

Best Available Retrofit Technology

**Selective Catalytic Reduction
Technical Feasibility Analysis**

for

North Dakota Lignite

July 2009

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Table of Contents

Page

Part I: High Dust SCR

- A. Technical Review
- B. Summary
- C. Conclusions

Part II Low Dust and Tail Gas SCR

- A. Introduction
- B. Flue Gas Characteristics
- C. Catalyst Deactivation
- D. Vendor Information
- E. Similar Facilities using SCR
- F. Conclusions

References

Attachment I - Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2

Part I: **High Dust SCR**

A. Technical Review

The SCR process is based on the chemical reduction of the NO_x molecule using a metal based catalyst with activated sites to increase the rate of the reduction reaction. A nitrogen based reducing agent (reagent), such as ammonia or urea, is injected into the post combustion flue gas. The reagent reacts selectively with the flue gas NO_x within a specific temperature range and in the presence of the catalyst and oxygen to reduce the NO_x molecule into molecular nitrogen and water vapor.²

The BART Guidelines¹ state that in order for SCR to be technically feasible, it must be both “available” and “applicable”. SCR has been applied to the many different types of coal throughout the world. Based on its widespread usage, it would initially appear to be available for use at North Dakota power plants.

The BART Guidelines¹ also state that decisions regarding technical feasibility are 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 being transferred. Unless significant differences between the source types exist that are pertinent to the successful operation of the control device, the control option is presumed to be technically feasible. In order to compare the flue gas streams where SCR has been successfully applied to the flue gas from units burning North Dakota (Fort Union) lignite, a comparison of the fuel (coal) characteristics is necessary.

EPA’s Air Pollution Control Cost Manual² states: “Certain fuel constituents which are released during combustion act as catalyst poisons. Catalyst poisons include calcium oxide and magnesium oxide, potassium, sodium, arsenic, chlorine, fluorine, and lead. These constituents deactivate the catalyst by diffusing into active pore sites and occupying them irreversibly. Catalyst poisoning represents the main cause of catalyst deactivation.

Ammonia-sulfur salts, fly ash, and other particulate matter in the flue gas cause blinding, plugging or fouling of the catalyst. The particulate matter deposits on the surface and in the active pore sites of the catalyst. This results in a decrease of the number of sites available for NO_x reduction and an increase in flue gas pressure loss across the catalyst.

Impingement of particulate matter and high interstitial gas velocities erode the catalyst material. Catalysts with hardened leading edges or increased structural strength are less susceptible to erosion. Increasing catalyst strength through hardening, however, reduces the number of active pore sites.”

The most significant problem for the successful operation of SCR catalysts on units that fire North Dakota lignite is the formation of low temperature sodium-potassium-calcium-magnesium sulfates and phosphates. Sodium is a significant contributor to the “stickiness” of the ash produced from firing North Dakota lignite. The sodium content of North Dakota lignite ash ranges from 2-13% with an average of approximately 4% for lignite combusted in North Dakota

power plants from 2002-2006. Powder River Basin (PRB) coal from Wyoming typically averages around 1.5% sodium³.

A review was conducted to compare the constituents of fuels for which SCR has been successfully applied to that of North Dakota lignite. Data was obtained from the U.S. Geological Survey's U.S. Coal Quality Database³. The results are shown in Table 1.

Table 1
COAL CHARACTERISTICS
COMPARISON

	ND Lignite^a	Texas Lignite^a	Wyoming PRB^a	PA Bituminous^a
Avg. Heat Value (10 ⁶ Btu/ton)	13.0 ^b	15.2	17.0 ^c	25.5
Avg. Ash Content	9.5 ^b	12.6	5.0 ^c	13.0
Avg. Na ₂ O (% of Ash)	3.60 ^b	0.54	1.58	0.28
Std. Deviation	1.24 ^b	0.58	1.26	0.20
Avg. CaO (% of Ash)	15.44	13.18	17.31	1.69
Std. Deviation	6.45	5.16	7.39	1.64
Avg. MgO (% of Ash)	5.47	2.28	3.82	0.64
Std. Deviation	2.04	1.05	2.12	0.34
Avg. K ₂ O (% of Ash)	0.49	0.52	0.53	1.87
Std. Deviation	0.44	0.31	0.42	0.77
Na ₂ O+CaO+MgO+K ₂ O (% of Ash)	25.00	16.52	23.24	4.48

^a Heating values, ash content and ash constituents from the USGS National Coal Database except as noted.

^b From 2002-2006 Annual Emission Inventory Reports.

^c From University of Wyoming.

In order to properly compare flue gas conditions, an estimate of the total emission rate of the deactivation (fouling and poisoning) constituents can be made. Although the catalyst deactivation rate may not be directly proportional to the emission rates of the various constituents, it does provide a means of comparison of the flue gas characteristics.

AP-42, Compilation of Air Pollutant Emission Factors⁴, lists the following particulate matter emission factors as shown in Table 2.

Table 2		
AP-42 EMISSION FACTORS		
Combustion Unit Type	Fuel	Emission Factor
Cyclone	Lignite	6.7A ^a
Cyclone	Bit./Subbit.	2.0A
Wall/Tangential	Bit./Subbit.	10.0A
Wall	Lignite	6.5A
Tangential	Lignite	5.1A

A = Ash content of the coal (%)

^a 9.4A based on stack testing data from Minnkota Power Cooperative

To assess whether the flue gas characteristics at the North Dakota electric generating facilities are different from characteristics at other generating stations where SCR has been successfully applied, the emission rate, or loading, of the various deactivation constituents and the chemical form (organic or inorganic) of these constituents must be evaluated. Using the coal characteristics data from Table 1, the emission factors from Table 2, the emission rate of the deactivation constituents were calculated. Emphasis was given to the sodium oxide (Na₂O) emission rate because North Dakota lignite generally contains more Na₂O than bituminous or subbituminous coal. Since cyclone boilers firing North Dakota lignite partition the ash, the sodium is concentrated in the ash leaving the boiler. The results of the following calculation will underestimate the amount of sodium in the flue gas for a cyclone boiler firing North Dakota lignite; however, it does provide a conservative comparison. The results of the calculation are provided in Table 3:

Table 3
Emission Rate Comparison

	ND LIGNITE^a	TEXAS LIGNITE^b	WYOMING PRB^b	PA BITUMINOUS^b
Na ₂ O (% of Ash)	3.60	0.54	1.58	0.28
CaO (% of Ash)	15.44	13.18	17.31	1.69
MgO (% of ash)	5.47	2.28	3.82	0.64
K ₂ O (% of Ash)	0.49	0.52	0.53	1.87
Na ₂ O+CaO+MgO+K ₂ O	25.00	16.52	23.24	4.48
Ash Content	9.5	12.6	5.0	13.0
Heat Value (10 ⁶ Btu/ton)	13.00	15.20	17.00	25.50
PM Emission Factor (lb/ton/1% Ash) ^{c,d}				
Cyclone Boiler	9.4	6.7	2.0	2.0
Wall/Tangentially-fired Boiler (Pulverized)	5.8	5.8	10.0	10.0
PM Emissions (lb/10 ⁶ Btu)				
Cyclone Boiler	6.86	5.55	0.59	1.02
Wall/Tangentially-fired Boiler (Pulverized)	4.23	4.81	2.94	5.10
Na ₂ O Cyclone Boiler Emissions				
lb/ton	3.21	0.46	0.16	0.07
lb/10 ⁶ Btu	0.2470	0.0300	0.0093	0.0029

Table 3
Emission Rate Comparison

	ND LIGNITE^a	TEXAS LIGNITE^b	WYOMING PRB^b	PA BITUMINOUS^b
lb/dscf	2.5054E-05	3.0417E-06	9.5032E-07	2.9191E-07
lb/wscf	2.0672E-05	2.5097E-06	8.7351E-07	2.6832E-07
Na₂O+CaO+MgO+K₂O				
Cyclone Boiler Emissions				
lb/ton	22.30	13.95	2.32	1.16
lb/10 ⁶ Btu	1.72	0.92	0.14	0.05
lb/dscf	1.7399E-04	9.3054E-05	1.3978E-05	4.6706E-06
lb/wscf	1.4356E-04	7.6779E-05	1.2848E-05	4.2931E-06
Ratio of ND Lignite Cyclone Emissions to Other Cyclones				
Na₂O				
lb/ton		7.04	20.33	44.11
lb/10 ⁶ Btu		8.24	26.58	86.53
lb/dscf		8.24	26.36	85.83
lb/wscf		8.24	23.67	77.04
Na₂O+CaO+MgO+K₂O				
lb/ton		1.60	9.60	19.15
lb/10 ⁶ Btu		1.87	12.55	37.56
lb/dscf		1.87	12.45	37.25
lb/wscf		1.87	11.17	33.44
Comparison of ND Lignite Cyclone Emissions to Pulverized Units				
Na₂O Emissions				
lb/ton	3.21	0.39	0.79	0.36

Table 3
Emission Rate Comparison

	ND LIGNITE^a	TEXAS LIGNITE^b	WYOMING PRB^b	PA BITUMINOUS^b
lb/10 ⁶ Btu	0.2470	0.0260	0.0465	0.0143
lb/dscf	2.5054E-05	2.6331E-06	4.7516E-06	1.4596E-06
lb/wscf	2.0672E-05	2.1726E-06	4.3675E-06	1.3416E-06
Na ₂ O+CaO+MgO+K ₂ O Emissions				
lb/ton	22.30	12.07	11.62	5.82
lb/10 ⁶ Btu	1.7155	0.7943	0.6835	0.2284
lb/dscf	1.7399E-04	8.0554E-05	6.9891E-05	2.3353E-05
lb/wscf	1.4356E-04	6.6466E-05	6.42415E-05	2.14654E-05
Ratio ND Lignite Cyclone Emissions to Pulverized Units				
Na ₂ O				
lb/ton		8.14	4.07	8.82
lb/10 ⁶ Btu		9.51	5.32	17.31
lb/dscf		9.51	5.27	17.17
lb/wscf		9.51	4.73	15.41
Na ₂ O+CaO+MgO+K ₂ O				
lb/ton		1.85	1.92	3.83
lb/10 ⁶ Btu		2.16	2.51	7.51
lb/dscf		2.16	2.49	7.45
lb/wscf		2.16	2.23	6.69
Comparison of ND Pulverized Units to Other Pulverized Units				
Na ₂ O Emissions				
lb/ton	1.981512	0.394632	0.79	0.364
lb/10 ⁶ Btu	0.152424	0.025962632	0.046470588	0.01427451

Table 3
Emission Rate Comparison

	ND LIGNITE^a	TEXAS LIGNITE^b	WYOMING PRB^b	PA BITUMINOUS^b
lb/dscf	1.54588E-05	2.63313E-06	4.7516E-06	1.4596E-06
lb/wscf	1.27551E-05	2.17261E-06	4.3675E-06	1.3416E-06
Na ₂ O+CaO+MgO+K ₂ O Emissions				
lb/ton	13.7605	12.072816	11.62	5.824
lb/10 ⁶ Btu	1.0585	0.7943	0.6835	0.2284
lb/dscf	1.073529E-04	8.0554E-05	6.9891E-05	2.3353E-05
lb/wscf	8.85774E-05	6.6466E-05	6.42415E-05	2.14654E-05
Ratio ND Pulverized Unit Emissions to Other Pulverized Units				
Na ₂ O		5.02	2.51	5.44
lb/ton		5.87	3.28	10.68
lb/10 ⁶ Btu		5.87	3.25	10.59
lb/dscf		5.87	2.92	9.51
lb/wscf				
Na ₂ O+CaO+MgO+K ₂ O				
lb/ton		1.14	1.18	2.36
lb/10 ⁶ Btu		1.33	1.55	4.63
lb/dscf		1.33	1.54	4.60
lb/wscf		1.33	1.38	4.13

^a Source: Annual Emission Inventory Reports 2002-2006 (weighted average).

^b Source: USGS National Coal Database and University of Wyoming.

^c Source: AP-42, Compilation of Air Pollutant Emission Factors except for cyclone units burning ND lignite; factor is based on stack test data.

^d Emission factor for wall-fired and tangentially fired units combusting lignite is the average of the AP-42 emissions factors.

The most useful emission rate calculation is that in terms of pounds per wet standard cubic foot (lb/wscf). This estimated emission rate represents the actual concentration of the constituents in the ductwork leaving the boiler at standard temperature and pressure. However, most laboratory and pilot scale testing report the results in lb/dscf or mg/Nm³. Table 3 shows that the potential for deactivation of the SCR catalyst is much greater for a boiler combusting North Dakota lignite.

The Energy & Environmental Research Center (EERC) at the University of North Dakota is recognized as one of the world's leading coal research facilities. Since 1951, the EERC has focused on research and development, technology demonstration and technology commercialization. As part of the BART assessment for Minnkota Power Cooperative and Basin Electric Power Cooperative, a report by the EERC titled Ash Impacts on SCR Catalyst Performance⁵ was included. In that report, it is stated: "The ash deposition behavior of the lignites from North Dakota is the most complex and severe of any coals in the world, and installation of catalysts for NO_x reduction is going to be plagued with problems." The report further states: "Alkali and alkaline earth sulfates are enhanced by cyclone-fired systems. The cyclone firing results in partitioning of the ash between bottom slag and the body of the boiler. The sulfate forming materials are more concentrated in the fly ash as a result of cyclone firing."

In reviewing the flue gas characteristics of plants firing coal types where SCR has been applied with those firing North Dakota lignite, it appears comparison of the characteristics for cyclone fired units combusting North Dakota lignite to cyclone units firing other types of coal alone is more appropriate because of the enhanced sulfates formation in cyclone units. Likewise, it is appropriate to compare pulverized lignite fired units to pulverized units firing different types of coal. The Department's review indicates that the sodium oxide loading in the flue gas for the North Dakota lignite-fired unit would be nearly 24 times (on a lb/wscf basis) that of a cyclone unit burning PRB subbituminous coal. This ratio is actually conservative (expected to higher) because of the partitioning of the ash that occurs in a cyclone boiler firing North Dakota lignite. The estimated combined loading of catalyst deactivation constituents sodium oxide, calcium oxide, magnesium oxide and potassium oxide is more than eleven times that of PRB subbituminous coal-fired cyclone units. For pulverized units, a unit firing North Dakota lignite is expected to emit three times as much sodium oxide as a unit firing PRB subbituminous coal. Although the deactivation of the SCR catalyst may not be directly proportional to the emission rate, it is evident that the concentration of various SCR deactivation chemical constituents in the flue gas of a North Dakota lignite-fired power plant is much different from a unit firing PRB subbituminous coal or other types of coal.

Gutberlet⁶ in his technical paper on deactivation of SCR catalyst states: "Alkaline metals chemically attach to active catalyst pore sites and cause blinding. Sodium (Na) and potassium (K) are of prime concern especially in their water soluble forms which are mobile and penetrate into the catalyst pores." Minnkota, in its March 19, 2007 response to questions indicates that most sodium in North Dakota lignite is organically associated. Combustion of the organically associated sodium produces soluble sodium compounds that are readily available for reactions with catalysts and flue gas species. Minnkota also stated that in a conversation with Fleming Hansen of Haldor Topsoe (see Minnkota's November 9, 2007 response to comments¹⁰), Mr. Hansen indicated that sodium was a major concern and that it causes deactivation, especially in the organically associated form. It is evident to the Department that the form (soluble) of

sodium present in the ash from the combustion of North Dakota lignite will deactivate an SCR much more quickly than the other types of coals where SCR has been successful.

The next issue to address is whether the difference in these characteristics would preclude the successful use or reasonable operation of SCR technology on units fired on North Dakota lignite.

The BART Guidelines¹ state: “In Step 2, you evaluate the technical feasibility of the control options you identified in Step 1. You should document a demonstration of technical infeasibility and should explain, based on physical, chemical, or engineering principles, why technical difficulties would preclude the successful use of the control option on the emissions unit under review.” “An available technology is applicable if it can reasonably be installed and operated on the source type under consideration.” The BART Guideline¹ does not define successful use of the control option or reasonably be installed and operated.

The EERC, several utilities and catalyst vendors conducted pilot scale testing at the Coyote Station, which is a cyclone fired unit that combusts North Dakota lignite. The pilot scale SCR deployed at the Coyote Station was plugged and the catalyst pores deactivated after 2 months (approx. 1430 hours). The Department believes “successful use or reasonably operated” is considerably more than a few thousand hours of operation. For example, the EPA Air Pollution Control Cost Manual² states: “For coal-fired boiler applications, SCR catalyst vendors typically guarantee that catalyst for an operating life ranging between 10,000 hours to 30,000 hours.” In the technical paper Nitrogen Oxides Emission Control Options for Coal Fired Electric Utility Boilers,⁹ it is stated: “On dry-bottom, coal-fired U.S. boilers equipped with full SCR, the planned time between catalyst changes on a typical unit is typically > 24,000 operating hours or ≥ 3 years of operations.” The paper also indicated that Merrimack 2, a cyclone boiler with 100% flyash reinjection, the expected time between the replacement of layers is 14,000 operating hours. It appears that 10,000 hours of operation would be a minimum time for successful use or reasonable operation.

Pritchard⁷ states in his paper on optimizing SCR catalyst design: “Our experience show that coal-fired SCRs are successful when the system impact and catalyst deterioration factors are understood and specific counter measures are implemented in system and catalyst design.” The Coyote pilot test may not have provided much useful data for designing an SCR system for plants firing North Dakota lignite; however, it did indicate a difference between lignite and subbituminous coal. The pilot scale testing protocol was the same for the Coyote Station, Columbia Station and Baldwin Station; however, the test at the Columbia Station used a different catalyst. The Coyote Station combusts lignite while the Columbia Station and Baldwin Station fire subbituminous coal. 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. This indicates to the Department that design of an SCR system for North Dakota lignite would be different from a unit burning subbituminous coal. Because of the lack of deactivation data from the pilot test at the Coyote Station, it would appear to be extremely difficult to design an SCR system that could be successfully used or reasonably operated. Proceeding with installation of such a design without engineering data collected during appropriate pilot testing is subject to an extreme risk. This suggests to the Department that additional research and testing on the effects of the flue gas constituents are required to design a high dust SCR system.

Kling et. al.¹¹ conducted pilot and bench scale testing of SCR catalysts when subjected to the flue gas from the combustion of biomass. The testing was conducted using three different types of catalyst. Catalyst Type A was typical of that use for coal-fired boilers, Type B was a “bio-optimized” catalyst with an increased vanadium content and Type C has a very high vanadium content. Kling¹¹ and later Zheng et. al.¹² have concluded that it is the alkali aerosols that are less than or equal to 0.1 micrometers that cause most of the catalyst deactivation. In North Dakota lignite, the alkali metals are generally associated with the organic matter of the lignite while in other coals the alkaline constituents are associated with the inorganic portion of the coal (e.g. clays). The combustion of the organically associated alkaline elements causes them to vaporize; when they condense they form submicron aerosols. The combustion of inorganically associated alkalis causes only a small portion to vaporize. Minnkota has supplied information that indicates these condensed alkali aerosols have a mass mean diameter of approximately 0.1 micrometers. Therefore, 50% of the aerosols would be less than 0.1 micrometers in size on a mass basis. The mass of sodium oxide and potassium oxide leaving a pulverized boiler combusting North Dakota lignite would average 1.55×10^{-5} lb/dscf (266 mg/Nm³) and 2.11×10^{-6} lb/dscf (36 mg/Nm³), respectively. This value would be higher for cyclone boilers (431 and 59 mg/Nm³ respectively).

Crespi¹³ has provided data that suggests potassium oxide is approximately twice as potent catalyst deactivation chemical on a molar basis (1.3 times on a mass basis) than sodium oxide. The equivalent potassium oxide emission rate for a pulverized boiler based on this data would be 241 mg/Nm³. The aerosols are most likely in the sulfate form. This would lead to an equivalent potassium sulfate emission rate of 446 mg/Nm³.

Kling¹¹ found a deactivation rate of 21-52% over 1500 hours for fuel made up of tree bark and 30% demolition wood waste. This fuel had a potassium chloride loading of 16.7 mg/Nm³ and a sodium chloride loading of 5.8 mg/Nm³. The Kling results were for aerosols with an aerodynamic diameter of less than 0.1 micrometers. If all of the sodium and potassium in lignite vaporizes, 50% of the total loading would be less than or equal to 0.1 micrometers or 223 mg/Nm³ for a pulverized unit. Zheng¹² has suggested that potassium chloride is two and one half times more potent catalyst poison than potassium sulfate (0.4% per day versus 1% per day). An equivalent loading of sodium and potassium for North Dakota lignite as potassium chloride would be 89 mg/Nm³. This loading is more than four times that of the Kling¹¹ testing. For a cyclone boiler it would be approximately seven times as much loading. The Kling¹¹ results suggest 2,885-7,140 hours until 100% deactivation. The higher loading at the North Dakota facilities suggests a much shorter catalyst life.

Zheng et. al.¹¹ found a catalyst deactivation rate of 0.4% per day for a potassium sulfate. The testing was conducted using a concentration of 20-30 mg/Nm³ of potassium sulfate with a mass mean diameter of 0.55 micrometers. Although data is not available to determine the loading of aerosols with a diameter less than 0.55 micrometers for all boilers burning North Dakota lignite, a comparison to the fraction less than 0.1 micrometers indicates a concentration is 7-11 times larger than the concentration in Zheng’s tests. The 0.4% deactivation rate per day is equivalent to 6000 hours at 100% deactivation. Flue gas from the combustion of North Dakota lignite in a pulverized boiler would likely produce a much higher deactivation rate. A cyclone boiler would probably deactivate an SCR catalyst even faster.

The recent testing by Kling¹¹ and Zheng¹² indicate that it is unlikely to achieve 10,000 hours of catalyst life when combusting North Dakota lignite. In fact, the catalyst life could be only a few thousand hours as suggested by the pilot scale testing at the Coyote Station.

Besides catalyst deactivation, a high-dust SCR would experience plugging problems due to ash deposition and the carryover of “popcorn ash” from the boiler. Ash deposition is a problem for all units firing North Dakota lignite. Sodium is a significant contributor to the “stickiness” of the ash. Since the ash of North Dakota lignite contains much more sodium than other types of coal where SCR has been applied, deposition problems will be greatly increased. Since this sticky ash is not easily removed, the catalyst life could be severely reduced.

The flue gas temperature variation at the location a high dust SCR would be placed is also a concern for cyclone units. Minnkota indicates that the temperature generally ranges from approximately 430°F to 960°F for Unit 1 depending on the unit’s load. For Unit 2, it could vary from 430-880°F. However, temperatures as high as 1050°F at Unit 1 and 990°F at Unit 2 have been measured. Basin Electric has indicated that the Unit 2 temperature can be significantly higher than 750°F.

The EPA Air Pollution Control Cost Manual² states:

“The NO_x reduction reaction is effective only within a given temperature range. The use of a catalyst in the SCR process lowers the temperature range required to maximize the NO_x reduction reaction. At temperatures below the specified range, the reaction kinetics decrease and ammonia passes through the boiler (ammonia slip). At temperatures above the specified range, nitrous oxide (N₂O) forms and catalyst sintering and deactivation occurs.

In an SCR system, the optimum temperature depends on both the type of catalyst utilized in the process and the flue gas composition. For the majority of commercial catalysts (metal oxides), the optimum temperatures for the SCR process range from 480°F to 800°F (250°C to 427°C). The figure shows that the rate of the NO_x removal increases with temperatures up to a maximum between 700°F to 750°F (370°C to 400°C)” (figure omitted here).

The Control Cost Manual² goes on to state: “The relationships between flue gas temperature, catalyst volume, and NO_x removal are complicated functions of the catalyst formulation and configuration. The physical and chemical properties of each catalyst are optimized for different operating conditions. For a given catalyst formulation, the required catalyst volume and/or temperature range can even change from one manufacturer of the catalyst to another. The selection of catalyst, therefore, is critical to the operation and performance of the SCR system.”

This complicated relationship suggests that additional research, design and testing may be required before the temperature problem could be overcome for cyclone units.

The final reason for technical infeasibility is erosion of the catalyst. Because of the high ash content and frequent cleaning cycles due to the deposition characteristics of North Dakota lignite ash, erosion may be more of a concern than with a bituminous or subbituminous coal-fired unit.

The BART assessments for Minnkota and Basin Electric were prepared by Burns and McDonnell, which has considerable experience with SCR systems, and the EERC, which has extensive experience with North Dakota lignite. Sargent and Lundy, LLC (S&L), another

consulting firm acting on behalf of Basin Electric Power Cooperative, also made two presentations to the Department on the application of SCR technology to North Dakota lignite. S&L indicated it had designed 46% of the SCR systems in the United States. Of the SCR systems, 39 were for coal-fired units with 10 designed for Powder River Basin subbituminous coal. S&L listed⁸ their “Keys to Achieving Success” as:

- Understand deactivation mechanisms
- Understand ash behavior
- The “Understanding” establishes:
 - Catalyst formulation
 - Catalyst pitch
 - Reactor velocity
 - Catalyst surface and volume
- Results in reactor size and shape to match catalyst management plan
- Physical model for:
 - NH₃ and NO_x mixing
 - Gas distribution and velocity profile
- CFD modeling:
 - Identify and mitigate areas of potential ash deposits
 - Mixing gases of different temperatures

S&L also provided possible solutions for deactivation of the catalyst. However, they indicated there was no known solution for deactivation due to soluble alkalis such as the soluble sodium compounds generated by the combustion of North Dakota lignite. S&L speculated that more catalyst and a larger reactor may be possible solutions; however, how much more catalyst or how much larger the reactor would have to be to solve the problem was unknown. S&L also pointed out that some design issues for North Dakota have not been addressed by Powder River Basin experience. Some of these issues include:

- The high level of soluble alkali in North Dakota lignite
- The particle size and sticky nature of high alkaline North Dakota lignite
- Potential abrasive qualities of North Dakota lignite ash

S&L concluded their presentation with the following statement about North Dakota lignite: “There are attributes of this fuel in an SCR environment that are not well understood today and need more investigation to predict its performance.” S&L recommendations included a parametric pilot test program to:

Answer questions on:

- soluble alkalis
- ash characteristics
- size
- stickiness
- abrasive qualities
- Compare findings with PRB experience.

The BART Guidelines¹ describe the process commonly used for bringing a control technology concept to reality as a commercial product as follows:

- concept stage
- research and patenting
- bench scale or laboratory testing
- pilot scale testing
- licensing and commercial demonstration
- commercial sales

The BART Guidelines¹ go on to state “A control technique is considered available within the context presented above, if it has reached the stage of licensing and commercial availability. Similarly, we do not expect a source owner to conduct extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, you would not consider technologies in the pilot scale testing stages of development as “available” for purposes of BART review.”

“Commercial availability by itself, however is not necessarily a sufficient basis for concluding a technology to be applicable and therefore technically feasible. Technical feasibility, as determined in Step 2, also means a control option may reasonably be deployed on or “applicable” to the source type under consideration.”

B. Summary:

The characteristics of the exhaust, or flue gas stream, after combustion of fuel by a boiler are governed by the design and operating characteristics of the boiler and the characteristics of the fuel. In this scenario, the fuel is North Dakota (Fort Union) lignite. The BART applicants concluded in their BART analyses that available SCR catalysts are not applicable for their unit(s).

One foremost issue in the NO_x BART analyses is whether any unique characteristics due to lignite fired by the boilers are cause for doubt that known SCR technology is not applicable and technically infeasible. We note that plugging of a catalyst on its face due to deposition of particles larger than the pitch of a catalyst (a.k.a. catalyst channel blockage) and plugging of pores on surfaces of a catalyst are generally different physical interactions. Our review of the supplemental information (see Minnkota BACT analysis¹⁰) concludes that the following facts are not disputed by EPA.

- 1) In cyclone firing of Fort Union lignite, about 45 - 50% of the ash forming components of the coal end up as flue-gas ash. For wall-fired and tangentially fired units, 25 - 35% of the ash ends up in the flue gas. Unburned or partially burned organic fraction of the Fort Union lignite, which contains more sodium than other coals, reacts with silicate particles causing a “stickiness” quality of flue gas ash, which results in ash deposits on heat transfer surfaces. And larger particles fracture from heat-transfer surfaces (a.k.a. popcorn ash) and enter the flue gas stream. Consequently, deposition on surfaces of catalytic reactors occurs and rates of deposition are higher.

- 2) Fort Union lignite has a higher moisture content and is oxygen rich compared to other coal types. This lignite also has a higher sulfur content compared to PRB coal. Consequently, the flue gas stream is rich in sulfur dioxide (SO₂) and sulfate (SO₄) compared to other coal types.
- 3) Fort Union lignite has a higher organic matter content. This lignite contains a higher proportion of alkali metal constituents, especially sodium (Na). Cyclone combustion of the coal produces ash, which is partitioned as slag on high temperature boiler surfaces and as flue gas vapor and fine particles (less than 15 micrometers (microns)). About 75% of total sodium in the lignite is associated with the organic fraction of the lignite; so very little of the sodium is associated with the mineral fraction of the lignite such as clays. During combustion, organic and water-soluble sodium vaporizes. Consequently, combustion of the coal leads to higher flue-gas concentrations of alkali metals in vapor form.
- 4) Alkali vapors condense (homogeneous nucleation) due to flue-gas cooling or react (heterogeneous nucleation) with other flue gas constituents, e.g., mineral silicates and sulfate. The size distribution of flue gas particles is bi-modal, relating to organically associated inorganics in coal and coalesced minerals and inorganics in flue gas; the size distribution varies by coal type and combustion method.
- 5) NO_x reduction occurs on the flat surfaces of a catalyst and in pores within the flat surfaces. The pores are open to the flue gas passing through the catalyst reactor. Condensed vapors, alkali sulfates and alkaline-earth oxides and silicates are minute particles (less than 1 microns), which enter pores of the catalyst (a.k.a. plugging) and prevent catalytic reaction with NO_x. Residual alkali vapors, Na, potassium (K) and calcium (Ca) displace hydrogen (H) on fresh catalyst, which prevents catalytic reaction with NO_x (a.k.a poisoning) and reacts with sulfate to cause blinding of catalyst surfaces. Pore condensation of sodium also causes catalyst deactivation, which is a major deactivation mechanism. The rate of catalyst deactivation depends on the concentration and form of alkali in the flue gas; higher Na and K accelerate catalyst poisoning, blinding and plugging, which requires more frequent catalyst maintenance.
- 6) There are no SCR systems planned, constructed or operating in the flue gas stream of boilers fired with Fort Union lignite. Fort Union lignite has some coal characteristics that are uniquely different than Gulf Coast lignites, such as the larger proportion of organic matter and association of alkali, sodium specifically, with that organic matter.
- 7) Slipstream SCR reactors of the same design were installed at three power plants to test SCR for NO_x emissions control. One of the plants was cyclone fired with Fort Union lignite and the others with subbituminous coal. Deposition on the reactor surface after two months using the lignite was significantly greater; the deposits were rich in sodium, calcium and sulfur. The tests confirmed catalyst blinding and plugging, but did not provide rates for catalyst deactivation. Tests also indicated that the deposits causing blinding and plugging of pores contained more sodium compared to PRB coal.

- 8) There may be an engineering solution to reduce deposition on the surface of catalytic reactors. But there is no known in-reactor engineering solution to:
 - (a) reduce deactivation rates caused by heterogeneous reactions that form the particles that cause pore blinding and plugging, or
 - (b) to restore the catalytic reactions by removing particles from catalyst pores.
- 9) There are no usable data for rates of deactivation of SCR catalyst in the flue gas from combustion of Fort Union lignite. Catalyst pitch is the only apparent catalyst geometric affecting ash deposition; but pitch also affects flue gas velocity through the reactor and, thus, times of exposure of NO_x for reduction to nitrogen (N₂) and water (H₂O).
- 10) The BART Guidelines¹ do not provide specific numeric performance measures that an SCR NO_x control technology must achieve to satisfy the guideline's applicable (technically feasible) criteria.
- 11) The State of Louisiana recently determined that high dust SCR was not technically feasible for an activated carbon plant which utilizes lignite in the process because of the flue gas characteristics (high alkaline compounds) that will deactivate the catalyst.

Companion issues including ammonia slip and pyrosulfates emitted from a high-dust SCR will exaggerate flue-gas particulate (ash) deposits on low-temperature convective pass surfaces in the economizer and the primary air pre-heaters.

C. Conclusions:

The Department has completed an extensive review of all aspects of the application of SCR technology to the North Dakota power plants. Whether the problems associated with adapting SCR technology to a unit firing North Dakota lignite can be overcome is highly speculative.

The Department makes the following conclusions:

- 1) North Dakota lignite is extremely variable in heat content, ash content, and in the constituents that make up the ash. This variability will affect the design and operation of an SCR system.
- 2) The only pilot scale testing that has ever been conducted on a unit firing North Dakota lignite was at the Coyote Station. The pilot scale SCR plugged after only 2 months and little useful data was obtained. However, the testing used the same protocol as testing at the Columbia and Baldwin Station which had fewer problems. The Columbia and Baldwin Stations burn subbituminous coal. The Coyote testing demonstrates to the Department that North Dakota lignite firing will have more severe effects (plugging and catalyst deactivation) than units firing subbituminous coal when the same design is employed. Operation of an SCR

system for only 2 months between catalyst change out is much less time than is normally expected (at least 10,000 hours or 13.7 months) for power plants. Operation of an SCR system for only 2 months between catalyst replacement is not considered successful use or reasonable operation of SCR technology.

- 3) North Dakota lignite contains primarily organic sodium compounds. The combustion of the lignite produces soluble sodium compounds which causes more severe catalyst deactivation problems than insoluble sodium compounds.
- 4) The flue gas constituents that cause SCR catalyst deactivation at North Dakota power plants are significantly different from Texas lignite, Wyoming PRB subbituminous coal, and Pennsylvania bituminous coal. When cyclone boilers combusting North Dakota lignite are compared to any other type of combustion unit burning the other types of coal, the concentration of sodium compounds in the flue gas is at nearly five times greater (based on average coal and lb/wscf basis) than the other types of fuel and the total primary alkali constituents (CaO, Na₂O, MgO and K₂O) are approximately double. When pulverized units firing North Dakota lignite are compared to pulverized units firing other coals, the sodium ratio is approximately three times and the total primary alkali constituents ratio is approximately 1.4. The flue gas generated at North Dakota power plants is different from the flue gas at any plant where SCR technology has been applied, primarily due to the high concentration of soluble sodium compounds and the total flue gas loading of catalyst deactivation chemicals. Recent testing by Kling¹¹ and Zheng¹² suggest that it may not be possible to obtain 10,000 hours of catalyst life and probably much less than 10,000 hours. This difference in flue gas characteristics will preclude the successful use or reasonable operation of existing SCR technology at these units. Additional pilot scale testing is necessary to learn if the technology can be adapted.
- 5) Both Burns and McDonnell and Sargent and Lundy have extensive experience with the design and operation of SCR systems. Burns and McDonnell has expressed concerns whether an SCR system can be successfully designed and operated at a boiler combusting North Dakota lignite. S&L has indicated that certain design issues have not been addressed by PRB (subbituminous coal) experience. They have also indicated that some important unanswered questions pose significant risks for an SCR design engineer and recommended pilot scale testing before design takes place. The questions left unanswered include:
 - High level of soluble alkali in North Dakota lignite
 - Particle size and sticky nature of high alkaline North Dakota lignite ash
 - Potential abrasive qualities of North Dakota lignite ash
- 6) The BART Guidelines¹ list the stages in the development of a commercial control system from concept stage to commercial sales. Experimentation with the SCR system takes place during the bench scale/laboratory testing or pilot scale testing stages. Although adjustments of full scale (commercial product) units is often necessary, the source operator should not be required at this stage to conduct

experimentation in order to make the equipment work. This could cause extended time delays and resource penalties for the source operator. To design and install an SCR system for a unit firing North Dakota lignite without obtaining additional data from bench scale or pilot scale testing would be experimentation.

- 7) The temperature variation of the flue gas at cyclone units entering the SCR will adversely affect performance and must be resolved for successful application of this technology. Engineering studies will be required to determine if this problem can be resolved. Minnkota and Basin Electric are not required to experience extended time delays or resource penalties to allow research to be conducted. Neither are they required to experience extended trials to learn how to apply a technology. The temperature problems for the SCR will require extensive, and correspondingly expensive, engineering studies to determine if this problem can be resolved.
- 8) There are unresolved issues regarding catalyst erosion from the ash. Recent pilot scale testing will have to be evaluated to determine if the erosion problems are resolvable.
- 9) Poisoning, blinding and plugging of a catalyst are affected by the geometries and properties of the catalyst. Firing of Fort Union lignite results in a flue gas stream that highly accelerates poisoning, blinding and plugging (of pores) due to the rich sodium and potassium vapors, particles and ammonium sulfates (due to ammonia injection) in lignite-fired flue gas. The engineering solutions of a larger SCR reactor, more catalyst and larger pitch do not resolve the rapid plugging of catalyst pores, at least with some certainty to assure a predictable useful life of catalyst before change out. There is no catalyst vendor solution to reduce or eliminate catalyst pore plugging. The chemical and physical process of pore plugging cannot be reversed, which dictates catalyst change out.
- 10) Without pilot scale testing, the long term NO_x reduction efficiency, the volume of the reactor, the catalyst pitch, life of the catalyst, or even the type of catalyst to be used cannot be predicted with a high degree of confidence. Sargent and Lundy has pointed out that to design an SCR system for a plant burning North Dakota lignite without pilot scale testing would present significant risks for the SCR design engineer. Without these design factors determined, any cost estimate would be conjecture and any evaluation of cost effectiveness or incremental cost in Step 4 of the BART analysis would be meaningless. The BART sources are not required to conduct pilot testing to obtain this data.

Therefore, the Department has determined, based on guidance in 40 CFR 51, Appendix Y¹, that high dust SCR technology is not available and thus not technically feasible at this time for units combusting North Dakota lignite.

Part II. **Low Dust and Tail Gas SCR**

A. Introduction

Selective catalytic reduction (SCR) systems that are placed downstream of the particulate matter (PM) and sulfur dioxide (SO₂) control systems are generally referred to as tail end SCR. Tail end SCR systems have been used on coal-fired and biomass fired boilers in the United States as well as other countries. However, no SCR system including a tail end SCR, has ever been operated on a boiler firing North Dakota lignite. The flue gas produced by the combustion of North Dakota lignite contains high concentrations of alkali aerosols (primarily sodium and potassium). Cyclone boilers, such as the two units at the M.R. Young Station, produce higher concentrations of submicron aerosols than conventional pulverized or fluidized bed boilers. The higher temperature in the cyclone boilers vaporizes the organically associated sodium and potassium in North Dakota lignite. When these elements condense, they form submicron aerosols. Minnkota¹⁴ (page 12) has indicated that the condensed vapors have a mean diameter of approximately 0.1 micrometers. Papers by Kling¹¹ and Zheng¹² have indicated that the aerosols with a diameter less than or equal to 0.1 micrometers cause the greatest catalyst deactivation.

The NSR Manual¹ states that decisions regarding technical feasibility are 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 being transferred. Unless significant differences between the 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.

Since no low dust or tail end SCR system has even been applied to a boiler that combusts North Dakota lignite, an evaluation of the flue gas characteristics was made to determine if they were substantially different from facilities that have successfully applied SCR technology or to determine if empirical data would indicate whether LDSCR or TESCR can be successfully applied.

B. Flue Gas Characteristics

The Minnkota lignite represents the worst-case for the evaluation of low dust or tail SCR application to a unit combusting North Dakota lignite. At the M.R. Young Station, both units use an electrostatic precipitator (ESP) to control PM emissions. Unit 2 is equipped with a wet scrubber to control SO₂ emissions while a wet scrubber will be constructed for Unit 1. Minnkota¹⁵ (p. 20) as part of their BACT analysis has provided an analysis of the particulate matter emitted from Unit 2. The analysis indicated the PM was 6.56% sodium (Na), 2.26% potassium (K), 5.71% sulfur (S), 57.52% oxygen (O) and the remaining other elements.

The form of the sodium and potassium is most likely in sulfate form¹⁶ (p. 32). If all of the sodium and potassium are in the sulfate form, sodium sulfate and potassium sulfate would compromise approximately 25% of the total particulate matter emitted from Unit 2. Minnkota has indicated that the sample of the particulate matter that was analyzed was obtained while some flue gas was bypassing the SO₂ scrubber. The amount of sodium,

potassium and/or sulfur in the sample could be biased high when compared to a sample when all flue gas passes through the wet scrubber.

A review of the latest PM stack tests at M.R. Young Unit 2 (8/07 and 5/08) indicated an average PM emission rate of 10.61 milligrams per normal cubic meter (mg/Nm^3). Based on 25% of the PM being sodium and potassium sulfate, the combined emission rate of these two compounds is approximately $2.7 \text{ mg}/\text{Nm}^3$. This indicates a sodium and potassium removal efficiency of greater than 99% by the ESP and wet scrubber.

Minnkota has submitted data from a study by Markowski¹⁶ (p. 31) which indicated that approximately 81% of the sulfate emitted is less than 1.1 micrometers in size and approximately 36% is less than 0.26 micrometers in size. Based on the latest stack tests and the Markowski data, the submicron sodium sulfate plus potassium sulfate emission rate would be less than $2.2 \text{ mg}/\text{Nm}^3$ and the emission rate of sodium and potassium sulfate less than 0.26 micrometers in size would be approximately $1.0 \text{ mg}/\text{Nm}^3$. These values are similar to those Markowski reported which were $1.335 \text{ mg}/\text{m}^3$ and $0.602 \text{ mg}/\text{m}^3$ respectively.

C. Catalyst Deactivation

The two primary flue gas constituents that will cause SCR catalyst deactivation in a tail end configuration are sodium and potassium, most likely in sulfate form¹⁶ (p.32-35). Crespi¹⁷ (et.al.), in their paper regarding the Amager Station, presented a graph which shows the effect of various poisons on the activity of vanadia – titania catalysts. Minnkota¹⁴ (page 21) provided similar information that indicates that potassium oxide is a more potent catalyst poison on a molar basis than sodium oxide. Although no actual data is supplied, analysis of the graph indicates that potassium oxide is $1.7^{17} - 2.0^{18}$ times more potent catalyst poison than sodium oxide (on a molar basis) up to a vanadium/titanium to poison ratio of 0.6. Because potassium oxide has a larger molecular weight than sodium oxide, the poisoning ratio is 1.1 – 1.3 on a mass basis.

As indicated earlier, Kling¹¹ and Zheng¹² have indicated that the aerosols less than or equal to 0.1 micrometers cause the catalyst deactivation. Data are not available to calculate the portions of the PM emissions from Unit 2 that would be less than or equal to 0.1 micrometers. A conservative assumption is that all of the sodium and potassium sulfate less than 0.26 micrometers is less than or equal to 0.1 micrometers. The total emission rate for sodium and potassium sulfate combined is estimated at less than $1.0 \text{ mg}/\text{Nm}^3$ of which $0.78 \text{ mg}/\text{Nm}^3$ is sodium sulfate and $0.20 \text{ mg}/\text{Nm}^3$ is potassium sulfate based on the filter analysis submitted by Minnkota¹⁵.

Kling¹¹ has provided catalyst deactivation rates for various biomass fuels which produce a flue gas that contains sodium and potassium aerosols. The testing was conducted using different types of honeycomb $\text{W}_2\text{O}_5/\text{TiO}_2$ SCR catalyst. Type A catalyst was catalyst typically applied at coal-fired power plants, Type B was a “bio-optimized” catalyst with increased vanadium content, and Type C had an even higher vanadium content.

For a mixture of peat and 15% wood, the flue gas contained 4.4 mg/Nm³ of potassium chloride and 0.8 mg/Nm³ of sodium chloride aerosols with an aerodynamic particle diameter less than 0.1 micrometers.

	<u>Peat + 15% Wood*</u>	<u>Center Lignite**</u>
Potassium (mg/Nm ³)	4.4	0.20
Sodium (mg/Nm ³)	0.8	0.78

*As chloride

**As sulfate

The maximum deactivation rate was 12% in 768 hours using Type A catalyst. Another result indicated 15% deactivation in 1488 hours using Type B catalyst. The shorter test on peat plus 15% wood indicates 6400 hours to 100% deactivation while the longer test indicates 9920 hours to 100% deactivation. Regarding the deactivation rates, Kling¹¹ et.al stated “Exposure of this kind of short samples gives a larger deactivation compared to a full-length catalyst [1,4] that is mainly a consequence of turbulence of the inlet of the catalyst, before laminar flow is attained.”

The flue gas concentration of sodium from Center lignite is similar to that of the peat plus 15% wood; however, the potassium content is approximately 17 times lower. Zheng¹² has reported that potassium chloride has an SCR catalyst deactivation rate of 1% per day versus 0.4% per day for potassium sulfate, or 2½ times more. It appears the catalyst life for an SCR at M.R. Young Station would be substantially longer than that estimated for peat plus 15% wood.

Zheng et.al.¹² found a deactivation rate of 0.4% per day for potassium sulfate or 6,000 hours to 100% deactivation. The testing was conducted at a loading of 20-30 mg/Nm³. The aerosols varied in size from 0.07 micrometers to 1.05 micrometers with a mass mean diameter of 0.55 micrometers. The Markowski data indicates that approximately 53% of outlet sulfate was less than or equal to 0.52 micrometers. Based on the latest stack tests at M.R. Young Unit 2, this equates to an emission rate of approximately 1.4 mg/Nm³ for those sodium and potassium sulfate aerosols less than 0.52 micrometers. The Minnkota emission rate is substantially less (14-21 times) than the Zheng testing. Again, this does not consider the fact that potassium sulfate is a more potent catalyst poison than sodium sulfate. This suggests that a much longer catalyst life is possible for North Dakota lignite.

For a LDSCR application, the only air pollution control device prior to SCR will be a dry electrostatic precipitator (ESP). Stack test results from the FINE Particles – Technology, Environmental and Health Technology Programme²⁰ suggests that an ESP on a biomass boiler will have a control efficiency of greater than 90% for submicron particles and can achieve greater than 96% for particles less than 0.1 micrometers in size. This is consistent with AP-42⁴ data for Kraft recovery boilers which indicates an ESP can remove more than 98% of the submicron particulate matter in the flue gas which is primarily sodium sulfate²¹. Similar results are reported for coal-fired/biomass boilers by Mohr²², Lind²³ and the Power Station Emissions Handbook²⁴. This indicates that most of

the submicron sodium and potassium aerosols, including those aerosols less than 0.1 micrometers in size, will be removed by electrostatic precipitators.

Minnkota has submitted data on the ash composition that accumulate on the electrodes of the Power Span ECO electrodes during a pilot test¹⁴ (p. 26). The data suggests that the sodium and potassium concentration in the particulate matter downstream of the Unit I ESP is higher than the concentration in the particulate matter downstream of the Unit II wet scrubber. However, the concentration is less than a factor of two higher. The total loading of sodium and potassium, as indicated by the data submitted by Minnkota, would still be considerably less than the loadings in the Kling¹¹ and Zheng¹² tests. This suggests that the catalyze deactivation rate of LDSCR and MRYS should be lower than in the referenced tests.

D. Vendor Information

The U.S. Department of Justice, through their contractor Mr. Hans Hartenstein, has provided emails from various catalyst and SCR system providers¹⁹ as part of Minnkota BACT process. Each of the responses from the vendors indicated that tail end SCR is technically feasible for the Milton R. Young Station.

The Department contacted three of the vendors, Ceram Environmental, Haldor Topsoe and Babcock Power. The companies generally confirmed the information in the emails to Mr. Hartenstein. Babcock Power indicated they had no worries about getting 10,000 hours of catalyst life at the M.R. Young Station. However, they recommended “coupon” testing prior to design of the SCR. Ceram was convinced it was technically feasible; however, their representative did acknowledge that if the sodium and potassium aerosols are making it through the ESP and wet scrubber, catalyst deactivation could be a problem. Haldor Topsoe indicated that the catalyst deactivation at M.R. Young would be manageable if the catalyst is kept dry during outages. Although no written guarantees have been provided by the vendors, it appears that vendors are willing to provide them for a tail end SCR at the M.R. Young Station.

E. Similar Facilities using SCR

There are no boilers that combust North Dakota lignite and are equipped with SCR technology. In general, other U.S. coals are much lower in the organically associated alkalis that cause SCR catalyst deactivation. Biomass fired boilers would have flue gas characteristics that more closely approximate those from North Dakota lignite. At least four biomass boilers that are equipped with tail end or low dust SCR are currently in operation.

These include:

- Whitefield Power & Light, New Hampshire – Boiler uses whole tree chips and has operated since October 2004.
- Bridgewater Power, New Hampshire – Boiler uses whole tree chips and has operated since October 2007.

- Pine Tree Power, New Hampshire.
- Boralex Stratton, Main – Boiler was whole tree chips, waste wood, and construction and demolition waste. The boiler has operated since December 2004.

The Department is also aware of proposed installation at the Burlington Electric Plant in Vermont, Synterprise Global Solutions in Tennessee and the Amager Heat and Power Plant near Copenhagen, Denmark. The Amager Station is also allowed to burn coal and may not be required to operate the SCR when combusting biomass.

Although there are boilers that combust 100% biomass and utilize SCR for NO_x control, there is very little information about the actual loading of potassium and sodium aerosols at the inlet to the SCR. The New Hampshire Department of Environmental Services (NHDES) was contacted regarding the biomass boilers that use low dust/tail end SCR. The Whitefield Power Plant is a 16 MWe spreader stoker that is equipped with a multiclone and electrostatic precipitator for particulate matter control. The NHDES confirmed the boiler had been operating for approximately four years. NHDES was not aware of any catalyst deactivation problems at this facility. The plant has a NO_x emission limit of 0.075 lb/10⁶ Btu. The other facilities in New Hampshire are similar; however, they are not operated as long. No data was available regarding the loading of potassium and sodium at the inlet of the SCR.

F. Conclusions

The Department has concluded that an SCR system must have a catalyst life of at least 10,000 before SCR technology could be deemed successfully applied to the source. No data has been found from an actual operating facility which has similar flue gas characteristics to M.R. Young Station for applying high dust, low dust or tail end SCR. However, experimental and pilot scale testing by Kling¹¹ provides a good comparison for a low dust or tail end SCR. The total sodium and potassium loading of aerosols less than 0.1 micrometers expected at the inlet of a tail end SCR at M.R. Young Station is expected to be at least 5 times less than found in Kling tests on peat plus 15% wood. Kling's data indicated up to 9920 hours of catalyst life for catalyst type B. Zheng's¹² data suggested 6,000 hours of catalyst life when exposed to potassium sulfate at a concentration (0.55 micrometer aerosols) which is 14-21 times higher than the concentration of sodium and potassium sulfate aerosols of this size expected after a wet scrubber at M.R. Young Station. Kling¹¹ also pointed out that the testing probably over estimates the deactivation rate because of turbulence in the pilot scale inlet of the catalyst which would be more laminar in a full scale SCR.

Existing biomass boilers are using tail end SCR successfully. Although the boilers are not cyclone fired units, the new Hampshire units use similar PM control devices as M.R. Young Station (i.e. ESP). The Whitefield Plant has operated for more than four years without deactivation problems. Kling¹¹ has referred to "bio-optimized" catalyst and higher vanadium catalysts that appear to have a longer life than the typical coal-fired boiler SCR catalyst for a given concentration of sodium and potassium aerosols. A "bio-

optimized” catalyst will be installed at the Amager Station¹³. Vendors believe that tail end SCR is technically feasible and can be successfully applied at M.R. Young Station.

The Minnkota situation represents the worst-case scenario for boilers burning North Dakota lignite that are subject to BART. Based on the experimental data available, the use of tail end SCR on biomass fired boilers, and vendor information that tail end SCR is feasible at the M.R. Young Station, the Department concludes that tail end and low dust SCR are technically feasible for boilers combusting North Dakota lignite that are subject to BART requirements.

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