cost effectiveness of LDSCR at the MRYS with the average costs of a small group of facilities is inconsistent with the NSR Manual and frustrates the technology-forcing function of the BACT process because it ignores the higher costs that other sources had to bear to install the same controls. Since the NSR program is designed to maximize the use of improved technologies and requires controls that will achieve the maximum reductions, the BACT analysis cannot just compare the cost effectiveness of proposed controls with the average costs borne by other sources, but should favor consideration of the highest control costs borne by other sources. The requirement in the Clean Air Act is for the "Best" available controls, not the "Average" available controls.

Even the select group of control costs that NDDH used in the Draft BACT Determination demonstrates that the cost effectiveness of LDSCR at MRYS was on the same order as the costs borne by other facilities. NDDH's Draft BACT determination concludes that the cost effectiveness for NO_x controls at Wygen 3 was \$4,037 per ton. This is within 4% of NDDH's conclusions regarding the cost effectiveness of LDSCR at Unit 1 (\$4,201 per ton) and within 19 % of NDDH's conclusions regarding the cost effectiveness of LDSCR at Unit 2 (\$4,822 per ton). NDDH also compares the cost effectiveness of LDSCR at MRYS with the BART cost analysis conducted for a number of units. Although EPA is not clear why NDDH relied upon these cost analyses, the cost of installing LDSCR at MRYS would also be on the same order as the cost of installing SCR at these units, even based upon NDDH's inflated cost estimates.

NDDH also had information in the record relating to the cost effectiveness of at least two units that were on the same order as the cost effectiveness as LDSCR at MRYS, but did not include any discussion of these units in the Draft BACT Determination. On May 4, 2010, in response to a request from EPA, NDDH sent EPA "two files which contain excerpts from the BACT analyses we reviewed."[7] These files contained a Permit Application Analysis from the Wyoming Department of Environmental Quality (WDEQ) with information regarding the cost estimates for Wygen 2. This document shows that the cost effectiveness of installing SCR at Wygen 2 to meet a rate of 0.06 lbs/MMBtu was \$4,156 per ton. WDEQ stated "[t]he BACT analysis indicates that 0.06 lb/MMBtu is technically feasible and the Division considers the total and incremental cost effectiveness to be reasonable."[8] The files also contained documents from the NDDH record with information from the RACT BACT LAER Clearinghouse relating to

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[7] *See* Enclosure 1.
[8] *See* Enclosures 1 & 2.

Wisconsin Public Service Company's Weston 4 coal fired power plant. This information indicates that $6,116 per ton for installing SCR was considered cost effective by Wisconsin.[9]

Since the NSR Manual provides that "control cost options which are within ± 20 to 30 percent of each other should generally be considered to be indistinguishable when comparing options," even the data from NDDH's record indicates that the cost of LDSCRs at MRYS is on the same order as the cost effectiveness of other sources and should, therefore, be presumed to be cost effective.

The Draft BACT Determination states that the cost effectiveness of some of the facilities that it used for its comparison can be misleading because Minnkota used the highest removal efficiency of any analysis reviewed. As NDDH points out, the NSR Manual does state that an unrealistically low assessment of the emission reduction potential of a certain technology could result in inflated cost effectiveness figures. The NSR Manual explains that the emissions reductions must be considered reasonable, and supportable assumptions regarding control efficiencies should be made. Since the emissions reductions that were used in the cost estimates in this case were proposed by Minnkota and are consistent with current industry trends, it is reasonable to expect the LDSCRs at MRYS to achieve this removal efficiency. Furthermore, the discrepancy in assumed control efficiency can likely be attributed to MRYS's high baseline emission rate and thus, a higher potential for emission reduction. For example, the baseline emission rate noted in the NDDH determination for Sherco #2 is 0.20 lb/MMBtu compared to 0.85 lb/MMBtu for MRYS Unit 1. As such, the SCR technology can be expected to have a higher percent removal at MRYS Unit 1 compared to Sherco #2 when the baseline emissions at MRYS are over four times higher than the baseline emissions at Sherco #2.

After EPA received NDDH's Draft BACT Determination, it conducted a review of the cost effectiveness of NO_x controls at other facilities and a review of relevant literature and policy documents related to the cost effectiveness of NO_x controls. The determination of BACT is based on the pollutant that triggered PSD, in this case NO_x, and therefore the cost effectiveness (in dollars per ton removed) of any BACT control for NO_x for any type of source can be compared to the cost effectiveness of any other source of NO_x.. The results of this review, which are described below, make it clear that LDSCR is cost effective at MRYS, even based upon the inflated cost estimates used by NDDH:

- In 2001, EPA issued guidance related to presumptive BACT for NO_x at refineries being modified to meet EPA's low sulfur gasoline regulation. This guidance used a cost effectiveness threshold of $10,000 per ton of NO_x controlled in 2001 dollars.[10]

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[9] *See* Enclosure 1.

- The cost effectiveness threshold used for NO_x reduction by several California air pollution control districts are substantially more than the threshold in this EPA guidance document, ranging from $9,700 to $24,500 per ton.[11]
- Nebraska, Utah, Alabama, and Oklahoma have each stated that costs below $5,000 per ton will be presumed to be cost effective.[12]
- EPA Region 5 sent letters to Ohio and Indiana finding controls that were more expensive than LDSCR at MRYS to be cost effective.[13]
- EPA Region 4 sent letters to Alabama finding controls that were more expensive than LDSCR at MRYS to be cost effective.[14]
- A paper presented at the June 2002 Air and Waste Management meeting reported the results of a survey of the threshold for economic feasibility in the BACT determinations and in the LAER determinations separately by state. This survey reported that Connecticut's BACT Determination average cost per ton was $9,000, Arkansas's was $5,108, and Michigan's was $22,000.[15]

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10. *See* Memorandum from John S. Seitz, Director, OAQPS, to Air Division Directors regarding BACT and LAER for Emissions of Nitrogen Oxides and Volatile Organic Compounds at Tier 2/Gasoline Sulfur Refinery Projects., *available at* http://www.epa.gov/ttn/caaa/t1/memoranda/bactguid.pdf. *See also*, Delaware Air Regulation Development Committee Meeting #2 Minutes, April 19, 2006, *available at* http://www.regulations.gov/search/Regs/home.html#documentDetail?R=09000064807b7424.

11. *See* San Joaquin Valley Unified Air Pollution Control District, Final Staff Report: Update to BACT Cost Effectiveness Thresholds, May 14, 2008 *available at*. http://www.valleyair.org/busind/pto/bact/May%202008%20BACT%20cost%20effectiveness%20threshold%20update%20staff%20report.pdf, *See also* San Joaquin Valley Unified Air Pollution Control District, Draft BACT Control Technology Policy, March 1, 2010, (proposing to change BACT threshold for NOx form $9,700 to $24,500), *available at* http://71.6.68.10/Workshops/postings/2010/03-01-10/Draft%20BACT%20policy%20-%20Mar%202010%20_2_.pdf.

12. *See* Nebraska Department of Environmental Quality BACT Guidance Document, *available at* http://www.deq.state.ne.us/Publica.nsf/c4afc76e4e077e11862568770059b73f/0949822f884b8ce1862573bd007da0e9?OpenDocument, Utah Department of Environmental Quality, Best Available Control Technology Summary, *available at* http://www.airquality.utah.gov/Permits/FORMS/Form01b.pdf, and Energy and Environmental Analysis, Inc's Regulatory Requirements Database for Small Electricity, *available at* http://www.eea-inc.com/rrdb/DGRegProject/States/AL.html, and http://www.eea-inc.com/rrdb/DGRegProject/States/OK.html.

13. These letters are set forth in Enclosure 3. Note that the cost effectiveness outlined in these letters should be adjusted to 2006 dollars for an accurate comparison to LDSCR at MRYS.

14. These letters are set forth in Enclosure 4. Note that the cost effectiveness outlined in these letters should be adjusted to 2006 dollars for an accurate comparison to LDSCR at MRYS.

15. *See* Enclosure 5. "Comparison of the Most Recent BACT/LAER Determinations for Combustion Turbines by State Air Pollution Control Agencies, Paper #: 42752, AWMA Meeting June 2002. Enclosure 4 also contains an email from the state of Florida explaining that the reported results for Florida in this survey reflect the average actual cost effectiveness during the relevant time period, and does not reflect Florida's view of the cost effectiveness thresholds.

- In 2001, EPA and the States of Arkansas, Nebraska, and Utah entered into a Consent Decree with NuCor that stated that pollution control projects that are demonstrated to cost $5,000 or less per ton reduced are presumptively economically feasible.[16]
- Wyoming Department of Environmental Quality's Permit Application Analysis for Mountain Cement Company's Laramie Cement Plant considered an average cost effectiveness of $4,540 per ton to be cost effective.[17]
- A review of information in the RACT BACT LAER Clearinghouse revealed at least fourteen facilities in twelve states that identified NO_x controls that were more expensive than NDDH's estimates of the cost effectiveness of LDSCR at MRYS.[18]
- The Environmental Appeals Board noted in a 1989 decision that the range of costs normally expended for NO_x removal was $3,000 - 6,500/ton. After adjusting for inflation, these costs are at least on the order of NDDH's cost estimates for LDSCR at MRYS. *See* In the Matter of Columbia Gulf Transmission Company, PSD Appeal No. 88-11 (EAB, Jun 21, 1989) at 825.

If a permitting authority compares the cost effectiveness of a BACT determination today with the cost effectiveness of a BACT determination from past years, it must consider the effects of inflation to properly compare the older project to the one under consideration.

As more fully set forth in EPA's previous comments to NDDH, 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 all support the position that SCR is not only technically feasible, but also cost effective for controlling NO_x emissions from North Dakota Lignite.

NDDH's Draft BACT Determination concluded that "[t]he expected cost effectiveness [of LDSCR at MRYS] is higher than other plants where SCR has been applied as BACT."[19] The information set forth above clearly demonstrates that even NDDH's inflated cost estimates are on the same order as costs previously borne by other sources and must be considered cost effective.

NDDH's Draft BACT Determination also considered the incremental costs of LDSCR. The incremental cost effectiveness calculation compares the costs and emissions performance level of a control option to those of the next most stringent option. The incremental cost

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16. *See* Enclosure 6.
17. *See* Enclosure 7.
18. *See* Enclosure 8.
19. *See* NDDH's Draft BACT Determination at p. 12.

effectiveness is then determined by the difference in total annual costs between two contiguous options divided by the difference in emissions reduction.[20]

In *In re General Motors*, 10 E.A.D. 360, (EAB 2002), the Environmental Appeals Board explained the interplay between average and incremental cost. The Board explained that "the Draft NSR Manual, while allowing for both average and incremental cost effectiveness analysis, places primary stress on the average cost measure. See Draft NSR Manual at B.31 (BACT cost effectiveness analysis turns on the average and, where appropriate, incremental cost effectiveness of the control alternative). Moreover, the Draft Manual cautions that:

> [U]ndue focus on incremental cost-effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the cost-effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs. Id. at B.46. This caution against allowing incremental cost calculations to unjustifiably inflate the cost component of the BACT analysis is in keeping with the objective of the CAA that less effective control technologies be employed only when the source-specific economic impacts or other costs prevent a source from using a more effective technology. See generally Senate Debate on S. 252 (June 8, 1977) reprinted in 3 Senate Committee on Environmental and Public Works, A Legislative History of the Clean Air Act Amendments of 1977, p. 729 (statement of Sen. Edmund Muskie, sponsor of S. 252, stating that BACT, while allowing for flexibility based upon source specific factors, is intended to "maximize the use of improved technology")." Id. at 370-378

Although it is not clear from the Draft BACT Determination how much emphasis NDDH placed on the incremental cost effectiveness of LDSCR at MRYS, it is clear that the incremental cost effectiveness of LDSCR compared to SNCR is not a valid basis for rejecting SCR as BACT. Since the average cost effectiveness of LDSCR at MRYS is well within the range of acceptable BACT costs, it would be inconsistent with the NSR Manual to place undue focus upon the incremental cost effectiveness of these controls to reject LDSCR as BACT.

In its analysis, NDDH lists several projects where a permitting agency rejected a more stringent control option and the corresponding incremental cost effectiveness for the rejected technology. It is not possible to tell from the Draft BACT Determination how much weight the permitting agency gave, if any, to incremental cost effectiveness in the selection of the less-stringent option. As noted above, incremental cost effectiveness is not the primary criteria used in a BACT determination. As such, it should not be assumed that the permitting agency gave significant weight to incremental costs in the determinations cited by NDDH. Moreover, considering the relatively small amount of emphasis that can be given to incremental cost effectiveness, making any sort of direct comparison of the incremental cost effectiveness from one project to the next is difficult at best.

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[20] *See* NSR Manual at B.43.

The only three projects where NDDH states that the more stringent control technology was rejected "based on" incremental cost are the Dry Fork Plant near Gillette, Wyoming (SCR at 0.043 lb/MMBtu), the ADM facility in Columbus, Nebraska (SNCR achieving 0.05 lb/MMBtu), and Deseret Power in Uintah County, Utah (limestone injection and a wet scrubber). The other projects listed by NDDH simply state the incremental cost effectiveness for the rejected control option. NDDH does not state that incremental cost effectiveness was a significant factor in the determination.

EPA examined the three BACT determinations that NDDH stated were based on excessive incremental costs. The Draft BACT Determination stated "[t]he State of Wyoming rejected an SCR operating at 0.043lb/10^6 Btu at the Dry Fork Plant based on an incremental cost of $10,300/ton."[21] This statement is incorrect. As more fully set forth above, NDDH sent EPA excerpts of the documents that it relied upon to compare the cost effectiveness of LDSCR at MRYS with other facilities. One of these documents included excerpts from the WDEQ Permit Application Analysis for the Dry Fork coal fired power plant. EPA obtained a copy of the complete document. Page 7 of this document, which was not included in the excerpts from NDDH, directly contradicts NDDH's conclusion regarding incremental cost effectiveness, and states "[t]he Division considers the incremental cost effectiveness of $10,303/ton reasonable for an additional 117 tpy emission reduction but does not consider an incremental cost effectiveness of $23,744/ton reasonable for an additional 50 tpy emission reduction."[22]

EPA also reviewed the details of Nebraska's BACT determination for the ADM facility.[23] While Nebraska states "$5600 per of additional NO_x emissions reduction is excessive," it is clear that incremental cost was not the only reason Nebraska eliminated SNCR at a rate of 0.05 lb/MMBtu and made a BACT determination of SNCR at a rate of 0.07 lb/MMBtu. In fact, Nebraska's analysis states that 0.05 lb/MMBtu for SNCR is "not considered technically feasible due to the increased opacity and fabric filter plugging from high levels ammonia salt formation." Since the State of Nebraska concluded that it was not technically feasible for the facility to meet a 0.05 lb/MMBtu rate, NDDH cannot conclude that Nebraska rejected this control option based upon the incremental cost effectiveness. Nebraska also stated that the reasons why SNCR at 0.05 lb/MMBtu was rejected as BACT include "opacity increases by 10 percentage points or more, ammonia slip level increases above 10 ppm increases condensable PM emissions, and the increases in fine particulate matter and ammonia emissions make the proposed BACT limit for particulate matter unattainable." Even if the incremental cost was given significant emphasis by Nebraska, as noted above, $5,600 per ton is even less than what has been considered to be cost effective for average costs. Therefore, Nebraska's citation

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[21] NDDH's Draft BACT Determination at p. 12.

[22] *See* Enclosure 9. Although it is not clear where NDDH obtained these excerpts or how it reached a conclusion that is directly contradicted by the plain language of the full document, we expect that NDDH may have obtained these excerpts from EPA's administrative record in the Deseret Bonanza matter.

[23] *See* Nebraska PSD Permit for ADM's Columbus, Nebraska facility, p. 148, *available at* http://www.epa.gov/region07/air/nsr/archives/2006/finalpermits/adm_columbus_final_psd_permit.pdf.

of \$5,600 per ton being excessive for incremental cost effectiveness should be considered an outlier and reliance on this determination as a basis for incremental cost effectiveness is unwarranted.

NDDH's reliance upon Region 8's incremental cost analysis regarding the Deseret Bonanza Waste Coal-Fired Unit (WCFU) is misplaced for several reasons. First, the incremental cost analysis that NDDH refers to relates to SO_2, and not NO_x. Second, EPA Region 8's elimination of wet scrubbing with limestone injection in favor of dry scrubbing plus limestone injection for SO_2 BACT at WCFU was not entirely "based on an incremental cost of \$10,540/ton," as stated by NDDH. EPA Region 8 noted in its Final Statement of Basis for the permit that, in addition to the relatively higher H_2SO_4 formation that results from a wet scrubber, "[w]et FGD systems also require significantly more water than the dry FGD system. This is an especially important consideration for Deseret's project, which will be located in an arid region of Utah."[24] The issue of water use in wet versus dry scrubbing systems is generally recognized in SO_2 BACT determinations in Region 8 states. While there have been some projects that have proposed wet scrubbers for larger pulverized-coal units, there have also been pulverized-coal projects permitted with dry scrubbing as BACT controls for SO_2. The issue of water use is often cited as why dry scrubbing is selected over wet scrubbing. This is significant in that for pulverized-coal facilities, there is no limestone injection upstream of the control device removing substantial amounts of SO_2, as there are with circulating fluidized bed (CFB) boilers, such as that being permitted for the Bonanza WCFU project. Since there is no limestone injection upstream of a scrubbing system (wet or dry) for a pulverized-coal unit, the selection of dry scrubbing, with lower SO_2 removal efficiencies compared to wet scrubbing, becomes even more critical because the difference in overall tons of SO_2 removed would be greater for pulverized coal units compared to CFB units. Nonetheless, there have been BACT determinations in the West for pulverized coal fired units that have concluded dry scrubbing is BACT for SO_2.

Dry scrubbing with limestone was the most stringent BACT control option found by Region 8 to have been selected by permitting agencies for CFB boilers at the time the Bonanza WCFU permit was issued.[25] In fact, Region 8 stated in its Final Statement of Basis for the permit that it was "not aware of any CFB boilers equipped with a wet scrubbing system." However, Region 8 did find wet scrubbing to be a technically feasible control option for the Bonanza WCFU. Limestone injection to the CFB boiler with 85% control was assumed in the overall control efficiency of all add-on control options presented.

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[24] *See* Final Statement of Basis for Deseret Power Electric Cooperative Bonanza Power Plant, p. 96, *available at* http://www.epa.gov/region8/air/pdf/FinalStatementOfBasis.pdf.

[25] *See* Final Statement of Basis for Permit No. PSD-OU-0002-04.00 pages 97 – 100. Permits with BACT determinations issued to AES Puerto Rico and Nevco Energy issued 8/10/04 and 10/12/04 respectively. Permit applications had also been submitted for CFB units proposing dry scrubbing (in addition to limestone injection) for Red Trail Energy LLC – Richardton Ethanol Plant, MDU Co. - Gascoyne Generating Station and Great Northern Power Development – South Heart.

Finally, the overall control efficiencies listed in the Final Statement of Basis for wet scrubbing and dry scrubbing (in combination with limestone injection) are 99.1% and 98.8%, respectively. The difference in overall SO_2 reduction between wet scrubbing and dry scrubbing (in combination with limestone injection) was 63 tons per year. In contrast, the incremental NO_x emission reductions between ASOFA plus SCR and ASOFA plus SNCR calculated in the NDDH NO_x BACT Determination are 3,439 tons per year for Unit 1 and 5,490 tons per year for Unit 2. This equates to an incremental difference in NOx emission reductions at MRYS compared to the SO_2 emission reductions at Bonanza WCFU of 55 times more for Unit 1, 87 times for more Unit 2, and 142 times more collectively.

In summary, while it is true that Region 8 did cite "unacceptably high incremental SO_2 removal costs" in its reasoning for selecting dry scrubbing over wet scrubbing in the Bonanza WCFU SO_2 BACT determination, it cannot be said that this decision was "based on" the incremental cost. As described above, there were other important considerations (most notably water conservation in an arid location) that went into this determination. These other considerations were determined by Region 8 to outweigh the additional 63 tons per year reduction that would be achieved by selecting a wet scrubber over a dry scrubber. It should be noted that Region 8's final BACT determination selected the most stringent control technology of any CFB unit permitted at that time with a permitted level of control consistent with the most stringent BACT determinations. As such, the $10,540 ton per year incremental cost cited in this determination should not be viewed as an independent "bright line" value. As noted above, there are many significant differences between the Bonanza WCFU and MRYS projects. Furthermore, as explained below, the non-standard cost methods used in the NDDH Draft BACT Determination undermine the ability to make meaningful comparisons between the incremental costs calculated for MRYS with other similar projects.

II. NDDH's Draft BACT Determination Failed to Follow EPA's NSR Workshop Manual

NDDH was and is required to conduct its BACT determination in accordance with the NSR Manual and OAQPS Control Cost Manual (Control Cost Manual). The Draft BACT Determination did not, however, follow the requirements in these manuals. Rather, it used unauthorized cost methods, included costs for items that are not authorized, and relied upon unreasonably high estimates for a number of costs. As more fully set forth below, conservative revised cost estimates conducted in accordance with the NSR Manual and Control Cost Manual and based upon more realistic estimates for a number of items cause the cost effectiveness of LDSCR at MRYS to drop to approximately $2,000 per ton.

Since the significance of cost effectiveness values is determined by comparing the costs for a given project to costs at other sources, it is critical that permitting authorities throughout the United States follow a standardized approach for determining the cost effectiveness of controls. The NSR Manual explains:

> Consistency in the approach to decision-making is a primary objective of the top-down BACT approach. In order to maintain and improve the consistency of BACT decisions made on the basis of cost and economic considerations, procedures for estimating control equipment costs are based on EPA's OAQPS Control Cost Manual and are set forth in Appendix B of this document. Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis.[26]

The Control Cost Manual also emphasizes the importance of using a consistent approach to determining the cost effectiveness of controls. The Introduction to the Control Cost Manual explains:

> The objectives of this Manual are two-fold: (1) to provide guidance to industry and regulatory authorities for the development of accurate and consistent costs (capital costs, operating and maintenance expenses, and other costs) for air pollution control devices, and (2) to establish a standardized and peer reviewed costing methodology by which all air pollution control costing analyses can be performed.[27]

A. <u>Inflated Capital Cost Estimates and Cost Methods</u>

SCR systems are being successfully applied to virtually every kind of stationary source (utility boilers, incinerators, cement plants, glass plants, etc.) and fuel type (coal, biomass, coke, etc.) worldwide. In meeting these varied and significant challenges for the widespread deployment of SCR technology, system designers must always tailor the specifics of SCR application to the varied conditions at each facility and the most suitable location for installing the system. Although there are admittedly some unique aspects of the MRYS, almost all facilities that have installed SCRs have had unique design challenges.

Capital costs for the installation of SCR on a coal fired electric generating unit are commonly reported on a dollar per kilowatt of capacity basis. Minnkota's BACT analysis, prepared by Burns & McDonnell (B&McD), which was used by NDDH to determine the cost effectiveness of LDSCR, states that the estimated capital cost for LDSCR at MRYS based upon a shared facilities approach was $543/kW for Unit 2 and $525/kW for Unit 1.[28]

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26. *See* NSR Manual, at B-52

27. *See* Control Cost Manual, 2002, Chapter 1, Section 1.1.

28. *See* November 2009 report by Burns & McDonnell, "NO_x Best Available Control Technology Analysis Study – Supplemental Report for the Milton R. Young Station Unit 1, revised February 2010, p. 4-11, and November 2009 report by Burns & McDonnell, "NO_x Best Available Control Technology Analysis Study – Supplemental Report for the Milton R. Young Station Unit 2, p. 4-11.

In its BACT analysis, B&McD stated that a cost range for conventional high-dust SCR was reported as between $55 and $150/kW.[29] On February 16, 2006, PowerGen magazine reported the results of survey of SCR capital costs. The survey was conducted by the Electric Utility Cost Group, and included responses from 72 individual units totaling 41 GW (representing 39% of installed SCR systems in the U.S. by MW at the time of the study). The results of this survey showed that costs were generally reported to be in the $100 to $200/kW (in 2006 dollars) range for the majority of the systems, with only three reported installations exceeding $200/kW.[30] Although some studies have reported slightly higher costs, most have reported results that are generally within this range.[31] Furthermore, two PSD permit applications submitted to NDDH in 2005 and 2006 for CFB utility boilers contemplated SCRs downstream of a dry scrubber and baghouse (TESCR) and included estimated capital costs.[32] The estimated capital costs for these two projects ranged from $117/kW to $132/kW. Since these units were designed to burn North Dakota lignite and are very close in size to MRYS Unit 1, it is unclear why the estimated capital cost for MRYS Unit 1 are about four times higher than what was reported in those permit applications.[33]

The fact that B&McD estimated capital costs for the LDSCRs at MRYS are so much higher than the capital costs at other facilities calls the reliability of these cost estimates into question. The reliability of these estimates becomes more questionable in light of the fact that a number of extremely complicated and challenging SCR installations have had capital costs well below the cost estimates for LDSCR at MRYS. There are at least two cold side SCRs that have recently been installed in the United States that should be considered as a relatively reasonable comparison. In 2007, Washington Group International prepared an "Emission Reduction Study" that evaluated what would be the most cost effective SCR configuration at the WE Energies South Oak Creek Units 5, 6, 7 and 8. The report concluded that retrofitting the units with cold-side LDSCRs was determined to be the least expensive option and predicted capital costs for the SCR systems of $190,500,000 total for all units. This comes out to approximately $168/kW for the SCR equipment alone on the combined 1,135 MW at the facility.[34]

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[29] *Id.*

[30] *See* M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. http://www.powermag.com/coal/Estimating-SCR-installation-costs_506.html. The reported range of $100 - $221/kW.

[31] *See* Enclosure 10. J. Edward Cichanowicz, Current Capital Cost and Cost Effectiveness of Power Plant Emissions Control Technologies, June 2007.

[32] *See* Enclosure 11. August 18, 2005 Application to Permit to Construct – South Heart Power Project, page 4-16 and June 2006 Gascoyne 500 Generating Station and Gascoyne Mine Application For A Permit To Construct And Air Quality Technical Analysis.

[33] Although NDDH rejected TESCR for these projects due to high cost effectiveness, these examples illustrate how exceptionally high the B&McD estimates are for capital costs.

[34] *See* Enclosure 12. WE Energies submitted information to the Public Service Commission (PUC) of Wisconsin indicating that the cost of its SCR system was higher than the costs identified in this study. Even if the costs from the PUC submittal are used to calculate the cost per kW, however, these costs are significantly below Minnkota's estimated capital costs.

PSE&G also retrofitted its Mercer Units 1 and 2 with cold-side SCRs. The capital cost for these retrofits was about $120 million.[35] This comes out to approximately $185/kW. Although EPA and NDDH asked Minnkota to conduct a general comparison of the capital costs of installing SCR at MRYS with the costs of LDSCR at these units, Minnkota declined to conduct this comparison.

Minnkota has not explained the fact that the estimated capital costs for LDSCR and TESCR at MRYS are so much higher than any other SCR system built, including the LDSCR systems for Oak Creek and Mercer Stations. B&McD implies that the unique nature of the application of SCR at MRYS creates a situation where seemingly no comparison to another SCR installation is appropriate. As noted above, even if an SCR installation at MRYS would provide unique challenges because of the different fuel or boiler type, this would not result in capital costs that are over one and a half times as high as the upper end of SCR installations with the highest degree of retrofit difficulty. The differences for the basic capital cost equipment at MRYS would not be expected to differ from other SCR installations on the scale estimated by B&McD and no reasonable explanation has been provided by Minnkota for the large disparity. As such, close examination of the stated costs must be conducted by NDDH to justify the cost-effectiveness in its BACT determination.

EPA has examined these costs based on the information available during the public notice period and believes that the B&McD analysis that NDDH relied upon included redundant costs, insufficient justification for some of the cost estimates, and many components in the cost methodology used to calculate Total Capital Investment that are unauthorized, inappropriate, and inconsistent with the Control Cost Manual or other EPA-approved methods. When these items are taken into account, it is clear that the cost values submitted by Minnkota and adopted into the Draft BACT Determination result in a calculation of cost effectiveness that is grossly inflated and ill-suited for comparisons with other BACT determinations.

First, as explained in detail in Mr. Hans Hartenstein's April 2010 expert report[36], many of the assumptions and design parameters that B&McD specified to SCR system and catalyst vendors resulted in excessive equipment components and sizing of the SCR system and the auxiliary/ balance of plant components, which drove up materials and labor costs. If the system was designed to minimize capital costs, the general design would be different and the cost of materials and labor would be much less. Furthermore, there appears to be redundancy for some items that were included as "SCR System Equipment" and "Auxiliaries/Balance of Plant" costs.

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[35] *See* PSG&E press release at: http://www.pseg.com/media_center/pressreleases/articles/2006/2006-11-30.jsp. EPA verified the capital costs with communications with the New Jersey Department of Environmental Protection and Mr. Hans Hartenstein.

[36] *See* Enclosure 13. Portions of this enclosure are subject to a confidential business information claim and will be submitted separately and noted as CBI.

For example, the "Auxiliaries/Balance of Plant" costs include "SCR bypass ducts and isolation dampers." The SCR system vendor that provided a pricing proposal, which appears to have been directly used by B&McD for the "SCR System Equipment" cost, included an SCR system with "gas bypass for maintenance." Although vendor information can be used instead of the capital cost equations detailed in the Control Cost Manual, Minnkota has not provided a basis for the "Auxiliaries/Balance of Plant" costs, which are 80% of the "SCR System Equipment" costs. Perry's Chemical Engineering Handbook, 6th Edition (Table B2) uses factors related to total equipment costs which would be similar to the "SCR System Equipment" used in the B&McD analysis. Perry's adds 55% to equipment costs for auxiliaries compared to B&McD's 80%. The redundancies and comparatively high costs used for "Auxiliaries/Balance of Plant" that NDDH relied upon in the Draft BACT Determination are unreasonable and not supported by the record without further justification.

Another major concern is the degree to which the B&McD capital cost analysis deviates from the Control Cost Manual methodology and includes numerous indirect cost and other accounting mechanisms that are not included in the Control Cost Manual and not adequately justified. Minnkota's February 11, 2010 submittal claims that, "Burns & McDonnell used standard estimating practices to estimate direct, installation, and indirect capital costs for MRYS Unit 1's and Unit 2's hypothetical application of low-dust and tail end technologies." While these estimating practices may be standard for use by B&McD or the utility industry for internal justification or other accounting purposes, they are not appropriate for use in the context of the BACT analysis. The standard approach is outlined in the Control Cost Manual, so that comparisons of cost-effectiveness can be made with other projects nationally. B&McD's approach undermines the ability to make these comparisons.[37]

For example, B&McD calculated total indirect capital costs that equal about 50% of the total direct capital cost compared to the Control Cost Manual which uses 20%. Of this 50%, approximately 15% is listed as a "scope contingency" and another 15% is listed as a "pricing contingency." The Control Cost Manual includes two contingencies for SCRs. The first is a "process contingency" that is calculated as 5% of the <u>direct</u> capital costs. The second is a 15% "project contingency" and is not considered to be part of the indirect capital costs. B&McD indicates that its "pricing contingency" is equivalent to the "project contingency" in the Control Cost Manual. B&McD's "pricing contingency" will actually be somewhat lower than the Control Cost Manual's "project contingency" because, unlike the "project contingency" of the Control Cost Manual, the 15% is not applied to the indirect capital costs. The "project contingency" of the Control Cost Manual is calculated as 15% of the total direct <u>plus</u> indirect

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[37] Enclosure 14 is an example of a cost analysis submitted to NDDH as part of a BART submittal that does not include many of the indirect capital costs and contingencies included in B&McD's analysis. Although EPA may not be in agreement with every aspect of the cost analysis in the example, it does illustrate a case where the Control Cost Manual format is generally followed and the estimated capital costs are far less (by a factor of almost 4 for LDSCR on Unit 2, which is a smaller unit in comparison to the example and should cost less) than what was estimated for MRYS.

capital costs. However, B&McD's "scope contingency" of 15% is significantly higher than the Control Cost Manual's 5% "process contingency." Assuming, as B&McD did, that the "project contingency" is part of the indirect capital costs, it would equal 18% of the direct capital costs and the total indirect capital costs for the Control Cost Manual would equal 38% of the direct capital cost compared to 50% of the capital costs in the B&McD.[38] There are other discrepancies between B&McD's indirect costs and those in the Control Cost Manual. These differences are tabulated below.

Table 1. Comparison of Control Cost Manual & B&McD Indirect Capital Costs[39]

Indirect Capital Costs	Control Cost Manual (% of Direct Cap Cost "A")	B&McD Analysis (% of Direct Cap Cost "A")	Comparison
General Facilities (Construction Mgt)	0.05 *X* A	0.04 *X* A	B&McD 1% Lower
Engineering & Home Office Fees	0.10 *X* A	0.15 *X* A	B&McD 5% Higher
Startup Expenses	0	0.02 *X* A	B&McD 2% Higher
Process Contingency (Scope Contingency)	0.05 *X* A	0.15 *X* A	B&McD 10% Higher
Project Contingency (Pricing Contingency)	0.18 *X* A	0.15 *X* A	B&McD 3% Lower
Totals	**0.38 X A**	**0.51 X A**	**B&McD 13% Higher**

While this difference of 13% is significant, B&McD then adds two more contingencies ("cost escalation during project" and "owner's costs – other") and includes an allowance for funds during construction (interest) before calculating the total capital investment. The Control Cost Manual allows for "preproduction costs" of 2% of the total direct, indirect capital costs, and the "project contingency." Table 2 below compares these "other" costs used by B&McD and the preproduction costs in the Control Cost Manual. To normalize these costs with those tabulated above, percentages were converted back to the direct capital costs ("A").[40]

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[38] Per the Control Cost Manual, indirect capital costs = 0.2 times the direct capital costs. So, 15% of the total of direct capital costs plus indirect capital costs = (1.2 * direct capital costs) (0.15) = 18% of direct capital costs.

[39] Although, B&McD stated in their December 11, 2010 submittal that their BACT cost estimates "follow the outline of Table 2.5 in the SCR Chapter of EPA's Control Cost Manual," many items do not match in description, so some assumptions had to be made. Where there are differences, the B&McD cost is in parentheses. Also, as noted above, this comparison assumes that "project contingency" of 15% is part of the indirect costs, so when applied exclusively to the direct capital costs only, it becomes 18%.

[40] Preproduction costs are listed as being 2% of the total direct (A), indirect (B), and "project contingency" (C) costs. This becomes 3% of the total direct capital costs. (B = 0.20 * A; C = 0.18 * A; A + B + C = 1.38 A; 0.02 * 1.38 A = 0.03).

Table 2. Comparison of EPA Control Cost Manual & B&McD "Other" Capital Costs

Other Costs	Control Cost Manual (% of Direct Cap Cost "A")	B&McD Analysis (% of Direct Cap Cost "A")	Comparison
Cost Escalation	0	0.30 *X* A	B&McD 30% Higher
Allowance for Funds During Construction (Interest During Construction)	0	0.20 *X* A	B&McD 20% Higher
Preproduction Costs	0.03A	0	B&McD 3% Lower
Owners Cost – Other (Owner Contingency)	0	0.17 *X* A	B&McD 17% Higher
Totals	**0.03 X A**	**0.67 X A**	**B&McD 64% Higher**

Based on Tables 1 & 2 above, the B&McD cost analysis methodology results in capital costs that are higher by a factor of about 1.8 (0.13 + 0.64 higher) than what would be calculated using the Control Cost Manual, assuming the same base costs for total direct capital costs. As noted above, the total direct capital costs used by B&McD appears to be overestimated. A large portion of this discrepancy comes from the "other" costs added by B&McD (Table 2) that are not included in the Control Cost Manual. These appear to be strictly contingencies and accounting items which would not be at all unique to MYRS and, therefore, are not justified in the analysis. These accounting items are unauthorized under the Control Cost Manual, create an unlevel playing field for comparison with other BACT analyses and alone account for an increase in capital costs from the Control Cost Manual by a factor of 1.6.

Although NDDH asked B&McD to provide a detailed explanation regarding its high indirect capital cost estimates, B&McD's February 11, 2010, response to this request fails to justify why the B&McD cost methodology should be allowed for the MRYS BACT analysis, when it is not part of the Control Cost Manual and is not the standardized methodology used by other sources. While the Control Cost Manual does contemplate some flexibility in some contingencies (such as degree of retrofit difficulty), B&McD has not substantiated the need to go beyond standard contingencies applied through the Control Cost Manual. As stated in the Control Cost Manual, "[c]ontingencies is a catch-all category that covers unforeseen costs that may arise, such as possible redesign and modification of equipment, escalation increases in cost of equipment, increase in field labor costs, and delays encountered in start-up."41 Thus, the contingency in the Control Cost Manual should already account for possible changes in labor costs, and inclusion of a contingency plus escalation of costs is redundant according to the Cost Manual Methodology. Escalation of costs should not be included as a separate estimate in the estimate of Total Capital Investment since it is included as part of the contingency estimate. In Table 2.5 of the SCR chapter of the Control Cost Manual, the "Allowance for Funds During

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41. *See* Control Cost Manual, 2002, Chapter 2, Section 2.3.1.

Construction" (inflation) is specifically listed as zero. It is unclear then why B&McD added what amounts to 20% of the direct capital costs to cover inflation. Including "owner's costs" and "owner's contingency" is also not consistent with the Cost Manual Methodology and appears to be redundant.

B&McD mentions that it is anticipated that significant retrofit work will be required which will affect the scope and price of the project. However, there have been many SCR retrofits facing much more difficult challenges with space limitations and boiler modifications than MRYS can be expected to face installing a LDSCR or TESCR downstream of the ESP (or FGD) in a rural location. The contingencies outlined in the Control Cost Manual (5% process contingency and 15% project contingency) are sufficient for purposes of the BACT analysis.

B. Inflated Annual Cost Estimations & Cost Methods

In addition to the inflated capital cost estimates and inappropriate cost methods used by B&McD in the MRYS BACT analysis that NDDH relied upon, B&McD also used inflated and unjustified cost estimates for annual costs and used costing methods that are unauthorized by the Control Cost Manual. Below are some of the issues identified by EPA. These are listed following the numbering scheme in the detailed itemized B&McD BACT cost analysis submitted December 11, 2009 and updated February 11, 2010.

(1) Annual Maintenance Costs:

B&McD uses a factor of 3% of the installed capital costs of the SCR equipment and auxiliary equipment. The Control Cost Manual uses a factor of 1.5% of total capital investment. No justification was given by B&McD for using a cost factor that is twice as high.

(2) Annual Reagent Costs:

As stated in NDDH's January 11, 2010, letter to Minnkota and in Mr. Hartenstein's expert report, the choice to use urea instead of anhydrous ammonia drives up annual costs. As also stated in Mr. Hartenstein's expert report, the reasons given by B&McD in the February 11, 2010, response to NDDH are not unique to MRYS and do not constitute justification for choosing the more expensive reagent. Since excessive cost is the main reason cited by NDDH for not selecting the top level of control as BACT and there is a less expensive option that is available, the analysis should be redone using anhydrous ammonia.

(3) Annual Electricity Costs:

In its February 11, 2010, response to NDDH, B&McD provided an explanation of the electricity costs associated with extended outage periods for catalyst replacements and ASOFA maintenance.[42] In its analysis, B&McD estimates the following times for various stages of catalyst replacement:

1) Reactor Cool Down:	48-60 hours
2) Installation into spare catalyst layer:	128 hours (16 shifts - one time event)
3) Removal of spent catalyst and installation of fresh catalyst:	192 hours (24 shifts)
4) Reactor heating for startup:	36-48 hours
Total (Items 1, 2 & 4):	276-300 hours

Conservatively assuming that one spent catalyst is always removed when a fresh catalyst is added and disregarding the unreasonable assumption that only two shifts per day would be used to perform the work while the unit remains idle, the range of total outage time estimated by B&McD to cool down the reactor, exchange catalyst, and reheat the reactor is 276 – 300 hours, or 11.5 – 12.5 days. This does not include the 96 hours (or four days) of regular scheduled boiler cleaning downtime that should be subtracted from these totals. **When this is accounted for, there would be a maximum of 204 hours for each catalyst exchange in excess of normal downtime for each unit.**

Even under B&McD's unwarranted "Scenario B" assumption that catalyst is replaced three times per year for Unit 1 and four times per year for Unit 2, this equates to a maximum of 900 hours per year of catalyst replacement time for Unit 1 and 1,200 hours per year for Unit 2. This does not include the 96 hours (or four days) of regular downtime that should be subtracted from these totals for each outage period. **When this is accounted for, there would be a maximum of 612 (900 – 288) hours per year for Unit 1 and 816 (1,200- 384) hours per year for Unit 2 under B&McD's worst case scenario.**

B&McD states that the excess downtime for SCR catalyst replacements under "Scenario A" would be 213 and 256 hours for Unit 1 TESCR and LDSCR respectively, and 206 and 247 hours for Unit 2 TESCR and LDSCR respectively. It is unclear how B&McD came up with these values considering they are higher than the high end total of what was outlined for each stage of the catalyst replacement once subtraction was made for normal boiler cleaning (maximum of 204 hours).

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[42] The NSR Workshop Manual states: "Lost production costs are not included in the cost estimate for a new or modified source." Appendix B, p.11. For the purpose of this analysis, EPA is assuming lost production is included in the cost estimate.

Furthermore, B&McD states that the excess downtime for SCR catalyst replacements under "Scenario B" would be 980 and 938 hours for Unit 1 LDSCR and TESCR respectively, and 1,234 hours for Unit 2 (LDSCR and TESCR). Again, it is unclear how B&McD came up with these values considering they are higher than the high end total of what was outlined for each stage of the catalyst replacement, even if no time of the outage was subtracted for normal boiler cleaning (900 hours for Unit 1 and 1,200 hours for Unit 2). When the subtraction for normal boiler cleaning is made, there is an even larger discrepancy between B&McD's estimations and what was outlined for each stage of the catalyst replacement (612 hours for Unit 1 and 816 hours for Unit 2).

While B&McD's additional outage times do not appear to correspond to the sum of the catalyst replacement steps outlined in their February 11, 2010, submittal, they also do not appear to reflect the information they received from SCR system and catalyst vendors and their consultants. The information received from these sources is addressed below.

Reactor Cool Down: Based on a September 29, 2010, email from Babcock & Wilcox Construction Co. Inc., Minnkota was advised that "we typically see 36 to 48 hrs before entering the SCR." It is unclear why B&McD used 48-60 hours (although, as noted above, even using the high end of their range, the additional outage times stated by B&McD seem to exceed what would be calculated.) **EPA believes 48 hours for reactor cool down would be a conservative estimate.**

Catalyst Exchange: According to a September 15, 2009, email, B&McD's consultant Fuel Tech's, "'rule of thumb' estimate for catalyst installation is thirty (30) minutes per module." This is based on conventional access, use of hoists for module handling and transport, and a typical crew of 4 to 6 people. With different system design and more personnel, the time period can certainly be reduced."

As stated in Mr. Hartenstein's expert report, "[b]ased on the catalyst designs from HTI and CERAM submitted to Minnkota, the number of modules per layer ranges from 96 – 104 for Unit 1 and 162 – 182 for Unit 2. Using the stated conservative 'rule of thumb' estimate of thirty minutes per module, this equates to maximum time of 2.2 days for Unit 1 and 3.8 days for Unit 2 to replace a layer of catalyst. As stated by Fuel Tech, this 'rule of thumb' estimate could be further reduced through design and personnel." This equals a maximum of 52 hours for Unit 1 and 91 hours for Unit 2.

Based on B&McD's February 11, 2010, submittal the difference in time between removing spent catalyst (16 shifts) and the removal of spent catalyst and installing fresh catalyst (24 shifts) is 64 hours.

So, the maximum total time for removing a layer of spent catalyst and installing fresh catalyst is as follows:

Unit 1: 64 hours + 52 hours = 116 hours
Unit 2: 64 hours + 91 hours = 155 hours

These are both lower than the time described in the February 11, 2010, response for removing spent catalyst and installing fresh catalyst (192 hours) Again, even using the apparently inflated value of 192 hours, the additional outage times stated by B&McD seem to exceed what would be calculated using these values.

Reactor Preheating for Startup: B&McD has stated this will take 36-48 hours. Based on the very conservative nature of their other estimates and the comments in Mr. Hartenstein's expert report on this subject, **EPA believes 36 hours for reactor preheating would be a conservative estimate.**

Using the information supplied to B&McD and Minnkota from SCR system and catalyst vendors, and B&McD's consultants, EPA calculates that a conservative total estimate of excess downtime (subtracting the four days for normal cleaning downtime) from bringing the unit down, to replacing spent catalyst with fresh catalyst, to bringing the SCR back online for one layer of catalyst exchange is as follows:

Table 3. EPA Estimates for Catalyst Exchange Times

Replacement Step	**Time Unit 1 (hours)**	**Time Unit 2 (hours)**
Reactor Cool Down	48	48
Spent Catalyst Removal and Installing Fresh Layer	116	155
Reactor Preheating for Startup	36	36
Subtract Scheduled Downtime	-96	-96
EPA Total Estimate	104	143
B&McD Estimate (Scenario A)	213-247	206-247
Difference	**109-143**	**63-104**

As can be seen from Table 3 above, B&McD's estimates for catalyst exchange times are over twice as high for Unit 1 and over 50% higher for Unit 2 when compared to EPA's estimates (which were based directly on the information provided to Minnkota and B&McD by vendors and consultants).

Furthermore, B&McD added an additional 181-188 hours per year to the annual electricity costs for extra downtime due to advanced separated overfire air (ASOFA) maintenance. Even assuming these values are realistic and necessary, which should be justified by Minnkota, since the more realistic EPA estimates for catalyst exchanges for both Unit 1 and Unit 2 are less than the stated ASOFA maintenance times, it should be assumed that the SCR maintenance would be performed at least partially within the same time allotted for ASOFA-related maintenance. B&McD gives no explanation as to why the outage times for ASOFA and SCR are cumulative and the work could not be scheduled and conducted concurrently. One possible reason would be if there were short interruptions required for ASOFA maintenance that did not correspond with the normal unit cleanings. This seems unlikely (especially for 181 – 188 hours per year) and B&McD has not indicated that this would be the case normally. Appendix C3 of the original 2006 NO_x BACT Analysis provides the only basis that EPA can find for including any ASOFA downtime. Page C3-3 describes lost availability due to "forced or extended scheduled boiler outages that may result from problematic cyclone slag tapping operational conditions encountered during substoichiometric cyclone operation with SOFA." These times should be justified, as well as the need to conduct this maintenance at a different time from the normal boiler cleanings and/or the SCR catalyst replacements. If it is found that ASOFA maintenance times can fall within the same normal boiler cleaning outages, B&McD's cost estimate must subtract all electricity costs attributed to extended outage times for catalyst replacements accordingly.

Finally, it appears that for "Scenario A", B&McD did not take into account that the catalyst exchanges will not be occurring each year. Since they will be occurring approximately every other year, these costs need to be adjusted to an annual basis.

(4) Annual Water Costs:

No comments.

(5) Catalyst Replacement Costs:

Based on Note 5 in the detailed itemized B&McD BACT cost analysis submitted December 11, 2010, and updated February 11, 2010, B&McD assumed a catalyst price of $7,500 per cubic meter (in 2006 dollars) in calculating annual catalyst replacement costs. This assumption appears to be significantly higher than either of the bids the two catalyst vendors provided to Minnkota. Furthermore, this value is also substantially higher than two of the three vendor bids received by Mr. Hartenstein's in response to his vendor inquiry. It is unclear why B&McD used a unit catalyst price higher than any vendor bid they received for their BACT analysis. While a higher unit price may be justifiable for TESCR compared to LDSCR, it appears from Note 5 that B&McD used the same price for LDSCR and TESCR. Sufficient detail is not provided on how adjustments were made for the different volumes required for each catalyst replacement in a LDSCR and TESCR application.

Furthermore, B&McD did not seem to consider the use of regenerated catalyst in pricing catalyst replacements. Catalyst regeneration has been in practice in the utility industry for years to help save SCR maintenance costs and typically costs less than half of what new catalyst would cost. If there is some reason Minnkota cannot use regenerated catalyst at MRYS, this should be justified.

(6) Natural Gas for Flue Gas Reheating & Urea Conversion System:

As noted above and in Mr. Hartenstein's expert report, EPA questions whether natural gas needs to be used instead of steam to reheat flue gas and whether urea needs to be used instead of anhydrous ammonia at MRYS. See Mr. Hartenstein's expert report for more information.

(7) Operating Labor for SCR:

EPA agrees that no operating labor (or supervisory labor) should be included, consistent with the Control Cost Manual.

(8) Annual Costs for Capital Recovery:

Based on greatly inflated capital costs (addressed extensively above), the annual capital recovery cost is likewise greatly inflated.

(9) Administrative Overhead, Insurance, Taxes, etc.:

No comments.

In addition to the above comments, the levelized total annualized cost approach used by B&McD is inappropriate, as it is inconsistent with the Control Cost Manual. Based on Note 15 in the detailed itemized B&McD BACT cost analysis submitted December 11, 2010, and updated February 11, 2010, B&McD increased the total direct annual costs (all annual costs with the exception of capital recovery) by a factor of 1.25. While these estimating practices may be standard for use by B&McD or the utility industry for internal justification or other accounting purposes, they are not appropriate for use in the context of the BACT analysis. The standard approach is outlined in the Control Cost Manual, so that comparisons of cost-effectiveness can be made with other projects nationally. B&McD's approach undermines the ability to make these comparisons.

The Control Cost Manual methodology provides estimates of operation and maintenance that do not change with interest rate and equipment life. The equivalent uniform annual cost estimates from the Control Cost Manual are equal across the life of the equipment. Changing the interest rate and equipment life will change the annualized capital cost estimate, but should not change the annual operation and maintenance costs. The Control Cost Manual procedure provides real estimates of costs (that is, inflation-adjusted), and not nominal costs.

C. EPA Corrected Cost Analysis

Due to the inflated nature of B&McD's cost estimates, EPA conducted an independent cost analysis for LDSCR and TESCR at MRYS. This analysis consisted of two parts. The first was to request budgetary proposals from several catalyst vendors on catalyst performance guarantees (NO_X removal, initial catalyst life, and ammonia slip), catalyst volume and dimensions, catalyst exchange diagrams up to approximately 100,000 hours, and catalyst price. The Request for Proposal (RFP) was based on what EPA believes to be representative flue gas characteristics and design specifications for a LDSCR on Unit 1 and a TESCR on Unit 2. Mr. Hartenstein was hired by the Department of Justice to perform this work on behalf of EPA.

The RFP was sent to three catalyst vendors (CERAM, Johnson Matthey Catalysts (JMC), and Haldor Topsoe) on March 3, 2010. While the facility in the RFP was not identified as MRYS, the flue gas characteristics in the RFP were based on relevant actual flue gas parameters found at MRYS, including recent stack test information for Unit 1 and Unit 2 and the 1983 Markowski data on particulate matter concentrations and compositions data for Unit 2. Furthermore, it was clearly stated in the RFP that the majority of the sulfates within the particulate matter are expected to be sodium and potassium sulfates. Upon request from two catalyst vendors (CERAM and JMC), a typical coal composition of Center lignite was provided. Responses from all three vendors were received between March 12 and March 31, 2010. As noted in Mr. Hartenstein's expert report, all three catalyst vendors were able to provide an initial catalyst life guarantee of 24,000 operating hours in response to the RFP, as well as providing catalyst size and price specifications at the guaranteed NO_X and ammonia slip rates. More detail is provided in Mr. Hartenstein's expert report. The RFP and the vendor responses are also attached.[43]

The second part of the EPA's independent cost analysis was to calculate SCR cost effectiveness (dollars per ton) based on the Control Cost Manual or other appropriate methods using the relevant cost information obtained from the vendor survey conducted by Mr. Hartenstein in combination with appropriate information in the B&McD cost analysis. For this effort, EPA hired ERG as consultants.

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43. *See* Enclosure 15. Request for Proposal and Vendor Responses. Portions of this enclosure are subject to a confidential business information claim and will be submitted separately and noted as CBI.

ERG first evaluated the cost factors and methodology used by Minnkota and made a comparison with the cost factors and methodology used in the Control Cost Manual. To cross check the Control Cost Manual results, ERG also compared cost factors and methodology used by Minnkota to those used in Perry's Chemical Engineering Handbook 6th Edition (Perry's). To make these comparisons, ERG used the capital and annual cost tables for shared facilities in Minnkota's December 11, 2009, submittal. For the capital costs, ERG back-calculated the cost factors B&McD used to escalate SCR equipment costs to a final capital cost number. This calculation showed that for the B&McD analysis:

- The cost for auxiliaries/balance of plant is approximately 80% of the SCR costs.
- Capital constructions costs are approximately 50% of capital equipment costs (SCR plus auxiliaries).
- Indirect capital costs are approximately 50% of total capital costs.
- B&McD added another 47% to the capital plus indirect total to account for cost escalation, interest, and owner's costs.

ERG then compared these cost factors with percentages used in the Control Cost Manual, as well as Perry's. The comparison of total capital costs calculated by B&McD and the Control Cost Manual is described in detail above under the capital cost analysis. Perry's uses costs factors that are applied to total equipment costs. These total equipment costs would be considered equivalent to the SCR system cost used by B&McD's methodology. Comparing the B&McD and Perry's cost factors shows:

- Perry's adds 55% to equipment costs for auxiliaries compared to B&McD's value of approximately 80%.
- Total direct costs in Perry's are 2.3 times the SCR system costs while the B&McD total direct costs are about 2.7 times the SCR costs.
- For the indirect line items included in B&McD's cost table, Perry's adds 56% to the direct costs which is similar to Minnkota's value of approximately 50%.
- Perry's does not include the factors B&McD added to the capital plus indirect to account for cost escalation, interest, and owner's costs.

Because B&McD's cost factors are higher than both the Control Cost Manual and Perry's factors, EPA calculated two additional capital cost cases for comparison. Both cases used the same format as in B&McD's estimate, but used the Control Cost Manual and Perry's cost factors, where available. ERG used the 2009 B&McD's SCR costs which were back-calculated from the 2018 costs provided by Minnkota.[44] As can be seen from Table 4 and Figure 1, the capital costs estimated by B&McD for Minnkota are much higher than both the Control Cost Manual and Perry's. The Control Cost Manual and Perry's methods compare favorably.

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[44] EPA strongly disagrees with B&McD assumption that the SCR in this matter will not be installed until 2018.

Table 4. Capital Cost Comparison				
Capital Costs (2009, 1,000$)	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**
Minnkota	$146,753	$254,175	$192,830	$329,150
OAQPS	$91,114	$162,999	$120,629	$212,529
Perry's	$87,613	$147,699	$108,416	$196,954

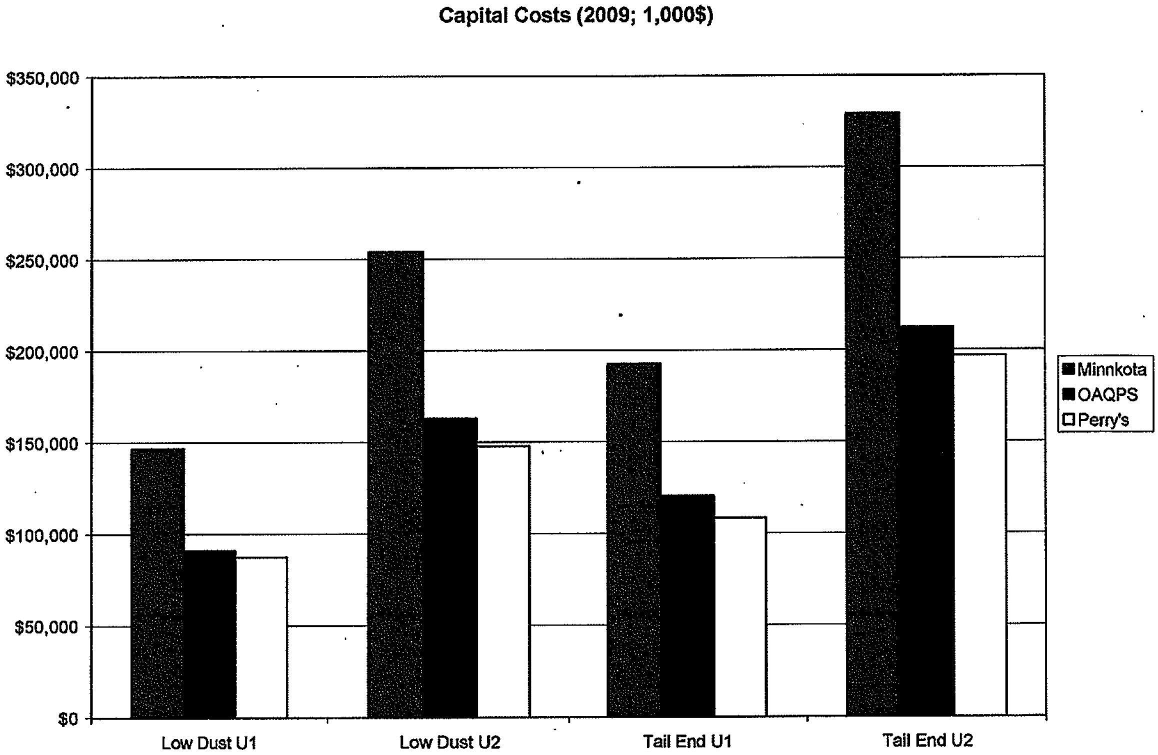

Figure 1: Comparison of Capital Costs Using Different Cost Methods

ERG then performed a new cost analysis that calculated capital and annual costs using the Control Cost Manual methodology and factors where applicable along with B&McD's original SCR equipment costs and other cost data that could not be independently verified by EPA within the time allowed (auxiliaries/balance of plant, construction costs, natural gas pipeline, reagent costs, natural gas costs), supplemented with other cost data and assumptions provided by EPA. While EPA could not independently verify many of these costs, they were included to produce an estimate that may overestimate actual costs, but is conservative in a manner favorable to Minnkota. EPA provided ERG with different information regarding catalyst volume, catalyst cost, catalyst replacement frequency, and estimated additional outage time for replacing spent catalyst. A conservative value for catalyst cost of $6,000 per cubic meter was used. As noted above, this cost could be significantly reduced if regenerated catalyst was used. Contingencies were calculated using the Control Cost Manual assumptions. The maintenance costs were adjusted using the cost factor in the Control Cost Manual and annual costs were not "levelized" as done in the B&McD analysis.

ERG used the above information and calculated annual costs. ERG calculated four different catalyst replacement scenarios. Scenarios 1 through 3 assume catalyst replacement of one layer per year, one layer every two years, and one layer every three years. EPA believes Scenario 3 is the most appropriate, as it reflects the performance guarantees provided by three catalyst vendors in response to Mr. Hartenstein's RFP and the proposals provided to Minnkota by one vendor. No calculations were made for the "Scenario B" assumptions used by B&McD because, as EPA has stated previously and is well-documented in Mr. Hartenstein's expert report, these assumptions are unsubstantiated and arbitrary. ERG's Scenarios 1-3 do not include downtime for ASOFA because this has not been justified by Minnkota. Scenario 4 was run as the "worst-case" scenario and assumes all of the additional outage time is based on the additional outage times estimated for ASOFA provided by B&McD. There would be no additional unit outage time (and associated electricity costs) for catalyst replacement, because all of this work could be completed within the time allocated for ASOFA maintenance. As noted above, EPA does not necessarily concur that these additional outage times for ASOFA are legitimate and believes they should be justified by Minnkota. ERG modified the amount of time required for each catalyst layer replacement from B&McD's assumptions, recalculated the unit availability using the revised downtime, and recalculated electricity costs and corresponding NO_X emissions using the new availability. Table 5 shows the costs for each scenario. The annual costs in this table include the annual costs associated with capital recovery.

Table 5. Annual Cost Comparison

Annual Costs (2009, 1,000$)	Low Dust U1	Low Dust U2	Tail End U1	Tail End U2
Minnkota - Scenario A	$36,923	$63,162	$43,290	$73,245
Minnkota - Scenario B	$49,829	$95,310	$56,098	$106,022
OAQPS - Scenario 1	$19,753	$34,114	$23,016	$39,345
OAQPS - Scenario 2	$18,714	$30,837	$21,768	$36,464
OAQPS - Scenario 3	$18,081	$30,524	$21,660	$36,287
OAQPS - Scenario 4	$20,449	$33,370	$23,708	$38,598

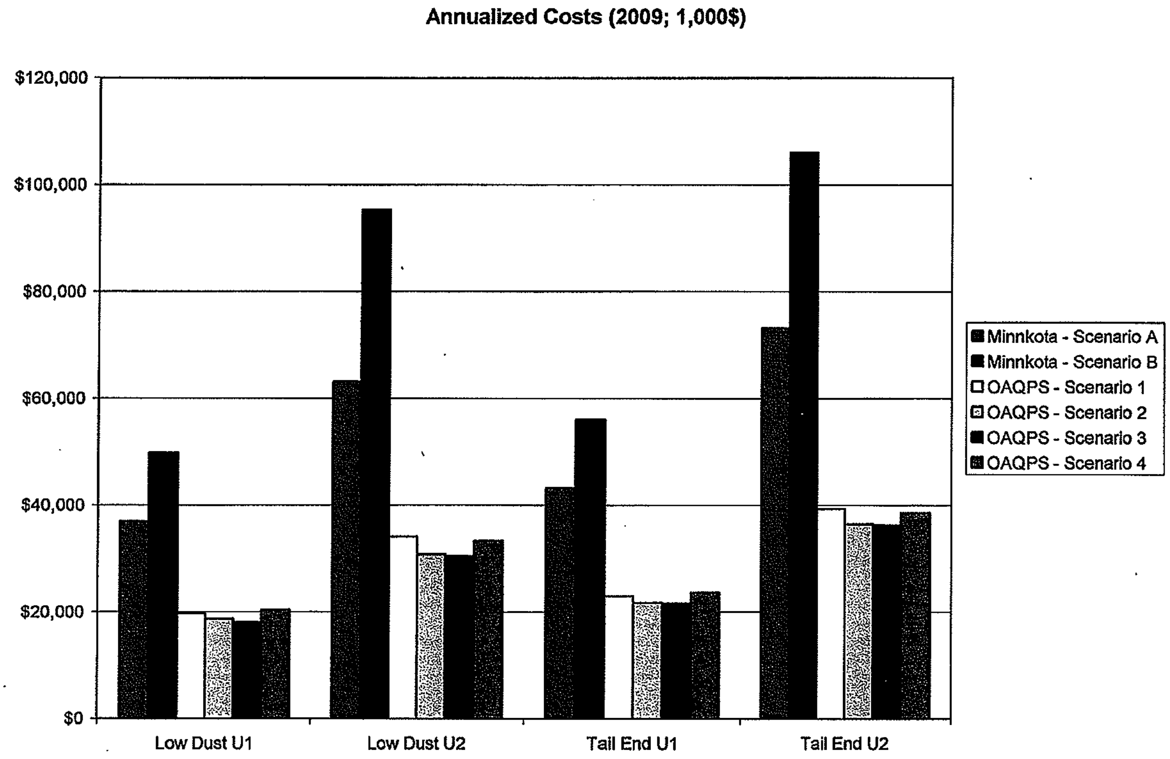

Figure 2: Comparison of Annual Costs Using Different Cost Methods

Table 6 shows the costs in dollars per ton of NO_X removed in both 2009 and 2006 dollars. North Dakota averaged B&McD's Scenario A and B in their summary, which is also shown on the table. As can be seen from the table, when the Control Cost Manual cost factors are used in conjunction with baseline cost information provided by B&McD, supplemented with more reasonable cost data and assumptions on certain cost data, the cost-effectiveness is less than half of the "average" value of the two B&McD scenarios used by NDDH, even under the assumption that a layer of catalyst is replaced is every year (Control Cost Manual Scenario 1). This assumption is three times higher than the catalyst exchange rate that was provided in proposals from one catalyst vendor to Minnkota and performance guarantees provided to Mr. Hartenstein from three catalyst vendors. ERG's analysis is attached.[45]

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[45] *See* Enclosure 16.

Table 6. Cost Comparison Dollar per Ton Removed				
2009 Dollars (1,000$)				
Annual Costs	**Low Dust U1**	**Low Dust U2**	**Tail End U1**	**Tail End U2**
Minnkota - Scenario A	$3,950	$4,250	$4,632	$4,930
Minnkota - Scenario B	$5,300	$6,362	$5,969	$7,078
North Dakota	$4,625	$5,306	$5,301	$6,004
OAQPS - Scenario 1	$2,120	$2,301	$2,464	$2,654
OAQPS - Scenario 2	$2,010	$2,081	$2,332	$2,461
OAQPS - Scenario 3	$1,942	$2,061	$2,321	$2,451
OAQPS - Scenario 4	$2,194	$2,188	$2,537	$2,531
2006 Dollars (1,000$)				
Minnkota - Scenario A	$3,586	$3,859	$4,206	$4,476
Minnkota - Scenario B	$4,813	$5,777	$5,420	$6,426
North Dakota	$4,200	$4,818	$4,813	$5,451
OAQPS - Scenario 1	$1,925	$2,089	$2,238	$2,410
OAQPS - Scenario 2	$1,825	$1,890	$2,117	$2,235
OAQPS - Scenario 3	$1,764	$1,872	$2,108	$2,225
OAQPS - Scenario 4	$1,992	$1,987	$2,304	$2,298

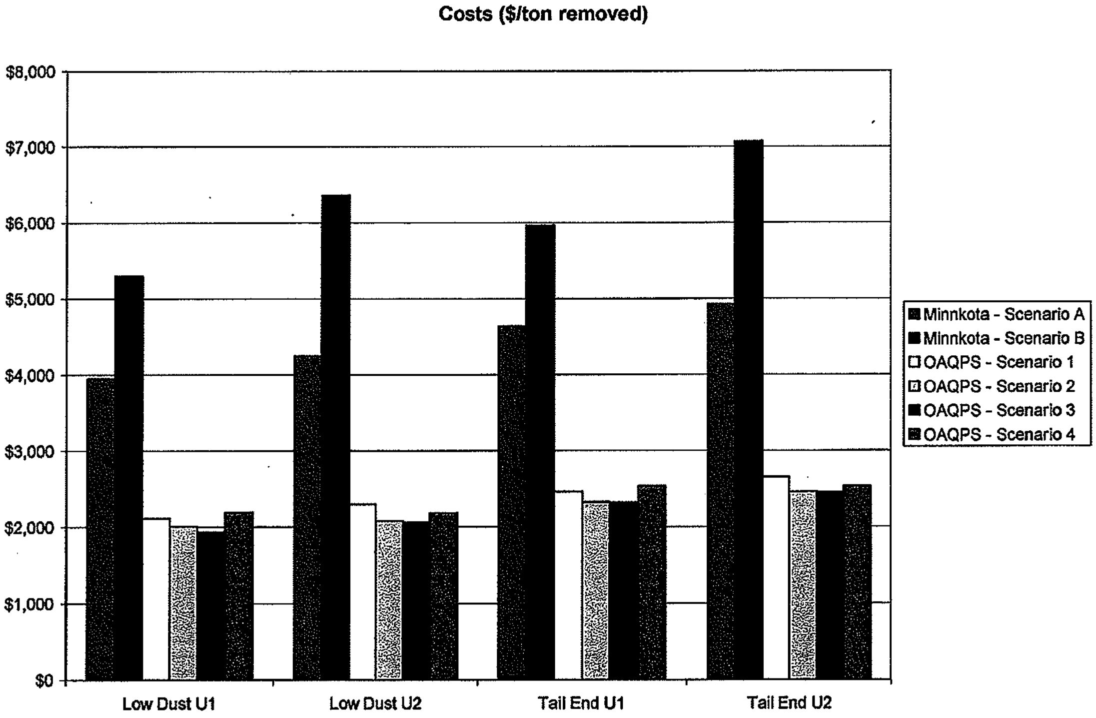

Figure 2: Comparison of Cost-Effectiveness Using Different Cost Methods

III. Conclusions

EPA requests that NDDH reconsider its preliminary BACT determination and find that SCR represents BACT controls at MRYS. Since SCR has been successfully applied worldwide to such a wide variety of sources, there is a presumption that it is both technically and economically feasible at MRYS. Minnkota failed to produce sufficient evidence to overcome this presumption. Although NDDH identified some adverse energy and environmental impacts associated with the use of SCR, it correctly concluded that these impacts would not preclude the selection of SCR as BACT.

As more fully set forth above, Minnkota's cost estimates were not conducted in accordance with the NSR Manual and the Control Cost Manual, and resulted in grossly overestimated SCR costs. NDDH relied upon Minnkota's faulty cost estimates to conclude that the cost effectiveness of LDSCR at MRYS was $4,201 per ton for Unit 1 and $4,822 per ton for Unit 2. Even these inflated and unreasonable cost estimates must result in a conclusion that LDSCR is cost effective at MRYS. It is clear that many other sources have borne costs that are more than this.

NDDH is required to base its BACT determination on cost estimates that are consistent with the NSR Manual and the Control Cost Manual. If Minnkota had followed the applicable methodology, it would have resulted in a determination that the cost effectiveness of SCR at MRYS was about $2,000 per ton. For the reasons set forth above, NDDH should reject Minnkota's cost analysis and base its BACT determination on the application of the NSR Manual and the Control Cost Manual. An objective review of these results would show that SCR is cost effective.

If you would like to discuss any of these matters, please call Cynthia Reynolds at (303) 312-62006 or Brenda Morris at (303) 312-6891.

Sincerely,

Andrew M. Gaydosh
Assistant Regional Administrator
Office of Enforcement, Compliance and
Environmental Justice

Enclosures

cc: David Glatt, NDDH (w/o Enclosures),
Dean Haas, NDDH (w/o Enclosures),
Jerry MacLaughlin, USDOJ (w/o Enclosures),
Jeff Kodish, OECA, (w/o Enclosures),
Brenda Morris, EPA (w/o Enclosures),
Hans Buenning, EPA

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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MAY 2010
Received
Air Quality

May 11, 2010

Ref: 8ENF-L

Via US Mail & Email
Mr. John Cochran
CERAM Environmental, Inc.
7304 W. 130th Street, Suite 140
Overland park, Kansas 66213

Re: CERAM's Confidential Business Information (CBI)
Claim Regarding Proposal No. NR090911-2

Dear Mr. Cochran:

The United States Environmental Protection Agency (EPA) has submitted its comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination). EPA's comments on NDDH's Draft BACT Determination refer to information in enclosures 13 and 15 subject to CERAM's confidential business information (CBI) claim regarding CERAM Proposal No. NR090911-2. EPA previously obtained written approval to submit the CBI to NDDH. EPA has maintained the CBI designation and transmitted that information in accordance with the federal policies regarding CBI. EPA has not reviewed this information to ascertain if it is CBI, and is not taking a position as to whether or not such a claim is valid. NDDH has a process for handling CBI which can be found at NDAC 33-15-01-16. Should EPA receive a request for this information at a later date, EPA will follow its federal CBI process.

Sincerely,

Brenda L. Morris

Brenda L. Morris, Attorney
U.S. EPA Region 8
Tel: 303-312-6891
morris.brenda@epa.go

cc: Terry O'Clair, NDDH
Jerry MacLaughlin, DOJ
Jeff Kodish, EPA, OECA
Hans Buenning, EPA, ENF-AT

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DENVER, CO 80202-2466
Phone 800-227-8917
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May 11, 2010

Ref: 8ENF-L

Via US Mail & Email
Wayne S. Jones
Haldor Topsoe, Inc.
17629 El Camino Real
Houston, TX 77058

Re: Haldor Topsoe's Confidential Business Information
(CBI) Claim regarding Quotation No. 09-6362

Dear Mr.Jones:

The United States Environmental Protection Agency (EPA) has submitted its comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination). EPA's comments on NDDH's Draft BACT Determination refer to information in enclosures 13 and 15 subject to Haldor Topsoe's confidential business information (CBI) claim regarding Haldor Topsoe's Quotation No. 09-6362. EPA previously obtained written approval to submit the CBI to NDDH. EPA has maintained the CBI designation and transmitted that information in accordance with the federal policies regarding CBI. EPA has not reviewed this information to ascertain if it is CBI, and is not taking a position as to whether or not such a claim is valid. NDDH has a process for handling CBI which can be found at NDAC 33-15-01-16. Should EPA receive a request for this information at a later date, EPA will follow its federal CBI process.

Sincerely,
Brenda L Morris
Brenda L. Morris, Attorney
U.S. EPA Region 8
Tel: 303-312-6891
morris.brenda@epa.go

cc: Terry O'Clair, NDDH
Jerry MacLaughlin, DOJ
Jeff Kodish, EPA, OECA
Hans Buenning, EPA, ENF-AT

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May 11, 2010

Ref: 8ENF-L

Via US Mail & Email
Ken Jeffers
Johnson Matthey Catalysts LLC
1121 Alderman Drive, Suite 204
Alpharetta, GA 30005

Re: Johnson Matthey's Confidential Business Information (CBI) Claim regarding Proposal 71779

Dear Mr. Jeffers:

The United States Environmental Protection Agency (EPA) has submitted its comments on the North Dakota Department of Health's (NDDH's) April 2010, Draft Best Available Control Technology (BACT) Determination for Nitrogen Oxides (NO_x) for Milton R. Young Station (MRYS), Units 1 and 2 (Draft BACT Determination). EPA's comments on NDDH's Draft BACT Determination refer to information in enclosures 13 and 15 subject to Johnson Matthey's confidential business information (CBI) claim regarding Johnson Matthey's Proposal No. 71779. EPA previously obtained written approval to submit the CBI to NDDH. EPA has maintained the CBI designation and transmitted that information in accordance with the federal policies regarding CBI. EPA has not reviewed this information to ascertain if it is CBI, and is not taking a position as to whether or not such a claim is valid. NDDH has a process for handling CBI which can be found at NDAC 33-15-01-16. Should EPA receive a request for this information at a later date, EPA will follow its federal CBI process.

Sincerely,

Brenda L. Morris, Attorney
U.S. EPA Region 8
Tel: 303-312-6891
morris.brenda@epa.go

cc: Terry O'Clair, NDDH
Jerry MacLaughlin, DOJ
Jeff Kodish, EPA, OECA
Hans Buenning, EPA, ENF-AT

National Parks Conservation Association®
Protecting Our National Parks for Future Generations®

May 10, 2010

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

RE: Comments on the April 2010 Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2

Dear Mr. O'Clair:

On behalf of the National Parks Conservation Association, Dakota Resource Council, Friends of the Boundary Waters Canoe Area Wilderness, Minnesota Center for Environmental Advocacy, Plains Justice, Sierra Club, and Voyageurs National Park Association, we respectfully submit the following comments on the April 2010 Preliminary Best Available Control Technology (BACT) Determination for Control of Nitrogen Oxides (NOx) for Minnkota Power Cooperative's Milton R. Young Station (MR Young) Units 1 and 2. We additionally attach and incorporate by reference comments on the June 2008 Preliminary BACT Determination and the draft Regional Haze Rule.[1]

The North Dakota Department of Health (NDDH)'s BACT determination incorrectly dismisses Selective Catalytic Reduction (SCR), the most cost effective, technically feasible control technology capable of reducing NOx emissions by 90% or better. By overestimating costs and misrepresenting technical capability, NDDH incorrectly dismisses SCR as BACT. Therefore, NDDH is proposing legally deficient NOx BACT emission limits for the two units at MR Young. In light of the flawed BACT determination and impacts of MR Young's NOx emissions on air quality, visibility, public lands and public health, we urge NDDH to appropriately revise its BACT analysis and accordingly require SCR as BACT for both MR Young units.

MR Young, located near Center, North Dakota, consists of two cyclone boilers firing lignite from the adjacent Center Mine. Unit 1 is owned by Minnkota Power Cooperative (Minnkota) and

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[1] Comments of Plains Justice and Sierra Club on the June 2008 Preliminary BACT Determination for Control of Nitrogen Oxides at the Milton R. Young Station, July 30, 2008 [hereinafter " Plains Justice Comments]; Comments of National Parks Conservation Association et. al. on North Dakota's Regional Haze State Implementation Plan, January 8, 2010.

is 257 MW. Unit 2 is owned by Square Butte Electric Cooperative (Square Butte) and has a rating of 744 MW. Minnkota operates both units.[2]

In April 2006, the United States and the State of North Dakota filed a complaint for injunctive relief and civil penalties pursuant to sections 113(b)(2) and 167 of the Clean Air Act (CAA). 42 U.S.C. §§ 7413(b)(2) and 7477. The Complaint alleged Minnkota and Square Butte violated the Prevention of Significant Deterioration (PSD) provisions of CAA, as well as North Dakota's State Implementation Plan by undertaking construction of a major emitting facility without undergoing PSD review. Because of the complaint, the U.S. District Court of North Dakota ordered a Consent Decree for Civil Action No. 1:06-CV-034. The Consent Decree required Minnkota to install and operate control technology for the emission of NO_x.[3] The Decree sets out a two-step process for limiting NO_x emissions.

Phase 1 requires both units to "install and commence continuous operation of Over-fire Air" or a technology equivalent that will achieve a NO_x rate of no more than 0.36 lb/MMBtu based on a 30-day rolling average. Minnkota had until December 31, 2009 to install Over-fire Air at both units. Phase 2 requires Minnkota and Square Butte to perform BACT analyses for their respective boilers. The analyses must follow the BACT Top-Down approach that is laid out in the "New Source Review Workshop Manual—Prevention of Significant Deterioration and Nonattainment Area Permitting" (Draft October 1990) (NSR Manual), and must include any additional information requested by the Environmental Protection Agency (EPA) and NDDH. Additionally, the BACT analyses must "include an evaluation of Selective Catalytic Reduction, Selective Non-Catalytic Reduction, Over-fire Air, and Rich Reagent Injection, as well as other NO_x control technologies." Under Phase 2, NDDH must review the BACT analyses and make a BACT determination, which must include specific control technologies to be installed and a specific 30-day rolling average NO_x emission limitation for each unit.[4]

In accordance with the Consent Decree, Minnkota and Square Butte submitted BACT analyses and NDDH made its draft BACT Determination. In June 2008, NDDH preliminarily determined the BACT limit for Unit 1 is 0.36 lb/MMBtu, except during startup or shutdown, when the limit shall not exceed 2070.2 lb/hr on a 24-hour rolling average basis. For Unit 2, the proposed limit is 0.35 lb/MMBtu, with startup/shutdown period not to exceed 3995.6 lb/hr on a 24-hour basis. The proposed control technology for both units is Selective Noncatalytic Reduction (SNCR) operated in conjunction with Advanced Separated Over-fire Air (ASOFA). The April 2010 BACT Determination supplements and reaffirms the above conclusions of the June 2008 Preliminary BACT Determination.

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[2] June 2008 Preliminary BACT Determination, p. 1.

[3] The Consent Decree also requires the installation and operation of control technology for the emission of sulfur dioxide and particulate matter.

[4] Consent Decree, at 19, 20.

NDDH subsequently reexamined the technical feasibility of three versions of SCR: high-dust SCR (HDSCR), low-dust SCR (LDSCR), and tail-end SCR (TESCR). Upon reconsideration, NDDH found LDSCR and TESCR to be technically feasible, and requested additional information and a revised BACT analysis from Minnkota.[5]

While we agree that LDSCR and TESCR are technically feasible, we disagree with the determination that HDSCR is technically infeasible for MR Young. As described in previous comments, HDSCR is technically feasible, and should be considered in the BACT analysis along with several other controls which were not evaluated or incorrectly evaluated.[6] To the extent that other issues with the BACT Determination remain the same, we reiterate and specifically incorporate the Plains Justice comments.

Further, in reviewing this BACT Determination, we note that the proposed BACT limits of 0.35 and 0.36 lb/MMBtu are over three times above the New Source Performance Standards of 0.11 lb/MMBtu, as revised in 2008. The revised NSPS do not appear to have been considered in this BACT Determination, and we would like a response as to why the state considers the higher proposed limits acceptable.

The NOx BACT analysis for MR Young must be considered in the context of the far-reaching impacts of the facility's NOx emissions on air quality, visibility, public lands and public health under step five of the top-down approach.

North Dakota's recently submitted regional haze state implementation plan (SIP) identified several Class I areas impacted by emissions from facilities in North Dakota, including MR Young. There are two Class I areas in North Dakota—Theodore Roosevelt National Park and Lostwood National Wildlife Refuge Wilderness Area – which are affected by NOx emissions from MR Young. Other Class I areas impacted by North Dakota sources of air pollution include: Badlands National Park and Wind Cave National Park in South Dakota, Medicine Lake National Wildlife Refuge Wilderness Area and U.L. Bend National Wildlife Refuge Wilderness Area in Montana, Boundary Waters Canoe Area Wilderness Area and Voyageurs National Park in Minnesota, and Isle Royale National Park and Seney National Wildlife Refuge Wilderness Area in Michigan.

These Class I areas preserve the region's inspiring landscapes, rare geologic formations, breathtaking water country, and diverse wildlife and vegetation. They also serve as living museums of our nation's history. Visitors from across the nation and globe are drawn to these lands and their tourist dollars benefit state and local economies.

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[5] April 2010 BACT Determination, at 3.

[6] Comments of Plains Justice and Sierra Club on the June 2008 Preliminary BACT Determination for Control of Nitrogen Oxides at the Milton R. Young Station, July 30, 2008; Comments of National Parks Conservation Association et. al. on North Dakota's Regional Haze State Implementation Plan, January 8, 2010.

National parks and wilderness areas are of great natural and cultural value and also engines for sustainable local capital. For example, in 2008, National Park Service units received over 274 million visits accounting for over $2.5 billion in revenue.[7] National parks support $13.3 billion of local private-sector economic activity and 267,000 private-sector jobs.[8] They also attract businesses and individuals to the local area, resulting in economic growth in areas near parks that is an average of 1 percent per year greater than statewide rates over the past three decades.[9] National parks also generate more than four dollars in value to the public for every tax dollar invested.[10] Of the number of annual park visitors in 2008, approximately 516,804 people journeyed to Theodore Roosevelt National Park spending nearly half a million dollars. The same year 845,734 people visited Badlands National Park; 573,433 visited Wind Cave National Park; 221,585 visited Voyageurs National Park and 14,038 visited Isle Royale National Park.[11]

Excessive NOx emissions from MR Young and other North Dakota facilities not only obscure the region's scenic vistas, but also contribute to a host of public health problems as well as adverse impacts to wildlife and vegetation. For example, NO_x is a precursor to ground level ozone, or smog, which is associated with respiratory diseases, asthma attacks, and decreased lung function.[12] Beyond these direct health impacts, associated hospital admissions, decreased productivity, and lost school and work days have significant economic costs.

Maximizing reductions in NOx emissions from MR Young would not only help protect and restore treasured landscapes and the economies that rely on them, but also benefit public health. It is in this context that we offer the comments below for consideration by NDDH and encourage the Department to require SCR, the most efficient control technology, as BACT at MR Young.

With an estimated reduction efficiency of 93.8%, SCR is by far the top control technology for the MR Young facility and other like sources. The top control technology is assumed to be BACT unless significant adverse energy, environmental, or economic impacts will occur with its use. The analysis must provide a "comprehensive demonstration, based on objective factors, that the technology is inappropriate in the specific circumstance," if a technology is to be dismissed.[13] Such a comprehensive demonstration has not been provided.

Here, the BACT Determination cites two main reasons for erroneously concluding that LDSCR and TESCR are not BACT: (1) outstanding technical questions and (2) high cost effectiveness

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[7] *See* http://www.census.gov/compendia/statab/2010/tables/10s1215.pdf.

[8] Hardner and Gullison, "The U.S. National Park System, An Economic Asset at Risk" (November 2006) [prepared for the National Parks Conservation Association].

[9] Id.

[10] Id.

[11] *See* http://www.nature.nps.gov/stats/index.cfm.

[12] 70 Fed. Reg. 25162, 25169 (May 12, 2005).

[13] 1990 NSR manual, p. 120.

and incremental cost. These issues are overstated, and none preclude the application of SCR as BACT at MR Young. Collectively they do not justify a decision that SCR is not BACT. Rather, in light of all factors considered in a full BACT analysis, SCR is the appropriate choice as BACT for the MR Young facility.

1. NDDH's Technical Feasibility Analysis is Legally and Technically Deficient

NDDH maintains concerns about the technical implementation of LDSCR and TESCR, mainly as a result of the refusal of two catalyst vendors to provide catalyst life guarantees without pilot scale testing. These concerns are not a sufficient basis upon which to reject SCR as BACT.

SCR, including LDSCR and TESCR, is an available, established technology. It is in use at hundreds of coal-fired boilers, including cyclone furnaces, across the country and worldwide. It is used at facilities burning coals (including lignite), biomass, and wastes, as well as cement kilns and other sources with a variety of gas stream characteristics. While it has never been specifically applied to a facility using North Dakota lignite, no valid technical or other constraints make its installation technically infeasible. Rather, analysis reveals that its application is technically feasible and the most effective control option as detailed below.

Testing of the gas stream at MR Young has indicated high levels of sodium and potassium. In particular, one catalyst vendor, CERAM, stated that they were unaware of any SCR application with the level and form of sodium in the ash at MR Young. NDDH argues that this variation in the gas stream makes MR Young a "totally new and dissimilar source type" as described by the NSR Manual. This logic is erroneous. As noted by US EPA in comments on the June 2008 Preliminary BACT Determination, a difference in the gas stream characteristics does not by itself imply that that difference is significant enough to impact the successful operation of the control technology.[14] The variation in gas stream characteristics at MR Young is well within the wide variability already found in the universe of sources which have successfully adapted SCR to their site-specific parameters, making it similar to these facilities and therefore not preclusive of successful application of SCR technology.

The remainder of the section of the NSR manual cited by NDDH belies the intention to prevent unreasonable research burdens, not to prevent reasonable application of a well known technology to a similar but not identical situation:

> "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 <u>extended time delays or resource penalties</u> to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience <u>extended trials to learn how to apply a technology to a totally new and</u>

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[14] p. 6.

> dissimilar source type. Consequently, technologies in the pilot-scale testing states of development would not be considered available for BACT review." [emphasis added]

In this instance, vendors have refused to offer guarantees of catalyst life without pilot testing at the MR Young facility. This does not mean, as posited by NDDH, that SCR is in the pilot-scale testing stage. Again, as addressed by US EPA in earlier comments, the question of pilot-scale testing pertains to the availability of a control technology, not its applicability, and SCR is plainly available.[15] The pilot-scale testing here would not require "extended time delays or resource penalties." Pilot-scale testing in this case is a means to optimize SCR design to a specific situation prior to more expensive full-scale installation.

The NSR manual elsewhere specifically addresses the lack of vendor guarantees, noting that "lack of a vendor guarantee by itself does not present sufficient justification that a control option or an emissions limit is technically infeasible."[16]

The principle of technology transfer, as outlined in the NSR manual, assumes some appropriate level of risk for transfer of a technology to a similar but not identical situation. With the extensive track record of successful adaptation of the various types of SCR to a wide variety of combustion sources and fuels, the risk inherent in applying SCR at MR Young is well within the bounds of that contemplated by the BACT process. To dismiss SCR on these grounds would, in fact, be contrary to the technology-forcing function of the BACT process that was intended by Congress.[17]

2. NDDH Fails to Accurately Calculate Cost Effectiveness of SCR

NDDH also argues that SCR is not BACT on the basis of cost, both total and incremental. This argument is flawed because the cost calculations are unclear, overestimated, and inappropriately compared only to regionally-limited BART determinations rather than generally accepted BACT cost effectiveness thresholds and prior BACT determinations.

The site specific cost estimates developed for MR Young generally lack sufficient detail to determine whether the claimed costs are supported. The cost calculations do not rely on the standard EPA Control Cost Manual, instead relying primarily on vendor quotes that are not available. Even the most detailed breakdowns of these costs provided in the BACT Determination and related material do not provide critical information about how the values were obtained.[18]

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[15] p. 10 – 14.

[16] B.20.

[17] See discussion in comments by US EPA on the June 2008 Preliminary BACT Determination, p. 14.

[18] See April 2010 BACT Determination Appendix B, Enclosure A, Attachment 1; Minnkota Responses to NDDH Request, NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2, Regarding SCR Feasibility, December 11, 2009 as revised February 2011, Attachment 1; NOx Best Available Control Technology Analysis

While we disagree with the aspects of the cost analysis that are discernable, as discussed below, should NDDH opt to move forward based on these estimates, we request comprehensive and detailed material upon which the cost estimates rely be made available for public review, and an additional 30-day public comment period from the date the additional material is made accessible.

Costs of SCR Are Overestimated

Despite the lack of clarity and documentation of cost estimates, it is clear that some of the relied on costs are overestimated. The capital costs for a retrofit of SCR at MR Young, as reported on a $/kW basis, are significantly higher than those found by several studies of SCR installations. Those reports found a range of installed costs between $83 – 300/kW, the highest of which were highly complex retrofits with severe space constraints.[19] Of particular note is Wisconsin Electric's estimated cost to retrofit a cold-side SCR on Oak Creek Units 5-8. The estimated cost of $168/kW[20] was certified in July 2008 for construction by the Wisconsin Public Services Commission.[21] These are all significantly lower than the estimated cost of $543 – 706/kW for SCR installation at MR Young.[22] Even considering the slightly higher costs associated with the use of a cold-side SCR, the costs for MR Young are excessive and without basis. It is thus clear that costs have been overestimated, likely the result of numerous factors. Several of the issues contributing to excessive costs are documented below.

Annual Capital Costs

Total capital investment or TCI includes all costs required to purchase equipment needed for a control system, the costs of labor and materials for installing the equipment, costs for site preparation and buildings, and certain other indirect installation costs.[23] Cost effectiveness is determined by converting the total capital investment into an annual cash flow (annual capital costs), adding annual operating and maintenance costs, and dividing by the tons of pollution removed. This process results in an estimate of cost effectiveness expressed in dollars per ton.

Study – Supplemental Report, as revised February 2010, prepared by Burns & McDonnell Engineering Company, Inc. for Minnkota Power.

[19] See discussion on p. 16 – 18 of Comments on EPA's Advanced Notice of Proposed Rulemaking regarding Best Available Retrofit Technology (BART) for the Navajo Generating Station and the Four Corners Power Plant [EPA-R09-OAR-2009-0598] submitted by the Center for Biological Diversity et. al. October 28, 2009.

[20] Wisconsin Electric Power Company's Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Appendix C, Emission Reduction Study, Volume 1, Addendum August 20, 2007. Unit cost = ($190,500,000/1,135,000 kW) = $168 kW, in 2006$

[21] 70 Certificate and Order, Application to Install Wet Flue Gas Desulfurization and Selective Catalytic Reduction Facilities and Associated Equipment on Oak Creek Power Plant Units 5, 6, 7 & 8 for Control of Sulfur Dioxide and Nitrogen Oxide Emissions, Case 6630-CE-299, July 10, 2008.

[22] NOx Best Available Control Technology Analysis Study – Supplemental Report, as revised February 2010, p. 4-11, prepared by Burns & McDonnell Engineering Company, Inc. for Minnkota Power.

[23] Control Cost Manual, pp. 2-5 to 2-10.

The total capital investment is converted into annual costs by multiplying by a capital recovery factor or CRF. The CRF is given by:

$CRF = [\ i(1+i)^n]/[(1+i)^n - 1\ ]$

where i is the interest rate and n is the life of the pollution control equipment. In essence, annualization establishes an annual payment sufficient to finance the capital investment for its entire life.[24]

The CRF depends on two factors, the interest rate and lifetime of the control system. The lower the lifetime, the higher the CRF and the higher the ratio of annual to total capital costs. NDDH underestimated the equipment lifetime, thus substantially overestimating the CRF and annual capital costs.

Equipment Lifetime

A lifetime of 20 years was assumed for the SCR. The default lifetime for SCR used in EPA's CUE Cost Manual is 30 years. A 30+ year service life is consistent with actual experience with existing SCRs and with the nature of the equipment.

An SCR system should last as long as the plant it is installed on. It is a stationary device whose major components have no moving parts and which uses few pieces of rotating equipment, e.g., pumps. It consists of ducting, a metal frame that is filled with blocks of catalyst, an ammonia delivery system (tank, pumps, piping), a control system, and instrumentation. The ducting and metal frame are similar to the balance of the plant and should last as long as the plant itself with proper maintenance. The ammonia injection system, accounting for a tiny fraction of the overall cost, should also last as long as the plant if wearable parts are replaced as part of routine maintenance. Thus, on a new facility, it would be expected to last 50+ years, or the life of the plant.

Vendor experience lists identify a number of SCR units that were installed more than 30 years ago in Japan that are still in service.[25] In the United Stated, Mitsubishi, for example, installed three SCR systems on process heaters at the Chevron Richmond Refinery in California in 1984. These units are still in service. There have been no maintenance, operational or compliance problems, and the original catalyst has not been changed out. These SCRs currently have a demonstrated life of 25 years with expectation for many more.

Further, the equipment life for an SCR based on a financial risk study conducted by Stephen Unwin, *et al.* for SCRs installed at the Monroe Power Plant outside of Detroit concluded a 30-

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[24] Control Cost Manual, January 2002, Section 1, p. 2-21.

[25] McIlvaine Company, Worldwide Utility Plans, NOx Installation and Component Suppliers (Ex. 12); Vendor Experience Lists for Hitachi and Mitsubishi.

year life was reasonable. This study was designed to examine the economic risks from operating SCR at this plant, including siting characteristics and operating/maintenance strategy and their effect on SCR system lifetime. The authors' choice of a 30-year life for the SCR system is an important parameter in their study.[26]

On retrofits, such as these, SCR would be expected to last for the remaining useful life of the plant. Minnkota's cost analysis assumes only 20 years as the service life of the SCR. However, clearly, it could be much longer. The record does not disclose the remaining useful life of the MR Young units or the basis for selecting only 20 years when expected SCR life is plainly longer and SCRs in operation today have been in service for longer times.

The capital recovery factor for the BACT Determination's assumptions (i=6%, n = 20 yrs) is 0.08718. The capital recovery factor assuming 30 years, is 0.07265 or 83% that relied upon by the BACT Determination.

Maintenance Labor and Materials

The underlying materials for the BACT Determination estimated costs for maintenance labor and materials as 3% of installed capital costs.[27] The Control Cost Manual indicates these costs should be calculated as 1.5% of the total capital investment. Thus, these costs are overestimated by a factor of two.

Levelization Factor and Escalation

The annual operating and maintenance costs were increased by multiplying them by a "levelization factor" of 1.24873. Levelization escalates costs. The constant levelization factor is generally used to express the relationship between the value of an expenditure at the beginning of the first year and an equivalent annuity, or levelized value. It depends on both the annual cost of money or the discount rate and the nominal escalation rate. Escalation costs were also included in the estimates of indirect capital costs.

Cost effectiveness analyses do not include escalation. The total annual cost method used in cost effectiveness analysis, as laid out in the Control Cost Manual, expresses costs in real dollars. Thus, they are based on the "real" interest rate, which does not include inflation.[28] Inflation is not included in BACT cost effectiveness analyses as they rely on the most accurate information

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[26] Unwin, Stephen D., Johnston, Robert W., and Rudy, Steven W. and Delargey, James E. and Rogers, William. "Selective Catalytic Reduction (SCR) System Design and Operations: Quantitative Risk Analysis of Options," presented at CCPS 17th Annual International Conference: Risk, Reliability, and Security. p. 3, available at http://www.unwin-co.com/files%5CSCR-Risk-Paper,CCPS-RRS2002.pdf (last visited 5/10/2010).

[27] NOx Best Available Control Technology Analysis Study – Supplemental Report, as revised February 2010, p. 4-22, prepared by Burns & McDonnell Engineering Company, Inc. for Minnkota Power.

[28] Control Cost Manual, 3rd Edition, February 1987, pp. 2-13 to 2-14.

available at current prices and do not try to extrapolate those prices into the future.[29] Regardless, no basis is provided for the various escalation factors that were used.

Catalyst Replacement Costs

The cost estimates relied on in the BACT Determination used a catalyst replacement cost of $7,500/cubic meter in 2006 dollars. For new catalyst, this cost is more typically between $3,500 and $6,500/cubic meter. Additionally, catalyst replacement cost did not consider catalyst regeneration, which has become an attractive alternative to purchasing new catalyst since the Cost Control Manual was last updated. Catalyst regeneration typically costs about 60% of the cost of new catalyst.[30]

Foundations and Supports

The direct capital costs associated with foundations and supports range from ~$15.1 – 39.6/kW.[31] This is extremely high compared to upper bound costs reported for other retrofits, which range from $9/kW to $11/kW.[32] These costs should be justified in the record.

Indirect Costs

The indirect costs include owner's costs, which are not included in the Control Cost Manual. The Control Cost Manual does include "home office fees." All owners do not manage and implement capital projects, but rather retain engineering firms, called the owner's engineer, to perform these functions. Other owner activities would be part of its overhead. Cost factors used to estimate capital costs are ordinarily reported all in and would include these costs. Further, these costs, if not directly part of the project, are outside of the battery limits of a control project and would be part of the owner's overhead. Thus, they are not usually separately included in cost effectiveness analyses.

In addition to the cost overestimation issues noted above, we raise concerns about the costs associated with electrical equipment and installation, with the claimed revenue lost from SCR installation and maintenance, contingency expenses, and other issues not apparent due to the lack of available information, especially with regard to the capital costs of the SCR system equipment and the auxiliaries/balance of plant.

Cost Effectiveness Comparisons Are Inappropriate

In addition to artificially high cost estimates, NDDH incorrectly compares the cost effectiveness of installing SCR at MR Young to select regional BART analyses. In so doing, NDDH inappropriately narrows the window of cost comparisons by failing to account for the full range of cost effectiveness determinations in a BACT context, and thereby arrives at the erroneous

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[29] See, e.g., Control Cost Manual, 6th Edition, January 2002, Section 1, p. 2-36.

[30] Mike Cooper, New Life for Catalyst, Power Engineering, March 2006.

[31] Based on Minnkota Responses to NDDH Request, NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2, Regarding SCR Feasibility, December 11, 2009 as revised February 2011, Attachment 1, p. 1.

[32] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, p. 25.

conclusion that SCR is not cost effective. In fact, even if the overestimation of costs described above were correct, SCR's cost effectiveness is well within the realm of those established by BACT cost effectiveness thresholds and other BACT determinations.

Cost effectiveness is the economic criterion used to determine whether a given control option has adverse economic impacts compared to controls at similar facilities. Cost, estimated using the total annual cost method, is measured in terms of annualized control costs, and cost effectiveness is measured in annual dollars per ton of pollutant removed.[33] Two cost metrics can be considered: (1) total cost effectiveness and (2) incremental cost effectiveness.

Total cost effectiveness, the metric most commonly used, is calculated by dividing annualized cost by the reduction in emissions, defined as baseline emissions minus controlled emissions.[34] Incremental cost effectiveness compares the costs and emission performance with those of the next most stringent option.[35] Incremental cost effectiveness should not be used to eliminate a top control option as BACT if the total cost effectiveness is acceptable.

BACT is an emission limit based on the maximum degree of reduction that does not cause adverse economic impacts. A technically feasible control option can be eliminated if it results in adverse economic impacts. A technically feasible control option cannot be eliminated simply because its costs are higher than another option. Said another way, BACT is not the control option that minimizes cost, but rather, the control option that maximizes emission reductions without causing adverse economic impacts.

Adverse impacts are defined in terms of "cost effectiveness," which is the annual cost of a control expressed in dollars per ton of pollutant removed. If cost effectiveness is on the same order as the costs deemed to be reasonable for other sources, the control option should initially be considered economically achievable and thus acceptable as BACT. The significance of a given cost effectiveness value is determined relative to the costs borne by sources across the country. Several states have established cost effectiveness thresholds based on pollutant controlled not bound by the emitting source category. Here, applicants rely on a narrow and distortive subset of geographically constricted BART sources where it is required to consider a broader list of factors including relevant non-geographically constrained BACT determinations.

General thresholds for reasonable cost effectiveness have been set in several places. In 2001, U.S. EPA determined that a $10,000/ton control cost ceiling was reasonable for NOx and SO2 in attainment areas, equivalent to over $13,000/ton today.[36] Several air quality districts in

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[33] NSR Manual, Chapter B, Sec. IV.D.2.b.

[34] NSR Manual, p. B.37.

[35] NSR Manual, p. B.41.

[36] See expert report of Matt Haber - EPA, Best Available Control Technologies for the Baldwin Generating Station, Baldwin, Illinois, prepared for the United States in connection with United States v. Illinois Power Company and

California have set cost effectiveness thresholds for NOx, including those set at \$9,700/ton,[37] \$17,000/ton,[38] and \$17,500.[39] The cost effectiveness for the application of SCR at MR Young is below any of these thresholds under any of the scenarios contemplated by the BACT Determination.

BACT determinations have been made for SCR and other technologies well over the costs estimated by NDDH for installation of SCR at MR Young.[40] As part of a BACT determination, the cost effectiveness for SCR at the MR Young facility should be compared to these BACT decisions and thresholds, not to limited select regional BART analyses. Even the high cost estimates in the BACT Determination are well within the range of a reasonable cost effectiveness for a BACT determination.

The BACT Determination also asserts that high incremental cost effectiveness is a reason to dismiss SCR as BACT. As noted above, if the total cost effectiveness is reasonable, as it is here, incremental cost effectiveness should not then be used to discount a top control technology. As described in the NSR Manual,

> "undue focus on incremental cost effectiveness can give an impression that the cost of a control alternative is unreasonably high, when, in fact, the total cost effectiveness, in terms of dollars per total ton removed, is well within the normal range of acceptable BACT costs."[41]

In this instance, SCR is clearly cost effective, even with artificially inflated costs. Furthermore, incremental cost effectiveness would also decrease with more appropriate costing.

Conclusion

The BACT selection process requires selection of the top control technology unless a comprehensive demonstration illustrates that it is inappropriate. For the reasons detailed above, the technical and economic concerns described in the BACT Determination are unfounded and insufficient to constitute a comprehensive demonstration. Thus, as the most effective, feasible

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Dynegy Midwest Generation, Inc., Civil Action 99-883-MJR, in the U.S. District Court for the Southern District of Illinois, April 2002, p. 17; Memorandum of John S. Seitz to Air Division Directors, BACT and LAER for emissions of nitrogen oxides and volatile organic compounds at Tier 2/Gasoline Sulfur Refinery Projects (Jan. 19, 2001), at 3. Costs adjusted using the Chemical Engineering Plant Cost Index (CEPCI).

[37] San Joaquin Valley Unified Air Pollution Control District, Final Staff Report: Update to BACT Cost Effectiveness Thresholds, May 14, 2008.

[38] South Coast Air Quality Management District, Best Available Control Technology Guidelines, Part A: Policy and Procedures, May 21, 1999.

[39] Bay Area Air Quality Management District, BACT/TBACT Workbook: Guidelines for Best Available Control Technology.

[40] See attached examples of cost effectiveness determinations over \$5,800/ton from the RBLC database.

[41] B.45 – 46.

control technology, SCR is BACT. We ask NDDH to revise its BACT analysis to require the use of SCR at MR Young accordingly.

Thank you for the opportunity to comment on the Preliminary NOx BACT Determination for MR Young.

Sincerely,

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IN REPLY REFER TO:

May 10, 2010

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MAY 2010
Received
Air Quality

Terry L. O'Clair, P.E., Director
Division of Air Quality
North Dakota Department of Health
Environmental Health Section
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Dear ~~Mr. O'Clair~~ Terry:

As requested in your recent Public Notice, the National Park Service (NPS) is submitting the enclosed comments regarding the proposed Best Available Control Technology (BACT) determinations for the Milton R. Young Station (MRYS) near Center, North Dakota. MRYS is located within 300 km of two Class I areas, Lostwood National Wildlife Refuge administered by the U.S. Fish & Wildlife Service and Theodore Roosevelt National Park administered by the NPS. Our comments include appendices regarding baseline emissions and costs of adding Selective Catalytic Reduction (SCR) at MRYS. We conclude that SCR is technically and economically feasible at MRYS and should be determined to be BACT for that facility, thereby minimizing the impacts of MRYS at these Class I areas.

We look forward to working with the North Dakota Department of Health and with EPA as this process advances. We believe that good communication and sharing of information will help expedite this process, and suggest that you contact Don Shepherd of my staff (don_shepherd@nps.gov, 303-969-2075) if you have any questions or comments.

Sincerely,

John Bunyak

John Bunyak
Chief, Policy, Planning and Permit Review Branch

Enclosures

cc:
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NPS Comments on NDDH Best Available Control Technology Determination For Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2
May 10, 2010

Background

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

On 17 June 2002, Minnkota received a Notice of Violation (NOV) from EPA stating that Minnkota allegedly violated the Prevention of Significant Deterioration (PSD) regulations. The NOV was issued pursuant to Section 113 of the Clean Air Act. The alleged violation was caused by modifications to both Unit #1 and #2 at MRYS which allegedly resulted in a potential increase of SO_2, NO_X and PM. Without an admission of liability, Minnkota entered into a settlement in the form of a Consent Decree (CD) with the EPA and the North Dakota Department of Health (NDDH) to resolve the issues. The CD requires that Minnkota install a level of control for SO_2, NO_X[1]and PM on both Unit #1 and #2 at MRYS, equivalent to Best Available Control Technology (BACT).[2]

Best Available Control Technology (BACT) Review

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

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

Following are our comments on application of the five steps by Minnkota and NDDH.

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[1] The Consent Decree requires Minnkota and Square Butte to perform a "NO_X Top-Down Best Available Control Technology (BACT) Analysis" to describe the emission limits for NO_X that will be required at Units #1 and #2, expressed as a 30-Day Rolling Average NO_X Emission Rate.

[2] The effect of the CD on the Best Available Retrofit Technology (BART) analysis and the requirement to install BACT-level controls are discussed later in the report.

Step 1 – Identify All Control Technologies
NDDH identified Low-Dust Selective Catalytic Reduction (LDSCR) and Tail-End Selective Catalytic Reduction (TESCR) as technically-feasible options. While we agree with those selections, we believe that NDDH should have considered Regenerative Selective Catalytic Reduction (RSCR) which is currently available from Babcock Power and in operation on large biomass boilers. RSCR has the potential to significantly reduce reheat expenses versus the approach evaluated by NDDH.

Step 2 – Eliminate Technically Infeasible Options
Minnkota rejected the use of steam to reheat the gas stream ahead of either SCR approach on the basis that it would reduce plant output. This is not an issue of technical feasibility—instead, Minnkota and NDDH must evaluate the economic feasibility of steam reheat.

Step 3 – Rank Remaining Control Technologies by Control Effectiveness
NDDH adequately evaluated the effectiveness of both LDSCR and TESCR.

Step 4 – Evaluate Most Effective Controls and Document Results
As discussed in our Appendix A, "NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions," we believe that Minnkota and NDDH have underestimated the amount of NO_X that would be reduced by the SCR options. For example, NDDH has estimated baseline emissions by using historic average emission data instead of upper-bound emission data as directed by the NSR Manual. NDDH compounded this error by comparing its cost-effectiveness results for lower emission rates and utilization to other permits[3] that were based upon assumptions of maximum allowable emissions at 100% utilization. The effect of this approach by NDDH is to bias the cost-effectiveness analysis toward higher values than would have been derived had NDDH used the same approach as was used for the permits it used for comparison.

As discussed in our Appendix B, "NPS Comments on Milton R. Young Station (MRYS) Unit #1 (and Unit #2) Tail-End Selective Catalytic Reduction (TESCR) Costs," we believe that Minnkota and NDDH have overestimated the costs of TESCR. We applied the EPA OAQPS Control Cost Manual (Cost Manual) approach to MRYS to estimate the cost of adding SCRs but did not include any estimates for the associated reheat systems because that information was not made available to us.[4]

Because some method must be applied to reheat the gases leaving the wet scrubber, additional equipment would be required and additional costs would be incurred. However, it was not possible from the information provided to determine how much this additional equipment would cost. Therefore, we compared the estimates presented by Minnkota to the ratios used by the Cost Manual to relate capital and some operating costs, to Total Direct Capital Cost. The Cost Manual

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[3] For example, the analyses and resulting permit limits for WYGEN 3 and Dry Fork permits cited by NDDH were based upon maximum allowable emissions at 100% utilization.

[4] We are requesting information that will allow us to evaluate the costs of each major component and will then be able to apply our SCR-only cost estimates to the SCR-specific costs included in the information we are requesting.

can be applied for estimating annual operating costs and we found several differences between the Cost Manual approach and the Minnkota estimates. For example, Minnkota incorrectly included major costs for "Allowance for Funds During Construction," "Escalation" and "Owner's Costs", and added a "levelization" factor to the "Total Annual Cost", which are not allowed by the Cost Manual. Our estimates for the costs of installing and operating ASOFA plus TESCR with reheat systems are shown in the table below and explained in detail in the enclosures.

Operating company	**Basin Electric Power**	
Facility	**Milton R. Young**	
Unit	#1	#2
Rating (MW Gross)	257	477
Rating (mmBtu/hr)	3,200	6,300
Current Emissions (tpy)	12,054	23,731
Current Emission Rate (lb/mmBtu)	0.86	0.86
ASOFA		
New Emission Rate (lb/mmBtu)	0.513	0.489
New Emissions (tpy)	7,190	13,493
Capital Cost	$4,277,000	$10,008,000
Capital Cost ($/kW)	$17	$21
O&M Cost	$65,776	$159,744
Total Annual Cost	$469,494	$1,104,429
Cost-Effectiveness ($/ton)	$97	$108
TESCR		
Emissions Reduction (tpy)	6,503	12,141
Capital Cost	$180,206,747	$266,981,971
Capital Cost ($/kW)	$701	$560
O&M Cost	$7,383,763	$12,033,720
Total Annual Cost	$24,394,005	$37,234,930
Incremental Cost-Effectiveness ($/ton)	$3,751	$3,067
ASOFA+TESCR		
Control Efficiency	94%	94%
New Emission Rate (lb/mmBtu)	0.049	0.049
New Emissions (tpy)	687	1,352
Emissions Reduction (tpy)	11,367	22,379
Capital Cost	$184,483,747	$276,989,971
Capital Cost ($/kW)	$718	581
O&M Cost	$7,449,539	$12,193,465
Total Annual Cost	$24,863,500	$38,339,358
Average Cost-Effectiveness ($/ton)	$2,187	$1,713

Step 5 – Select BACT

NDDH has correctly noted that BACT determinations are typically based upon comparisons to other BACT determinations for similar sources, and that cost data on SCR determinations are relatively sparse because such cost analyses are seldom conducted for this top level of control. Of the BACT determinations summarized by NDDH in its Table 8, we have sufficient data on only the Dry Fork and WYGEN 3 projects. In those two cases, the Wyoming Department of Environmental Quality (WY DEQ) determined that Average Annual Costs of $1,511/ton and $4,037/ton, respectively, were reasonable for the combinations of combustion controls plus SCR. WY DEQ also determined that Incremental costs of $10,303 and $11,102, respectively, were reasonable for the SCR scenarios.

NDDH has also included cost data on several Best Available Retrofit Technology (BART) determinations.[5] However, because BACT is usually based upon evaluations of control technologies that have been accepted, we believe that NDDH should have primarily considered those BART determinations in which SCR was accepted. Of the sources listed by NDDH in its Table 9, only for PGE Boardman ($3,096/ton), Big Stone #1 ($825/ton), Boswell Energy Center #3 ($3,201/ton), and Healy #1 ($3,374/ton) was SCR determined to represent BART. In addition to those sources, SCR has been determined to be BART at Jim Bridger #3 & #4 ($4,262/ton each) and Naughton #3 ($2,830/ton) in Wyoming.

It can be seen from the data presented by NDDH and by NPS that, for the 12 sources where SCR was selected as BACT or BART, Average Annual Costs ranged from $825/ton - $4,262/ton, and for ten of those 12 SCR determinations, Average Annual Costs equaled or exceeded the Average Annual Costs we estimated for addition of SCR on both units at MRYS. We therefore conclude that, when compared to the costs of those SCRs accepted as BACT or BART, LDSCR and TESCR are economically feasible at MRYS and should be determined to be BACT.

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[5] MRYS Units #1 and #2 were determined to be subject to BART by the NDDH. However, prior to the completion of the BART analysis, Minnkota entered into a Consent Decree (CD) that requires the MRYS to install BACT-level controls for NO_X, SO_2, and PM. Thus, the BART analysis was reduced to an evaluation of the BACT-level control technologies and emission reductions specified by the CD. Because BACT and BART analyses have similar steps, the only remaining step for recommending BART was to perform a visibility impairment impact analysis and discern if there was an acceptable impact reduction. NPS submitted comments to NDDH on BART in October of 2009.

Appendix A. NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions

Minnkota p4-3: 4.1 RANK OF NOX CONTROL OPTIONS BY EFFECTIVENESS
The first step in this supplemental "top-down" BACT evaluation is to determine the expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives, so that they may be compared and ranked relative to the technically-feasible NO_X control techniques and technologies included from the initial NO_X BACT Analysis Study report. To do this, we start with the basis for determining the NO_X emissions control effectiveness, which is the historic baseline emissions expressed in pounds per million Btu of heat input from the five-year lookback period.

NPS: Use of historic baseline emissions is permissible only if they are documented and do not determine the outcome of the analysis/or constraints are enforceable, and provided that the cost-effectiveness is compared to similar sources using similar approaches. According to the NSR Workshop Manual [***emphasis added***]:

"...baseline emissions are essentially uncontrolled emissions, calculated using realistic upper boundary operating assumptions."

"...in developing a realistic upper boundary case, baseline emissions calculations can also consider inherent physical or operational constraints on the source.

Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the ***applicant should submit documentation to verify these constraints***. If the applicant does not adequately verify these constraints, then the reviewing agency should not be compelled to consider these constraints in calculating baseline emissions. In addition, the reviewing agency may require the applicant to calculate cost effectiveness based on values exceeding the upper boundary assumptions to determine whether or not the assumptions have a deciding role in the BACT determination. ***If the assumptions have a deciding role in the BACT determination, the reviewing agency should include enforceable conditions in the permit to assure that the upper bound assumptions are not exceeded.***

In addition, historic upper bound operating data, typical for the source or industry, may be used in defining baseline emissions in evaluating the cost effectiveness of a control option for a specific source. For example, if for a source or industry, historical upper bound operations call for two shifts a day, it is not necessary to assume full time (8760 hours) operation on an annual basis in calculating baseline emissions. ***For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis.***"

MRYS #1 Baseline Emissions

Minnkota p4-4: Unit 1 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12- month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

- MRYS Unit 1's highest 12-month NOX mass emissions averaged 0.849 lb/mmBtu at a corresponding average unit heat input rate of 2,744 mmBtu/hr and unit gross electrical output of 244.5 MWg.
- During this lookback time period, Unit 1 at Milton R. Young Station was typically operated in a base-loaded manner.

NPS: **MRYS #1's highest annual NO_X mass emissions averaged 0.866 lb/mmBtu in 1995 and 0.843 in 2004.** MRYS #1's highest annual average unit heat input rate of 2,761 mmBtu/hr occurred in 2003. MRYS #1's highest annual availability of 97% occurred in 2001 and again in 2004.

In its 2009 BART determination, **NDDH stated that MRYS #1 had a Boiler Rating of 3,200 x 10^6 Btu/hr**, with 2000 – 2004 NO_x emissions averaging 8,665 tons/year (tpy) and 0.81 lb/mmBtu. NDDH used a baseline emission rate of 9,032 tpy. The subsequent **NDDH BART permit again stated the rated capacity as 3,200 mmBtu/hr** and limited NO_x emissions to 0.36 lb/mmBtu on a 30-day rolling average; there were no limits on annual emissions.

In its 2010 BACT determination, NDDH stated that MRYS Unit 1 had a heat input of 2,728 mmBtu/hr and 2003 – 2007 NO_x emissions averaging 9,081 tpy and 0.840 lb/mmBtu. NDDH calculated a maximum emission rate of 9,676 tpy and used a baseline emission rate of 9,934 tpy. **ASOFA would achieve 0.513 lb/mmBtu.**

According to Tom Bachmann of NDDH (4/26/10 e-mail), **"the Title V Permit to Operate limits NO_x emission from Unit 1 to 2752 lb/hr... This effectively caps annual emissions..."** to 12,054, tpy at 8760 hr/yr operation which is equivalent to 0.86 lb/mmBtu @ 3,200 mmBtu/hr @ 100% utilization. **It is clear that NDDH is using 3,200 mmBtu/hr heat input, 100% utilization, and 0.86 lb/mmBtu in conducting its BART analyses and developing its Title V permit.**

In the absence additional constraints, baseline emissions for the purpose of evaluating the cost-effectiveness of additional NO_x controls should be estimated at 0.86 lb/mmBtu and SCR cost-effectiveness should be assumed at 0.513 lb/mmBtu @ 3,200 mmBtu/hr with 100% capacity utilization.[1] This yields a baseline NO_x emission rate of 12,054 tpy for the uncontrolled situation and 7,190 tpy for the emissions into the SCR.

MRYS #2 Baseline Emissions

Minnkota p4-4: Unit 2 boiler's baseline pre-control emissions at Milton R. Young Station are based upon the same highest rolling 12-month average unit emission rate (lb/mmBtu) and corresponding highest rolling 12- month average gross heat input rate (mmBtu/hr) that were reported in 2001-2005:

- MRYS Unit 2's highest 12-month NO_X mass emissions averaged 0.786 lb/mmBtu at a corresponding average unit heat input rate of 4,885 mmBtu/hr and unit gross electrical output of 440 MW.
- During this lookback time period, Unit 2 at Milton R. Young Station was typically operated in a base-loaded manner.

NPS: **MRYS #2's highest annual NO_X mass emissions averaged 0.856 lb/mmBtu in 2007.** MRYS #2's highest annual average unit heat input rate of 5,230 mmBtu/hr occurred in 1997. MRYS #2's highest annual availability of 95% occurred in 2000 and again in 2008.

In its 2009 BART determination, **NDDH stated that MRYS #2 had a Boiler Rating of 6,300 x 10^6 Btu/hr**, with 2000 – 2004 NO_x emissions averaging 14,705 tons/year and 0.81 lb/mmBtu. NDDH used a baseline emission rate of 15,507 tpy. The subsequent **NDDH BART permit again stated the rated capacity as 6,300 mmBtu/hr** and limited NO_x emissions to 0.35 lb/mmBtu (excluding startup) on a 30-day rolling average; there were no limits on annual emissions.

In its 2010 BACT determination, NDDH stated that MRYS #2 had a heat input of 4,691 mmBtu/hr and 2003 – 2007 NO_x emissions averaging 14,858 tons/year and 0.835 lb/mmBtu. NDDH calculated a maximum emission rate of 15,818 tpy and used a baseline emission rate of 15,793 tpy. **ASOFA would achieve 0.489 lb/mmBtu.**

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[1] According to the NSR Workshop Manual, "For comparing cost effectiveness, the same realistic upper boundary assumptions must, however, be used for both the source in question and other sources (or source categories) that will later be compared during the BACT analysis." In its Table 8, NDDH has used cost-effectiveness data from permits issued by Wyoming to Basin Electric for its Dry Fork PC boiler and to Black Hills Power for its Wygen 3 PC boiler. Because both of those cost-effectiveness analyses were based upon 100% utilization of the PC boilers, NDDH must use the same 100% capacity utilization for comparison to MR Young. (At 97% availability, the historic maximum availability for MRYS #1, the baseline NO_x emission rates would be 11,704 tpy for the uncontrolled situation and 6,982 tpy for the emissions into the SCR.)

According to Tom Bachmann of NDDH (4/26/10 e-mail), **"the Title V Permit to Operate limits NO_x emission...to...5418 lb/hr from Unit 2. This effectively caps annual emissions..."** to 23,731, tpy at 8760 hr/yr operation which is equivalent to 0.86 lb/mmBtu @ 6,300 mmBtu/hr @ 100% utilization. **It is clear that NDDH is using 6,300 mmBtu/hr heat input, 100% utilization, and 0.86 lb/mmBtu in conducting its BART analyses and developing its Title V permit.**

In the absence additional constraints, baseline emissions for the purpose of evaluating the cost-effectiveness of additional NO_x controls should be estimated at 0.86/b/mmBtu and SCR cost-effectiveness should be assumed at 0.489 lb/mmBtu @ 6,300 mmBtu/hr with 100% capacity utilization.[2] This yields a baseline NO_x emission rate of 23,731 tpy for the uncontrolled situation and 13,493 tpy for the emissions into the SCR.

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[2] At 95% availability, the historic maximum availability for MRYS #2, the baseline NO_x emission rates would be 22,652 tpy for the uncontrolled situation and 12,880 tpy for the emissions into the SCR.)

Appendix B. SCR Cost Information

According to an article in the June 2009 "Power" magazine:[1]

"One more current data set is the historic capital costs reported by AEP averaged over several years and dozens of completed projects. For example, AEP reports that their historic average capital costs for SCR systems are $162/kW for 85% to 93% NO$_X$ removal..."

"...historical data finds the installed cost of an SCR system of the 700MW-class as approximately $125/kW over 22 units with a maximum reported cost of $221/kW in 2004 dollars. This data was reported prior to the dramatic increase in commodity prices of 14% per year average experienced from 2004 to 2006 (from the FGD survey results). Applying those annual increases to the 2004 estimates for three years (from the date of the survey to the end of 2007) produces an average SCR system installed cost of $185/kW..."

"Overall, costs were reported to be in the $100 to $200/kW range for the majority of the systems, with only three reported installations exceeding $200/kW."

Five industry studies conducted between 2002 and 2007 have reported the installed unit capital cost of SCRs, or the costs actually incurred by owners, expressed in dollars per kilowatt.

The first study evaluated the installed costs of more than 20 SCR retrofits from 1999 to 2001. The installed capital cost ranged from $106 to $213/kW, converted to 2007 dollars.[2] Costs are escalated through using the Chemical Engineering Plant Cost Index ("CEPCI").

The second survey of 40 installations at 24 stations reported a cost range of $76 to $242/kW, converted to 2007 dollars.[3]

The third study, by the Electric Utility Cost Group, surveyed 72 units totaling 41 GW, or 39% of installed SCR systems in the U.S. This study reported a cost range of $118/kW to $261/kW, converted to 2007 dollars.[4]

A fourth study, presented in a course at PowerGen 2005, reported an upper bound range of $180/kW to $202/kW, converted to 2007 dollars.[5]

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[1] June 13, 2009 "Power" magazine article "Air Quality Compliance: Latest Costs for SO2 and NOx Removal (effective coal clean-up has a higher–but known–price tag)" *by* Robert Peltier. http://www.masterresource.org/2009/06/air-quality-compliance-latest-costs-for-so2-and-nox-removal-effective-coal-clean-up-has-a-higher-but-known-price-tag/

[2] Bill Hoskins, Uniqueness of SCR Retrofits Translates into Broad Cost Variations, Power Engineering, May 2003. Ex. 2. The reported range of $80 to $160/kW $123 - $246/kW was converted to 2008 dollars ($116 - $233/kW) using the ratio of CEPCI in 2008 to 2002: 575.4/395.6.

[3] J. Edward Cichanowicz, Why are SCR Costs Still Rising?, Power, April 2004, Ex. 3; Jerry Burkett, Readers Talk Back, Power, August 2004, Ex. 4. The reported range of $56/kW - $185/kW was converted to 2008 dollars ($83 - $265/kw)using the ratio of CEPCI for 2008 to 1999 (575.4/.390.6) for lower end of the range and 2008 to 2003 (575.4/401.7) for upper end of range, based on Figure 3.

[4] M. Marano, Estimating SCR Installation Costs, Power, January/February 2006. Ex. 5. The reported range of $100 - $221/kW was converted to 2008 dollars ($130 - $286/kW) using the ratio of CEPCI for 2008 to 2004: 575.4/444,2. http://findarticles.com/p/articles/mi_qa5392/is_200602/ai_n21409717/print?tag=artBody;col1

[5] PowerGen 2005, Selective Catalytic Reduction: From Planning to Operation, Competitive Power College, by Babcock Power, Inc. and LG&E Energy, December 2005, Ex. 6. The reported range of $160 - $180/kW) was converted to 2008 dollars ($197 - $221/kW) using the ratio of CEPCI for 2008 to 2005 (575.4/468.2).

A fifth summary study, focused on recent applications that become operational in 2006 or were scheduled to start up in 2007 or 2008, reported costs in excess of $200/kW on a routine basis, with the highest application slated for startup in 2009 at $300/kW.[6]

Thus, the overall range for these industry studies is $50/kW to $300/kW. The upper end of this range is for highly complex retrofits with severe space constraints, such as Belews Creek, reported to cost $265/kW,[7] or Cinergy's Gibson Units 2-4. Gibson, a highly complex, space-constrained retrofit in which the SCR was built 230 feet above the power station using the largest crane in the world,[8] only cost $251/kW in 2007 dollars.[9]

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[6] J. Edward Cichanowicz, Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies, June 2007, pp. 28-29, Figure 7-1 (Ex. 1).

[7] Steve Blankinship, SCR = Supremely Complex Retrofit, Power Engineering, November 2002, Ex. 7. The unit cost: ($325,000,000/1,120,000 kW)(608.8/395.6) = $290/kW. http://pepei.pennnet.com/display_article/162367/6/ARTCL/none/none/1/SCR-=-Supremely-Complex-Retrofit/

[8] Standing on the Shoulder of Giants, Modern Power Systems, July 2002, Ex. 8.

[9] McIlvaine, NOX Market Update, August 2004, Ex. 9. SCR was retrofit on Gibson Units 2-4 in 2002 and 2003 at $179/kW. Assuming 2002 dollars, this escalates to ($179/kW)(608.8/395.6) = $275.5/kW. http://www.mcilvainecompany.com/sampleupdates/NoxMarketUpdateSample.htm

Appendix B. NPS Comments on Milton R. Young Station (MRYS) Unit #1 Tail-End Selective Catalytic Reduction (TESCR) Costs

As discussed in Appendix B, recent industry literature suggests that most SCR retrofits can be accomplished at a Total Capital Investment (TCI) under $200/kW, with the average cost at about $185/kW. We have found that the OAQPS Control Cost Manual (Cost Manual) tends to produce much lower estimates for TCI. In order to allow one to "adjust" the Cost Manual approach to produce TCI estimates more comparable to the industry literature, we have added "extra[1] retrofit" factors to adjust both the Direct Capital Cost (DCC) and the Indirect Capital Cost. These extra retrofit factors also allow us to account for unusual retrofit situations. In this case, we assumed extra retrofit factors that yielded a TCI of $185/kW for the addition of SCR (with bypass, or $179/kW without bypass). Because this is consistent with the industry estimates, we believe this to be a reasonable estimate of TCI for the SCR portion of this project. Following is a detailed discussion of selected individual elements of the cost analysis.

Baseline Emissions

The EPA New Source Review Workshop Manual (NSR Manual) states that "...baseline emissions are essentially uncontrolled emissions, **calculated using realistic upper boundary operating assumptions.**" (emphasis added) The enclosed document "NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions" describes our rationale for determining the following "upper boundary baseline emissions" for MRYS #1 instead of the average values used by Minnkota and NDDH:

- **Heat input = 3,200 mmBtu/hr** stated in NDDH BART analyses. NDDH used 2,728 in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Utilization = 100%** from NDDH underlying assumptions in their BART analyses and resulting Title V permit. Instead, NDDH used 96.4% in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Uncontrolled NOx Concentration (lb/mmBtu) = 0.86** because this is consistent with the MRYS #1 Title V permit and MRYS Unit 1's highest annual NO_X mass emissions averaged 0.866 lb/mmBtu in 1995 and NDDH used 0.86 lb/mmBtu in its BART analysis. NDDH used 0.840 lb/mmBtu in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.

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[1] The Cost Manual approach already includes an estimate for additional retrofit costs.

Given Information, Assumptions, and Direct Capital Costs

We applied the Cost Manual approach to MRYS #1 to estimate the cost of adding SCR **but did not include any estimates for the associated reheat systems because that information was not made available to us.**[2] Following is a discussion and comparison of specific combustion control (Advanced Separated Over-Fire Air = ASOFA) plus stand-alone tail-end SCR (TESCR) cost items that warrant explanation:

- ASOFA Annualized Capital Cost = $403,719 based upon $4,277,000 DCC amortized over a 20-year life @ 7% interest (Cost Manual).
- ASOFA Annual O&M Cost (not levelized) = $65,776 calculated from company BACT analysis **minus the $1,631,000 lost generation cost**[3] and adjusted to 100% availability.
- **ASOFA Total Annual Cost = $469,494.** NDDH estimated $2,489,000/yr. The differences are primarily due to the unsupported cost of lost generation and the application of an improper levelization factor.
- Fuel Sulfur Content was held at the pre-scrubbed value but would effectively decrease for a TESCR and yield a smaller SCR.
- 29% Ammonia Solution Cost ($/lb) was taken from the BART analyses conducted by PacifiCorp in Wyoming because Minnkota chose urea as the SCR reagent, primarily for safety reasons. However, according to the Institute of Clean Air Companies,[4] "With the proper controls, ammonia use is safe and routine."
- **Catalyst Cost ($/m^3) = $3,000** was taken from the BART analyses conducted by PacifiCorp in Wyoming because the Minnkota/Burns & McDonnell estimate of $7,500/m^3 was much higher than the $3,000 - $6,000/m^3 we typically see from other consultants.
- **Operating Life of Catalyst (hours) = 16,000** which appears to be the consensus estimate from the catalyst vendors.
- **Natural gas unit cost ($/mcf) = $5** based upon current prices according to EIA.
- Natural gas for reheat (mcf) = 460,090 mcf (from Minnkota) and does not include NG to vaporize urea because ammonia is used in this scenario.

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[2] We are requesting information that will allow us to evaluate the costs of each major component and will then be able to apply our SCR-only cost estimates to the SCR-specific costs included in the information we are requesting.

[3] Minnkota estimated that retrofitting of ASOFA would result in 181 hr/yr of lost operating time due to maintenance of ASOFA, and that Unit 2 operation would drop to 8,048 hr/yr as a result. Minnkota installed ASOFA on Unit #2 in 2007 and availability increased from the pre-ASOFA 89% (7,792 hr/yr) average to the post-ASOFA 95% (8,256hr/yr).

[4] May 2009 Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants"*Can Ammonia Be Handled Safely?* Yes. Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 2006, 17 billion pounds of ammonia were produced in the U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine.

- **Volcatalyst = 634 m^3 for one reactor.** The Cost Manual approach results in the reactor having four layers of catalyst plus one spare layer. Minnkota estimated three layers plus one spare with catalyst volume at 633 m^3.
- **Direct Capital Cost (DCC), A = $14 million before adjustments and $29 million with adjustments. Minnkota estimates** DCC = $127 million for SCR plus ASOFA and the associated reheat equipment. Subtracting the $4 million DCC cost of ASOFA results in **DCC = $123 million for SCR plus the associated reheat equipment.** We would like to see the separate cost estimates developed by Minnkota for the SCR as well as the reheat system so that we could directly compare our SCR cost estimate.

Total Capital Investment

The next portion of our cost analysis will assume that Minnkota has properly estimated its Direct Capital Costs for SCR plus the associated reheat equipment. We will also assume that the ratios of Indirect Capital Costs (ICC) to Direct Capital Costs (DCC) used by the Cost Manual for stand-alone SCR also apply to the complete SCR plus reheat "package" evaluated by Minnkota.[5] Our SCR-only costs are estimated on the "ICC" tab of the associated Excel workbook. Our evaluation of the Minnkota SCR+reheat system costs are shown on the "ICC (2)" tab.

- Total Indirect Installation Costs (TIIC), B = $9 million; this is 30% of DCC (because of our extra retrofit factor—instead, the Cost Manual estimates TIIC = 20% of DCC.) **Minnkota estimates TIIC = $45 million** for SCR plus associated equipment; this is 37% of Minnkota's $123 million DCC and appears excessive when compared to the 20% ratio used by the Cost Manual. **A more appropriate value for TIIC would be $25 million.**
- Project Contingency, C = $9 million; this is 29% of (DCC+TIIC). (The Cost manual estimates TIIC = 18% of (DCC+TIIC).) **Minnkota estimates Project Contingency = $20 million** for SCR plus associated equipment; this is 16% of (DCC = $127 million + adjusted TIIC = 25 million). **A more appropriate value for Project Contingency would be $22 million.**
- Total Plant Cost (TPC), D = $46 million = our estimate is 159% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 138% of DCC. **Minnkota estimates TPC = $188 million** for SCR plus associated equipment; this is 153% of DCC and appears excessive. **A more appropriate value for TPC would be $170 million.**
- Allowance for Funds During Construction (AFDC), E = $0. **Minnkota estimates AFDC = $27 million for SCR plus associated equipment; this is not allowed by the Cost Manual.**
- Total Capital Investment (TCI = D+G+H) = $47 million for SCR; this is 163% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 146% of DCC. **Minnkota estimates TCI = $290 million for SCR plus reheat equipment**; this is 236% of DCC. In addition to overestimates and the invalid $27 million for AFDC noted above, **Minnkota has**

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[5] Minnkota appears to have used a similar approach.

included $42 million for "Escalation" and $26 million for "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs and applying the Cost Manual 146% ratio to the $123 million DCC, the resulting TCI for TESCR on MRYS #1 becomes $180 million ($701/kW).

Annual Costs & Cost-effectiveness

We believe that the Cost Manual approach is directly applicable and appropriate to estimate annual costs of the stand-alone SCR ("Ann Cost" tab) and of the entire Minnkota SCR+reheat system ("Ann Cost (2) tab) using the corrected TCI derived above. The following discussion describes the cost estimates in the "Ann Cost (2)" tab.

- Annual Maintenance Cost = 1.5% of TCI (= $47 million). Minnkota has incorrectly assumed 3% of TCI to estimate $7 million. If we assume that Annual Maintenance Cost = 1.5% of the $180 million TCI for TESCR derived above, then **we estimate $3 million**.
- **Annual Reagent Cost = $1 million for ammonia.** Minnkota estimates $3 million for urea.
- **Annual Electricity Cost = $0.5 million.** Minnkota estimates $6 million, primarily due to "lost generation."
- Annual Catalyst Cost = $1 million. Minnkota estimates $1 million.
- **Annual natural gas Cost = $2 million.** Minnkota estimates $4 million, primarily due to use of NG to vaporize urea and a higher unit gas price.
- Direct Annual Cost (DAC) = $7 million and is the sum of the individual annual costs using our estimates modified to reflect a TCI of $180 million. (See the "Annual Cost (2)" tab. Minnkota estimated $20 million.
- Indirect Annual Cost = $17 million based a TCI of $180 million.
- **Total Annual Cost (TAC) = $25 million** for ASOFA+SCR plus reheat equipment based a TCI of $180 million (for ASOFA+SCR plus reheat equipment); Minnkota estimates TAC = $44 million and includes an improper "levlization" factor to escalate cost.
- **SCR Cost-effectiveness to remove 6,503 tpy of NO_X is = $3,800/ton.**
- **Total Cost-effectiveness to remove 11,367 tpy of NO_X is = $2,200/ton. NDDH estimates $4,615/ton**

Results & Conclusions

Based upon the approach recommended by the Cost Manual, our estimate for the cost of adding only the ASOFA and SCR components of a Tail-End SCR (TESCR) system to MRYS #1 is a Total Capital Investment of $52 million ($201/kW) and a Total Annual Cost of $8 million. Using upper bound emission estimates, as recommended by the NSR Manual, combined with NDDH estimates of controlled emissions, we estimate that ASOFA + TESCR could reduce NO_X emissions by **11,367 tpy (6,503 tpy** by the SCR alone). The Average Cost-Effectiveness for the ASOFA + TESCR system would be $700/ton and addition of the TESCR has a cost-effectiveness of $1,200/ton.

Because some method must be applied to reheat the gases leaving the wet scrubber, additional equipment would be required and additional costs would be incurred. It was not possible from the information provided to determine how much this additional equipment cost. Therefore, we compared the estimates presented by Minnkota to the ratios used by the Cost Manual to relate capital and some operating costs to Total Direct Capital Cost. Minnkota incorrectly included major costs for "Allowance for Funds During Construction," "Escalation" and "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs, the resulting Total Capital Investment for TESCR on MRYS #1 becomes $180 million ($701/kW) versus the Minnkota estimate of $295 million.

The Cost Manual can be applied for estimation of annual operating costs and we found several differences between the Cost Manual approach and the Minnkota estimates. Our corrected Direct Annual Cost estimate is $7 million versus the Minnkota estimate of $20 million; the major differences are costs for "Lost Generation" and "Maintenance." Our estimated Total Annual Cost (TAC) is $25 million. Minnkota estimates TAC = $44 million. Our estimate of the Average Cost-Effectiveness for the complete ASOFA + TESCR + reheat system would be $2,200/ton and addition of the TESCR has a cost-effectiveness of $3,800/ton.

Appendix B. NPS Comments on Milton R. Young Station (MRYS) Unit #2 Tail-End Selective Catalytic Reduction (TESCR) Costs

As discussed in Appendix B, recent industry literature suggests that most SCR retrofits can be accomplished at a Total Capital Investment (TCI) under $200/kW, with the average cost at about $185/kW. We have found that the OAQPS Control Cost Manual (Cost Manual) tends to produce much lower estimates for TCI. In order to allow one to "adjust" the Cost Manual approach to produce TCI estimates more comparable to the industry literature, we have added "extra[1] retrofit" factors to adjust both the Direct Capital Cost (DCC) and the Indirect Capital Cost. These extra retrofit factors also allow us to account for unusual retrofit situations. In this case, we assumed extra retrofit factors that yielded a TCI of $192/kW for the addition of SCR (with bypass, or $187/kW without bypass). Because this is consistent with the industry estimates, we believe this to be a reasonable estimate of TCI for the SCR portion of this project. Following is a detailed discussion of selected individual elements of the cost analysis.

Baseline Emissions

The EPA New Source Review Workshop Manual (NSR Manual) states that "...baseline emissions are essentially uncontrolled emissions, **calculated using realistic upper boundary operating assumptions**." (emphasis added) The enclosed document "NPS Comments on Milton R. Young Station (MRYS) Baseline Emissions" describes our rationale for determining the following "upper boundary baseline emissions" for MRYS #1 instead of the average values used by Minnkota and NDDH:

- **Heat input = 6,300 mmBtu/hr** stated in NDDH BART analyses. NDDH used 4,691 in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Utilization = 100%** from NDDH underlying assumptions in their BART analyses and resulting Title V permit. Instead, NDDH used 92.2% in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.
- **Uncontrolled NOx Concentration (lb/mmBtu) = 0.86** because this is consistent with the MRYS #2 Title V permit and MRYS #2's highest annual NO_X mass emissions averaged 0.856 lb/mmBtu in 2007 and NDDH used 0.86 lb/mmBtu in its BART analysis. NDDH used 0.835 lb/mmBtu in its BACT analysis which appears to represent a historic two-year average and not a historic annual upper bound.

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[1] The Cost Manual approach already includes an estimate for additional retrofit costs.

Given Information, Assumptions, and Direct Capital Costs

We applied the Cost Manual approach to MRYS #2 to estimate the cost of adding SCR **but did not include any estimates for the associated reheat systems because that information was not made available to us.**[2] Following is a discussion and comparison of specific combustion control (Advanced Separated Over-Fire Air = ASOFA) plus stand-alone tail-end SCR (TESCR) cost items that warrant explanation:

- ASOFA Annualized Capital Cost = $944,684 based upon $10,008,000 DCC amortized over a 20-year life @ 7% interest (Cost Manual).
- ASOFA Annual O&M Cost (not levelized) = $159,744 calculated from company BACT analysis **minus the $2,65,000 lost generation cost**[3] and adjusted to 100% availability.
- **ASOFA Total Annual Cost = $1,104,429**. Minnkota estimated $4,376,000/yr. The differences are primarily due to the unsupported cost of lost generation and the application of an improper levelization factor.
- Fuel Sulfur Content was held at the pre-scrubbed value but would effectively decrease for a TESCR and yield a smaller SCR.
- 29% Ammonia Solution Cost ($/lb) was taken from the BART analyses conducted by PacifiCorp in Wyoming because Minnkota chose urea as the SCR reagent, primarily for safety reasons. However, according to the Institute of Clean Air Companies,[4] "With the proper controls, ammonia use is safe and routine."
- **Catalyst Cost ($/m^3) = $3,000** was taken from the BART analyses conducted by PacifiCorp in Wyoming because the Minnkota/Burns & McDonnell estimate of $7,500/m^3 was much higher than the $3,000 - $6,000/m^3 we typically see from other consultants.
- **Operating Life of Catalyst (hours) = 16,000** which appears to be the consensus estimate from the catalyst vendors.
- **Natural gas unit cost ($/mcf) = $5** based upon current prices according to EIA.
- Natural gas for reheat (mcf) = 754,563 mcf (from Minnkota) and does not include NG to vaporize urea because ammonia is used in this scenario.

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[2] We are requesting information that will allow us to evaluate the costs of each major component and will then be able to apply our SCR-only cost estimates to the SCR-specific costs included in the information we are requesting.

[3] Minnkota estimated that retrofitting of ASOFA would result in 181 hr/yr of lost operating time due to maintenance of ASOFA, and that Unit 2 operation would drop to 8,048 hr/yr as a result. Minnkota installed ASOFA on Unit #2 in 2007 and availability increased from the pre-ASOFA 89% (7,792 hr/yr) average to the post-ASOFA 95% (8,256hr/yr).

[4] May 2009 Institute of Clean Air Companies white paper titled "Selective Catalytic Reduction (SCR) Control of NO_x Emissions from Fossil Fuel-Fired Electric Power Plants"*Can Ammonia Be Handled Safely?* Yes. Concern over the handling of ammonia was initially raised as a problem with SCR technology applications due to the transportation and storage of a hazardous gas under pressure. However, large quantities of ammonia already are used for a variety of applications with an excellent overall safety record. (In 2006, 17 billion pounds of ammonia were produced in the U.S.) These applications include the manufacture of fertilizers and a variety of other chemicals, as well as refrigeration. With the proper controls, ammonia use is safe and routine.

- **Volcatalyst = 617 m^3 each of two reactors.** The Cost Manual approach results in each reactor having one layer of catalyst plus one spare layer. The SCR vendor info assumed two layers plus one spare. Fuel Tech estimated catalyst volume at 249 m^3/reactor for MRYS#2. CERAM estimated catalyst volume at 390 m^3/reactor for MRYS#2. Minnkota estimated three layers plus one spare with catalyst volume at 1110 m^3/reactor.
- **Direct Capital Cost (DCC), A = $22 million before adjustments and $44 million with adjustments. Minnkota estimates** DCC = $200 million for SCR plus ASOFA and the associated reheat equipment. Subtracting the $10 million DCC cost of ASOFA results in **DCC = $190 million for SCR plus the associated reheat equipment.** We would like to see the separate cost estimates developed by Minnkota for the SCR as well as the reheat system so that we could directly compare our SCR cost estimate.

Total Capital Investment

The next portion of our cost analysis will assume that Minnkota has properly estimated its Direct Capital Costs for SCR plus the associated reheat equipment. We will also assume that the ratios of Indirect Capital Costs (ICC) to Direct Capital Costs (DCC) used by the Cost Manual for stand-alone SCR also apply to the complete SCR plus reheat "package" evaluated by Minnkota.[5] Our SCR-only costs are estimated on the "ICC" tab of the associated Excel workbook. Our evaluation of the Minnkota SCR+reheat system costs are shown on the "ICC (2)" tab.

- Total Indirect Installation Costs (TIIC), B = $18 million; this is 40% of DCC (because of our extra retrofit factor—instead, the Cost Manual estimates TIIC = 20% of DCC.) **Minnkota estimates TIIC = $70 million** for SCR plus associated equipment; this is 37% of Minnkota's $190 million DCC and appears excessive when compared to the 20% ratio used by the Cost Manual. **A more appropriate value for TIIC would be $38 million.**
- Project Contingency, C = $18 million; this is 42% of (DCC+TIIC). (The Cost manual estimates TIIC = 18% of (DCC+TIIC).) **Minnkota estimates Project Contingency = $30 million** for SCR plus associated equipment; this is 16% of (DCC = $190 million + adjusted TIIC = 38 million) **and appears reasonable.**
- Total Plant Cost (TPC), D = $80 million = our estimate is 182% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 138% of DCC. **Minnkota estimates TPC = $290 million** for SCR plus associated equipment; this is 153% of DCC and appears excessive. **A more appropriate value for TPC would be $262 million.**
- Allowance for Funds During Construction (AFDC), E = $0. **Minnkota estimates AFDC = $41 million for SCR plus associated equipment; this is not allowed by the Cost Manual.**

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[5] Minnkota appears to have used a similar approach.

- Total Capital Investment (TCI = D+G+H) = $82 million for SCR; this is 186% of the DCC upon which it is based. However, the Cost Manual ratio (without extra retrofit factors) is TPC = 146% of DCC. **Minnkota estimates TCI = $426 million for SCR plus reheat equipment**; this is 225% of DCC. In addition to overestimates and the invalid $41 million for AFDC noted above, **Minnkota has included $55 million for "Escalation" and $33 million for "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs and applying the Cost Manual 141% ratio to the $190 million DCC, the resulting TCI for TESCR on MRYS #2 becomes $267 million ($560/kW).**

Annual Costs & Cost-effectiveness

We believe that the Cost Manual approach is directly applicable and appropriate to estimate annual costs of the stand-alone SCR ("Ann Cost" tab) and of the entire Minnkota SCR+reheat system ("Ann Cost (2) tab) using the corrected TCI derived above. The following discussion describes the cost estimates in the "Ann Cost (2)" tab.

- Annual Maintenance Cost = 1.5% of TCI (= $267 million). Minnkota has incorrectly assumed 3% of TCI to estimate $10 million. If we assume that Annual Maintenance Cost = 1.5% of the $267 million TCI for TESCR derived above, then **we estimate $4 million**.
- **Annual Reagent Cost = $2 million for ammonia.** Minnkota estimates $4 million for urea.
- **Annual Electricity Cost = $1 million.** Minnkota estimates $10 million, primarily due to "lost generation."
- **Annual Catalyst Cost = $2 million.** Minnkota estimates $1 million.
- **Annual natural gas Cost = $4 million.** Minnkota estimates $6 million, primarily due to use of NG to vaporize urea and a higher unit gas price.
- Direct Annual Cost (DAC) = $12 million and is the sum of the individual annual costs using our estimates modified to reflect a TCI of $267 million. (See the "Annual Cost (2)" tab. Minnkota estimated $32 million.
- Indirect Annual Cost = $25 million based a TCI of $267 million.
- **Total Annual Cost (TAC) = $38 million** for ASOFA+SCR plus reheat equipment based a TCI of $277 million (for ASOFA+SCR plus reheat equipment); Minnkota estimates TAC = $69 million and includes an improper "levlization" factor to escalate cost.
- **SCR Cost-effectiveness to remove 12,141 tpy of NO_X is = $3,100/ton.**
- **Total Cost-effectiveness to remove 22,379 tpy of NO_X is = $1,700/ton. NDDH estimates $4,772/ton**

Results & Conclusions

Based upon the approach recommended by the Cost Manual, our estimate for the cost of adding only the ASOFA and SCR components of a Tail-End SCR (TESCR) system to MRYS #2 is a Total Capital Investment of $92 million ($192/kW) and a Total Annual Cost of $18 million. Using upper bound emission estimates, as recommended by the NSR Manual, combined with NDDH estimates of controlled emissions, we estimate that ASOFA + TESCR could reduce NO_X emissions by **22,379 tpy (12,141 tpy** by the SCR alone). The Average Cost-Effectiveness for the ASOFA + TESCR system would be $800/ton and addition of the TESCR has a cost-effectiveness of $1,400/ton.

Because some method must be applied to reheat the gases leaving the wet scrubber, additional equipment would be required and additional costs would be incurred. It was not possible from the information provided to determine how much this additional equipment cost. Therefore, we compared the estimates presented by Minnkota to the ratios used by the Cost Manual to relate capital and some operating costs to Total Direct Capital Cost. Minnkota incorrectly included major costs for "Allowance for Funds During Construction," "Escalation", "Owner's Costs" which are not allowed by the Cost Manual. Adjusting for these unsupported costs, the resulting Total Capital Investment for TESCR on MRYS #2 becomes $266 million ($560/kW) versus the Minnkota estimate of $426 million.

The Cost Manual can be applied for estimation of annual operating costs and we found several differences between the Cost Manual approach and the Minnkota estimates. Our corrected Direct Annual Cost estimate is $12 million versus the Minnkota estimate of $32 million; the major differences are costs for "Lost Generation" and "Maintenance." Our estimated Total Annual Cost (TAC) is $38 million. Minnkota estimates TAC = $69 million. Our estimate of the Average Cost-Effectiveness for the complete ASOFA + TESCR + reheat system would be $1,700/ton and addition of the TESCR has a cost-effectiveness of $3,100/ton.

Appendix B. SCR Cost Survey Results

Discussion of OAQPS Cost Manual Method for AQCS Estimation

submitted to the NM Environment Department by Public Service of NM regarding BART for the San Juan Generating Station
http://www.nmenv.state.nm.us/aqb/reghaz/documents/03292008DiscussionofOAQPSCostManualMethodRev080329.pdf

SCR Capital Cost Survey Results

from Table 7-1. of CURRENT CAPITAL COST AND COST-EFFECTIVENESS OF POWER PLANT EMISSION CONTROL
Prepared by J. Edward Cichanowicz for Utility Air Regulatory Group, June, 2007

Reference	Average and Low-High Cost Observations		Cost Basis
	Capital, MW ($/kW, 2006 Basis)	Observed ($/kW)	
Hoskins, 2003	128 (400 MW)	80-160	2002. 15 of 20 reported unit costs exceeded $100/kW. Weak relationship of unit cost and scale.
Cichanowicz, 2004	84 (600-899 MW) to 128 (100-399 MW)	56-185	2003. For four categories of generating capacity, the least cost units were among the first installed.
Marano, 2006	118 (>900) to 167 (<300 MW)	Most costs reported to be within 100-200	2005. “Units with a capacity of 600 to 900 MW appear to be more difficult to retrofit than those in other size ranges.”

Estimation of Costs and Impacts of NOx Control Technologies Applied to the PGE Boardman Plant

http://www.deq.state.or.us/aq/haze/docs/ergMemo.pdf

Reference	Average and Low-High Cost Observations		Cost Basis
	Capital, MW ($/kW, 2006 Basis)	Observed ($/kW)	
ERG 2008	227	207 - 267	2007

Appendix B.
Milton R. Young Unit #1
OAQPS Control Cost Manual Section 4.2

Given/Assumptions

New or Retrofit?	Retrofit			
Extra Direct retrofit cost	1.5	NPS estimate		
Extra Indirect retrofit cost factor	1.5	NPS estimate		
Generation capacity (MW)	257	NDDH BART report		
SCR bypass included?	Yes	from BACT analysis		
Fuel High Heating Value (Btu/lb)	6,662	from 2006 BACT analysis		
Maximum Fuel Consumption Rate (lb/hr)	4.8E+05	calculated from	3,200	mmBtu/hr from NDDH BART report
Average Annual Fuel Consumption (lb)	4.21E+09	calculated		
Number of SCR Operating Days	365	assumed		
Plant Capacity Factor	100%	from NDDH Title V permit		
Uncontrolled NOx Concentration (lb/mmBtu)	0.88	calculated from NDDH Title V permit		
Uncontrolled NOx Emissions (tpy)	12,054	calculated from NDDH Title V permit		
ASOFA Total Capital Cost	$ 4,277,000	company BACT analysis	16.6	$/kW The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
ASOFA Annualized Capital Cost	$ 403,719	calculated from TCC		
ASOFA Annual O&M Cost (not levelized)	$ 65,776	calculated from company BACT analysis minus the lost generation cost and adjusted to	100%	availability
ASOFA Total Annual Cost	$ 469,494	calculated		
LNB outlet = SCR inlet NOx Concentration (lb/mmBtu)	0.51	from NDDH BACT analysis		
Required Controlled NOx Concentration (lb/mmBtu)	0.049	from NDDH BACT analysis		
Acceptable Ammonia Slip (ppm)	2.0	from OAQPS Cost Manual		
Fuel Volume Flow Rate (ft3/min/mmBtu/hr)	547	from OAQPS Cost Manual		
Fuel Sulfur Content	0.81%	from 2006 BACT analysis		
Fuel Ash Content	8.74%	from 2006 BACT analysis		
Number of SCR reactor chambers	1	from BACT analysis		
ASR	1.05	from OAQPS Cost Manual		
Stored Ammonia Concentration	29%	from OAQPS Cost Manual		
Reagent Molecular Weight (g/mole)	17.03	from OAQPS Cost Manual		
Reagent Density (lb/ft3 @ 60F)	56.0	from OAQPS Cost Manual		
Reagent Specific Volume (gal/ft3)	7.481	from OAQPS Cost Manual		
NOx Molecular Weight (g/mole)	46.01	from OAQPS Cost Manual		
Number of Days of Storage for Ammonia	14	assumed		
Pressure Drop for SCR Ductwork H2O")	3	from OAQPS Cost Manual		
Pressure Drop for each Catalyst Layer (H2O")	1	from OAQPS Cost Manual		
Temperature at SCR Inlet (degrees F)	563	from 2009 BACT analysis		
Equipment Life (years)	20	from OAQPS Cost Manual		
Annual Interest Rate	7%	from OAQPS Cost Manual		
Inflation Since 1998	1.35	CEPCI 2007/CEPCI 1998		
Catalyst Cost, Initial ($/ft3)	$ 85	calculated from	$ 3,000	/m^3 from PacifiCorp report
Catalyst Cost, Replacement ($/ft3)	$ 85	calculated from	$ 3,000	/m^3 from PacifiCorp report
Electrical Power Cost ($/kWh)	0.035	calculated from	$ 35.00	/MWhr from company report
29% Ammonia Solution Cost ($/lb)	$ 0.058	calculated from	$ 400.00	ton from PacifiCorp report
Operating Life of Catalyst (hours)	16,000	NDDH BACT report		
Natural gas unit cost ($/mcf)	$ 4.98	EIA 2010 price forecast		
Natural gas for reheat (mcf)	460,090	from BACT analysis		

MR Young Unit 1

Scenario	Upper Bound Heat Input (mmBtu/hr)	Upper Bound NOx Emission Rate (lb/mmBtu)	Upper Bound NOx Emission Rate (lb/hr)	Upper Bound Capacity Utilization	Upper Bound NOx Emission Rate (tpy)	NOx Emission Reduction (tpy)
Pre-BART	3,200	0.87	2,770	100%	12,135	
Post-ASOFA	3,200	0.51	1,642	100%	7,190	4,945
Pre-BART	3,200	0.87	2,770	95%	11,583	
Post-ASOFA	3,200	0.51	1,642	95%	6,863	4,720
Title V	3,200	0.86	2,752	100%	12,054	
Post-ASOFA	3,200	0.51	1,642	100%	7,190	4,864
Title V	3,200	0.86	2,752	96%	11,572	
Post-ASOFA	3,200	0.51	1,642	100%	7,190	4,381

LNB Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc
(0.86 - 0.513)/ 0.86 = 40%

Boiler Calculations

2.3 $Q_B = HVm\text{-}dot_{fuel}$
QB = 6662 Btu/lb * 480336.24 lb/hr
QB = 3200 Btu/hr

2.7 $CF_{Plant} = \text{actual } m_{fuel}/\text{maximum } m_{fuel}$
CFPlant = 4.21E+09 lb/yr / 8760 hr/yr / 480336.24 lb/hr
CFPlant = 100%

2.8 $CF_{SCR} = t_{SCR}/365 \text{ days}$
CFSCR = 365 days/ 365 days
CFSCR = 100%

$CF_{Total} = CF_{Plant} \times CF_{SCR}$
CFTotal = 100% * 100%
CFTotal = 100%

2.12 $q_{fluegas} = q_{fuel}Q_B(460+T)/(460+700^{o}F)n_{SCR}$
qfluegas = 547 ft3/min/(mmBtu/hr)* 3200 mmBtu/hr*(460 + 563)/(460 + 700)/ 1
qfluegas = 1,543,672 acfm

2.9 $\eta_{NOx} = (NOx_{in} - NOx_{out}) / NOx_{in}$
ηNOx = (0.513 lb/mmBtu - 0.049 lb/mmBtu)/ 0.513 lb/mmBtu
ηNOx = 90%

Uncontrolled NOx emissions (tpy) **12,054**

Overall Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc
(0.86 - 0.049)/ 0.86 = 94%

NOx removed = 11,367 tpy

Controlled NOx emissions (tpy) = 687 tpy

SCR Reactor Calculations

2.19 $Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times T_{adj}/N_{SCR}$

Volcatalyst = 2.81 * 3200 = 8992

2.2 $\eta_{adj} = 0.2869 + (1.058 \times \eta)$

ηadj = 0.2869 +(1.058 * 0.90)

ηadj = 1.244

2.22 $Slip_{adj} = 1.2835 - (0.0567 \times Slip)$

Slipadj = 1.2835 - (0.057 * 2)

Slipadj = 1.170

2.21 $NOx_{adj} = 0.8524 + (0.3208 \times NOx_{in})$

NOxadj = 0.8524 + (0.321 * 0.51)

NOxadj = 1.017

2.23 $S_{adj} = 0.9636 + (0.0455 \times S)$

Sadj = 0.9636 + (0.046 * 0.81)

Sadj = 1.000

2.24 $T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$

Tadj = 15.16 - (0.039 * 563) + 2.74E-05 * 316969

Tadj = 1.680

Volcatalyst = 22,365 ft3 each = 633.8 m3 each

2.25 $A_{catalyst} = q_{fluegas}/(16 \text{ ft/sec} \times 60 \text{ sec/min})$

Acatalyst = 1543672 /(16 * 60)

Acatalyst = 1608 ft2

2.26 $A_{SCR} = 1.15 \times A_{catalyst}$

ASCR = 1.15 * 1608

ASCR = 1849 ft2

2.27 $l = w = A_{SCR}{}^{1/2}$

l = w = 43.0 ft

2.28 $n_{layer} = Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$

nlayer = 22365 /(3.1 * 1608)

nlayer = 4.0

2.29 $h_{layer} = [Vol_{catalyst}/(n_{layer} \times A_{catalyst})] + 1$

hlayer = 22365 /(3 * 1608) + 1

hlayer = 5.6

2.3 $n_{total} = n_{layer} + n_{empty}$

ntotal = 4 + 1

ntotal = 5

2.31 $h_{SCR} = n_{total}(c_1 + h_{layer}r) + c_2$

hSCR = 5 * (7 + 5.6) + 9

hSCR = 72 ft

Reagent Calculations

2.32 $\text{m-dot}_{reagent} = NOx_{in}Q_{B}ASR\eta_{NOx}M_{reagent}/M_{NOx}$

m-dotreagent = **0.513** * 3200 * 1.05 * **90%** * 17.03 / 46.01

m-dotreagent = 577 lb/hr

2.33 $\text{m-dot}_{sol} = \text{m-dot}_{reagent}/C_{sol}$

m-dotsol = 577 / 0.29

m-dotsol = 1990 lb/hr

2.34 $q_{sol} = (\text{m-dot}_{vol}/\rho_{sol})V_{sol}$

qsol = 1990 * 7.481 / 56

qsol = 266 gph

2.35 Tank Volume = $q_{sol}t$

Tank Volume = 266 * 14 * 24

Tank Volume = 89,317 gal

Direct Capital Cost

2.36 $DC = Q_B[(\$3380/MMBtu/hr) + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)](3500/Q_B)^{0.35} + f(Vol_{catalyst})$

DC = 3200 (($ 3,380 +

2.37 $f(h_{SCR}) = \{[\$612/(ft\text{-}mmBtu/hr)]h_{SCR}\} - \$187.9/(mmBtu/hr)$

f(hSCR) = 6.12 * 72 - 187.9

f(hSCR) = $ 254 /mmBtu/hr

2.38 $f(NH_3rate) = [(\$411/lb/hr)(m\text{-}dot_{reagent}/Q_B)] - \$473/(mmBtu/hr)$

f(NH3rate) = 411 * 577 / 3200 - 47.3

f(NH3rate) = $ 27 /mmBtu/hr

2.39 f(new) = $0/(mmBtu/hr) for retrofit

f(new) = $ -

2.41 f(bypass) = $0/(mmBtu/hr) for no bypass

f(bypass) = $ 127 /mmBtu/hr

2.43 $f(Vol_{catalyst}) = Vol_{catalyst}CCinitial$

f(Volcatalyst) = 22365 * 85 * 1 chambers

f(Volcatalyst) = $ 1,901,371

DC = 3200 * ($ 3,380 + $ 254 + $ 27 + $ - + $ 127)*(3500 / 3200)^ 0.35 + $ 1,901,371

DC = $ 14,408,071

Extra Direct retrofit cost factor = 1.5

Inflation Adjustment = 1.35

DC = $ 29,176,343

Indirect Capital Costs

							Cost/DCC
Total Direct Capital Costs, A						$ 29,176,343	
Indirect Installation Costs							
General Facilities				0.05 A		$1,458,817	
Engineering and Home Office Fees				0.10 A		$2,917,634	
Process Contingencies				0.05 A		$1,458,817	
Total Indirect Installation Costs, B	Retrofit factor =	1.5	*	0.20 A =	0.30 A =	$8,752,903	30%
Project Contingency, C =	Retrofit factor =	1.5	*	0.15 (A+B) =	0.225 (A+B) =	$8,534,080	29%
Total Plant Cost D =					A+B+C	$46,463,327	159%
Allowance for Funds During Construction, E =					0	$0	
Royalty Allowance, F =					0	$0	
Preproduction Cost, G =					0.02 (D+E)	$929,267	
Inventory Capital, H =							
Initial Catalyst and Chemicals, I =	0.058 /lb *	1990 lb/r *		24 hr/day *	14 days =	$38,778	
Total Capital Investment TCI = D+G+H					+D+E+F+G+H+I	$47,431,372	163%
					Cost/kW =	$185	
Total Capital Investment TCI including ASOFA =						$51,708,372	
					Cost/kW =	$201	

Indirect Capital Costs

					Manual Cost	Manual Cost/DCC	Minnkota Cost	Minnkota Cost/DCC
Total Direct Capital Costs, A					$ 123,201,171		$123,201,171	
Indirect Installation Costs								
General Facilities			0.05 A		$6,160,059			
Engineering and Home Office Fees			0.10 A		$12,320,117			
Process Contingencies			0.05 A		$6,160,059			
Total Indirect Installation Costs, B	Retrofit factor =	1.0 *	0.20 A =	0.20 A =	$24,640,234	20%	$ 45,332,315	37%
Project Contingency, C =	Retrofit factor =	1.0 *	0.15 (A+B) =	0.15 (A+B) =	$22,176,211	18%	$ 19,529,462	16%
Total Plant Cost D =				A+B+C	$170,017,616	138%	$188,062,948	153%
Allowance for Funds During Construction, E =				0	$0		$ 27,278,000	
Royalty Allowance, F =				0	$0			
Preproduction Cost, G =				0.02 (D+E)	$3,400,352			
Inventory Capital, H =								
Initial Catalyst and Chemical	0.058 /lb *	1990 lb/r *	24 hr/day *	14 days =	$38,778			
Escalation							$ 42,013,593	
NG pipeline					$ 6,750,000		$ 6,750,000	
Owner's costs							$ 26,204,034	
Total Capital Investment TCI = D+G+H				+D+E+F+G+H+I	$ 180,206,747	146%	$290,308,575	236%
				Cost/kW =	$701		$609	
Total Capital Investment TCI including ASOFA =					$184,483,747		$300,316,575	
				Cost/kW =	$718		$630	

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI
Annual Maintenance Cost = 0.015 * $ 47,431,372
Annual Maintenance Cost = $ 711,471

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$
top = 100% * 8760
top = 8760
Annual Reagent Cost = 1990 * 8760 * 0.058
Annual Reagent Cost = $ 1,011,006

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$
Power = 0.105 * 3200 *(0.513 * 90% + 0.5 *(3 + 5 * 1))
Power = 1500 kW
Annual Electricity Cost = 1500 * 8760 * 0.035
Annual Electricity Cost = $ 459,871

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$
Catalyst Replacement Cost = 1 * 22365 * 85.01581521 / 1
Catalyst Replacement Cost = $ 1,901,371

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$
Y = 16000 /(100% * 8760)
Y = 2
FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)
FWF = 0.48
Annual Catalyst Cost = $ 918,537

Annual natural gas Cost = mcf/hr * 8,760 hr/y * $4.98 /mcf
Annual natural gas Cost = $ -

DAC = $ 3,100,884

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$
CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)
CRF = 0.0944

Indirect Annual Cost = CFR * TCI
Indirect Annual Cost = 0.0944 * $ 47,431,372
Indirect Annual Cost = $ 4,477,186

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost
Total Annual Cost = $ 3,100,884 + 4,477,186
Total Annual Cost = $ 7,578,070 + $ 469,494 = $ 8,047,565

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$
NOx Removed = 0.513 * 90% * 3200 * 8760 / 2000
NOx Removed = 6,503

Total NOx Removed = 11,367

2.58 Cost effectiveness = TAC/NOx removed
SCR Cost effectiveness = $ 1,165
Total Cost effectiveness = $ 708

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * **$ 180,206,747**

Annual Maintenance Cost = $ 2,703,101

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = 100% * 8760

top = 8760

Annual Reagent Cost = 1990 * 8760 * 0.058

Annual Reagent Cost = $ 1,011,006

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 3200 *(**0.513** * 90% + 0.5 * (3 + 5 * 1))

Power = 1500 kW

Annual Electricity Cost = 1500 * 8760 * 0.035

Annual Electricity Cost = $ 459,871

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 1 * 22365 * 85.01581521 / 1

Catalyst Replacement Cost = $ 1,901,371

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$

Y = 16000 /(100% * 8760)

Y = 2

FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)

FWF = 0.48

Annual Catalyst Cost = $ 918,537

Annual natural gas Cost = 460,090 mcf/yr * $4.98 /mcf

Annual natural gas Cost = $ 2,291,248

DAC = $ **7,383,763**

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)

CRF = 0.0944

Indirect Annual Cost = CFR * TCI

Indirect Annual Cost = 0.0944 * **$ 180,206,747**

Indirect Annual Cost = $ 17,010,242

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 7,383,763 + 17,010,242

Total Annual Cost = $ **24,394,005** + $ 469,494 = $ 24,863,500

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = **0.513** * 90% * 3200 * 8760 / 2000

NOx Removed = 6,503

Total NOx Removed = 11,367

2.58 Cost effectiveness = TAC/NOx removed

SCR Cost effectiveness = $ 3,751

Total Cost effectiveness = $ 2,187

Operating company	**Basin Electric Power**		
Facility	**Milton R. Young**		
State	**ND**		
Contact	**Tom Bachman**	**tbachman@nd.gov**	**(701) 328-5188**

# of Class I Areas evaluated/within 300 km		2	
Unit		#1	
Boiler Type		cyclone	ND DOH report
Fuel		ND lignite	ND DOH report
Rating (MW Gross)		257	NDDH BART report
Presumptive BART limit (lb/mmBtu)		**0.10**	**cyclone > 200 MW firing lignite**
Rating (mmBtu/hr)		3,200	mmBtu/hr from NDDH BART report
Current Emissions (tpy)		12,054	calculated from NDDH Title V permit
Current Emisison Rate (lb/mmBtu)		0.86	calculated from NDDH Title V permit
ASOFA			
Control Efficiency		40%	calculated
New Emisison Rate (lb/mmBtu)		0.513	from NDDH BACT analysis
New Emissions (tpy)		7,190	calculated
Emissions Reduction (tpy)		4,864	calculated
Capital Cost	$	4,277,000	company BACT analysis
Capital Cost ($/kW)	$	17	calculated
O&M Cost	$	65,776	calculated from company BACT analysis minus the lost generation cost and adjusted to 100%
Total Annual Cost	$	469,494	calculated
Cost-Effectiveness ($/ton)	$	97	calculated
SCR			
Control Efficiency		90%	calculated
New Emisison Rate (lb/mmBtu)		0.049	from NDDH BACT analysis
New Emissions (tpy)		687	calculated
Emissions Reduction (tpy)		6,503	NPS based upon OAQPS Control Cost Manual
Capital Cost	$	180,206,747	calculated
Capital Cost ($/kW)	$	701	calculated
O&M Cost	$	7,383,763	NPS based upon OAQPS Control Cost Manual
Total Annual Cost	$	24,394,005	NPS based upon OAQPS Control Cost Manual
Incremental Cost-Effectiveness ($/ton)	$	3,751	NPS based upon OAQPS Control Cost Manual
ASOFA+SCR			
Control Efficiency		94%	calculated
New Emisison Rate (lb/mmBtu)		0.049	from NDDH BACT analysis
New Emissions (tpy)		687	calculated
Emissions Reduction (tpy)		11,367	calculated
Capital Cost	$	184,483,747	calculated
Capital Cost ($/kW)	$	718	calculated
O&M Cost	$	7,449,539	calculated
Total Annual Cost	$	24,863,500	calculated
Cost-Effectiveness ($/ton)	$	2,187	calculated
NPS			
Effective Reduction from Current		94%	calculated
Effective BART Limit (tpy)		**687**	calculated
Effective Reduction from Current (tpy)		11,367	calculated

Appendix B.
Milton R. Young Unit #2
OAQPS Control Cost Manual Section 4.2, SCR, p2-50

Given/Assumptions

New or Retrofit?	Retrofit		
Extra Direct retrofit cost	1.5	NPS estimate	
Extra Indirect retrofit cost factor	2	NPS estimate	
Generation capacity (MW)	477	NDDH BART report	
SCR bypass included?	Yes	from BACT analysis	
Fuel High Heating Value (Btu/lb)	6,662	from 2006 BACT analysis	
Maximum Fuel Consumption Rate (lb/hr)	9.5E+05	calculated from	6,300 mmBtu/hr from NDDH BART report
Average Annual Fuel Consumption (lb)	8.28E+09	calculated	
Number of SCR Operating Days	365	assumed	
Plant Capacity Factor	100%	from NDDH Title V permit	
Uncontrolled NOx Concentration (lb/mmBtu)	0.86	calculated from NDDH Title V permit	
Uncontrolled NOx Emissions (tpy)	23,731	calculated from NDDH Title V permit	
ASOFA Total Capital Cost	$10,008,000	company BACT analysis	21 $/kW The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
ASOFA Annualized Capital Cost	$ 944,684	calculated from TCC	
ASOFA Annual O&M Cost (not levelized)	$ 159,744	calculated from company BACT analysis minus the lost generation cost and adjusted to	100% availability
ASOFA Total Annual Cost	$ 1,104,429	calculated	
LNB outlet = SCR inlet NOx Concentration (lb/mmBtu)	0.489	from NDDH BACT analysis	
Required Controlled NOx Concentration (lb/mmBtu)	0.049	from NDDH BACT analysis	
Acceptable Ammonia Slip (ppm)	2.0	from OAQPS Cost Manual	
Fuel Volume Flow Rate (ft3/min/mmBtu/hr)	547	from OAQPS Cost Manual	
Fuel Sulfur Content	0.81%	from 2006 BACT analysis	
Fuel Ash Content	8.74%	from 2006 BACT analysis	
Number of SCR reactor chambers	2	from BACT analysis	
ASR	1.05	from OAQPS Cost Manual	
Stored Ammonia Concentration	29%	from OAQPS Cost Manual	
Reagent Molecular Weight (g/mole)	17.03	from OAQPS Cost Manual	
Reagent Density (lb/ft3 @ 60F)	56.0	from OAQPS Cost Manual	
Reagent Specific Volume (gal/ft3)	7.481	from OAQPS Cost Manual	
NOx Molecular Weight (g/mole)	46.01	from OAQPS Cost Manual	
Number of Days of Storage for Ammonia	14	assumed	
Pressure Drop for SCR Ductwork H2O")	3	from OAQPS Cost Manual	
Pressure Drop for each Catalyst Layer (H2O")	1	from OAQPS Cost Manual	
Temperature at SCR Inlet (degrees F)	563	from 2009 BACT analysis	
Equipment Life (years)	20	from OAQPS Cost Manual	
Annual Interest Rate	7%	from OAQPS Cost Manual	
Inflation Since 1998	1.35	CEPCI 2007/CEPCI 1998	
Catalyst Cost, Initial ($/ft3)	$ 85	calculated from	$ 3,000 /m^3 from PacifiCorp report
Catalyst Cost, Replacement ($/ft3)	$ 85	calculated from	$ 3,000 /m^3 from PacifiCorp report
Electrical Power Cost ($/kWh)	0.035	calculated from	$ 35.00 /MWhr from company report
29% Ammonia Solution Cost ($/lb)	$ 0.058	from OAQPS Cost Manual	$ 400.00 ton from PacifiCorp report
Operating Life of Catalyst (hours)	16,000	NDDH BACT report	
Natural gas unit cost ($/mcf)	$ 4.98	EIA 2010 price forecast	
Natural gas for reheat (mcf)	754,569	from BACT analysis	

MR Young Unit 2

Scenario	Upper Bound Heat Input (mmBtu/hr)	Upper Bound NOx Emission Rate (lb/mmBtu)	Upper Bound NOx Emission Rate (lb/hr)	Upper Bound Capacity Utilization	Upper Bound NOx Emission Rate (tpy)	NOx Emission Reduction (tpy)
Pre-BART	6,300	0.86	5,393	100%	23,620	
Post-ASOFA	6,300	0.49	3,081	100%	13,493	10,127
Pre-BART	6,300	0.86	5,393	95%	22,546	
Post-ASOFA	6,300	0.49	3,081	95%	12,880	9,666
Title V	6,300	0.86	5,418	100%	23,731	
Post-ASOFA	6,300	0.49	3,081	100%	13,493	10,237
Title V	6,300	0.86	5,418	95%	22,652	
Post-ASOFA	6,300	0.49	3,081	95%	12,880	9,772

LNB Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.86 - 0.489)/ 0.86 = 43%

Boiler Calculations

2.3 $Q_B = HVm\text{-}dot_{fuel}$

QB = 6662 Btu/lb * 945661.96 lb/hr

QB = 6300 Btu/hr

2.7 $CF_{Plant} = \text{actual } m_{fuel}/\text{maximum } m_{fuel}$

CFPlant = 8.28E+09 lb/yr / 8760 hr/yr / 945661.96 lb/hr

CFPlant = 100%

2.8 $CF_{SCR} = t_{SCR}/365 \text{ days}$

CFSCR = 365 days/ 365 days

CFSCR = 100%

$CF_{Total} = CF_{Plant} \times CF_{SCR}$

CFTotal = 100% * 100%

CFTotal = 100%

2.12 $q_{fluegas} = q_{fuel}Q_B(460+T)/(460+700^{0}F)n_{SCR}$

qfluegas = 547 ft3/min/(mmBtu/hr)* 6300 mmBtu/hr*(460 + 563)/(460 + 700)/ 2

qfluegas = 6,078,207 acfm

2.9 $\eta_{NOx} = (NOx_{in} - NOx_{out}) / NOx_{in}$

ηNOx = (0.489 lb/mmBtu - 0.049 lb/mmBtu)/ 0.489 lb/mmBtu

ηNOx = 90%

Uncontrolled NOx emissions (tpy) **23,731**

Overall Control Efficiency = (Inlet Conc - Outlet Conc)/Inlet conc

(0.86 - 0.049)/ 0.86 = 94%

NOx removed = 22,379 tpy

Controlled NOx emissions (tpy) = 1,352 tpy

SCR Reactor Calculations

2.19 $Vol_{catalyst} = 2.81 \times Q_B \times \eta_{adj} \times Slip_{adj} \times NOx_{adj} \times S_{adj} \times T_{adj}/N_{SCR}$

Volcatalyst = 2.81 * 6300 = 17703

2.2 $\eta_{adj} = 0.2869 + (1.058 \times \eta)$

ηadj = 0.2869 +(1.058 * 0.90)

ηadj = 1.239

2.22 $Slip_{adj} = 1.2835 - (0.0567 \times Slip)$

Slipadj = 1.2835 - (0.057 * 2)

Slipadj = 1.170

2.21 $NOx_{adj} = 0.8524 + (0.3208 \times NOx_{in})$

NOxadj = 0.8524 + (0.321 * **0.49**)

NOxadj = 1.009

2.23 $S_{adj} = 0.9636 + (0.0455 \times S)$

Sadj = 0.9636 + (0.046 * 0.81)

Sadj = 1.000

2.24 $T_{adj} = 15.16 - (0.03937 \times T) + (2.74 \times 10^{-5} \times T^2)$

Tadj = 15.16 - (0.039 * 563) + 2.74E-05 * 316969

Tadj = 1.680

Volcatalyst = 21,762 ft3 each = 616.7 m3 each

2.25 $A_{catalyst} = q_{fluegas}/(16 \text{ ft/sec} \times 60 \text{ sec/min})$

Acatalyst = 6078207 /(16 * 60)

Acatalyst = 6331 ft2

2.26 $A_{SCR} = 1.15 \times A_{catalyst}$

ASCR = 1.15 * 6331

ASCR = 7281 ft2

2.27 $l = w = A_{SCR}^{1/2}$

l = w = 85.3 ft

2.28 $n_{layer} = Vol_{catalyst}/(h'_{layer} \times A_{catalyst})$

nlayer = 21762 /(3.1 * 6331)

nlayer = 1.0

2.29 $h_{layer} = [Vol_{catalyst}/(n_{layer} \times A_{catalyst})] + 1$

hlayer = 21762 /(3 * 6331) + 1

hlayer = 2.1

2.3 $n_{total} = n_{layer} + n_{empty}$

ntotal = 1 + 1

ntotal = 2

2.31 $h_{SCR} = n_{total}(c_1 + h_{layer}r) + c_2$

hSCR = 2 * (7 + 2.1) + 9

hSCR = 27 ft

Reagent Calculations

2.32 $\text{m-dot}_{reagent} = NOx_{in}Q_BASR\eta_{NOx}M_{reagent}/M_{NOx}$

m-dotreagent = **0.489** * 6300 * 1.05 * **90%** * 17.03 / 46.01

m-dotreagent = 1077 lb/hr

2.33 $\text{m-dot}_{sol} = \text{m-dot}_{reagent}/C_{sol}$

m-dotsol = 1077 / 0.29

m-dotsol = 3715 lb/hr

2.34 $q_{sol} = (\text{m-dot}_{vol}/\rho_{sol})V_{sol}$

qsol = 3715 * 7.481 / 56

qsol = 496 gph

2.35 Tank Volume = $q_{sol}t$

Tank Volume = 496 * 14 * 24

Tank Volume = 166,747 gal

Direct Capital Cost

2.36 $DC = Q_B[(\$3380/MMBtu/hr) + f(h_{SCR}) + f(NH_3rate) + f(new) + f(bypass)](3500/Q_B)^{0.35} + f(Vol_{catalyst})$

DC = 6300 (($ 3,380 +

2.37 $f(h_{SCR}) = \{[\$612/(ft\text{-}mmBtu/hr)]h_{SCR}\} - \$187.9/(mmBtu/hr)$

f(hSCR) = 6.12 * 27 - 187.9

f(hSCR) = $ (21) /mmBtu/hr

2.38 $f(NH_3rate) = [(\$411/lb/hr)(m\text{-}dot_{reagent}/Q_B)] - \$473/(mmBtu/hr)$

f(NH3rate) = 411 * 1077 / 6300 - 47.3

f(NH3rate) = $ 23 /mmBtu/hr

2.39 f(new) = $0/(mmBtu/hr) for retrofit

f(new) = $ -

2.41 f(bypass) = $0/(mmBtu/hr) for no bypass

f(bypass) = $ 127 /mmBtu/hr

2.43 $f(Vol_{catalyst}) = Vol_{catalyst}CCinitial$

f(Volcatalyst) = 21762 * 85 * 2 chambers

f(Volcatalyst) = $ 3,700,172

DC = 6300 * ($ 3,380 + $ (21) + $ 23 + $ - + $ 127)*(3500 / 6300)^ 0.35 + $ 3,700,172

DC = $ 21,696,819

Extra Direct retrofit cost factor = 1.5

Inflation Adjustment = 1.35

DC = $ 43,936,059

Indirect Capital Costs

						Cost/DCC
Total Direct Capital Costs, A					$ 43,936,059	
Indirect Installation Costs						
General Facilities			0.05 A		$2,196,803	
Engineering and Home Office Fees			0.10 A		$4,393,606	
Process Contingencies			0.05 A		$2,196,803	
Total Indirect Installation Costs, B	Retrofit factor =	2.0 *	0.20 A =	0.40 A =	$17,574,424	40%
Project Contingency, C =	Retrofit factor =	2.0 *	0.15 (A+B) =	0.3 (A+B) =	$18,453,145	42%
Total Plant Cost D =				A+B+C	$79,963,627	182%
Allowance for Funds During Construction, E =				0	$0	
Royalty Allowance, F =				0	$0	
Preproduction Cost, G =				0.02 (D+E)	$1,599,273	
Inventory Capital, H =						
Initial Catalyst and Chemicals, I =	0.058 /lb *	3715 lb/r *	24 hr/day *	14 days =	$72,396	
Total Capital Investment TCI = D+G+H				+D+E+F+G+H+I	$81,635,296	186%
				Cost/kW =	$171	
Total Capital Investment TCI including LNB + ASOFA =					$91,643,296	
				Cost/kW =	$192	

Indirect Capital Costs						Manual Cost	Manual Cost/DCC	Minnkota Cost	Cost/DCC
Total Direct Capital Costs, A						$ 189,620,329		$189,620,329	
Indirect Installation Costs									
General Facilities				0.05 A		$9,481,016			
Engineering and Home Office Fees				0.10 A		$18,962,033			
Process Contingencies				0.05 A		$9,481,016			
Total Indirect Installation Costs, B	Retrofit factor =	1.0	*	0.20 A =	0.20 A =	$37,924,066	20%	$ 70,460,562	37%
Project Contingency, C =	Retrofit factor =	1.0	*	0.15 (A+B) =	0.15 (A+B) =	$34,131,659	18%	$ 29,593,180	16%
Total Plant Cost D =					A+B+C	$261,676,054	138%	$289,674,071	153%
Allowance for Funds During Construction, E =					0	$0		$ 41,228,900	
Royalty Allowance, F =					0	$0			
Preproduction Cost, G =					0.02 (D+E)	$5,233,521			
Inventory Capital, H =									
Initial Catalyst and Chemicals, I =	0.058 /lb *	### lb/r *		24 hr/day *	14 days =	$72,396			
Escalation								$ 55,436,089	
NG pipeline						$ 6,750,000		$ 6,750,000	
Owner's costs								$ 33,248,637	
Total Capital Investment TCI = D+G+H					+D+E+F+G+H+I	$266,981,971	141%	$426,337,697	225%
					Cost/kW =	$560		$894	
Total Capital Investment TCI including LNB + ASOFA =						$276,989,971		$436,345,697	
					Cost/kW =	$581		$915	

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI
Annual Maintenance Cost = 0.015 * $ **81,635,296**
Annual Maintenance Cost = $ 1,224,529

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$
top = 100% * 8760
top = 8760
Annual Reagent Cost = 3715 * 8760 * 0.058
Annual Reagent Cost = $ 1,887,466

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$
Power = 0.105 * 6300 *(**0.489** * 90% + 0.5 * (3 + 2 * 1))
Power = 1945 kW
Annual Electricity Cost = 1945 * 8760 * 0.035
Annual Electricity Cost = $ 596,279

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$
Catalyst Replacement Cost = 2 * 21762 * 85.01581521 / 1
Catalyst Replacement Cost = $ 3,700,172

2.52 FWF = $i\{1/[(1+i)^Y-1]\}$

2.53 Y = $h_{catalyst}/h_{year}$
Y = 16000 /(100% * 8760)
Y = 2
FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)
FWF = 0.48
Annual Catalyst Cost = $ 1,787,523

Annual natural gas Cost = 754,563 mcf/yr * $4.98 /mcf
Annual natural gas Cost = $ 3,757,724

DAC = $ **9,253,520**

2.55 CRF = $i(1+i)^n/[(1+i)^n-1]$
CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)
CRF = 0.0944

Indirect Annual Cost = CFR * TCI
Indirect Annual Cost = 0.0944 * $ **81,635,296**
Indirect Annual Cost = $ 7,705,794

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost
Total Annual Cost = $ 9,253,520 + 7,705,794
Total Annual Cost = $ **16,959,315** + $ 1,104,429 = $ 18,063,743

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$
NOx Removed = **0.489** * 90% * 6300 * 8760 / 2000
NOx Removed = 12,141

Total NOx Removed = 22,379

2.58 Cost effectiveness = TAC/NOx removed
SCR Cost effectiveness = $ 1,397
Total Cost effectiveness = $ 807

Annual Costs

2.45 DAC = Annual Maintenance Cost + Annual Reagent Cost + Annual Electricity Cost + Annual Water Cost + Annual Catalyst Cost

2.46 Annual Maintenance Cost = 0.015 TCI

Annual Maintenance Cost = 0.015 * **$ 266,981,971**

Annual Maintenance Cost = $ 4,004,730

2.47 Annual Reagent Cost = $q_{reagent}Cost_{reagent}t_{op}$

2.47a $t_{op} = CF_{total}8760hr/yr$

top = 100% * 8760

top = 8760

Annual Reagent Cost = 3715 * 8760 * 0.058

Annual Reagent Cost = $ 1,887,466

2.49 Annual Electricity Cost = Power $(Cost_{elect})t_{op}$

2.48 Power = $0.105Q_B[NOx_{in}\eta NOx + 0.5(\Delta P_{duct} + n_{total}\Delta P_{catalyst})]$

Power = 0.105 * 6300 *(**0.489** * 90% + 0.5 * (3 + 2 * 1))

Power = 1945 kW

Annual Electricity Cost = 1945 * 8760 * 0.035

Annual Electricity Cost = $ 596,279

2.51 Annual Catalyst Replacement Cost = (Catalyst Replacement Cost)FWF

2.5 Catalyst Replacement Cost = $n_{SCR}Vol_{catalyst}CC_{replace}/R_{layer}$

Catalyst Replacement Cost = 2 * 21762 * 85.01581521 / 1

Catalyst Replacement Cost = $ 3,700,172

2.52 $FWF = i\{1/[(1+i)^Y-1]\}$

2.53 $Y = h_{catalyst}/h_{year}$

Y = 16000 /(100% * 8760)

Y = 2

FWF = 0.07 *(1 /(1 + 0.07)^ 2 - 1)

FWF = 0.48

Annual Catalyst Cost = $ **1,787,523**

Annual natural gas Cost = 754,563 mcf/yr * $4.98 /mcf

Annual natural gas Cost = $ 3,757,724

DAC = **$ 12,033,720**

2.55 $CRF = i(1+i)^n/[(1+i)^n-1]$

CRF = 0.07 *(1 + 0.07)^ 20 /((1 + 0.07)^ 20 - 1)

CRF = 0.0944

Indirect Annual Cost = CFR * TCI

Indirect Annual Cost = 0.0944 * **$ 266,981,971**

Indirect Annual Cost = $ 25,201,209

2.56 Total Annual Cost = Direct Annual Cost + Indirect Annual Cost

Total Annual Cost = $ 12,033,720 + 25,201,209

Total Annual Cost = $ **37,234,930** + $ 1,104,429 = $ 38,339,358

2.57 NOx Removed = $NOx_{in}\eta_{NOx}Q_Bt_{op}$

NOx Removed = **0.489** * 90% * 6300 * 8760 / 2000

NOx Removed = 12,141

Total NOx Removed = 22,379

2.58 Cost effectiveness = TAC/NOx removed

SCR Cost effectiveness = $ 3,067

Total Cost effectiveness = $ 1,713

Operating company		**Basin Electric Power**	
Facility		**Milton R. Young**	
State		**ND**	
Contact		**Tom Bachman**	**(701) 328-5188**
# of Class I Areas evaluated/within 300 km		2	
Unit		#2	
Boiler Type		cyclone	ND DOH report
Fuel		ND lignite & PRB	ND DOH report
Rating (MW Gross)		477	ND DOH report
Presumptive BART limit (lb/mmBtu)		**0.10**	**cyclone > 200 MW firing lignite**
Rating (mmBtu/hr)		6,300	mmBtu/hr from NDDH BART report
Current Emissions (tpy)		23,731	calculated from NDDH Title V permit
Current Emisison Rate (lb/mmBtu)		0.86	calculated from NDDH Title V permit
ASOFA			
Control Efficiency		43%	calculated
New Emisison Rate (lb/mmBtu)		0.489	from NDDH BACT analysis
New Emissions (tpy)		13,493	calculated
Emissions Reduction (tpy)		10,237	calculated
Capital Cost	$	10,008,000	company BACT analysis
Capital Cost ($/kW)	$	21	calculated
O&M Cost	$	159,744	calculated from company BACT analysis minus the lost generation cost and adjusted to 100%
Total Annual Cost	$	1,104,429	calculated
Cost-Effectiveness ($/ton)	$	108	calculated
SCR			
Control Efficiency		90%	calculated
New Emisison Rate (lb/mmBtu)		0.049	from NDDH BACT analysis
New Emissions (tpy)		1,352	calculated
Emissions Reduction (tpy)		12,141	NPS based upon OAQPS Control Cost Manual
Capital Cost	$	266,981,971	calculated
Capital Cost ($/kW)	$	560	calculated
O&M Cost	$	12,033,720	NPS based upon OAQPS Control Cost Manual
Total Annual Cost	$	37,234,930	NPS based upon OAQPS Control Cost Manual
Incremental Cost-Effectiveness ($/ton)	$	3,067	NPS based upon OAQPS Control Cost Manual
ASOFA+SCR			
Control Efficiency		94%	calculated
New Emisison Rate (lb/mmBtu)		**0.049**	**lb/mmBtu (30-day rolling average)**
New Emissions (tpy)		1,352	calculated
Emissions Reduction (tpy)		22,379	NPS based upon OAQPS Control Cost Manual
Capital Cost	$	276,989,971	calculated
Capital Cost ($/kW)		581	calculated
O&M Cost	$	12,193,465	calculated
Total Annual Cost	$	38,339,358	calculated from company & ND DOH reports
Cost-Effectiveness ($/ton)	$	1,713	calculated
NPS			
Effective Reduction from Current		94%	calculated
Effective BART Limit (tpy)		**1,352**	calculated
Effective Reduction from Current (tpy)		22,379	calculated

**BASIN ELECTRIC
POWER COOPERATIVE**

1717 EAST INTERSTATE AVENUE
BISMARCK, NORTH DAKOTA 58503-0564
PHONE: 701-223-0441
FAX: 701-557-5336

MAY 2010
Received
Air Quality

May 7, 2010

ND Department of Health
Terry L. O'Clair, Director
Division of Air Quality
918 East Divide Ave, 2nd floor
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

Basin Electric Power Cooperative (**Basin Electric**) appreciates this opportunity to comment on the Department of Health's (**the "Department"**) Notice of Intent to issue a Best Available Control Technology (**BACT**) determination pursuant to Consent Decree in the case of United States of America and the State of North Dakota vs. Minnkota Power Cooperative Inc. and Square Butte Electric Cooperative. The Notice requests comments on the Department's cost estimates and its reasoning for the rejection of low dust and tail end SCR (**TE-SCR**) as BACT.

Basin Electric supports the Department's preliminary determination that low dust and tail-end selective catalytic reduction (**SCR**) do not represent BACT for the Milton R. Young Station.

Basin Electric has particular interest in the Department's decision in this matter because it owns and operates the Leland Olds Station (**LOS**) near Stanton, North Dakota. LOS is a Phase I BART source under the Regional Haze provisions of the Clean Air Act, and, as such, has undergone BART Determination review. LOS Unit 2, like M. R. Young Station, is a cyclone boiler that uses North Dakota lignite feed stock.

Basin Electric retained Sargent & Lundy (**S&L**) to provide a supplemental review for the potential application of SCR controls on the LOS Unit 2 cyclone boiler as part of its BART review. At that time, S&L enjoyed a market participation factor of 46% of all SCR projects built in the United States. Basin Electric's fundamental question to S &L was "is it possible to design an SCR today for Basin Electric's LOS Unit 2 North Dakota Lignite fired cyclone boiler with confidence in its performance?" S&L concluded that they could not design an SCR application for LOS without extensive pilot testing, due to the nature of the cyclone boiler and the burning of North Dakota lignite fuels. This information was presented to the Department and EPA by Basin Electric and S&L representatives in May, 2007 and subsequent discussion specifically relating to the applicability of TE- SCR in March 2009. The presentations were led by S&L's Mr. Bill DePriest, Senior VP and Director of Environmental Services for S&L and Dr. Raj Gaikwad, PhD in Chemical Engineering. S&L's conclusion was that the attributes of lignite gases in an SCR environment are not well understood and need an extensive pilot testing level of investigation to predict performance.

The Department then requested Basin Electric prepare a cost effectiveness evaluation for a TE-SCR control system on LOS Unit 2. A hypothetical cost effectiveness study was performed by S&L (May 2009) and submitted to the Department. The analysis was performed recognizing a high level of uncertainty due to the lack of design and operational knowledge surrounding the application of a TE-SCR on a ND lignite-fired cyclone boiler. The cost evaluation analysis determined a cost effectiveness for TE-SCR (assuming technical feasibility) to be in the range of $4,170 and $5,976/ton depending on the rate of catalyst degradation and the cost of consumables (ammonia and natural gas).The cost estimate developed by S&L represents similar costs as found by the Departments April 2010 BACT Determination for Control of Nitrogen Oxides for Milton R. Young Station ($4,201 -$4,822/ton). These ranges accurately reflect the high cost per ton of implementing SCR technologies and we concur with the Department's determination that these costs are unreasonable for the application of TE-SCR on a North Dakota fired cyclone boiler.

Basin Electric finds it particularly significant that when actually called upon by Minnkota to provide a guarantee, two catalyst vendors, who had apparently earlier indicated that such a guarantee was available, refused to provide a catalyst life guarantee for either low-dust SCR or tail-end SCR without pilot scale testing. That refusal confirms the concerns noted in the report of S&L submitted by Basin Electric to the Department in the spring of 2007 and the follow-up May 2009 report.

In conclusion, Basin Electric supports the Department's findings that BACT for the M. R. Young Station is represented by SNCR plus ASOFA.

Thank you very much for this opportunity to comment.

Sincerely,

Cris Miller

Cris Miller
Senior Environmental Project Administrator

cm/dfl/ds

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OTTER TAIL
POWER COMPANY

APR 2010
Received
Air Quality

April 29, 2010

Mr. Terry O'Clair
Director
Division of Air Quality
North Dakota Department of Health
918 East Divide Avenue, 2nd Floor
Bismarck, ND 58501-1947

Dear Mr. O'Clair:

Subject: Notice of Intent to Issue a BACT Determination Pursuant to Consent Decree
M. R. Young Station

The purpose of this letter is to respond to the North Dakota Department of Health's April 6, 2010, Notice of Intent to Issue a Best Available Control Technology Determination Pursuant to Consent Decree for the reduction of nitrogen oxides emissions from the Milton R. Young Station near Center North Dakota. The following comments are made by Otter Tail Power on behalf of the Coyote Station co-owners-- NorthWestern Energy, Montana-Dakota Utilities Co., Northern Municipal Power Agency whose interests are represented by Minnkota Power Cooperative and Otter Tail Power Company.

Otter Tail understands that the Department made a preliminary determination that high dust, low dust, and tail end selective catalytic reduction (SCR) were not technically feasible at the M. R. Young Station in June of 2008. Following additional public comment, the Department subsequently determined that low dust and tail end SCR were technically feasible based on information available at the time of the determination.

Otter Tail has reviewed the Department's April 2010 evaluation "Best Available Control Technology Determination for Control of Nitrogen Oxides for M. R. Young Station Units 1 and 2." Given that both of the vendors Minnkota contacted refused to provide a catalyst life guarantee for either the low dust or the tail end SCR without pilot testing, Otter Tail agrees with and supports the Department's proposed determination that low dust and tail end SCR do not represent BACT.

Otter Tail further supports the Department's observation that since the vendors will not provide a catalyst guarantee without pilot-scale testing indicates such use on a boiler firing North Dakota lignite could, and arguably, should be considered in the pilot scale testing stage of development. Based on Section IV.B of EPA's New Source Review Workshop Manual, technologies in the pilot-scale testing states of development would not be considered available for BACT review.

Consequently, the Department has made a correct determination that high dust, low dust and tail end selective catalytic reduction do not represent BACT at M. R. Young Station.

Otter Tail Power Company appreciates the opportunity to provide comments in this matter.

Sincerely,

Terry Graumann
Manager, Environmental Services

Enclosure

C. Mr. Dennis Wagner - NWPS
Mr. Alan Welte – MDU
Mr. Al Tschepen - MPC
Ms. Stacie Hebert – OTP

UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF NORTH DAKOTA

UNITED STATES OF AMERICA, STATE OF NORTH DAKOTA, Plaintiffs, v. MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE, Defendants.	)	CIVIL ACTION NO. 1:06-CV-034

STATE OF NORTH DAKOTA'S MEMORANDUM IN OPPOSITION TO UNITED STATES' PETITION FOR DISPUTE RESOLUTION UNDER THE 2006 CONSENT DECREE

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I. INTRODUCTION

Pursuant to the 2006 Consent Decree, between the State of North Dakota ("**State**"), the United States Environmental Protection Agency ("**EPA**"), Minnkota Power Cooperative ("**Minnkota**") and Square Butte Power Cooperative[1], the North Dakota Department of Health ("**NDDH**") reached a reasoned and well supported best available control technology ("**BACT**") determination authorized by the governing legal framework and fully supported by the underlying administrative record. The United States of America, on behalf of EPA now challenges the "reasonableness" of the BACT determination made by the State for Units 1 and 2 at the Milton R. Young Station ("**MRYS**").

The State's BACT determination came after a more than four year process during which the NDDH (1) carefully reviewed the nitrogen dioxide ("**NO_x**") Top Down BACT Analysis ("**BACT Analysis**") submitted by Minnkota; (2) worked closely with EPA and Minnkota to address questions and technical issues concerning the BACT Analysis; (3) conducted independent research and prepared extensive technical analyses; (4) solicited and considered comments from interested members of the public on multiple occasions - including extensive input from EPA; and (5) attempted to work closely with the EPA to come to an acceptable resolution on what level of BACT was appropriate and technically feasible at the MRYS.

In its "Findings of Fact for Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2," (dated November, 2010), the NDDH spent nearly fourteen (14) pages explaining the basis of its BACT determination. *See*

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[1] Minnkota and Square Butte were the "Settling Defendants" in the 2006 Consent Decree. Minnkota owns the 235 MW lignite coal-fired cyclone furnace EGU (Unit 1), and Square Butte owns the 440 MW lignite coal-fired cyclone furnace EGU (Unit 2), at MRYS. Minnkota operates Units 1 and 2.

Administrative Record (AR) 240. In addition to its Findings, the NDDH contemporaneously responded to all public comments received (including those from EPA). *See* AR 241. The State's BACT determination concluded that the installation of Selective Non-Catalytic Reduction ("**SNCR**") plus advanced separated overfire air ("**ASOFA**") as BACT to control emissions of NO_x at MYRS was appropriate, will result in substantial NO_x emission reductions, and complies with all applicable state and federal standards. In the course of conducting its BACT determination, the State considered but rejected Selective Catalytic Reduction ("**SCR**") technology - due to technical infeasibility.

The State's BACT determination is based upon a detailed accounting of its reasoned consideration of alternative technologies and their associated "energy, environmental, and economic impacts and other costs." 42 U.S.C. § 7479(3). Because the administrative record clearly supports the NDDH's reasoned BACT determination, this Court should, therefore, affirm the State's BACT determination and reject the relief sought by EPA.

II. JURISDICTION

The Consent Decree provides that jurisdiction is proper in this Court.

III. STANDARD OF REVIEW

The Consent Decree provides that "[t]he Court shall sustain the [BACT] determination decision by NDDH unless the Party disputing the BACT determination demonstrates that it is not supported by the state administrative record and not reasonable in light of applicable statutory and regulatory provisions." *See* Consent Decree para. 147(c).

The Court must determine whether North Dakota's BACT determination was "reasonable, in light of the statutory guides and the state administrative record." Alaska Department of Environmental Control v. U.S. E.P.A., 540 U.S. 461, 494 (2004). Under both the

Consent Decree and Alaska, "the production and persuasion burdens remain with EPA," Alaska v. EPA, 540 U.S. 494 and Consent Decree, para. 51. The Supreme Court has also made clear that an agency's explanation for a particular decision is "satisfactory" so long as the agency articulates a "rational connection between the facts found and the choice made." Motor Vehicle Mfrs. Ass'n v. State Farm Mut. Auto. Ins. Co., 463 U.S. 29, 43 (1983) (quotation omitted).

"Even when an agency explains its decision with 'less than ideal clarity,' a reviewing court will not upset the decision on that account 'if the agency's path may reasonably be discerned.'" Bowman Transp., Inc. v. Arkansas-Best Freight System, Inc., 419 U.S. 281, 286 (1974). Moreover, given that the subject matter that the NDDH is considering and issuing a determination on is "complex or technical and involves agency expertise" the NDDH's determination is entitled to deference. People to Save the Sheyenne River v. North Dakota Department of Public Health et al., 697 N.W. 2d. 319, 328-329 (N.D. 2005). Only where the agency decision is not "the product of a rational mental process by which the facts and the law relied upon are considered together for the purpose of achieving a reasoned and reasonable interpretation" is that decision arbitrary, capricious or unreasonable. Sheyenne River v. North Dakota, 697 N.W.2d 329.

IV. STATUTORY AND REGULATORY BACKGROUND

A. The Clean Air Act

The federal Clean Air Act (**"CAA"**) establishes "a comprehensive national program that makes the States and the Federal Government partners in the struggle against air pollution." General Motors Corp. v. United States, 496 U.S. 530, 532 (1990). At the same time, the CAA recognizes that "air pollution prevention * * * and air pollution control at its source is the primary responsibility of States and local governments." 42 U.S.C. § 7401(a)(3); *see also id.* §

7407(a) ("Each State shall have the primary responsibility for assuring air quality within the entire geographic area comprising such State"). Thus, while the CAA assigns the EPA the responsibility for establishing national ambient air quality standards ("**NAAQS**") for certain pollutants, the assigns the States the responsibility for implementing them. *See id.* §§ 7407(a), 7409, 7410(a).

To this end, the CAA requires each State to adopt and submit for the EPA's approval a state implementation plan ("**SIP**") that provides for the attainment and maintenance of the NAAQS. *See id.* § 7410(a). North Dakota has an EPA approved SIP. *See* 40 C.F.R. 52, Subpart JJ.

Areas of the country "that meet[] the [NAAQS] for a [given] pollutant" (attainment areas) or for which insufficient information exists to determine whether the NAAQS have been met (unclassifiable areas) are known as "clean air" areas. 42 U.S.C. § 7407(d)(1)(A)(ii), (iii). The CAA establishes maximum allowable increases (or increments) of certain pollutants in such clean air areas. *See Id.* § 7473; *see* 40 C.F.R. § 51.166(c) (establishing increments for nitrogen dioxide). To ensure in part that those increments are not exceeded, the CAA requires that each SIP contain emission limitations and such other provisions as may be necessary "to prevent significant deterioration of air quality" in clean air areas, including a Prevention of Significant Deterioration ("**PSD**") permit program. *Id.* 42 U.S.C. §§ 7410(a)(2)(C), 7471. The CAA provides that no "major emitting facility" may be constructed or modified in a clean air area without a PSD permit. *Id.* § 7475(a)(1). North Dakota is currently in attainment with all EPA NAAQS and air quality standards - including those for ozone and NO_X. *See* 40 C.F.R. § 81.335.

The CAA also provides that no major emitting facility may be constructed or modified unless "the proposed facility is subject to the [BACT] for each pollutant subject to regulation under [the CAA] emitted from, or which results from, such facility." 42 U.S.C. § 7475(a)(4). BACT is defined as

> "an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under [the CAA] emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility * * *." [*Id.* § 7479(3).]

As the legislative history of the CAA's PSD provisions makes clear, the determination of BACT is "key" to a State's ability to manage "growth" within its borders. *See* S. Rep. No. 95-127, at 31 (1977). For this reason, Congress "placed this responsibility with the State, to be determined in a case-by-case judgment." *Id.* "It is recognized that the phrase has broad flexibility in how it should and can be interpreted, depending on site." *Id.* The "flexible approach" adopted by Congress "enables [a] State to consider the size of the plant, the increment of air quality which will be absorbed by any particular major emitting facility, and such other considerations as anticipated and desired economic growth for the area." *Id.* The determination of BACT is "strictly a State and local decision"—"flexibility and State judgment are [its] foundations." *Id.*[2]

B. The 2006 Consent Decree

Consistent with the CAA and North Dakota's laws and EPA-approved SIP, the Consent Decree recognizes the NDDH as the permitting authority with responsibility for determining

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[2] *See also* Senate Debate on S.252 (June 8, 1977), reprinted in Senate Committee on Environment And Public Works, A Legislative History of the Clean Air Act Amendments of 1977 at 729 (Comm. Print August 1978) (Congressional Research Service, Serial No. 95-16). ("One objection which has been raised to requiring the use of the best available control technology is that a technology demonstrated to be applicable in one area of the country is not applicable at a new facility in another area because of difference[s] in feedstock material, plant configuration or other reasons. For this and other reasons, the committee voted to permit emission limits based on best available technology on a case-by-case judgment at the State level. This flexibility should allow such differences to be accommodated and still maximize the use of improved technology.") (emphasis added).

BACT for NO_x. *See* N.D. Admin. Code § 23-25. To implement the settlement provisions regarding NO_x, Paragraph 65 of the Consent Decree first requires Minnkota to develop and submit to the NDDH a "NO_x Top-Down BACT Analysis." Specifically, "NO_x Top-Down BACT Analysis shall mean a study prepared by [Minnkota] to identify the emission limits required by 42 U.S.C. § 7475(a)(4) and 40 C.F.R. § 52.21(j)(3), defined by 42 U.S.C. § 7479(3) and 40 C.F.R. §52.21(b)(12), and expressed as a 30-Day Rolling average NO_x Emission Rate." Consent Decree para. 24. The Consent Decree also expressly identifies the technologies Minnkota must evaluate as part of its BACT Analysis, including SCR, SNCR, ASOFA, and rich reagent injection (RRI). *See* Consent Decree para. 65. The BACT Analysis must address both a normal operating scenario and a startup scenario, specify the technology to be installed, and recommend an emission rate on 30-day rolling average basis, that is BACT for each of the units and for each scenario evaluated. *See Id.*

The Consent Decree further required Minnkota to complete its BACT Analysis in accordance with the provisions of EPA's draft guidance document "New Source Review Workshop Manual-Prevention of Significant Deterioration and Nonattainment Area Permitting," (Draft October 1990) ("**EPA's Draft NSR Manual**"). *See* EPA's Draft NSR Manual at AR 75. Specifically, Chapter B of the EPA Draft NSR Manual is to be consulted when conducting the BACT Analysis. The BACT Analysis required under the Consent Decree shall not include any other elements of PSD permitting required by other chapters of EPA's Draft NSR Manual (notwithstanding any cross-reference in Chapter B to such other chapters), 40 C.F.R. § 52.21, or N.D. Admin. Code § 33-15-15-01.2. *See* Consent Decree para. 24.

EPA's Draft NSR Manual contains, *inter alia*, 75 pages of guidance on how to conduct a BACT analysis. Importantly, the EPA Draft NSR Manual never identifies, or suggests, that there is a "correct" answer to what a BACT analysis must determine. Rather, a BACT analysis is done on a "case-by-case" basis, and involves a weighing of a number of factors including energy, environmental and economic impacts and other costs. *See* 42 U.S.C. § 7479(3). *See also* N.D. Admin. Code §§ 23-25, 33-15-15-01.2. While the Consent Decree requires that the BACT "top-down" method be utilized when conducting the BACT Analysis, the "top-down" method is merely recommended in the EPA Draft NSR Manual. The "top down" method ranks available control technologies in order of control effectiveness. *See* EPA Draft NSR Manual AR 75 at B.6-7. The method consists of five detailed analyses: identification of available control technologies, elimination of technically infeasible options, ranking of control technologies by control effectiveness, evaluation of most effective controls and documentation of results and the selection of BACT. *See* EPA Draft NSR Manual AR 75 at B.6-9. Importantly, the EPA Draft NSR Manual repeatedly recognizes the numerous subjective judgments that must be made in each and every step of the BACT analysis. The EPA Draft NSR Manual is replete with references to the exercise of "judgment" by the applicant and the reviewing authority.[3] It is the exercise of judgment, in accordance with applicable federal and state statutes, regulations and guidance that NDDH applied when reviewing and conducting the NO_x Top Down BACT Analysis and issuing its BACT determination. *See* Consent Decree at para. 66.

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[3] See, e.g., EPA Draft NSR Manual at B.13, (However, there may be instances where, in the permit authority's judgment, the consideration of alternative production processes is warranted and appropriate for consideration in the BACT analysis), B.19, ("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), B.20, ("Consequently, judgment should be used in deciding what alternatives will be evaluated in detail in the impacts analysis (Step 4) of the top-down procedure discussed in a later section"), B.24, ("Consequently, in assessing the capability of the control alternative, latitude exists to consider any special circumstances pertinent to the specific source under review, or regarding the prior application of the control alternative").

V. FACTUAL BACKGROUND

A. Overview of The State's BACT Analysis and Determination

On October 9, 2006, the NDDH received Minnkota's NO_x Top-Down BACT Analysis. *See* AR 84, 85. Upon receipt of Minnkota's BACT Analysis, NDDH reviewed and conducted its own analysis in accordance with the Consent Decree. Between the time of submission in October 2006 and NDDH's Preliminary BACT determination in February 2008, NDDH consulted with both Minnkota and EPA, receiving and exchanging information with each party. *See* AR 54, 55, 60, 63, 64, 74, 86-92, 94-98, 147 and 239. The NDDH considered and incorporated many of EPA's comments into the Preliminary BACT determination and in June 2008 sought public comment for the Preliminary BACT Determination. *See* AR 79.

The June 2008, Preliminary BACT Determination proposed that SCR, including high dust SCR ("**HDSCR**"), low dust SCR ("**LDSCR**"), and tail-end SCR ("**TESCR**"), was not technically feasible for the MRYS. *See* AR 79 at 10 and 51-59. Comments were received from EPA, environmental groups, and industry. *See* AR 99, 199, 200, 201 and 202. Generally, comments received pertained to issues involving the technical feasibility of many control options including SCR, appropriate emission limits, and other issues associated with the required BACT determination process.

In November 2008, as a result of public comments received, the NDDH confirmed that HDSCR was not technically feasible; however, it preliminarily considered that LDSCR and TESCR could possibly be successfully operated at MRYS. *See* AR 220. Based on the comments received during the June 2008 public comment period from SCR vendors and EPA, NDDH was led to conclude that TESCR and LDSCR had a good probability of successful application at MRYS. However, NDDH sought to further evaluate the issue of technical feasibility of LDSCR and TESCR and asked Minnkota to submit additional information regarding the technical feasibility of LDSCR and TESCR, which it did in February 2009. NDDH then requested that Minnkota submit an economic analysis and other information required to conduct the Steps 3 and 4 of the Top Down BACT Analysis for TESCR and LDSCR. *See* AR 220. This analysis was submitted by Minnkota in November 2009 and was revised in February 2010. *See* AR 173, 174, 176, 177.

In April 2010, the NDDH sought public comment on a second Preliminary BACT Determination. *See* AR 257. The second Preliminary BACT Determination proposed that BACT at MRYS was **SNCR plus ASOFA** and solicited public comment to this preliminary determination. Based upon the data and information received and the BACT Analysis conducted by Minnkota, the NDDH's second Preliminary BACT Determination proposed that SCR (HDSCR, LDSCR, and TESCR) was not BACT for MRYS and again concluded that HDSCR was not technically feasible. *See* AR 172. Since NDDH's 2008 preliminary technical feasibility determination, in which it indicated that TESCR and LDSCR had a good probability of successful application at MRYS, important information was presented to NDDH that indicated no SCR application was in fact feasible at MRYS. *See* AR 177, 221, 223, 238, 246.

First, the NDDH learned that contrary to information earlier provided, Haldor Topsoe, Incorporated ("**HTI**") and CERAM Environmental, Incorporated ("**CERAM**"), (both potential vendors for SCR catalyst at MRYS)[4], would not provide a catalyst life guarantee for either

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[4] HTI and CERAM are highly qualified catalyst suppliers. As noted by EPA's consultant Mr. Hartenstein, CERAM is "the most qualified and experienced catalyst supplier," and a leader in the industry. AR 249 at 12, *see also* AR 99 (EPA Comments) at p.11.

LDSCR or TESCR. *See* AR 221. Second, NDDH learned that both HTI and CERAM indicated that the flue gas evaluation done in the 2008 technical feasibility analysis was not sufficient to make a determination of whether SCR was sufficient to make a determination of SCR at MRYS. *See* AR 238 and AR 240 at p. 3. NDDH, and vendors of SCR, must look at the full range of flue gas characteristics from an electric generating unit when evaluating the application of SCR. Since catalyst deactivation can occur rapidly, the worst case flue gas characteristics of a unit are important and must be evaluated. *See* AR 238. The 2008 technical feasibility analysis only evaluated one concentration of sodium and potassium in the flue gas, and this concentration did not account for worst case conditions. *See* AR 220 at p. 12, pp. 21-23. Third, the vendors indicated that the flue gas characteristics at MRYS may be worse than the biomass boilers where 7 ESCR had been applied that NDDH evaluated. *See* AR 223 at p. 6. The vendors also stated that they were unaware of any SCR application in the industry with the same levels and forms of sodium that are present at MRYS. *See* AR 223 at p. 6. As a result of this information and analysis, NDDH determined that the information and data earlier supplied to it concerning the technical feasibility of TESCR and LDSCR was misleading and incomplete. *See* AR 172 at 9, 240 at 3. The NDDH also determined, as a result, SCR could not be BACT for MRYS. *See Id.*

On November 18, 2010, the NDDH concluded its BACT determination process by issuing two principal detailed documents. One was a "Response to Comments" and the other was entitled "Findings of Fact for Best Available Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2." *See* AR 240-241. The Findings of Fact detailed why and how the NDDH determined SCR is not technically feasible at MRYS. As detailed further below, the unique characteristics of the MRYS coupled with the fact that there has yet to be a source type with the same or similar flue gas characteristics similar to that of MRYS where SCR has been applied, led NDDH to reasonably conclude that LDSCR and TESCR are technically infeasible.

During the 2008 public comment period, NDDH received comments from EPA, environmental groups, and industry. During the second public comment period in 2010, comments were received from EPA, the Federal Land Managers, environmental groups, and industry. NDDH not only reviewed and closely considered all public comment, but also addressed these comments when it issued the BACT Determination. Further, the administrative record clearly demonstrates that NDDH consulted and worked with EPA before, during and after the formal public comment periods to address and consider EPA's comments to the BACT Analysis. At no point did NDDH dismiss or ignore EPA's comments.

VI. ARGUMENT

A. The Extensive Administrative Record Supports NDDH's Reasonable BACT Determination

EPA claims that NDDH incorrectly concluded that SCR is not available, because it "ignored the widely available literature and information regarding the availability of SCRs in the United States and elsewhere." EPA Memorandum in Support at p. 16. Further, EPA claims the administrative record reflects that SCR is currently in use on hundreds of coal fired boilers, and had been in commercial use throughout the world for over thirty years, including the United States since the 1990s, and is an available technology for use on coal-fired electrical generating units. *See* EPA Memorandum in Support at p. 18. Lastly, EPA claims that accordingly, SCR is beyond the developmental stage and is an "available" technology for use on coal-fired electrical generating units, even if there is no current application specifically on electrical generating units equipped with cyclone boilers burning North Dakota lignite coal. *See id.* EPA asserts that the technology's application in these similar sources is all the EPA Draft NSR Manual requires. *See id.*

The State's administrative record however, demonstrates that the NDDH closely analyzed the option of installing SCR at MRYS and based upon the information and data available, in its technical judgment determined that the use of SCR at MRYS is not a technically feasible control technology. *See* AR 240, 241. As demonstrated in the record and herein, it is too simplistic to say that an emission control technology such as SCR can be universally applied to any electric generating unit merely because it has been deployed on some units. As the EPA Draft NSR Manual clearly provides "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.)** *emphasis added.* EPA NSR Draft Manual B.19, AR 75. Clearly, the individual characteristics of a unit will therefore ultimately determine what control technology <u>can</u> be deployed. Far more technical analysis and consideration is required when making a BACT determination than just adopting a control technology because it is being used elsewhere.

1. A control technology is feasible only if its "available" and "applicable".

When evaluating whether a technology is feasible it must be determined to be "available" and "applicable". EPA NSR Draft Manual B.17, AR 75. Generally, a control technology, such as SCR, is considered commercially available "if it has reached the licensing and commercial sales stage of development." EPA NSR Draft Manual B.18, AR 75. However, merely because a control technology is commercially available "is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible." *Id.* To be technically feasible the control option must "reasonably be deployed on or "applicable" to the source type under consideration." *Id.* The state agency making a determination of technical feasibility exercises its "technical judgment ... in determining whether a control alternative is applicable to the source type under consideration." *Id.* And "[i]n general, a commercially available control option will be presumed applicable if it has been used on the same or a similar source type." *Id.*

While SCR technology is available and has been in use for many years, it has not been applied on a source with flue gas characteristics similar to or the same as is present at MRYS. In order for NDDH and Minnkota to demonstrate the technical feasibility of SCR, pilot testing is required. However, if a technology must be pilot tested, it is not considered by EPA to be available for BACT. Specifically, 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." EPA NSR Draft Manual B.18, AR 75. Further, even if a technology is commercially available does not mean it is technically feasible. *Id.*

As detailed below, the administrative record clearly supports NDDH's reasonable determination that SCR is neither available nor applicable and therefore is not technically feasible at MRYS.

2. The unique existing design characteristics of the MRYS units prevent the application of SCR at those units.

The MRYS units are cyclone boilers that utilize North Dakota lignite as fuel. *See* AR 84, 85 at 9. Because the lignite combusted at MRYS contains high quantities of soluble sodium and potassium, the flue gas from these units contains sodium and potassium and is organically associated (*i.e.* soluble sodium and potassium). Specifically, core samples for 2007-2010 indicated a sodium oxide (Na2O) concentration in the ash as high as 13.4% and a potassium oxide (K2O) concentration as high as 6.9%. *See* AR 91 at 104. Additionally, cyclone boilers produce more fine aerosols of sodium and potassium than other types of boilers due to a higher operating temperature. *See* AR 90 at p.9, 91 at p.22, 101 at p.3, 105 at p.7 and 223 at p.6.

During combustion of this fuel in the cyclone furnaces at MRYS, a significant portion of these organically associated elements are either vaporized or form small particles that leave the boiler in the flue gas. Soluble sodium and potassium are catalyst poisons even in dry conditions in the SCR. *See* AR 223 at p.6, 127, 128, 141 and 101 at p.33. The soluble sodium and potassium can also form sulfates that can blind and plug the catalyst pores and plug the catalyst channels. *See* AR 84 at p.110, 90 at p.14, 101 at p.8, and 105 at pgs.34-46. Further, the sticky nature of the ash at MRYS can cause severe ash deposition problems. *See* AR 84, and 85 at p.110. The flue gas characteristics of MRYS are significantly different from other boilers where SCR has been applied. *See* AR 223 at p.6. The high soluble sodium content (catalyst poison) and the sticky nature of the ash are characteristics that are different from facilities where SCR has been successfully applied.[5]

In conducting its analysis of the technical feasibility of SCR at MRYS, the NDDH examined "the physical and chemical characteristics of the pollutant-bearing gas stream," and attempted to compare it "to the gas stream characteristics of the source types to which the technology had been applied previously." EPA Draft NSR Manual, AR 75 B.18. However, because SCR has not been previously applied to a unit operating on North Dakota lignite there is no means by which to compare the deployment of SCR at MRYS to an "existing source with

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[5] In a May 2009 white paper, the ICAC opined on the feasibility of SCR in "similar boilers." AR 170. According to EPA, the ICAC determined that SCR is feasible in lignite coal boilers and that any difficulties that arise because of lignite's high sodium content can be resolved through technical advances, such as adjustments to the catalysts and improved temperature regulation. While in the NDDH record and considered, NDDH did not find this White Paper and its contents to be grounds to adopt. The NDDH found that the ICAC did not evaluate the flue gas characteristics of North Dakota lignite and erroneously claimed that sodium and potassium were not an issue as long as the catalyst remained above dew point conditions. In the 2010 Preliminary BACT Determination (AR 172, p. 9), the NDDH explained that CERAM had indicated that sodium and potassium aerosols can penetrate and neutralize active pore site even in dry conditions. Research by Zheng et.al. (AR 127 and 141) and Kling et. al. (AR 128) found rapid deactivation of SCR catalyst at biomass fired boilers when the catalyst remained well above dew point conditions. Minnkota has also addressed this issue in its submissions to NDDH. (AR 101, p. 21-24, 33).

similar gas stream characteristics." *Id.* If there were, NDDH may have been able to determine that there is "sufficient basis for concluding [SCR] is technically feasible." *Id.* However, as the BACT record demonstrates such a conclusion cannot be reached because there is no data or existing application of SCR at a unit that burns North Dakota lignite, let alone one that operates a cyclone boiler. *See* AR 84 at p.105, 240 at p.7 and 223 at p.6. Accordingly, NDDH's determination was reasonable since under the specific circumstances deployment of SCR at MRYS is precluded.

3. NDDH's determination that SCR is not an "applicable" technology at the MRYS Units was reached in accordance with the EPA Draft NSR Manual.

The United States asserts that under EPA's Draft NSR Manual the feasibility of SCR at MRYS should be presumed. *See* EPA Memorandum in Support at p. 22. However, under the EPA Draft NSR Manual this presumption can be overcome with quantitative evidence of the technical infeasibility for the source under review. "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." EPA Draft NSR Manual B.20, AR 75. Further, technical infeasibility may be shown "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." *Id* at B. 19, AR 75. Decisions about technical feasibility would be based on the chemical and engineering analyses (as noted above) in conjunction with information regarding vendor guarantees. *Id* at B.20, AR 75. Additionally, whether candidate add-on controls for the BACT determination may have been applied to a broad range of emission unit types that are similar, insofar as emissions characteristics, to the emission unit undergoing the BACT review are considered. *Id* at B.10, AR 75. Because similar sources have similar flue gas characteristics, evaluation and consideration of the application of similar technologies on similar sources is necessary.

As demonstrated in the NDDH administrative record, quantitative substantial evidence demonstrates that the application of SCR at MRYS is technically infeasible. There is no source similar to the MRYS units that has installed SCR. *See* AR 223 at p.6, AR 84 & 85 at p.105. While in other parts of the country SCR may be operating on units that burn lignite, those units are designed differently, e.g. may not be cyclone boilers. *See* AR 90 at p.8, 84 and 85 at p.105. Further, the North Dakota lignite burned at MRYS is different than the lignite burned at other units that have installed SCR controls. The composition of North Dakota lignite is a critical factor when determining the technical feasibility of SCR at MRYS, one that cannot be overlooked. The BACT Analysis demonstrates the technical basis for NDDH's conclusion that the composition of the lignite burned at MRYS would not permit the application of SCR. Decisions regarding the technical feasibility of SCR "are within the purview" of the NDDH. Draft EPA NSR Manual at B.19, AR 75. Accordingly, the NDDH, applying its reasonable judgment and expertise in these issues, concluded that SCR could not be BACT for MRYS.

4. **The record supports that no vendor will offer a catalyst guarantee for SCR at MRYS.**

EPA erroneously claims that NDDH misapplied the standards set forth in the Draft NSR Manual and inappropriately relies on the absence of a commercial catalyst guarantee to support its determination that SCR is technically infeasible. *See* EPA Memorandum in Support at p. 16. Whether a vendor catalyst guarantee can be secured is an important element of whether SCR is technically infeasible at MRYS, but as the record clearly demonstrates it is not the only reason why SCR is technically infeasible. The lack of a vendor guarantee, when considered with the overwhelming evidence that SCR at MRYS is technically infeasible and cost prohibitive, only serves to further demonstrate that SCR is not BACT at MRYS.

As documented by the NDDH in its administrative record, no vendor/contractor that supplied a proposal to Minnkota will provide Minnkota with a catalyst life guarantee for SCR at MRYS. *See* AR 221. While lack of a vendor guarantee is not itself sufficient to demonstrate that a technology is infeasible, it "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." EPA Draft NSR Manual B.20, AR 75. Decisions about technical feasibility are based on chemical and engineering analysis in conjunction with information about vendor guarantees. *See id.*

The NDDH consulted with EPA and EPA's consultants on whether SCR was technically feasible at MRYS. As set forth in the administrative record, in 2008 an EPA contractor initially indicated to NDDH that a catalyst life guarantee was available for TESCR at MRYS. *See* AR 99, EPA Comments with Enclosures 1 and 2 at 52. This initial assurance from the vendors led NDDH to initially indicate that LDSCR and TESCR were technically feasible and had a potential for successful application at MRYS. *See* AR 220.

When Minnkota received responses to its request for proposals for SCR at MRYS in 2009, two of the vendors that had initially told EPA they would provide catalyst life guarantees, (CERAM and HTI), subsequently informed Minnkota that they would not provide such guarantees without pilot testing. *See* AR 221 at pp.3-5. EPA, through their contractor Evonik Energy Services, LLC, then solicited proposals for SCR for a facility that supposedly represented

MRYS. *See* AR 225, BACT Cost Enclosures- Non CBI Enclosure, Enclosure 15. Three vendors (CERAM, HTI and Johnson Mathey) provided proposals to Evonik and all indicated they would provide a catalyst life guarantee for the facility described by Evonik. Unfortunately, it was later discovered that EPA's consultants provided the vendors with insufficient information about the nature and design of the MRYS units, including the unique chemical make-up of North Dakota lignite on the unique cyclone-fired boilers in place on MRYS Units 1 and 2. *See* AR 246 at p.61. As such, the vendors did not take these unique circumstances into account when it provided an initial assurance that a guarantee would be available were SCR installed at MRYS.

Based upon responses to Minnkota's request for proposals (*See* AR 177, Enclosure D), letters from CERAM and HTI (*See* AR 221) and phone conversations with CERAM and HTI (*See* AR 238), NDDH concluded that the vendors who had initially indicated that SCR could be applied at MRYS would no longer guarantee SCR at MRYS. *See* AR 240 at p.9 No.11and 12. Vendors have stated that they are unaware of any SCR application experience in the industry that has the same levels and forms of sodium in the ash as is present at MRYS. *See* AR 223 at p.6. And while SCR has been installed at units that burn lignite, the lignite burned at these other units is completely different than that of North Dakota lignite. *See* AR 79 at p.20, AR 90 at p.8, AR 91 at p.95, AR 94 at pp.8 & 22, and AR 101at p.30. As detailed in the administrative record, Minnkota demonstrated that the ash from MRYS is different from Gulf Coast lignite, Texas lignite and European brown coals where SCR has been applied. *See* AR 90 at p.8, AR 91 at p.95, AR 94 at p.22, and AR101at p.30. And while vendors have offered catalyst life guarantees for other lignite fired units, including Texas lignite, they refuse to provide a catalyst life guarantee for MRYS which burns North Dakota lignite. *See* AR 221, AR 238, AR 246 at p.63.

NDDH also independently confirmed with vendors that only were there to first be pilot testing at the MRYS units would the vendors agree to proceed with providing a catalyst life guarantee for SCR. *See* AR 238. But even with pilot testing, SCR at MRYS cannot still be considered technically feasible. "[T]echnologies in the pilot scale testing stages of development would not be considered available for BACT review." EPA Draft NSR Manual B. 18, AR 75. Further, pilot testing of a technology does not mean that such technology is to be considered as an "available" control technology. *See* EPA Draft NSR Manual B.18, AR 75. If it is necessary to first test a technology to determine whether it will be feasible, clearly that technology cannot be considered to be "available" for deployment at a unit.

5. Because SCR at MRYS is Technically Infeasible, its Excessive Cost Was Not Determinative in the Final BACT Determination.

By using increased cost as a basis for assessing the feasibility of SCR application at MRYS, EPA erroneously asserts NDDH improperly incorporated the economic impact of SCR into its feasibility analysis. EPA's assertion is incorrect. The basis for NDDH's rejection of SCR as BACT at MRYS was because SCR is technically infeasible at MRYS. If a technology is determined to be technically infeasible, it is "eliminated from further consideration in the BACT analysis." EPA Draft NSR Manual at B. 7, AR 75. As such, no cost analysis was required to be completed. However, even if a cost analysis was required, the excessive costs associated with SCR would be yet another factor that supports NDDH's determination that SCR is technically infeasible at MRYS.

EPA's approach in criticizing NDDH's BACT determination is itself contrary to EPA's own published guidelines. According to the EPA Draft NSR Manual — "in the economic impact analysis, primary consideration should be given to quantifying the cost of control and not the economic situation of the individual source." EPA Draft NSR Manual at B.31, AR 75. *See also* *id.* ("the economic impact of [control] alternatives on the particular source under review should not be nearly as pertinent to the BACT decision making process as the average and, where appropriate, incremental cost effectiveness of the control alternative"). Sources "should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations." *Id.* at B.32, AR 75.

Applying EPA's own criteria, NDDH determined that the cost of SCR on a per-ton-removal basis was excessive. Based on the average of the two catalyst replacement scenarios, the incremental cost effectiveness of LDSCR + ASOFA was $9,207/ton for Unit 1 and $10,872/ton for Unit 2. For TESCR + ASOFA, the incremental cost effectiveness was $10,872/ton and $12,578/ton for Units 1 and 2, respectively. The NDDH's determination that the cost of SCR at MRYS was excessive is consistent with EPA's own determination that excessive cost can eliminate a control technology as BACT. In EPA's analysis of the Deseret Power Plant it stated "The incremental cost of $10,540 per ton of SO_2 to install a wet scrubber rather than a dry scrubber is too high to justify the expenditure." *See* AR 241 p.2. EPA further found that "Limestone injection and wet FGD **is eliminated as a BACT control option, based on economic impacts** of wet FGD (unacceptably high incremental SO_2 removal costs) " *emphasis added. Id.*

EPA's inexplicable refusal to follow its own guidelines practically defines arbitrary and capricious behavior. *See* National Ass'n of Cas. & Surety Agents v. Board of Gov'rs of the Fed. Reserve Sys., 856 F.2d 282, 287 (D.C. Cir. 1988) ("It is, of course, a fundamental precept of administrative law that agencies are under an obligation to follow their own regulations, procedures, and precedents, or provide a rational explanation for their departure.") (quotation and alteration omitted), cert. denied, 490 U.S. 1090 (1989).

Further, NDDH did not fail to apply the appropriate cost analysis when considering SCR at MRYS as EPA erroneously asserts. The EPA Draft NSR Manual provides that "[t]he basis for equipment cost estimates also should be documented, **either with data supplied by an equipment vendor (i.e., budget estimates or bids)** or by a referenced source [such as the OAQPS Control Cost Manual (Fourth Edition)]." *emphasis added.* EPA Draft NSR Manual B.33, AR 75. The Draft Manual also provides that "BACT decisions **made on the basis of cost** and economic considerations" should be based the OAQPS Control Cost Manual. *Emphasis added.* EPA Draft NSR Manual at B.35, AR 75.

First, the BACT determination reached by NDDH was based solely on whether it was technically feasible. Significant evidence set forth in the administrative record demonstrates that SCR at MRYS is technically infeasible due to the unique design characteristics of the units. Had the BACT determination been made in part or solely on cost considerations, then arguably use of the OAQPS Manual would be appropriate. Secondly, NDDH determined that the OAQPS Cost Manual is not appropriate to solely rely on when making BACT determinations for LDSCR and TESCR. The OAQPS Cost Manual speaks of the economic analysis to be conducted when considering high-dust SCR, not LDSCR TESCR. *See* AR 241 p.6. In order to analyze the cost of LDSCR and TESCR NDDH had to look to data supplied by vendors and others. Moreover, the EPA Draft NSR Manual anticipates that states may rely on sources in addition to or other than the OAQPS Cost Manual when it states that the cost analysis may be based "either with data supplied by an equipment vendor (i.e., budget estimates or bids)" or the OAQPS Manual. *See* EPA Draft NSR Manual B.33, AR 75.

As set forth above, the technical feasibility of SCR at MRYS is the dominant factor that weighed against its selection as BACT. The NDDH carefully considered all the information presented to it in the record and ultimately reached the reasonable conclusion that SCR was not technically feasible because of unique operating conditions at MRYS, not because SCR was excessive in terms of costs.

6. NDDH Did Not Ignore its Own Previous Analysis of SCRs on a Same or Similar Source

EPA erroneously asserts that NDDH previously concluded that SCR was technically feasible to be used on a North Dakota lignite fired unit. *See* EPA Memorandum in Support at p. 23. In its May 2007 analysis of the Westmoreland Power, Inc. Gascoyne Station, NDDH stated that SCR appeared feasible, by reheating the flue gas and locating the SCR downstream of the other air pollution control devices. In its analysis of the Gascoyne Station, NDDH found that it "is not certain that this technology (tail-end SCR) will work with a North Dakota lignite-fired unit because it has not been used before. For these reasons, the Department retained, with reservations, "[SCR] as a technologically feasible control option." *See* AR 241 p.33, and AR 258 at p.74. Ultimately, SCR at the Gascoyne Station was eliminated from consideration due to cost and technical infeasibility. The BACT analysis prepared by Westmoreland set forth how the SCR technology continuously failed and that "[d]ue to the presence of alkali constituents, especially Na, in lignite-fired flue gas, SCR has not been installed or demonstrated to be technically feasible on a lignite-fired boiler." *Id.* Nor did NDDH or Westmoreland ever state that a LDSCR system could be made to work at the Gascoyne Station.

Importantly, there are distinct design differences between the Gascoyne Station and the MRYS units. The Gascoyne Station was a Circulating Fluidized Bed ("**CFB**") while the MRYS units are cyclone boilers. It is not possible to definitively apply any determination made or option considered by NDDH for the Gascoyne Station to the MRYS units since they are each differently designed. Additionally, the Westmoreland BACT analysis was prepared and submitted in June 2006, *prior to* Minnkota's BACT analysis (October 2006). As is the case with the Minnkota BACT Analysis, there was never a showing or final determination that SCR could be BACT at the Gascoyne Station.

7. NDDH Properly Considered a BACT Determination on Another Source Type

In reaching its conclusion that SCR is not feasible at MRYS, NDDH's Final BACT Determination also relied in part upon the technical reasoning from a recent BACT determination for the Red River Environmental activated carbon facility in Louisiana, where SCR was found not technically feasible. *See* AR 256.

The Louisiana Department of Environmental Quality ("**DEQ**") made a BACT determination for a multi-hearth furnace/waste heat boiler that utilizes gulf coast lignite as a feed stock. The BACT determination and the subsequent permit issued by the DEQ indicates BACT is low NOx burners and SNCR (RACT/BACT/LAER Clearinghouse ID LA-0148). The Louisiana DEQ determined that SCR was not technically feasible for BACT because of catalyst deactivation due to sodium sulfate poisoning, lack of operating experience, and concerns about obtaining a catalyst life guarantee. *See* AR 241 p. 42. These are some of the very same concerns that the NDDH has regarding the technical feasibility of SCR at the MRYS. *See* AR 240 at 7. EPA did not dispute Louisiana's BACT determination.

B. NDDH Consulted Extensively With EPA

The Consent Decree requires NDDH to provide EPA with an opportunity to consult on its BACT determination. "After consultation with EPA, NDDH shall provide to the parties its BACT Determination for NOx from each existing coal fired Unit at the Milton R. Young

Station." Consent Decree at para. 66. As the administrative record demonstrates, not only did NDDH receive numerous comments from EPA on the preliminary BACT determinations, NDDH actively consulted with EPA throughout its BACT determination process. *See* AR 54, 55, 63, 87, 88, 95, 102, 169, 203, 212, 222, 225, 230, 231, 233, 236, 237, 239, and 253. Nonetheless, EPA erroneously asserts that it did not have the timely opportunity to comment on NDDH's final BACT Determination. *See* EPA Memorandum in Support at p. 38.

NDDH's final BACT determination and Findings were issued on November 18, 2010. The Findings of Fact and Final BACT Determination were sent directly to EPA by NDDH. *See* AR 242. Between October of 2006 and the issuance of the final BACT Determination in November 2010, NDDH consulted with EPA on numerous occasions regarding the BACT Analysis. The June 2008 public comment period was also extended by the NDDH at the request of EPA. *See* AR 254. As NDDH undertook to analyze and consider whether the issue of SCR was technically feasible, NDDH considered the technical information submitted to it by EPA's consultant Hans Hartenstein. *See* AR 99, 169, 203, 249, 250, 251, 252.

In April of 2010, NDDH submitted for public comment the second Preliminary BACT Analysis. The Preliminary BACT Determination stated NDDH's significant concerns about the technical feasibility of LDSCR and TESCR. *See* AR 172 at p.9. In its notice for public comment, NDDH sought comment regarding the cost estimates and the reasons for the Department's preliminary decision regarding low dust and tail end SCR. *See* AR 257. The NDDH stated its reasons for not selecting SCR as "Based on concerns regarding technical feasibility of LDSCR and TESCR, the high cost effectiveness, the high incremental cost and increased greenhouse gas emissions, the Department has determined that neither LDSCR nor TESCR represent BACT at M.R. Young Station". *See* AR 172 at p.12. Not only did EPA submit public comments to NDDH in response to the notice, it sent follow-on communications to NDDH specifically regarding the SCR issue. For instance, EPA sent NDDH correspondence in June 2010 commenting on the issue of the vendor catalyst guarantee. Further, discussions between NDDH and EPA regarding the SCR issue occurred after the April 2010 notice was issued and the public comment period closed. *See e.g.* AR 230, 231, 234, 235, 236, 253 and 259. After considering all of the comments, including EPA's, the Department determined that SCR (HDSCR, LDSCR and TESCR) was not technically feasible at the MRYS.

NDDH extensively "consulted" with EPA throughout the BACT determination process. EPA had ample opportunity to submit comments on, among other things, "control technology requirements." 42 U.S.C. § 7475(a)(2). NDDH also provided notice to the [EPA] of every action related to the consideration of [the] [BACT determination]." *Id.* § 7475(d). Merely because the NDDH did not set aside its reasoned technical analysis and determination that SCR is technically infeasible at MRYS and adopt EPA's comments that SCR should be applied at MRYS does not mean that NDDH failed to consult with EPA or that NDDH's determination is incorrect.

C. NDDH Properly Evaluated Whether an NSPS Standard was Applicable to the BACT Determination

EPA's Draft NSR Manual requires permitting authorities to compare a proposed BACT control level with the applicable control level under the parallel New Source Performance Standard ("**NSPS**") provisions of the CAA. The BACT level must be at least as stringent as the applicable NSPS level. However, before a comparison of a BACT level to a NSPS can occur, it must be determined whether the NSPS is applicable. In the case of MRYS, the NSPS is not applicable since it was constructed prior to the applicability of the NSPS.

EPA improperly suggests that the NDDH BACT determination is unreasonable "because it set a BACT limit that was more than twice the NSPS limit." EPA Memorandum in Support at

p. 37-38. As detailed herein, the CAA, North Dakota's SIP and EPA's Draft NSR Manual all make clear that BACT will be developed by the State "permitting authority," i.e. the NDDH, on a case-by-case basis. The only limitations on this authority are found in the last sentence of CAA §169(3), 42 U.S.C. § 7479(3). "In no event shall application of "best available control technology" result in emissions of any pollutant which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of the Act."

EPA's argument is flawed because there is no existing standard applicable to the MRYS under CAA section 111 or 112 for NO_x emissions. MRYS was constructed prior to the applicability of the NSPS. Further, there has been no construction at MRYS that would have made it subject to the NSPS. EPA incorrectly suggests NDDH's BACT determination is "over twice the 0.15 lb/mmBtu limit" set by a NSPS promulgated pursuant to CAA §111. *See* EPA Memorandum in Support p. 37. NDDH also determined that several of EPA's statements for justifying the application of the NSPS promulgated under 40 C.F.R. § 60.44 Da to new, modified or reconstructed cyclone boilers burning North Dakota lignite were technically and factually erroneous.

VII. CONCLUSION

Nothing within the BACT regulations or EPA Draft NSR Manual require NDDH to reach the conclusion that SCR must be installed at MRYS. Under the authority granted to it by the CAA, and pursuant to North Dakota's laws and regulations and the Consent Decree the NDDH properly exercised its technical judgment when considering all of the factors and information available as to whether SCR is a technically feasible control technology at MRYS. The administrative BACT record supports the findings reached by NDDH. The State's explanation of its BACT determination, including its reason for rejecting SCR--that the costs of SCR were "excessive" both in terms of cost effectiveness and in terms of technical infeasibility, and that the unique situation of the MRYS warranted eliminating SCR on that basis—meets the standard set forth in Alaska v. EPA and Motor Vehicle Mfrs. Ass'n v. State Farm, supra. EPA, therefore, has no authority to disregard the State's "reasoned justification" and attempt to substitute its views for those of the State.

DATED: June 24, 2011

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UNITED STATES DISTRICT COURT
FOR THE DISTRICT OF NORTH DAKOTA

UNITED STATES OF AMERICA, STATE OF NORTH DAKOTA, Plaintiffs, v. MINNKOTA POWER COOPERATIVE, Inc. and SQUARE BUTTE ELECTRIC COOPERATIVE, Defendants.	**BRIEF OF AMICI CURIAE STATES OF SOUTH DAKOTA, OKLAHOMA, WYOMING, NEBRASKA, ALABAMA, UTAH, INDIANA, KENTUCKY, AND ALASKA IN SUPPORT OF THE STATE OF NORTH DAKOTA** **CIVIL ACTION NO. 1:06-CV-034**

INTRODUCTION

The States of South Dakota, Oklahoma, Wyoming, Nebraska, Alabama, Utah, Indiana, Kentucky, and Alaska as amici curiae ("**Amici States**"), respectfully submit this brief in support of the State of North Dakota. Pursuant to the 2006 Consent Decree between the State of North Dakota (the "**State**"), the United States Environmental Protection Agency ("**EPA**" or the "**United States**") Minnkota Power Cooperative ("**Minnkota**") and Square Butte Power Cooperative[1], the State reached a reasoned and well supported best available control technology ("**BACT**") determination for Minnkota's Units 1 and 2 at the Milton R. Young Station ("**MRYS**"). EPA now challenges the "reasonableness" of the State's BACT determination. Amici States oppose the rationale and relief sought by the United States in this matter because it would improperly skew the federal-state partnership envisioned by Congress under the federal Clean Air Act

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[1] Minnkota and Square Butte were the "Settling Defendants" in the 2006 Consent Decree. Minnkota owns the 235 MW lignite coal-fired cyclone furnace EGU (Unit 1), and Square Butte owns the 440 MW lignite coal-fired cyclone furnace EGU (Unit 2), at MRYS. Minnkota operates Units 1 and 2.

(the "**Act**"), 42 U.S.C. §§ 7401-7671, in general and, in particular, under the Act's Prevention of Significant Deterioration ("**PSD**") provisions, *id.*, §§ 7470-79. Amici States urge this Court to uphold the State of North Dakota's BACT determination.

STATEMENT OF INTEREST

Protection of public health and the environment is of manifest importance to all States. Air pollution affects health and quality of life, and it has obvious impacts on the environment. As a result, Amici States fully support the goals and policies that underlie and are embodied in the Act. At the same time, Amici States share an interest in ensuring that the Act is construed in a way that protects the social and economic well-being of their citizens, as well as their public health and welfare. Amici States also have a compelling interest in protecting their congressionally-mandated authority under the Act, in ensuring sound PSD permitting decisions, in avoiding confusion concerning the scope of state-versus-federal authority, and in promoting the orderly function of State administrative decision-making processes under the PSD program. Because the analysis and conclusion of the United States Petition in this case is contrary to each of these interests, Amici States support this Court's affirmance of North Dakota's BACT determination.

SUMMARY OF ARGUMENT

Under the Act, States and the Federal government are partners in addressing the issue of air pollution. *See* General Motors Corp. v. United States, 496 U.S. 530, 532 (1990). Under the Act itself, States are charged with the primary responsibility of preventing and controlling air pollution at its source. *See* 42 U.S.C. § 7401(a)(3). The Act recognizes and respects the tension that can arise between environmental protection and social and economic impacts on a community. Congress expressly reserved to the States the role of balancing those competing concerns under the Act's

PSD provisions, which apply in "clean air" areas of the country.[2]

The Act requires new or modified sources of air pollution emissions to use BACT in areas where air quality is already better than the National Ambient Air Quality Standards (the "**NAAQS**"). In the statutory definition of BACT, Congress provided that the States must decide what constitutes BACT for a particular source, based on a consideration of "energy, environmental, and economic impacts and other costs." 42 U.S.C. § 7479(3). Congress clearly assigned to the States the responsibility to determine BACT on a case-by-case basis. *See* S. Rep. No. 95-127 at 31. Further, BACT must be understood to have "broad flexibility in how it should and can be interpreted, depending on [the] site," and "[t]he weight assigned to [the statutory] factors is to be determined by the State." *Id.* Accordingly, the BACT decision is "strictly a State and local decision" and "[f]lexibility and State judgment are [its] foundations." *Id.*

Nowhere in the language or the structure of the Act, or in its legislative history, did Congress state or imply that the States' BACT determinations are merely preliminary. Yet, EPA is taking the position with North Dakota that as a practical matter a State's BACT decision is only an initial decision and is subject to the prerogative of EPA. Despite the clear statutory assignment of authority under the Act to the States, the United State's position effectively strips North Dakota, (and all the States), of the primary role of weighing the statutory BACT factors in implementation of its PSD program.

If allowed, EPA's position will significantly harm the States' environmental programs and, as a result, will harm the citizens of the States and the nation as a whole. First, as illustrated by this case, the environment itself will suffer if the States' crucial

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[2] *See* H.R. Rep. No. 95-294 at 146 ("The committee purposely chose not to dictate a Federal response to balancing sometimes conflicting goals. It purposely chose not to dictate what State and local decisions on air quality deterioration must be. Maximum flexibility and State discretion are the bases of the committee's approach.")

role in reviewing and making PSD permitting decisions is taken from them and essentially given to EPA. Congress had a good reason for explicitly making the States, not EPA, responsible for determining BACT: States simply are in a far better position to assess, analyze, and make determinations that impact their communities than EPA. This is not to say that EPA does not have an interest in the decisions that a State reaches. But as Congress recognized it is the State, not the EPA, that is best positioned to determine what is BACT. The end-result sought by the United States in this case, if accepted, will be flawed decisions with attendant adverse environmental and social consequences.

Second, if EPA's position were to be adopted, great uncertainty in the permitting process would ensue. Permit applicants, and the States, would be uncertain as to whether and when EPA would choose to inject itself into the state permit-issuance process. Moreover, once a permit is issued there is the risk that EPA would elect to overturn that permit, thereby eliminating the confidence that a permit holder has to rely on the state-issued PSD permit. That uncertainty, in turn, will frustrate growth, thereby depriving the States of control over the "growth management decisions" that Congress specifically "left . . . for resolution by the states." Alabama Power Co. v. Costle, 636 F.2d 323, 364 (D.C. Cir. 1979).

Third, the States' air quality protection programs and attendant administrative process will be thrown into disarray. State administrative procedures for hearings on and review of permitting decisions will be rendered superfluous as applicants work directly with EPA instead of through State air programs. Absent defined procedures in the context of administrative hearings, there will be no opportunity to test the bases for EPA's insistence on alternative BACT determinations, and no genuine administrative records to allow informed judicial review. EPA's bypassing of orderly administrative review procedures will have two negative consequences: It will impair the quality of ultimate BACT decisions while, ironically, making EPA's unilateral determinations virtually unreviewable.

EPA's position, if allowed to succeed, will not only significantly harm the States' environmental programs, but it will strip the States of the authority granted to them by Congress to address and implement solutions to air pollution. EPA's misinterpretation of the Act's BACT provisions only results in harm to the citizens of the States, and ultimately the nation as a whole.

ARGUMENT

I. EPA IMPROPERLY SEEKS TO DIMINISH STATE AUTHORITY TO DETERMINE BACT

A. Congress Expressly Reserved To The States Specific Authority Under The Clean Air Act

In the Act, Congress assigned distinct roles to the federal and state governments. A key federal role is the promulgation of the NAAQS, which define the amount of pollutants that may exist in a given area without harming public health and welfare. 42 U.S.C. § 7409. Despite EPA's responsibility for setting the NAAQS, which apply nationally, the Act makes clear that "air pollution prevention . . . and air pollution control at its source is the primary responsibility of States and local governments." *Id.* § 7401(a)(3). Thus, the States, through their approved State Implementation Plans ("**SIPs**"), are charged with implementation of the federally-set NAAQS. *Id.* § 7410. As this Court has recognized, "Congress plainly left with the States, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent." Union Elec. Co. v. EPA, 427 U.S. 246, 269 (1976); *see also* Train v. Natural Res. Def. Council, Inc., 421 U.S. 60, 79 (1975).

Congress also gave the federal and state governments distinct functions in the implementation of the PSD program. EPA sets the allowable increments that may be consumed for a particular regulated pollutant. *See* 42 U.S.C. § 7476(a). The States, meanwhile, determine the areas in which the increments will apply, and ensure through their SIPs that the increments are not exceeded. *Id.* § 7474(a); 40 C.F.R. § 51.166(a) (1999). EPA "is without authority to dictate to the States their policy for management of the consumption of allowable [PSD] increments." Alabama Power v. Costle, 636 F.2d 361. Rather, "assuming such compliance" with the maximum limitations defined by EPA through the increments, "growth-management decisions were left by Congress for resolution by the states." *Id.* at 364.

When Congress gave the States responsibility for managing the PSD program, it acted consistently with EPA's own earlier judgment that implementation of the PSD program is uniquely local in nature:

> "Any policy to prevent significant deterioration involves difficult questions regarding how the land in any area is to be used. Traditionally, these land use decisions have been considered the prerogative of local and State governments, and . . . the primary opportunity for making these decisions is reserved for the States and local governments. . . . In the Administrator's judgment, this matter normally should not be handled at the Federal level, . . ."
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> 39 Fed. Reg. 31000, 31001 (Aug. 27, 1974).

Not surprisingly in light of the Act's allocation to state and local governments of responsibility for "air pollution prevention . . . and air pollution control at its source," 42 U.S.C. § 7401(a)(3), Congress also charged those States with EPA-approved SIPs with responsibility for BACT determinations. The Act defines BACT as "an emission limitation . . . which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility . . ." 42 U.S.C. § 7479(3); *see also* 40 C.F.R. § 51.166(b)(12) (1999).[3]

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[3] States with approved SIPs are the "permitting authorit[ies]" under Section 169(3). Beyond making clear that States--not EPA--would select BACT, Section 169(3) confirms that the determination is a discretionary one. While the Act identifies the factors that the States must consider, the ultimate selection of BACT represents a judgment call, and there is no one "correct" BACT for a given source. That is precisely what Congress was thinking when it enacted the PSD provisions: "The decision regarding the actual implementation of best available technology is a key one, and the [Act] places this responsibility with the State, to be determined in a case-by-case judgment." S. REP. NO. 95-127, at 31 (1977). Moreover, "the phrase [BACT] has broad flexibility in how it should and can be interpreted, depending on site." *Id.*

Thus, the plain language of the statute itself, its legislative history, decisions of the Supreme Court and lower federal courts, and EPA's own interpretation of the PSD program confirm that States must determine BACT for a particular source, and must exercise discretion in that process.

B. EPA May Not Usurp Reserved State Authority Through "Reasonableness" Challenges

Here, the State of North Dakota exercised its authority to determine BACT in accordance with the Act. It considered a variety of possible technologies in light of the statutory factors listed in Section 169(3) of the Act; it engaged in a lengthy dialogue with the permit applicant, EPA, and other interested parties; it independently researched the pros and cons of the sundry of potentially available technologies; it prepared preliminary, draft final, and final technical analysis reports; and it ultimately selected a technology known as Selective Non-Catalytic Reduction ("**SNCR**") plus advanced separated overfire air ("**ASOFA**") as BACT.

Where did North Dakota go wrong? Stated bluntly, North Dakota exercised its authority granted to it under the Act, and using its technical expertise made a determination to select a technology different from the one that EPA favored--selective catalytic reduction ("**SCR**"). EPA, evidently concerned by North Dakota's failure to acquiesce to EPA's wishes, responded by petitioning this Court to find the State's BACT determination to be "unreasonable."

Under the United States' view, EPA has the final say over a State's air program, both under the PSD provisions (to which Section 167 applies) and under the State's SIP (to which Section 113(a)(5) applies). No matter that Congress specifically allocated authority to the States to determine BACT - EPA's enforcement power trumps that State authority. No matter that the particular issue calls for the exercise of discretion and that the Act does not require one objectively-definable outcome - if EPA disagrees with the

State's subjective analysis, it may override the State through the exercise of its "ultimate" enforcement authority.

Essentially, the United States' argument is that the Act gives the States only "initial responsibility" for PSD permitting decisions, and that "EPA has the ultimate authority to decide" BACT. This sweeping pronouncement, based on a misapplication of the narrow holding in Alaska Department of Environmental Conservation v. U.S. E.P.A., 540 U.S. 461 (2004), would relegate state programs to mere preliminary involvement with no substantial decision-making power in the issuance of PSD permits. If EPA's argument is accepted, the States' authority to determine BACT, and likely with respect to other issues the States are granted authority under the Act to oversee and implement, will be rendered an illusion. Truly, the United States' position seeking to bootstrap a difference of opinion into a violation of law - turns the Clean Air Act on its head.

II. THE RELIEF SOUGHT BY EPA WILL HARM THE STATE AIR-PROGRAMS AND INTERESTS

A. Divesting States Of Their Primary Authority To Determine BACT Will Impede Informed Decisions

The cooperative federalism embodied in the PSD program - with EPA setting the nationally-applicable standards and the States implementing those standards - is not merely what Congress mandated; it makes good sense. Back in the early years of the Act, Professor Richard Stewart noted the "sobering fact . . . that environmental quality involves too many intricate, geographically variegated physical and institutional interrelations to be dictated from Washington." Richard B. Stewart, Pyramids of Sacrifice: Problems of Federalism in Mandating State Implementation of National Environmental Policy, *86 YALE L.J. 1196, 1266 (1977).*

A meaningful state role in implementation of the Act's provisions is imperative for obvious reasons. Ours is a huge and diverse nation "with an astonishing range of environmental conditions and problems." Dwyer, supra, at 1218. To wit:

> "Differences in climate and weather (e.g., patterns of temperature, wind, rainfall, humidity), geography (e.g., deserts, mountains, plains, coastal regions), the relative importance of sources and types of pollution (e.g., cars, large utilities and factories, numerous small sources), environmental and public health risks (e.g., special need for visibility control, size of affected human population), and economic conditions confound attempts to have a successful, highly centralized regulatory program. . . . The practical need to tailor implementation and enforcement to local conditions requires decisionmakers who have, in addition to an adequate knowledge of these conditions, a sympathetic orientation toward local conditions. Effective implementation requires some consideration and accommodation of local concerns. Precisely because they are local, and locally accountable, state and local officials bring that knowledge and orientation to implementation and enforcement."

The events in North Dakota that gave rise to this case prove the wisdom of congressional assignment to the States of authority for PSD permitting decisions. North Dakota took its implementation responsibilities seriously and committed ample resources to select the most effective, yet feasible, control technology. Moreover, unlike EPA, the State had a unique appreciation for the facility's actual operation and its importance to the State. Thus, North Dakota selected SNCR plus ASOFA because the State, after lengthy and due consideration, could not find SCR to be technically feasible.

B. Permitting EPA To Veto State Selection Of BACT Will Lead To Uncertainty Among Permittees And Applicants, Which Will Frustrate The Act's PSD Program

Beyond increasing the likelihood of out-of-touch and flawed judgments, EPA's intrusion into the state role of determining BACT, if permitted, will inject a disturbing degree of uncertainty into the permitting process. No longer will the States have any real authority and, hence, no longer will applicants be able to rely on the State's word during negotiations or even on the State's issuance of a permit. Rather, applicants will have to guess whether EPA will preempt the State's judgment at any point during or after the permitting process. Or the State might refuse to issue a permit on terms dictated by EPA rather than by the State's independent exercise of its discretion to determine BACT. In both circumstances, the logical outgrowth of the uncertainty created by EPA's power-grab will be 'permitting paralysis'. Applicants likely will do nothing - they simply will not undertake construction or modification of facilities that would require PSD permits. This is inconsistent with Congress's expectation of state control over inherently local "growth-management decisions." Alabama Power, 636 F.2d at 364.

CONCLUSION

The positions advanced by the United States go a long way toward institutionalizing a feudal relationship between the States and EPA under the Clean Air Act's PSD program. But that is not what Congress intended and it is not good for the environment or for the citizens of the States. Therefore, Amici States urge this Court to affirm the BACT decision made by North Dakota.

Dated this 1st day of July, 2011.

Respectfully Submitted,

Charles D. McGuigan
Chief Deputy Attorney General
South Dakota Office of Attorney General
1302 E. Highway 14, Suite 1
Pierre, SD 57501
(605) 773-3215

E. Scott Pruitt
Attorney General of Oklahoma
313 N.E. 21st Street
Oklahoma City, Oklahoma 73105-4894
(405) 521-3921

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(402) 471-2682

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Salt Lake City, Utah 84114-2320

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IGC-South, Fifth Floor
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Indianapolis, IN 46204
(317) 232-6255

Jack Conway
Kentucky Attorney General
Suite 118, State Capitol
Frankfort, KY 40601
(502) 696-5643

John J. Burns
Attorney General of Alaska
P.O. Box 110300
Juneau, AK 99811

CERTIFICATE OF SERVICE

I hereby certify that on July 1, 2011, the forgoing document was served upon the following by mailing a true and correct copy thereof to the following participants:

Ignacia S. Moreno
Jerome W. Maclaughlin
United States Department of Justice
Environment and Natural Resources
Division
Post Office Box 7611
Washington, D.C. 20044-7611
Telephone: 202 616-7162
Facsimile: 202 616-2427
jerry.maclaughlin@usdoj.gov

Timothy Q. Purdon
United States Attorney
Cameron W. Hayden
Assistant U.S. Attorney
US Attorney's Office
District of North Dakota
220 East Rosser Avenue
P.O. Box 699
Bismarck, North Dakota 58502-0699

Brenda Morris
Enforcement Attorney
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202

Jeffrey A. Kodish
Attorney Advisor
U.S. Environmental Protection Agency
1595 Wynkoop Street
Denver, Colorado 80202

Wayne Stenehjem, Attorney General
Margaret Olson, Assistant Attorney General
Zac B. Smith, Assistant Attorney General
State of North Dakota
Office of the Attorney General
500 North 9th Street
Bismarck, North Dakota 58501-4509

Dennis Arfmann, Esq.
Hogan Lovells US, LLP
One Tabor Center, Suite 1500
1200 Seventeenth Street
Denver, CO 80202

Paul M. Seby
Moye White LLP
1400 16 Street 6th Floor
Denver, CO 80202

with postage prepaid, in the United States mail at Pierre, South Dakota.

Charles D. McGuigan

Charles D. McGuigan
Chief Deputy Attorney General
South Dakota Office of Attorney General
1302 E. Highway 14, Suite 1
Pierre, SD 57501
(605) 773-3215

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Appendix F.1
Public Participation Record

Appendix F.1.1
Public Notice

Notice of Intent
to Amend the
State Implementation Plan
for Air Pollution Control
Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from February 10, 2011 through March 12, 2011. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on March 16, 2011 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through March 26, 2011. If no request for a public hearing is received, an announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least three days prior to the hearing.

Dated this 27th day of January 2011

Terry L. O'Clair, P.E.
Director, Division of Air Quality

Appendix F.1.2
Affidavit of Publication

NDNA
NORTH DAKOTA NEWSPAPER ASSOCIATION

Affidavit of Publication

Colleen Park, being duly sworn, states as follows:

1. I am the designated agent, under the provisions and for the purposes of, Section 31-04-06, NDCC, for the newspapers listed on the attached exhibits.

2. The newspapers listed on the exhibits published the advertisement of: **ND Health Department – Reduction of Regional Haze; 1** time(s) as required by law or ordinance.

3. All of the listed newspapers are legal newspapers in the State of North Dakota and, under the provisions of Section 46-05-01, NDCC, are qualified to publish any public notice or any matter required by law or ordinance to be printed or published in a newspaper in North Dakota.

Signed: Colleen Park

State of NORTH DAKOTA
County of BURLEIGH
Subscribed and sworn to before me this 21ST day of FEB, 2011.

Linda J Judd

LINDA J. JUDD
Notary Public
State of North Dakota
My Commission Expires July 9, 2014

Appendix F.1.3
Invoice of Publication

NDNA
NORTH DAKOTA NEWSPAPER ASSOCIATION

North Dakota Newspaper Association
1435 Interstate Loop
Bismarck, ND 58503-0567
Ph (701) 223-6397 • Fax (701) 223-8185

INVOICE

Order **28894-11021NA1** Invoice # **142708**

February 22, 2011

Attn: **TOM BACHMAN**
ND HEALTH DEPARTMENT
600 E BOULEVARD AVE.
DEPT. 301
BISMARCK, ND 58505-0200
Voice: 701.328.5188 Fax: 701.328.5200

Advertiser: **Administrative Serv: Accounting**

P.O.#:

Amount Due	**$276.57**
Amount Paid	

Please detach and return this portion with your payment

Administrative Serv: Accounting Invoice # 28894-11021NA1-142708

Ad Size	*Rate Type*	*Rate*	*Total*	*Discount*	*(%)*	*Caption*	*Page*	*Run Date*
Bismarck Tribune (Bismarck ND)								
62.00	SPR2	0.76	47.12	0.00		Reduction of Regional		02/01/11
Dickinson Press (Dickinson ND)								
64.00	SPR2	0.70	44.80	0.00		Reduction of Regional		02/02/11
Fargo, The Forum (Fargo ND)								
63.00	SPR2	0.72	45.36	0.00		Reduction of Regional		02/07/11
Grand Forks Herald (Grand Forks ND)								
63.00	SPR2	0.73	45.99	0.00		Reduction of Regional		02/03/11
Minot Daily News (Minot ND)								
90.00	SPR2	0.51	45.90	0.00		Reduction of Regional		02/02/11
Williston Herald (Williston ND)								
60.00	SPR2	0.79	47.40	0.00		Reduction of Regional		02/02/11

Gross Advertising	276.57	Total Misc	0.00	Amount Paid	0.00
Agency Discount		Tax	0.00	Adjustments	0.00
Other Discount	0.00	Total Billed	276.57	Payment Date	
Service Charge	0.00	Unbilled	0.00	Balance Due	276.57

ND DEPT OF HEALTH
RECEIVED
FEB 23 2011
ACCOUNTING
TIME

Your payment is due upon receipt. Thank you in advance for your prompt payment!

OKay f/pmt
2-24-11 CSC,
511099
Terry O'Clair

Name, Address and Telephone No.
of Attorney:
Tom Tuntland
Attorney at Law
PO Box 1315
Mandan, ND 58554
701-667-1888
Attorney for Estate of
Fred Bay

Probate No.____

IN THE DISTRICT COURT OF BURLEIGH
COUNTY, STATE OF NORTH DAKOTA
In the Matter of the Estate of
Fred Bay, Deceased.

NOTICE TO CREDITORS

NOTICE IS HEREBY GIVEN that the undersigned have been appointed personal representative of the above estate. All persons having claims against the said deceased are required to present their claims within three months after the date of the first publication of this notice or said claims will be forever barred. Claims must either be presented to Jared Bay, personal representative of the estate, at the address listed below or filed with the Court.

Dated this 3rd day of February, 2011.

/s/Jared Bay
Jared Bay
Tom Tuntland
Attorney for Fred Bay Estate
PO Box 1315
Mandan, ND 58554

First publication on the 8th day of February, 2011.

2/8, 15 & 22 - 606330

STATE OF NORTH DAKOTA
COUNTY OF BURLEIGH
IN JUVENILE COURT
SOUTH CENTRAL JUDICIAL DISTRICT
IN THE INTEREST OF R.N.H., JR., A CHILD

State of North Dakota
Petitioner,
vs.
R. N.H., Jr., Child;
Ursula Weyaus, Mother;
Richard No Heart, Sr., Father;
Denise Kitson, Legal Guardian;
Respondents.

File No. 08-10-R-0693
Existing File No(s). 08-10-R-0641,
08-10-R-0473,
08-10-R-0145

SUMMONS

You are summoned to appear personally at the Juvenile Court in the Burleigh County Courthouse, Bismarck, Burleigh County, North Dakota, on the 15th day of March, 2011 at 8:30 a.m., for the purpose of hearing on the Petition filed with this Court. The Petition claims that the child is alleged to be an unruly child, as more fully appears from the Petition, a copy of which is hereto annexed and served upon you.

RIGHT TO HEARING BEFORE A JUDGE

You are entitled to have the Petition heard before a Judge of the Juvenile Court, instead of by a Referee, by filing a written request for a Judge with the Clerk of Court within five (5) days after receiving this Summons.

RIGHT TO COUNSEL

If you desire the assistance of an attorney, and are unable without undue financial hardship to employ one, the Court, upon your request, will appoint an attorney for you.

Dated this 1st day of February, 2011.

/s/John Grinsteiner
JOHN GRINSTIENER
JUDICIAL REFEREE

2/8, 15 & 22 - 606328

ADVERTISEMENT

The City of Bismarck is seeking cost proposals from qualified manufacturers or their representatives to provide LED Traffic Signal Modules & LED Pedestrian Modules. Proposals for the Modules for the City of Bismarck will be received by the Board of City Commissioners of the City of Bismarck, in the offices of the City Administrator, until three (3:00) o'clock

---

the best interest of the City of Bismarck.

City of Bismarck
W.C. Wocken
City Administrator

2/1, 8 & 15 - 606304

ADVERTISEMENT

The City of Bismarck is seeking proposals for the repair and upgrade of two (2) air handlers and upgrade of the existing temperature control system for the Police Department located at 700 South Ninth Street, Bismarck, ND 58504. This air handler and temperature control upgrade project includes the removal and replacement of the existing pneumatic controls with direct digital controls for AH#1 and AH#2 and upgrade of the two (2) air handlers pursuant to plans and specifications provided by the City of Bismarck.

Proposals will be received by the City Administrator until three (3:00) o'clock p.m., on Tuesday, March 1, 2011. Bids will be publicly opened and reviewed at four (4:00) o'clock p.m. on Tuesday, March 1, 2011. All bidders are invited to be present at the opening of the proposals.

The proposals must be mailed to the City Administrator (PO Box 5503, Bismarck ND 58506-5503) or otherwise deposited with the City Administrator (221 N 5th Street, Bismarck, ND 58501) and shall be sealed and endorsed "Proposals –Temperature Control & Air Handlers Project for the Police Department". If a bid is to be faxed, the bid must be sent to a bidder's agent independent of the City of Bismarck, placed in a sealed envelope, labeled according to this specification, and delivered to the City Administrator prior to the bid deadline.

A certified check or a bidder's bond in an amount equal to five (5) percent of the gross sum bid must accompany each proposal. Checks or bonds of the unsuccessful bidders will be returned to them after making the award.

Bids must be submitted on blanks furnished by the City of Bismarck and in accordance with specifications and conditions contained therein. Copies of proposal blanks and specifications may be obtained from the Director of Public Works or from Dennis Albers at dlalbers@nd.gov.

All bidders are encouraged to attend a pre-bid project review meeting held at the Police Department located at 700 South 9th Street, Bismarck, ND 58504 in the main office at 1:00 p.m. on Tuesday, February 22, 2011.

The right is reserved to hold all bids for a period of forty-five (45) days, to reject any and all bids, to waive technicalities or to accept such as may be determined to be for the best interest of the City of Bismarck.

City of Bismarck
W.C. Wocken
City Administrator

2/8, 15 & 22 - 606329

Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be

Dated this 2[illegible] day of January, 2011.

Terry L. O'Clair, P.E.
Director, Division of Air Quality

2/1 & 8 - 606300

ADVERTISEMENT

The Board of City Commissioners of th City of Bismarck will receive sealed bids fc the reconstruction of asphaltic concret pavement and related items in Stree Improvement District Number Fou Hundred Thirty-five (435).

All bids shall be submitted to the Cit Engineer by 3:00 p.m., Tuesday, February 22 2011. Such work is to be complete according to the plans and specifications o file in the office of the City Engineer. Bid will be opened at 4:00 p.m., Tuesda February 22, 2011, in the office of the Cit Engineer.

The proposals must be mailed to o deposited with the City Engineer and shal be sealed and endorsed "Proposal fo Construction of Asphaltic Concret Pavement and Related Items in Stree Improvement District Number Fou Hundred Thirty-five (435)."

The contractor shall include a copy of hi license or renewal thereof enclosed in the required bid bond envelope as requirec pursuant to Section 43-07-12 of the Nort Dakota Century Code, as amended.

Plans and specifications are on file in the office of the City Engineer. Plans may be obtained at the office of the City Engineer, 221 North Fifth Street, P.O. Box 5503, Bismarck, ND 58506-5503, upon a non-refundable payment of $70.00 per set.

The bid shall be made on the basis of cash payment for the work to be done. All work under this advertisement shall be started on a date to be specified in a written order from the Board of City Commissioners or not later than May 23, 2011.

Work shall consist of approximately 9,600 feet of 6-inch perforated pipe, curb and gutter patching, 26,000 square yards of asphalt removal, 25,400 tons of aggregate base, 24,700 square yards of geogrid, 8,625 tons of asphalt mixture, 13,600 cubic yards of unclassified excavation, 4,650 tons of drainage aggregate, 1,150 square feet of sidewalk, and 8 ADA panels.

The contractor shall substantially complete the pavements by August 26, 2011, and shall have all work completed by September 16, 2011. If the contractor fails to complete all the work within this time, or such additional time as has been granted for excusable delays, there shall be deducted from any money due the contractor the sum of three hundred dollars for each calendar day that the completion of the work is delayed. This deduction shall also apply to any work phases as specified. Such deducted amounts shall be charged as liquidated damages and not as a penalty.

Each bid shall be accompanied by a separate envelope containing a bidder's bond in the amount of five (5) percent of the amount of the bid as required by Section 48-01.1-05(3), North Dakota Century Code, as amended and executed as provided by law.

The Board of City Commissioners reserves the right to hold all bids for a period of thirty (30) days after the date fixed for the opening thereof and reject any or all bids and to waive irregularities whenever it is for the best interest of the City of Bismarck.

CITY OF BISMARCK
William C. Wocken
City Administrator

Dated this 25th day of January, 2011.

2/1 & 8 - 606305

ADVERTISEMENT FOR BIDS:

Sitting Bull College will receive bids on **February 18, 2011** for the construction of the **FINANCIAL CENTER CASEWORK ADDITION**. A Single Prime Bid for General Construction only shall be delivered to the Sitting Bull College Science Center located off ND highway 24 / 1806, Sitting Bull Drive South of 92nd Street no later than **3:00 PM CT** at which time qual-

2/8 Bismarck

2/2 Dickinson

KEY

ith frostbite

mes (four goals, 13 assists).

sto was a second-round draft pick of
lontreal Canadiens in 2008.

s is the second injury to one of
s top players in the last week.

Friday, Sioux captain Chay Genoway
he game against Colorado College
n apparent leg injury. He did not play
lay.

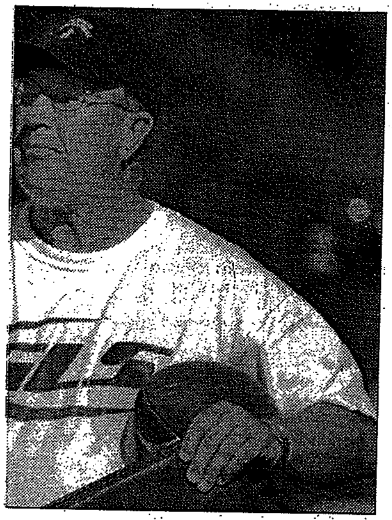
oway had tests this week in Grand
and UND is hoping to learn more
his prognosis mid-to-late week.

Sioux have this weekend off. They
to action Feb. 11 at home against Alas-
chorage. The WCHA playoffs begin on
11. The NCAA tournament begins
25 in Green Bay, Wis., St. Louis, Man-
r, N.H., and Bridgeport, Conn.

D currently is ranked fifth in the
al polls and third in the Pairwise
ngs.

ossman is a sports reporter for the Grand Forks Herald, which is owned by Forum Communications Co.

OOL FOOTBALL



Forum Communications Co. File Photo

s the North Dakota Shrine East
ractice on July 21, 2005 at North

ahl could
o coaching

g coach at Cavalier open
ning back for Shanley job

Public Notices

ADVERTISEMENT FOR CONSTRUCTION BIDS

NORTH DAKOTA STATE WATER COMMISSION
Owner
900 E. Boulevard Ave.
Bismarck, ND 58505
Address

Separate sealed bids for construction of **OMND Regional Service Area, Center Elevated Tank, Contract 5-16** will be received by the North Dakota State Water Commission (NDSWC), Bismarck, ND until 1:30 P.M., Local Time on the 3rd day of March, 2011 where and at which time they will be publicly opened and read aloud.

The scope of WORK generally consists of furnishing and installing one elevated composite, or spheroid style steel potable water storage tank, 750,000 gallons (min.), 175' to overflow, complete with access road, inlet/outlet piping, foundation, site piping, appurtenances, painting, sitework, outlet structure and other appurtenant items as required by the Project Drawings, Specifications, and Contract Documents. The Center Elevated Tank site is located in Oliver County, approximately 12 miles south of the City of Beulah, North Dakota.

Each BID must be accompanied by a separate envelope containing a copy of a current and valid North Dakota Contractor's License (must have been issued at least 10 calendar days before the date of the Bid Opening) and a BIDDER's Security in a sum equal to five percent of the full amount of the BID, executed by the BIDDER as Principal and by a surety, conditioned that if the Principal's BID is accepted and the CONTRACT awarded to the Principal, the Principal, within fifteen days after notice of award, shall execute a CONTRACT in accordance with terms of the BID and a CONTRACTOR's BOND as required by law and the regulations and determinations of the North Dakota State Water Commission (NDSWC).

Bidders are advised that the funding and/or regulatory agency for this project (in whole or in part) is the US Bureau of Reclamation (USBR). Bidders on this work will be required to comply with the Presidents Executive Order Nos. 11246 as amended, the Copeland "Anti-Kickback" Act, the Clean Air Act, the Federal Water Pollution Control Act, the Byrd Anti-Lobbying Amendment, the Endangered Species Act, as well as complying with other requirements. The requirements for bidders and contractors under these orders are explained in the Bureau of Reclamation (BOR) Supplemental Provisions.

Goals and timetables for Minority Utilization shall be included in all Federal and Federally assisted construction CONTRACTs and subcontracts in excess of $10,000. The goals are applicable to the CONTRACTOR's aggregate on-site construction workforce, not merely that part of the workforce that is performing WORK on a Federal or Federally assisted contract or subcontract. The goals and timetables for Women and Minorities are available from the United States Department of Agriculture (USDA).

Contract Documents are on file at the offices of the North Dakota State Water Commission, and Bartlett & West/AECOM, Bismarck, North Dakota, where they may be seen and examined between the hours of 8:00 A.M. and 5:00 P.M., local time, Monday through Friday. Address of Engineer's office is:

BARTLETT & WEST/AECOM
3456 East Century Avenue
P.O. Box 1077
Bismarck, ND 58502-1077
Telephone: (701) 258-1110
Fax: (701) 258-1111

Digital copies of the PLANS and SPECIFICATIONS (Contract Documents) are available at www.bartwest.com or www.questcdn.com. Bidding documents may be downloaded for $50.00 by enter-

will hold a public hearing at 9:00 a.m. Wednesday, February 23, 2011, at the N.D. Oil & Gas Division, 1016 East Calgary Ave., Bismarck, N.D. At the hearing the Commission will receive testimony and exhibits. Persons with any interest in the cases listed below, take notice.

PERSONS WITH DISABILITIES: If at the hearing you need special facilities or assistance, contact the Oil and Gas Division at 701-328-8038 by Thursday, February 10, 2011.

STATE OF NORTH DAKOTA TO:

Case No. 14061: Temporary spacing to develop an oil and/or gas pool discovered by the Fidelity Exploration & Production Co. #31-6H Kostelecky, Lot 2 Section 6, T.139N., R.97W., Stark County, ND, define the field limits, and enact such special field rules as may be necessary.

Signed by,
Jack Dalrymple, Governor
Chair[illegible], ND Industrial Commission
[illegible]ublished February 2, 2011)

Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/.

A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328?5188. Written comments may be submitted to the above address from February 10, 2011 through March 12, 2011. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on March 16, 2011 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through March 26, 2011. If no request for a public hearing is received, an announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least three days prior to the hearing.

Dated this 27th day of January 2011.
Terry L. O'Clair, P.E.
Director, Division of Air Quality
(Published February 2, 2011)

NOTICE OF RECALL ELECTION

Notice is hereby given that on Tuesday, the eighth day of February, 2011, a recall election will be held for the purpose of

L/C

Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328?5188. Written comments may be submitted to the above address from February 10, 2011 through March 12, 2011. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on March 16, 2011 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through March 26, 2011. If no request for a public hearing is received, an announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328-5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least three days prior to the hearing.

Dated this 27th day of January 2011.
Terry L. O'Clair, P.E.
Director, Division of Air Quality
(February 7, 2011) 1206673

CASE TYPE: OTHER CIVIL
MORTGAGE FORECLOSURE–BY ACTION
STATE OF MINNESOTA

COUNTY OF CLAY
DISTRICT COURT
SEVENTH JUDICIAL DISTRICT
Bruce W. Livingston, Plaintiff,
vs.
Comfort Homes, Inc.,
Ervin J. Lee,
John Doe and Mary Roe, Defendants.

NOTICE OF SALE UNDER JUDGMENT OF MORTGAGE FORECLOSURE
COURT FILE NO. 14-CV-10-4360

NOTICE IS HEREBY GIVEN: That by virtue of a judgment and decree entered in the above entitled action on January 3, 2011, that there is due to the Plaintiff the sum of $56,196.89 and interest thereon from January 3, 2011at the rate of 10% per annum.

A certified copy of the judgment has been delivered by the Court to I, the Sheriff of Clay County, State of Minnesota, directing the sale of the premises herein after described to satisfy said judgment.

The Sheriff of Clay County, at public auction, will sell to the highest bidder for cash on March 22, 2011 at 10:00 o'clock a.m. at the Clay County Sheriff's Office, 915 9th Ave. N., Moorhead, MN 56560, the following property located in Clay County, Minnesota, to wit:

Lot 5, Block 1, Moorhead Industrial Park Fourth Addition to the City of Moorhead according to the certified plat thereof of record and on file with the County

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IN JUVENILE COURT, COUNTY OF CASS,
STATE OF NORTH DAKOTA.
IN THE INTEREST OF N.D. and C.C., CHILDREN, r, Bradley Hassler, LSW, Petitioner
vs.
Director, Cass County Social Services, Chandra Cain, Thomas Dubois, Dickey Cain, John Doe, N.D., C.C. and Kathy Kassenborg, Respondents.

AMENDEDED SUMMONS
File No. 09-2011-JV-8 & 09-2011-JV-9

THE STATE OF NORTH DAKOTA TO THE ABOVE-NAMED RESPONDENTS:

You and each of you are hereby summoned and required to appear personally and bring the above-named children before the Juvenile Court at the Cass County Courthouse Annex at 1010 Second Avenue South in Fargo, North Dakota, on **March 22, 2011 at 2:00 p.m.** or as soon thereafter as the parties can be heard, for the purpose of a hearing on a Petition filed with the Court alleging the above-named children to be subject to the provision of Chapter 27-20, North Dakota Century Code by reason of the following: that the said child falls within the meaning of Section 27-20-02 of the said Code, as more fully appears from the Petition, a copy of which is on file in the office of the Clerk of the District Court of Cass County.

If you fail to appear personally and bring said children before the Court at said time and place the Findings and Recommendation of the Judicial Referee as confirmed by the Judge of the Juvenile Court, made by this court at a hearing had herein will become final.

You are entitled to legal counsel in these proceedings if you so desire. If you are unable without undue financial hardship to employ counsel the Court, upon request, will appoint legal counsel for you.

You are further informed that you are entitled to have the Petition heard by a Judge of the Juvenile Court instead of by a Judicial Referee if written request therefore is filed with the Clerk of the above-named Court within three days after receiving a copy of this Amended Summons.

Dated January 24, 2011
Scott C. Griffith, Judicial Referee
(February 7, 14, 21, 2011) 1207631

IN JUVENILE COURT, COUNTY OF CASS, STATE OF NORTH DAKOTA.
IN THE INTEREST OF E.L., A CHILD, Bradley D. Hassler, L.S.W., Petitioner,
vs.
Director, Cass County Social Services, Nadine Dubois, Elliot Longie, John Doe, E.L., and Renelda Weippert, Lay Guardian ad Litem, Respondents

AMENDED SUMMONS
File No. 09-2011-JV-10

THE STATE OF NORTH DAKOTA TO THE ABOVE-NAMED RESPONDENTS:

You and each of you are hereby summoned and required to appear personally and bring the above-named children before the Juvenile Court at the Cass County Courthouse Annex at 1010 Second Avenue South in Fargo, North Dakota, on **March 22, 2011 at 2:00 p.m.** or as soon thereafter as the parties can be heard, for the purpose of a hearing on a Petition filed with the Court alleging the above-named children to be subject to the provision of Chapter 27-20, North Dakota Century Code by reason of the following: that the said child falls within the meaning of Section 27-20-02 of the said Code, as more fully appears from the Petition, a copy of which is on file in the office of the Clerk of the District Court of Cass County.

If you fail to appear personally and bring said children before the Court at said time and place the Findings and Recommendation of the Judicial Referee as confirmed by the Judge of the Juvenile Court, made by this court at a hearing had herein will become final.

You are entitled to legal counsel in these proceedings if you so desire. If you are unable without undue financial hardship to employ counsel the Court, upon request, will appoint legal counsel for you.

You are further informed that you are entitled to have the Petition heard by a Judge of the Juvenile Court instead of by

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IN JUVENILE COURT, COUNTY OF CASS, STATE OF NORTH DAKOTA.
IN THE INTEREST OF D.C. , A CHILD, Phyllis Gaspers, L.S.W., Petitioner,
vs.
Director of Cass County Social Services, Tina Hulst, D.C., Abraham Chopper, Kathy Kassenborg, Lay Guardian ad Litem, Respondents

AMENDED SUMMONS
File No. 09-08-R-01079

THE STATE OF NORTH DAKOTA TO THE ABOVE-NAMED RESPONDENTS:

You and each of you are hereby summoned and required to appear personally and bring the above-named children before the Juvenile Court at the Cass County Courthouse Annex at 1010 Second Avenue South in Fargo, North Dakota, on **February 22, 201,** or as soon thereafter as the parties can be heard, for the purpose of a hearing on a Petition filed with the Court alleging the above-named children to be subject to the provision of Chapter 27-20, North Dakota Century Code by reason of the following: that the said child falls within the meaning of Section 27-20-02 of the said Code, as more fully appears from the Petition, a copy of which is on file in the office of the Clerk of the District Court of Cass County.

If you fail to appear personally and bring said children before the Court at said time and place the Findings and Recommendation of the Judicial Referee as confirmed by the Judge of the Juvenile Court, made by this court at a hearing had herein will become final.

You are entitled to legal counsel in these proceedings if you so desire. If you are unable without undue financial hardship to employ counsel the Court, upon request, will appoint legal counsel for you.

You are further informed that you are entitled to have the Petition heard by a Judge of the Juvenile Court instead of by a Judicial Referee if written request therefore is filed with the Clerk of the above-named Court within three days after receiving a copy of this Amended Summons.

Dated January 24, 2011. by Beth Perderson.
Signed, Kathryn Ouren, Clerk of Court
(February 7, 14, 21, 2011) 1207731

BIDS WANTED
THE PARK DISTRICT OF THE CITY OF FARGO

Sealed bids will be received at the office of The Park District of the City of Fargo, 701 Main Avenue, Fargo, North Dakota, until 2:00 P.M., March 1, 2011, and then opened and read aloud for

North Side Maintenance Facility, The Park District of the City of Fargo, North Dakota.

Bids will be accepted for the following packages:

1. General Construction
2. Mechanical
3. Electrical

Bids shall be on the basis of cash payment for work performed. All work included in the contract must be fully completed on or before March 31, 2012.

Bids must be submitted on copies of the bid form in the specifications and must be accompanied by a separate envelope containing a bidder's bond in a sum equal to five percent (5%) of the full amount of the bid executed by the bidder as principle and by a surety company authorized to do business in this state, conditioned that if the bidder's bid be accepted and the contract be awarded to the bidder, the bidder, within ten (10) days after notice of award, will execute and effect a contract in accordance with the terms of the bidder's bid and a contractor's bond as required by law and the regulations and determinations of the Park District. The successful bidder will be required to furnish a Contract Bond in the full amount of the contract.

The plans and specifications may be examined at the following locations:

Shultz & Associates, LTD, 612 ½ Main Avenue, Fargo, ND

Builders Exchange - Fargo, Bismarck, Grand Forks, Minneapolis

PUBLIC NOTICE

ports, Minneapolis, MN and Reed Construction Data, Norcross, GA. Qualified bidders may obtain Bidding Documents from the Architect upon deposit of $ 75.00, which will be refunded if a bonafide bid is submitted and plans are returned in good condition within 10 days after the receipt of bids.

Each bid must be accompanied by a Bid Bond payable to the Grand Forks Public School District #1 in the amount equal to five percent (5%) of the bid. This is to serve as a guarantee that the bidder will enter into a contract for the performance of such work if the contract is awarded to him. Only bids which are accompanied by such bond and a copy of the bidders current State of North Dakota Contractors License, attached to the bid form in a separate envelope, will be considered.

The construction of the project must be started, on the site, on or after June 1, 2011 and substantially completed by August 19, 2011.

All bidders must be licensed for the highest amount of their bids, as provided by Section 43-07-05 of the North Dakota Century Code.

No bid will be read or considered which does not fully comply with the above provisions as to bond and license and any bid deficient in these respects submitted will be resealed and returned to the bidder immediately.

All bids will be made on the basis of cash payment for such work. After bid opening the owner will return the bid security of all except the three lowest responsible bidders. When the Contract is awarded, the remaining unsuccessful bidder's bond will be returned.

The Owner reserves the right to reject any and all bids, and further reserves the right to award the Contract in the best interests of the Owner.

The Owner reserves the right to hold the three low bids for a period of thirty (30) days after the date of the bid opening.

Dated this, the Eighteenth day of January, 2011.

Grand Forks Public School District Number 1.

By: Perry Marto, Director of Buildings and Grounds

(February 3, 10, 7, 2011)

IN THE DISTRICT COURT OF GRAND FORKS COUNTY,

PUBLIC NOTICE

STATE OF NORTH DAKOTA
In the Matter of the Estate of
SHIRLEY L. FOSTER, Deceased.
Probate No. 18-2011-PR-00017
NOTICE TO CREDITORS

NOTICE IS HEREBY GIVEN that the undersigned has been appointed Personal Representative of the above estate. All persons having claims against the said deceased are required to present their claims within three months after the date of the first publication or mailing of this notice or said claims will be forever barred. Claims must either be presented to Sheri L. Baugh, Personal Representative of the estate at 206 Overland Trail White Hall, AR 71602, or filed with the Court.

Dated this 28th day of January, 2011

Sheri L. Baugh
Personal Representative

Russ J. Melland
ND ID# 04896
CAMRUD, MADDOCK, OLSON & LARSON, LTD.
401 DeMers Ave Suite 500
PO Box 5849
Grand Forks, ND 58206-5849
(701) 775-5595
Attorney for Personal Representative
(February 3, 10, 17, 2011)

Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328?5188. Written comments may be submitted to the above address from February 10, 2011 through March 12, 2011. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on March 16, 2011 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through March 26, 2011. If no request for a public hearing is received, an announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328?5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least three days prior to the hearing.

Dated this 27th day of January 2011.

Terry L. O'Clair, P.E.
Director, Division of Air Quality
(February 3, 2011)

Farmer Producers of Agri-Valley:
Notice of Annual Meeting
Weds., Feb. 16th, 2011
10:00 a.m., Ramada Inn-Grand Forks
Secretary - Noel Pilon
(February 3, 2011)

County Weed Board Meeting
Tuesday, February 8, 2011
at 9:00 a.m.

1. Roll Call
2. Approve Minutes
3. Approve Payment of Bills
4. Joel Anderson, Weed Officer
5. New and/or old Business

The meeting will be held at the County Office Building, Room 348, 151 South 4th Street, Grand Forks, ND.
(February 3, 2011)

2/3 Grand Forks

[illegible] e/e

NOTICES

please contact IPM, Inc. at (701) 852-1157.

(February 2, 2011)

NOTICE OF SALE
Civil No. 09-C-01244
IN DISTRICT COURT
NORTHWEST JUDICIAL DISTRICT
STATE OF NORTH DAKOTA
COUNTY OF WARD

Prairie Federal Credit Union,
Plaintiff,
vs.
Mark Peterson, State of North Dakota by and through the State Tax Commissioner, Tollefson's Carpetland, Continental Western Ins., United Community Bank, Farmers Union Oil, Job Service North Dakota, Wesco Distributing, Inc., Procollect Services, LLC, Smittys Repair Inc. and Robert M. Brunner, G. W. Petersen, Credit Collection Bureau, Concrete Mobile LLC, Brenda Glinz and Mark N. Glinz, United Accounts, Inc., State of North Dakota by and through the Commissioner of Labor, Jost Construction Inc., Credit Bureau of Bismarck, Inc.,
Defendants.

THE STATE OF NORTH DAKOTA AND THE SHERIFF OF WARD COUNTY

NOTICE IS HEREBY GIVEN that by virtue of a Judgment and decree in foreclosure, rendered by the District Court of the Northwest Judicial District, in and for the County of Ward, State of North Dakota, and entered and docketed in the office of the clerk of the District Court, in and for said County, on the 4th day of December, 2009, in an action wherein Prairie Federal Credit Union was Plaintiff, and Mark Peterson, et.al. were Defendants, in favor of the Plaintiff and against the Defendants for the sum of $63,260.29, which Judgment and decree, among other things, directs the sale of the real estate hereinafter described, and by virtue of a writ issued to me by the Clerk of said Court, in and for Ward County, and under the seal of said Court, directing me to sell said real property, pursuant to said judgment and decree, I, Steve Kukowski, Sheriff of Ward County, will sell the hereinafter described real estate to the highest bidder for cash, at public auction at the front door of the courthouse in the City of Minot, Ward County, North Dakota, on the 1st day of March, 2011, at 10:00 o'clock a.m. of that day, to satisfy the said Judgment with interest and costs thereon, and the costs and expenses of such sale, or so much thereof as the proceeds of such sale applicable thereto will satisfy.

The premises to be sold pursuant to said Judgment and decree and to said writ and to this notice, are described in said Judgment, decree and writ as follows:

W1/2NW1/4, less the West 300 feet of the North 2026 feet thereof, and W1/2SW1/4 of Section 25, Township 152 North, Range 81 West, Ward County, North Dakota

Dated this 26th day of January, 2011.

Steve Kukowski
Sheriff of Ward County, North Dakota
By s/ Brent R. Renaud
Deputy Sheriff
William E. Bergman
OLSON & BURNS P.C.
P.O. Box 1180
Minot, ND 58702-1180

(February 2-9-16, 2011)

Notice of Intent to Amend the State Implementation Plan for Air Pollution Control Relating to the Reduction of Regional Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.

A copy of the proposed supplement may be reviewed at the Department's website at

www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328-5188. Written comments may be submitted to the above address from February 10, 2011 through March 12, 2011. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on March 16, 2011 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through March 26, 2011. If no request for a public hearing is received, an announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328?5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least three days prior to the hearing.

Dated this 27th day of January 2011.

Terry L. O'Clair, P.E.
Director, Division of Air Quality

(February 2, 2011)

Case No. [illegible] Application of XTO Energy Inc. for an order authorizing the drilling, completing and producing of a total of not more than three wells on a 1280-acre spacing unit described as Sections 16 and 21, T.154N., R.96W., Grinnell-Bakken Pool, Williams County, ND, eliminating any tool error requirements and such other relief as is appropriate.

Case No. 14105: Application of XTO Energy Inc. for an order authorizing the drilling, completing and producing of a total of not more than three wells on a 1280-acre spacing unit described as Sections 30 and 31, T.158N., R.95W., McGregor-Bakken Pool, Williams County, ND, eliminating any tool error requirements and such other relief as is appropriate.

Case No. 14113: Application of Continental Resources, Inc. for an order pursuant to NDAC § 43- 02-03-88.1 pooling all interests in a spacing unit described as Sections 25 and 36, T.155N., R.103W., Squires-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14114: Application of Continental Resources, Inc. for an order pursuant to NDAC § 43- 02-03-88.1 pooling all interests in a spacing unit described as Sections 17 and 20, T.155N., R.97W., Dollar Joe-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14133: Application of Brigham Oil & Gas, L.P. for an order pursuant to NDAC § 43-02-03- 88.1 pooling all interests in a spacing unit described as Sections 2 and 11, T.156N., R.103W., Bull Butte-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14134: Application of Brigham Oil & Gas, L.P. for an order pursuant to NDAC § 43-02-03- 88.1 pooling all interests in a spacing unit described as Sections 14 and 23, T.156N., R.103W., Bull Butte-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14139: Application of Brigham Oil & Gas, L.P. for an order pursuant to NDAC § 43-02-03- 88.1 pooling all interests in a spacing unit described as Sections 14 and 23, T.155N., R.101W., Cow Creek-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14140: Application of Brigham Oil & Gas, L.P. for an order pursuant to NDAC § 43-02-03- 88.1 pooling all interests in a spacing unit described as Sections 15 and 22, T.155N., R.101W., Cow Creek-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such otherrelief as is appropriate.

Case No. [illegible]: Application of Brigham Oil &

sources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Section 36, T.155N., R.102W., and Section 1, T.154N., R.102W., Painted Woods-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14185: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Sections 4 and 9, T.154N., R.103W., Painted Woods-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14186: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Sections 15 and 22, T.154N., R.103W., Painted Woods-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14187: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Section 17, T.154N., R.103W., Round Prairie-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14188: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Sections 25 and 36, T.154N., R.103W., Painted Woods-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14189: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Sections 4 and 9, T.153N., R.103W., Painted Woods-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14190: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Sections 6 and 7, T.153N., R.103W., Painted Woods-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such otherrelief as is appropriate.

Case No. 14191: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a spacing unit described as Section 16, [illegible] Lake Trenton-Bakken Pool, Williams County, ND as provided by NDCC § 38-08-08 and such other relief as is appropriate.

Case No. 14192: Application of EOG Resources, Inc. for an order pursuant to NDAC § 43-02-03-88.1 pooling all interests in a

Executive Director
North Dakota Housing Finance Agency
Equal Housing Opportunity
(February 2, 2011)

Notice of Intent
to Amend the
State Implementation Plan
for Air Pollution Control
Relating to the Reduction of Regional
Haze

The North Dakota Department of Health has prepared an amendment to the State Implementation Plan (SIP) for the Control of Air Pollution for the State of North Dakota which addresses Regional Haze (visibility impairment) in the Federal Class I areas. The amendment addresses requirements for the Coyote Station and includes new information for the M.R. Young Station. The requirements at the Coyote Station will reduce regional haze in Theodore Roosevelt National Park (TRNP) and Lostwood Wilderness Area (LWA). The amendment includes a revised Permit to Construct for the Coyote Station which establishes nitrogen oxides emission limits which are intended to improve visibility impairment in TRNP and LWA.A copy of the proposed supplement may be reviewed at the Department's website at www.ndhealth.gov/AQ/RegionalHaze/. A copy of the proposed supplement may be obtained by writing to the North Dakota Department of Health, Division of Air Quality, 918 E Divide Avenue, 2nd Floor, Bismarck, ND 58501-1947 or calling (701)328?5188. Written comments may be submitted to the above address from February 10, 2011 through March 12, 2011. A public hearing will be held only if there is a request from the public for a hearing. Any request for a public hearing must be submitted in writing and received by the Department before the end of the public comment period. If a public hearing is requested, it will be held on March 16, 2011 at 9:00 a.m. CDT in the Gold Seal Center's fourth floor conference room at 918 E Divide Avenue, Bismarck, ND. If a public hearing is requested, the public comment period will remain open through March 26, 2011. If no request for a public hearing is received, an announcement that the hearing has been cancelled will be posted on the Department's website at www.ndhealth.gov/AQ/Notices.htm. The public may also call (701)328?5188 to find out if the hearing has been cancelled.

If you plan to attend a requested hearing and will need special facilities or assistance relating to a disability, please contact the Department of Health at the above address at least three days prior to the hearing.

Dated this 27th day of January 2011.

Terry L. O'Clair, P.E.

Director, Division of Air Quality

Appendix F.1.4
Response to Public Comments

Appendix F.1.4
Response to Public Comments
Amendment No. 1 to Regional Haze SIP
February 10 – March 12, 2011

Comment 1:
The commentor disagreed with the National Park Service (NPS) blaming all haze in Theodore Roosevelt National Park (TRNP) on coal-fired power plants. The commentor indicated that forest fires and prescribed burning by the NPS also contributes to regional haze. The commentor also noted that prescribed burning by the NPS caused complications for local residents with breathing problems.

Response:
The Department agrees that coal-fired power plants in North Dakota are not the only contributor to regional haze. All emission sources in North Dakota only contribute about 23% of the light extinction in TRNP during the 20% worst days. Coal-fired power plants only contribute a portion of that impact. Regarding the impact the NPS prescribed burning has on residents with breathing problems, the North Dakota Air Pollution Control Rules prohibit such activity. NDAC 33-15-04-02.2 states that permissible open burning cannot cause a public nuisance and the burning must not be conducted upwind of, or in proximity to, an occupied building such that the ambient air of such occupied building may be adversely affected by the air contaminants being emitted. The Department will take this issue up with the NPS.

February 12, 2011

ND Dept. of Health
Div of Air Quality
918 E Divide Ave
2nd Floor
Bismarck, ND 58501-1947

FEB 2011
Received
Air Quality

I am writing in regard to the National Park seeking comments on air quality and haze on Theodore National Park. I disagree with the Park Service blaming all haze on emissions on the Coyote Station. I believe that an equal or greater amount of haze comes from fires in national forests and forest fires in Canada.

A few years ago, representatives from the Dept. of Interior and the National Park Service held meetings in Medora, lamenting pollution from the coal fired generating plants, causing pollution in Theodore National Park. I was standing at the Dickinson Airport and could just make out the outline of the buttes several miles southwest of the airport. This smoke was from fires in the national forests in Montana and Idaho. There was no comment on this from federal officials.

The National Park does burning of the grasslands each spring to control weeds and establish native range. The smoke from these burns causes problems with those of us with breathing problems. I have never heard any comments from National Park Service employees about haze from other causes than coal fired generating plants.

Kenneth W. Thompson

Kenneth Thompson
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Dickinson, ND 58601

Appendix J.1.5
National Park Service Consultation Comments on Amendment No. 1 and Department's Response

No comments received.

Appendix J.3.3
U.S. Environmental Protection Agency Comments on Amendment No. 1 and Department's Response

No comments received.