NOx BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS STUDY - SUPPLEMENTAL REPORT

for

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

November 2009

31777

Minnkota Power

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NOx Best Available

Control Technology

Analysis Study

SUPPLEMENTAL REPORT

for

Milton R. Young Station Unit 1

prepared for

Minnkota Power Cooperative, Inc.

November 2009

Project No. 31777

prepared by

Burns & McDonnell Engineering Company, Inc.

Kansas City, Missouri

INDEX AND CERTIFICATION

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Certification

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REGISTERED PROFESSIONAL ENGINEER
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NORTH DAKOTA

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4.0 SUPPLEMENTAL NOx BACT ANALYSIS CONTROLS & COSTS – MRY STATION UNIT 1

This supplement to the NO_X BACT analysis for Milton R. Young Station (MRYS) Unit 1 has been prepared in response to the request of the North Dakota Department of Health[1]. The NDDH requested completion of a "full" BACT analysis for two specific technologies that had been eliminated at step 2 of the BACT analysis process[2] in the October 2006 NO_X BACT Analysis Study report[3]. These two technologies are low-dust selective catalytic reduction (SCR) and tail-end SCR. The approach taken in this supplemental NO_X BACT Analysis Study report for MRYS Unit 1 includes ranking by effectiveness and providing an impacts analysis of alternate control technologies for NO_X emissions that follows the third and fourth steps of a "top down" BACT analysis as described in the EPA's Draft New Source Review Workshop Manual[4]. The initial NO_X BACT Analysis Study for Milton R. Young Station identified potentially available NO_X control techniques and technologies, summarized in Table 3-3[5] of the October 2006 report. Commonly-applied and novel NO_X control techniques and technologies, including a technical description of the specific emission reduction processes and capabilities, were summarized in Section 3.2[6] and detailed in Appendix A1 of the initial NO_X BACT Analysis Study report. This supplemental analysis report does not include the details of the technical feasibility discussion previously provided in the initial NO_X BACT Analysis Study report for MRYS Unit 1.

SCR technology is considered technically infeasible by Minnkota for application at MRYS, so this information for the hypothetical application of low-dust and tail end SCR alternatives is included for comparative purposes only. Cost estimates and emission rates shown for such hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation, operation and maintenance of the SCR equipment on this boiler are solvable. There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to represent total installed costs that could be expected for MRYS Unit 1. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 1 significantly influence the capital cost estimate for variations of these hypothetical applications of SCR alternatives. Furthermore, the

[1] See Reference number 1, July 2009 and August 2009.
[2] As described in the EPA's Draft New Source Review Workshop Manual. See Reference number 2, October 1990.
[3] See Reference number 3, October 2006. This Supplement commences with Section 4.0, which places it at the end of the October 2006 Analysis, which ended at Section 3.5.2.
[4] As described in the EPA's Draft New Source Review Workshop Manual. Ibid Reference number 2, October 1990.
[5] Ibid Reference number 3, October 2006, page 3-5.
[6] Ibid Reference number 3, October 2006, page 3-6 through page 3-13, and pages A1-1 through A1-55.

"EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technologies, as the EPA Control Cost Manual states:

> "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."[7]

This requirement for flue gas reheating also applies to the hypothetical application of low-dust SCR to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical applications of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[8]. Low-dust and tail end SCR technologies should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. The October 2006 NO_X BACT Analysis Study report, and additional subsequent arguments included in responses to comments by the EPA, Department of Justice (DOJ), NDDH, and other parties[9], also present reasons for technical infeasibility of all SCR technologies considered for application at MRYS not included in this supplemental analysis report. In addition, the fact that catalyst vendors will not guarantee catalyst life on such SCR technologies without successful results from extensive pilot slipstream testing bolsters the previous submitted arguments of technical infeasibility of these NO_X control alternatives at MRYS.

4.0.1 ADDITIONAL NOx CONTROLS

The inclusion of hypothetical emissions control alternatives employing tail-end and low-dust SCR technologies in this supplemental NO_X BACT Analysis Study report does not constitute agreement by

[7] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.
[8] See Reference number 4, June, 2005.
[9] Responses submitted by Minnkota in 2007-2009.

Minnkota that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The rationale for rejection of all forms of SCR technology in this specific case, based on an interpretation of the EPA's Draft New Source Review Workshop Manual[10], has previously been submitted to the North Dakota Department of Health[11] and is not repeated herein. Nevertheless, this supplemental NO_X BACT Analysis Study report has been completed based on the *hypothetical assumption* that these two technologies pass the test for technical feasibility. The development of NO_X emissions control alternatives involving hypothetical application of technologies such as low-dust and tail end SCR systems at MRYS is based on preliminary plant layout design concepts that require pilot-scale slipstream SCR testing and more detailed equipment design for confirmation that all technical infeasibility issues previously raised have been, or can be, satisfactorily resolved. This supplemental analysis includes estimated capital costs and operating and maintenance (O&M) costs for four variations of alternatives involving hypothetical applications of tail-end and low-dust SCR technologies. Cost effectiveness for each hypothetically-applied SCR control technology case was plotted with previously-analyzed feasible control alternatives.

For the techniques and technologies considered for determining MRYS Unit 1 NO_X control cost-effectiveness, estimates were produced for predicted NO_X reductions that represent long-term expectations of the reduction techniques and technologies being presented in the technical analysis. Each evaluated alternative was tabulated and graphed.

It should be noted that as of October 2006, when the initial BACT Analysis Study report was completed, MRYS Unit 1 did not employ combustion-related or post-combustion NO_X emission reduction technology. However, the installation of an advanced form of a separated overfire air system (ASOFA), designed specifically for this boiler, is being implemented for operation starting prior to December 31, 2009. A summary of the available alternate NO_X emission control technologies is discussed below.

4.1 RANK OF NO_X CONTROL OPTIONS BY EFFECTIVENESS

The first step[12] 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

[10] Ibid Reference number 2, October 1990.
[11] See Reference number 5, November 2007.
[12] Step 3 per the NSR Manual, Ibid Reference 2, October 1990.

technologies included from the initial NO_X BACT Analysis Study report. To do this, we start with the basis for determining the NOx emissions control effectiveness, which is the historic baseline emissions expressed in pounds per million Btu of heat input from the five-year lookback period.

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 NO_X 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 MW_g.
- During this lookback time period, Unit 1 at Milton R. Young Station was typically operated in a base-loaded manner.

4.1.1 ESTIMATING CONTROL-EFFECTIVENESS OF NO_X EMISSIONS CONTROL OPTIONS

The estimated emission control performance for NO_X control techniques and technologies included from the initial NO_X BACT Analysis Study report is assumed to be the same as previously stated in Table 3-7[13]. The expected control effectiveness of the hypothetical application of tail end and low-dust SCR technology alternatives was added to the listing of highest-performing NO_X control alternatives remaining in consideration following the initial technical infeasibility determinations. These alternatives are ranked in declining order of expected emission reduction. These combined control options refer to "advanced" separated overfire air (ASOFA), and include the expected reduction from operating with modestly air-staged cyclone furnaces and relocated lignite drying system vent ports as applied to this Milton R. Young Station cyclone boiler without incurring potential significant negative impacts of this technique. This level of expected NO_X reduction from ASOFA operation is approximately forty percent below the pre-control baseline emissions rate of 0.849 lb/mmBtu.

[13] Ibid Reference number 3, October 2006, page 3-18.

TABLE 4-1 – Ranked NO_X Control Options for MRY Station Unit 1 Boiler with Expected Control Performance

Alt. Label[1]	NO_X Control Alternative	Emission Rate (lb/mmBtu)	Control Percentage[2]
T2	Hypothetical Tail-End SCR w/ ASOFA – Scenario A[3]	0.053	93.8[4]
T1	Hypothetical Tail-End SCR w/ ASOFA – Scenario B[3]	0.053	93.8[4]
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[3]	0.053	93.8[4]
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[3]	0.053	93.8[4]
E	SNCR (using urea) w/ ASOFA	0.355	58.1
D	Gas Reburn with ASOFA	0.374	56.0
C	Lignite Reburn w/ ASOFA	0.385	54.6
B	Fuel Lean Gas Reburn with ASOFA	0.460	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	39.5
-	Baseline	0.849	-

(1) - Alternative designation assigned from highest to lowest unit NOx emission rate.
(2) - Control percentages are relative to an average pre-control emission baseline of 0.849 lb/mmBtu based on annual operation at highest pre-control 12-month rolling NOx summation mass emissions divided by the 12-month heat input summation.
(3) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. 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, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.
(4) The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

All hypothetical applications of tail-end and low-dust SCR technology alternatives were assumed to achieve a NO_X emission level of 0.053 lb/mmBtu, which is approximately 90% reduction from a 0.51 lb/mmBtu level representing ASOFA when operating modestly air-staged cyclone furnaces with suitable combustion controls.

Hourly mass emission rates for the baseline pre-control condition were calculated by multiplying the unit emission rate (lb/mmBtu) by the average hourly gross heat input rate (mmBtu/hr), both calculated from Unit 1's highest 12-month NO_X mass emissions and heat inputs during the 5-year lookback period.

Equivalent annual NO_X emissions (tons) were calculated by multiplying the 12-month summation for unit operating hours during the same period as the highest NO_X emissions by the 12-month average mass emission rate (lb/hr) and dividing by 2000 lb/ton.

The annual tons for the control options were calculated by multiplying the alternative's equivalent average annual hourly mass emission rate (lb/h) by the equivalent annual unit operating hours [8,760 h/yr maximum possible operating time, adjusted by an annual uptime (availability) factor]. Scheduled and unplanned maintenance outages are expected to occur due to each hypothetically-applied SCR system. Catalyst cleaning and replacement events have been estimated, with two frequencies showing a range of possible results. Due to the variability and possible severity of fouling characteristics of gaseous and aerosol particulate emissions generated by cyclone combustion of lignite supplied from the Center mine, and the dependency of the fouling within the hypothetically-applied SCR systems on sodium, potassium, sulfur, and ammonia slip emission levels, conditions may occur during operation of the hypothetically-applied SCR systems that exceed the ability to adjust operational practices sufficiently to avoid forced outages to remove the deposits or prevent significant catalyst deactivation. Table C.4-1 in Section 4.2.1.2.1 includes estimated unit availability and corresponding operating time and outage time due to the four hypothetical applications of SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[14]. Based on these calculations, the estimated annual emissions for M.R. Young Station Unit 1 and the emission reduction corresponding to each technology alternative are shown in Table 4-2.

[14] Ibid Reference number 3, October 2006, pages C3-1 through page C3-11.

TABLE 4-2 – Expected Annual NO_X Control Performance for MRY Station Unit 1 Alternatives

		EMISSIONS				
Alt. Label[1]	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission[2] lbs/hr	Annual Emission[3] tons/yr	Emission Reduction[4] tons/yr	NOx Removal Efficiency[5] %
T2	Hypothetical Tail End SCR w/ ASOFA– Scenario A[6]	0.053	145	589	9,345	93.8[7]
T1	Hypothetical Tail End SCR w/ ASOFA– Scenario B[6]	0.053	145	536	9,398	93.8[7]
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[6]	0.053	145	586	9,348	93.8[7]
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[6]	0.053	145	533	9,401	93.8[7]
E	SNCR (using urea) w/ ASOFA	0.355	975	4,025	5,909	58.1
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6
B	Fuel Lean Gas Reburn w/ ASOFA	0.460	1,261	5,260	4,674	45.9
A	Advanced Separated Overfire Air (ASOFA)	0.513	1,409	5,874	4,060	39.5
-	Baseline	0.849	2,330	9,934	0	-

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Hourly NO_X emission estimates (lb/hr) were calculated based upon average annual unit emission rate (lb/mmBtu) x 2,744 mmBtu/hr heat input.
(3) - Estimated annual emission tons assume an annual unit availability factor specific to each alternative; 97.3% was assumed for the baseline case. See Appendix C3 of the October 2006 NO_X BACT Analysis Study report. Hypothetical application of tail end SCR case T2 assumes an annual unit availability factor of 92.8% (approx. 8,127 operating hours per year) and case T1 assumes an annual unit availability factor of 84.5% (approx. 7,402 operating hours per year). Hypothetically-applied low-dust SCR case L2 assumes an annual unit availability factor of 92.3% (approx. 8,084 operating hours per year) and case L1 assumes an annual unit availability factor of 84.0% (approx. 7,359 operating hours per year).
(4) - Estimated annual tons of emission reduction is the difference between annual baseline tons and each alternative's annual emissions (tons).
(5) - Estimated NO_X control level percentage reductions relative to 0.849 lb/mmBtu emission baseline at 2,744 mmBtu/hr MCR heat input.
(6) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The emission rate shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. 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, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.
(7) - The stated overall control percentage includes the anticipated long-term emission reduction of approximately 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate for hypothetically-applied SCR alternatives would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.

4.2 NO_X CONTROLS ANALYSIS AND IMPACTS EVALUATION

The next step[15] of this supplemental "top-down" BACT analysis is to evaluate the impacts of the hypothetical application of SCR alternatives' NO_X emission controls. Energy, economic, and environmental impacts are to be considered in the control technology evaluation. The purpose of the evaluation is to determine if there are any energy, economic or environmental impacts that would eliminate the top control technologies from consideration.

This evaluation of the effectiveness of the hypothetically-applied SCR alternatives, as well as that of the other control technologies previously considered technically feasible, was performed prospectively, i.e., assuming that none of the control technologies has been implemented. This approach assumes that the hypothetical application of SCR technology cases are considered to have been added to the previous NO_X BACT Analysis Study report submitted in October, 2006. The actual costs incurred for an installed advanced separated overfire air system, or firm price equipment quotes with performance guarantees for SNCR alternatives, have not been used to adjust the control effectiveness or cost impacts of the previously analyzed control alternatives. The approach taken in this supplemental analysis use installed capital costs estimated in calendar year 2009 escalated to project completion forecast in 2018 adjusted to calendar year 2006 basis for the hypothetically-applied tail end SCR and low-dust SCR technology cases that have been added to the list of alternatives previously evaluated.

4.2.1 NO_X CONTROL ECONOMIC IMPACTS FOR MRY STATION UNIT 1

An evaluation was performed to determine the various cost impacts of installing previously-analyzed feasible NO_X control alternatives and the hypothetical application of low-dust and tail end SCR technologies on Milton R. Young Unit 1. This evaluation includes estimated:

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

to engineer, design, procure, construct, install, startup, test, and place into commercial operation the particular control technology. The results of this evaluation are summarized in Tables 4-3 through 4-11.

[15] Step 4 per the NSR Manual, Ibid Reference 2, October 1990.

4.2.1.1 CAPITAL COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

The range of estimated capital costs to implement some of the various NO_X control technologies were derived from unit output capital cost factors ($/kW) published in technical papers discussing those control technologies. For MRY Station Unit 1, for the cases involving the use of advanced separated overfire air and SNCR alternatives, preliminary project cost estimates using vendor budgetary cost information were developed and used in place of, or to adjust, the published unit output cost factors. A discussion of the reburn alternatives' estimated capital costs was included in the 2006 NO_X BACT Analysis Study report and has not been repeated here. These cost estimates were considered to be study grade, which is + or – 30% accuracy.

For the hypothetical application of low-dust and tail end SCR alternatives at MRYS, there is no available information on recently-completed similar projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 1. For these alternatives, site-specific detailed preliminary (conceptual) designs were developed and budgetary cost information for major equipment was obtained for the development of the estimated installed capital cost.

The unit nameplate output capacity (gross electrical output in megawatts) assumed for the installed capital cost estimate basis of the NO_X control technologies evaluated was 257 MW_g for MRY Station Unit 1[16].

A review of the unit capital cost factor range and single point factors applicable to MRY Station Unit 1 NO_X control technologies are presented in Tables 4-3SA and 4-3SF. Note that the capital cost estimates for the hypothetical application of SCR alternatives were developed separately based on two different assumptions. In one case it was assumed that all costs for the hypothetically-applied Unit 1 SCR (tail end or low-dust) system would be accounted for as if the SCR equipment were being provided for Unit 1 only. This is referred to as the "stand alone" (SA) case, and all tables showing those costs are identified with that suffix. In the other case, it was assumed that the retrofit of hypothetically-applied SCR systems was being done for both Unit 1 and Unit 2, and there are some components that could be shared between the two units. This is referred to as the "shared facilities" (SF) case, and all tables showing those costs are identified with that suffix.

[16] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 390.

Per the EPA's NSR Manual, a BACT analysis is done on a "case-by-case basis"[17]. The "stand alone" estimated total project capital costs for the hypothetical application of SCR alternatives reflect the economic impacts incurred as a result of implementing such technologies on each individual unit at MRYS independent of what may be determined or assumed for other units at this facility or similar units at other facilities. The "shared facilities" estimated total project capital costs for the hypothetical application of SCR alternatives do not account for all economic impacts borne strictly by the unit subject to the analysis, and, as such, are subsidized by the unit(s) involved with the shared facilities. In this "shared facilities" approach, a BACT would be performed more in the manner of a "case-within-a-case" instead of on a "case-by-case" basis. Additionally, BACT is not to be applied on a facility basis. Units having different characteristics, (size, etc.) may have different technologies as BACT. Therefore, each unit should be treated as a separate "stand alone" case. Although the authors believe the "stand alone "case is the proper approach to use, information for both cases has been provided.

TABLE 4-3SA – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NO_X Control Alternative	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 1
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	867(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(4)	(4)	867(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	703(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	703(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	31.6(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	70.1(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	181.5(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	41.4(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	16.6(5)

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.
(4) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical

[17] Ibid Reference 2, October 1990, Chapter B. Introduction page B1.

infeasibility for installation of the SCR equipment on this boiler are solvable. 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, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[18] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text.

(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.

(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[19].

(7) - NESCAUM 2005 Technical Paper[20]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.

(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.

(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[21], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

TABLE 4-3SF – Unit Capital Cost Factors of NO_X Control Alternatives for MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label(1)	NO_X Control Alternative	Range(2) ($/kW)	Single Point Unit Capital Cost Factor(3), ($/kW) MRYS Unit 1
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	(4)	706(4),(5)
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B(4)	(4)	706(4),(5)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	(4)	543(4),(5)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	(4)	543(4),(5)
E	SNCR (using urea) w/ ASOFA	20-35(6)	31.6(5),(6)
D	Gas Reburn w/ ASOFA	15-30(7)	70.1(5),(7),(8)
C	Lignite Reburn w/ ASOFA	30-60(7)	181.5(5),(7),(9)
B	Fuel Lean Gas Reburn w/ ASOFA	--(6)	41.4(5),(6),(8)
A	Advanced Separated Overfire Air (ASOFA)	5-10(7)	16.6(5)

[18] See Reference number 6, March 2005, page 3-63.
[19] See Reference number 3, October 2006, pages C2-3 and C2-7.
[20] See Reference number 7, March 2005.
[21] See Reference number 8, April 2005, page 3-9.

(1) - Alternative designation has been assigned from highest to lowest unit NOx emission rate.
(2) - Unit capital cost factors ($/kW) of these individual technologies combined by simple addition. Actual installed costs may differ from this due to positive or negative synergistic effects. Range based on published values or vendor proposals.
(3) - Single point cost factor is best estimate for determination of total capital cost for a particular technology or combination, assuming maximum unit capacity is based on EPA's nameplate rating. Single point cost figures in 2006 dollars.
(4) - The inclusion of tail-end and low dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The single point unit capital cost factor shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. 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, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Due to the site-specific nature of factors influencing cost, no comparable cost data ranges for these technologies exist in the literature. A cost range for conventional high-dust SCR technology published in the 2005 EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034[22] was $55 to $150/kW. Single point unit capital cost factors were derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text.
(5) - The single point unit capital cost factor shown for the "advanced" version of SOFA derived from Burns & McDonnell internal database and cost estimate for North Dakota lignite-fired cyclone boilers.
(6) - Estimated capital cost for SNCR point estimate and FLGR point estimate derived from December 2004 budgetary proposal by Fuel Tech. The unit capital cost factor range for FLGR applications on boilers without an existing a high-pressure natural gas supply was not found in available technical literature. See Appendix C2 of the October 2006 NO_X BACT Analysis Study report for details[23].
(7) - NESCAUM 2005 Technical Paper[24]; reburn alternatives on page 2-22, overfire air on page 2-23; posted at their website. See technical references in Appendix A1 of the October 2006 NO_X BACT Analysis Study report for details.
(8) - The single point unit capital cost factor shown for a conventional or fuel-lean gas reburn system includes the estimated capital cost to install a high-pressure natural gas supply pipeline (31.4 $/kW or 15.7 $/kW, respectively), and that both MRYS boilers share the capital cost in proportion to their respective rated MW gross output capacities.
(9) - The single point unit capital cost factor shown for a lignite reburn system is highly site-specific, and assumes that new pulverizers and building enclosures are required. The general cost range for pulverized coal-fired boilers is included in the NESCAUM 2005 Technical Paper; for cyclone boilers is included in the 2005 WRAP Draft Report[25], posted at their website. The single point unit capital cost factor for this alternative for increased PM collection capacity included in lignite reburn option is 91.7 $/kW. See technical references in Appendix A1 of the October 2006 BACT Analysis report for details.

4.2.1.1.1 CAPITAL COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

There is no available information on recently-completed similar tail-end or low-dust SCR projects on coal-fired powerplants in the United States that could be used, with adjustments, to properly represent total installed costs that could be expected for MRYS Unit 1. Site-specific needs and challenges identified for applying tail end and low-dust SCR technologies to Milton R. Young Station Unit 1 significantly influence the capital cost estimate for variations of these hypothetically-applied SCR alternatives. Furthermore, the "EPA Air Pollution Control Cost Manual" is not applicable for use in estimating control equipment costs for these hypothetical applications of SCR technology cases, as the EPA Control Cost Manual states:

[22] See Reference number 6, March 2005, page 3-63.
[23] See Reference number 3, October 2006, pages C2-3 and C2-7.
[24] See Reference number 7, March 2005.
[25] See Reference number 8, April 2005, page 3-9.

> "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."[26]

This requirement for flue gas reheating also applies to the hypothetical applications of low-dust SCR technology to MRYS, due to the cold-side arrangement (downstream of the electrostatic precipitator) instead of a hot-side ESP assumed in the EPA Control Cost Manual. Therefore, the equations in the EPA Control Cost Manual cannot be used for estimating either of the hypothetical application of SCR configurations for which NDDH has requested economic analyses. Thus it was necessary to prepare independent site-specific cost estimates.

The installed capital costs for hypothetical application of tail end and low-dust SCR alternatives were estimated by Burns & McDonnell with inputs from an SCR system supplier with recent design experience involving these SCR configurations, equipment suppliers, and catalyst suppliers with significant European project experience in such technology. Both hypothetically-applied low-dust and tail end SCR designs for MRYS Unit 1 assume one reactor / gas reheat system installed, connecting to the new wet lime flue gas desulfurization absorber currently being constructed. Each hypothetically-applied SCR alternative includes flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCR systems. The estimated flue gas volume at a gross boiler heat input and oxygen content corresponding to unit gross nameplate output capacity determined the size of the hypothetically-applied single SCR reactor for these cases. Structures, foundations, ductwork, balance of plant equipment and materials were quantified and included with the hypothetically-applied SCR equipment, which were factored for installation costs. Escalation of project costs, including equipment, materials, engineering and labor costs, is included, along with interest during construction, due to the expected project execution duration being significantly longer than for the other alternatives. Price and scope contingencies were included to account for the uncertainties that the current preliminary design scope and pricing fully reflects what would be necessary to complete implementation of these hypothetically-applied alternatives. Total project costs were considered to be a future value from a financial perspective, which were returned to a 2009 calendar year basis using a present value factor at the 2.5% per year annual discount rate previously assumed in the 2006 NO_X BACT Analysis Study report. A ratio of regional construction cost indices for public utility construction costs between 2006 and 2009 was used to adjust the 2009 total estimated project costs to a 2006 calendar year basis for each of the hypothetically-applied SCR alternatives.

[26] See Reference number 10, Section 4.2, Chapter 2, page 2-41, October 2000.

The estimated installed and levelized annual capital costs for the hypothetically-applied SCR systems and previously-analyzed highest-performing form of the various feasible NO_X emission reduction technologies evaluated for cost-effectiveness are shown in Table 4-4SA and Table 4-4SF. These technologies are listed in order of control effectiveness, with the highest ranked option at the top.

TABLE 4-4SA – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Installed Capital Cost(2) $1,000	Annualized Capital Cost(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	222,864(4)	19,430(4)
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	222,864(4)	19,430(4)
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	180,739(4)	15,758(4)
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	180,739(4)	15,758(4)
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA(5)	18,006	1,570
C	Lignite Reburn w/ ASOFA(6)	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA(5)	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

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

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SA for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SA.

(6) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

TABLE 4-4SF – Estimated Capital Costs for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label[1]	NOx Control Alternative	Installed Capital Cost[2] $1,000	Annualized Capital Cost[3] $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[4]	181,484[4]	15,823[4]
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[4]	181,484[4]	15,823[4]
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[4]	139,639[4]	12,174[4]
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[4]	139,639[4]	12,174[4]
E	SNCR w/ ASOFA	8,113	707
D	Gas Reburn w/ ASOFA[5]	18,006	1,570
C	Lignite Reburn w/ ASOFA[6]	46,656	4,068
B	Fuel Lean Gas Reburn w/ ASOFA[5]	10,639	928
A	Advanced SOFA (ASOFA)	4,277	373
	Baseline	0	0

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

(2) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. See Table 4-5SF for presentation of installed capital costs determined for hypothetical application of SCR alternatives.

(3) - Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor.

(4) - The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The installed capital cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates prepared specifically for MRYS Unit 1 in 2018 dollars converted to 2006$ as described in the text. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(5) - Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR; and annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SF.

(6) - Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost, and $2,054,000/yr annualized capital cost.

The Total Project Costs estimated for tail end and low-dust SCR technologies hypothetically applied to MRYS Unit 1 are shown in Table 4-5SA and Table 4-5SF in 2018, 2009, and 2006 dollars.

The estimated installed capital costs for the hypothetical application of tail end or low-dust SCR system retrofits on MRYS Unit 1 included the following equipment and components:

- One SCR reactor utilizing a “3 +1” arrangement of catalyst layers, in which three layers of catalyst are initially installed, and space for installation of a fourth layer is provided.
- Sootblowers for each catalyst layer to maintain cleanliness of catalyst
- Flue gas reheat equipment that is typical for these applications but not required for conventional high-dust/hot side SCRs. This reheat equipment includes rotary regenerative heat exchangers (gas-to-gas heaters [GGH]) and natural gas-fired duct burners.
- Underground high-pressure natural gas supply pipeline and pressure regulators and metering equipment
- Hot air recirculation and heating equipment to maintain catalyst in a warm and dry condition during standby periods
- Induced draft booster fan and dampers
- Interconnecting ductwork
- SCR bypass duct and dampers (used during times the boiler is off-line)
- Storage tanks, building, and equipment for unloading and preparation of liquid urea solution
- Circulation pumps and piping for urea solution
- Urea-to-ammonia thermal conversion with urea conversion, metering, atomization, and injection equipment
- Ammonia gas dilution/combustion air fans and burners for natural gas-firing to decompose the urea solution to ammonia
- Service and sootblowing air compressors with dryers
- Electrical motor control centers
- Controls and instrumentation
- Reinforced concrete foundations
- Active coal yard storage modifications to regain lost live capacity and handling equipment due to space consumed by the SCR reactor structures
- Installation labor, materials, and management.

Addition of new electrical loads to the existing plant facilities will be required for the reagent system and new induced draft booster fan power consumption. Based on recent plant electrical distribution equipment installations, additional plant auxiliary electrical power will be available for powering the new hypothetically-applied SCR equipment. Confirmation of these concepts and cost estimates prior to any subsequent plans for implementation requires successful completion of extensive pilot-scale slipstream testing, and more detailed plant layout and equipment design than has been performed as part of this supplemental update to the October 2006 NO_X BACT Analysis Study report.

The capital cost estimated individually for an ASOFA system retrofit on MRYS Unit 1 as previously described in the initial NO_X BACT Analysis Study report was simply arithmetically added to the hypothetical application of SCR alternatives' capital cost estimates.

TABLE 4-5SA – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 1 Stand Alone SCR Projects

Alt. Label(1)	Hypothetical SCR Alternative(2)	Estimated BMcD Study Total Project Cost(3), 2018$ x 1000	Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000	Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000
T2, T1	Tail End SCR	294,586	235,884	214,221
	Urea preparation and storage, building, and equipment(6)	_	4,808(6)	4,366(6)
	ASOFA	_	_	4,277
T2, T1	TOTAL	_	_	222,864(6)
L2, L1	Low-Dust SCR	236,658	189,499	172,096
	Urea preparation and storage, building, and equipment	_	4,808(6)	4,366(6)
	ASOFA	_	_	4,277
L2, L1	TOTAL	_	_	180,739(6)

(1) All SCR alternatives are assumed to have the same SCR outlet NOx emission rate.
(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station.
(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Does not include installed capital cost for ASOFA, as shown in Table 4-4SA.
(4) Modified Total Project Costs are converted from 2018$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.80073.
(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.
(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and Total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SA.

TABLE 4-5SF – Estimated Capital Costs for Hypothetically-Applied SCR Alternatives - MRY Station Unit 1 Shared Facilities SCR Projects

Alt. Label(1)	Hypothetical SCR Alternative(2)	Estimated BMcD Study Total Project Cost(3), 2018$ x 1000	Estimated BMcD Study Modified TP Cost(4), 2009$ x 1000	Estimated BMcD Study Adjusted TP Cost(5), 2006$ x 1000
T2, T1	Tail End SCR	240,817	192,829	175,120
	Urea preparation and storage, building, and equipment(6)	–	2,298(6)	2,087(6)
	ASOFA	–	–	4,277
T2, T1	TOTAL	–	–	181,484(6)
L2, L1	Low-Dust SCR	183,274	146,753	133,275
	Urea preparation and storage, building, and equipment(6)	–	2,298(6)	2,087(6)
	ASOFA	–	–	4,277
L2, L1	TOTAL	–	–	139,639(6)

(1) All alternatives are assumed to have the same SCR outlet NOx emission rate.
(2) The inclusion of tail end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station.
(3) The Total Project Cost shown for each hypothetically-applied SCR system was estimated by Burns & McDonnell based on scope assumptions for installation of the SCR equipment on this boiler as described in the text, except as described in footnote 6 below. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation. Does not include installed capital cost for ASOFA, as shown in Table 4-4SF.
(4) Modified Total Project Costs are converted from 2018$ to 2009$ as described in the text, except as described in footnote 6 below. Present Value factor (discounted from future value) is 0.80073.
(5) Adjusted Total Project Costs are converted from 2009$ to 2006$ as described in the text. Handy-Whitman Index of Public Utility Construction Costs ratio is 0.908.
(6) Urea preparation and storage, building, and equipment installed capital costs were estimated separately in 2009$, and then adjusted using the Handy-Whitman cost ratio of 0.908 to get 2006$. The TOTAL numbers above are the sum of the Adjusted Total Project Cost; urea preparation and storage, building, and equipment; and Total Installed Capital Costs (TICC) for ASOFA alternative = estimated TICC for the hypothetically-applied SCR alternatives in Table 4-4SF

4.2.1.2 O&M COST ESTIMATES FOR NO_X CONTROL ALTERNATIVES

Operational costs to implement the hypothetical application of SCR alternatives and previously-analyzed feasible NO_X control alternatives for Milton R. Young Unit 1 were estimated using preliminary conceptual designs and budgetary vendor quotes in place of, or to adjust, the OAQPS cost factors established in the EPA's Air Pollution Control Cost Manual (OAQPS) for SNCR[27] and SCR[28], and using other costs published in technical papers discussing those control technologies. Maintenance costs were estimated as

[27] See Reference number 9, October 2000.
[28] See Reference number 10, October 2000.

percentages of installed capital costs, with additional catalyst replacement costs using budgetary vendor quotes based on preliminary conceptual designs and expected design life.

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

- Auxiliary electrical power consumption (megawatt-hours) and incremental purchased power unit costs for operating the additional control equipment;
- Natural gas consumption and unit cost for hypothetical application of SCR alternatives' flue gas reheating and urea-to-ammonia thermal conversion systems and feasible fuel reburn alternatives;
- Reagent consumption and reagent unit cost for hypothetical application of SCR alternatives and feasible SNCR alternatives;
- Reagent dilution water consumption and unit cost for SNCR alternatives.
- Catalyst removal and replacement for hypothetical application of SCR alternatives.
- Increases or savings in auxiliary electrical power consumption for changes in coal preparation equipment and loading, primarily for fuel reburn cases;
- General operating labor, plus maintenance labor and materials devoted to the additional emission control equipment and its impact on existing boiler and plant equipment;
- Costs for purchase of replacement electrical power expected to result from loss of unit availability, i.e., outages attributable to the control option which reduce annual net electrical generation available for distribution.

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

Tables 4-6SA and 4-6SF show the estimated annual operating and maintenance costs and levelized annual O&M cost values for the hypothetically-applied SCR alternative cases and the highest-performing form of previously-evaluated feasible NO_X emission reduction technologies. These are listed in order of control effectiveness, with the highest ranked options at the top. The cost methodology summarized in Appendix C3 of the 2006 NO_X BACT Analysis Study report provides more details for the levelized annual O&M cost calculations and cost factors for the previously-analyzed feasible NO_X control alternatives[29].

TABLE 4-6SA – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual O&M Cost(2) $1,000	Levelized Annual O&M Cost(2),(3) $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(4)	20,048	25,034
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(4)	29,361	36,664
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(4)	16,908	21,114
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(4)	27,882	34,817
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA(5)	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specific to MRYS Unit 1 in 2018 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.
(5) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

[29] Ibid Reference number 3, October 2006, pages C3 through 3-11.

TABLE 4-6SF – Estimated O&M Costs for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

Alt. Label[1]	NOx Control Alternative	Annual O&M Cost[2] $1,000	Levelized Annual O&M Cost[2],[3] $1,000
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[4]	18,806	23,484
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[4]	28,120	35,114
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[4]	15,675	19,574
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[4]	26,649	33,278
E	SNCR w/ ASOFA	5,417	6,764
D	Gas Reburn w/ ASOFA	28,641	35,765
C	Lignite Reburn w/ ASOFA[5]	5,862	7,320
B	FLGR w/ ASOFA	12,863	16,062
A	Advanced SOFA (ASOFA)	1,695	2,117
	Baseline	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at an average unit output (244.5 MWg) and assumes a 97.3% average annual availability, which is highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(3) - Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(4) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual O&M cost shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specific to MRYS Unit 1 in 2018 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.
(5) - Costs for increased PM collection capacity included in lignite reburn option are $2,024,000/yr for annual O&M cost, and $2,527,000/yr annualized O&M cost.

4.2.1.2.1 O&M COST ESTIMATES FOR HYPOTHETICAL APPLICATION OF SCR NO_X CONTROL ALTERNATIVES

The hypothetical application of tail-end and low-dust SCR w/ ASOFA alternatives will involve significantly higher operating costs compared with the existing operation of MRYS Unit 1. The system uses an amine reagent in the form of concentrated aqueous urea solution, which is thermally converted to gaseous ammonia, carbon dioxide, and water vapor. The estimated unit cost of this urea was assumed to average $379/ton (delivered to the plant site via truck-tanker trailers; unit pricing based on 50% concentration as established for the 2006 NO_X BACT Analysis Study report). Consumption of urea converted to ammonia reagent was based upon recent equipment vendor budgetary proposals and SCR consultant inputs.

For the hypothetically-applied SCR cases, using the existing induced draft fans is not expected to significantly change the overall fan horsepower demand on those fans' electric motors. There will be new plant electrical power demand due to a new induced draft booster fan required to overcome the estimated additional flue gas pressure drop resulting from reactor, ductwork, and gas-to-gas heat exchanger equipment assumed for the hypothetically-applied SCR systems. The additional auxiliary electric power demand for the hypothetically-applied tail end SCR systems was calculated to be 9.7 MW, using estimated annual average electrical loads of the booster fan, direct flue gas reheat burner combustion air fan, urea-to-ammonia conversion dilution/combustion air fan, and SCR sootblower and service air compressor equipment based on preliminary equipment vendor budgetary proposals developed from Burns & McDonnell ductwork sizing and designs. Estimated annual average electrical power demands for hypothetically-applied low-dust SCR systems were calculated to be 8.0 MW. Replacement of electrical power resulting from these reductions in net unit electrical output was included as a cost, assuming $35 per megawatt-hour.

Hypothetically-applied tail end and low-dust SCR equipment requiring annual maintenance includes booster fan, gas-to-gas heat exchangers, flue gas reheat duct burners, and compressor equipment. This general annual maintenance cost was estimated as 3 percent of installed capital costs.

To account for the possible range of O & M costs due to catalyst replacement, two variations (Scenario A and Scenario B) were applied. These two scenarios were used for both hypothetical applications of tail-end and low-dust SCR technology alternatives. Each scenario was based on scheduled additions and/or replacement of the exposed catalyst after a certain number of hours of operation, repeated throughout the 20 year operating span considered in the analysis. The installed unit cost of replacement catalyst assumed for the hypothetical application of full-time tail end or low-dust SCR alternatives is $7,500 per cubic meter in 2006 dollars. The basis for development of the two scenarios is described below.

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.

Based on information obtained in discussions with the catalyst vendors, the longest catalyst replacement schedule they would both agree upon as an estimated (not guaranteed) value was 16,000 hours. Both vendors indicated that actual experience could result in a shorter replacement cycle, and that the actual guarantee value could not be developed until extensive pilot slipstream testing had been completed. This led Burns & McDonnell to develop two hypothetically-applied SCR catalyst replacement scenarios to bracket possible outcomes.

Scenario A assumed a hypothetically-applied catalyst replacement schedule of 16,000 hours. Specifically for MRYS Unit 1, this scenario is based on the replacement of one catalyst layer every 16,000 operating hours (essentially every two years of operation).

Scenario B assumed that the fouling of the catalyst would be severe, and that it would be necessary for Minnkota to perform catalyst maintenance at each scheduled boiler cleaning outage. The current schedule of boiler cleaning outages on Unit 1 is three times per year. Therefore, Scenario B for Unit 1 is based on the replacement of one catalyst layer at each boiler cleaning outage. This means that each catalyst layer in the four layer SCR reactor is exposed to flue gas during approximately 16 months of operation and then is replaced. By assuming that catalyst management activities would coincide with scheduled boiler cleaning outages, Scenario B provides some minimization of the impact of catalyst replacement on unit operation.

As noted above, it is not known what the actual frequency of catalyst replacement would need to be for a hypothetically-applied tail-end or low dust SCR system operating on a cyclone-fired boiler burning North Dakota lignite, but the two scenarios described above are the catalyst replacement numbers assumed for this comparative economic analysis.

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 146 cubic meters per layer per reactor for the single reactor. A fourth (bottom) layer at 195 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.

Annual unit operating time will be reduced as a result of the expected outages and maintenance of the hypothetically-applied SCR equipment, including catalyst cleaning and management practices. Additional outage time of 213 hours per year was estimated to be attributable to the hypothetical application of tail end SCR Scenario A alternative (assuming 16,000 hour catalyst life), and 938 hours per year for Scenario B TESCR case (assuming three layers are replaced every year) over and above the hours per year of outage time assumed for ASOFA impacts. Additional outage time of 256 hours per year was estimated to be attributable to the hypothetical application of low-dust SCR Scenario A alternative, and 981 hours per year for the Scenario B LDSCR case over and above outage time assumed for ASOFA impacts. The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement power.

Table C.4-1 provides the estimated unit availability and corresponding operating time and outage time due to the four hypothetically-applied SCR technology cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[30].

[30] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-1 – Expected Availability Reductions for MRYS Unit 1 NO_X Controls

Alt.[1]	NOx Control Alternative	Estimated Annual Average Unit Operating Time			
		Unit Availability[2]	Unit Operating Time[3], hrs/yr	Unit Outage Time[4], hrs/yr	Unit Operating Time Reduction[5], hrs/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	0.928	8127	633	401
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	0.845	7402	1358	1126
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	0.923	8084	676	444
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	0.840	7359	1401	1169
E	SNCR w/ ASOFA	0.942	8255	505	273
D	Gas Reburn w/ ASOFA	0.952	8340	420	188
C	Coal Reburn w/ ASOFA	0.937	8212	548	316
B	FLGR w/ ASOFA	0.952	8340	420	188
A	Advanced SOFA (ASOFA)	0.952	8340	420	188
	Baseline	0.973	8528	232	0

(1) – Alternative number has been previously assigned from least removal to highest removal percentage.
(2) – 12-month baseline availability is assumed at 97.3 percent. These values reflect estimated amounts of negative reliability impact expected from the implementation of the individual NOx control technology.
(3) – Annual operating time is annual average availability multiplied by 8760 hrs/yr of possible uptime.
(4) – Annual outage time is 8760 hrs/yr possible operating time minus estimated annual operating time.
(5) – Annual operating time reduction resulting from the implementation of the individual NOx control technique is the difference between the baseline and expected annual outage times.
(6) – The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual unit availability factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-2 includes estimated equivalent average annual unit running plant capacity ratios and unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA and baseline numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[31]. These numbers assume the reduction in annual plant output is a combination of a reduction of annual operating time and capacity reductions associated with the control alternatives.

[31] Ibid Reference number 3, October 2006, pages C3-1 through C3-12.

TABLE C.4-2 – Expected Capacity Reductions for MRYS Unit 1 NO_X Controls

Alt. Label[1]	NOx Control Alternative	Estimated Annual Average Unit Electrical Power Generation Reduction from Operating Time Reduction		
		Unit Running Plant Capacity Ratio[2]	Unit Generation Reduction[3] kW-hrs/yr	Unit Generation Reduction Cost[4], 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[5]	0.937	97,976,764	3,429
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[5]	0.937	275,168,784	9,631
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[5]	0.942	108,399,824	3,794
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[5]	0.942	285,591,844	11,940
E	SNCR w/ ASOFA	0.965	67,660,606	2,368
D	Gas Reburn w/ ASOFA	0.957	46,120,681	1,614
C	Lignite Reburn w/ ASOFA	0.961	77,958,350	2,729
B	FLGR w/ ASOFA	0.962	46,400,200	1,624
A	Advanced SOFA (ASOFA)	0.966	46,586,546	1,631
	Baseline	0.966	0	0

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - 12-month baseline running plant capacity ratio is assumed at 96.6 percent (= 244.4/253.0). These values reflect estimated amounts of negative annual output capacity impact expected from the implementation of the individual NOx control technique. Used only for calculation of annual power usage in Table C.4-3.
(3) - Annual electricity generation reduction is annual unit operating time reduction multiplied by the 12-month average gross output of 244.4 MW.
(4) - Annual electricity generation reduction cost is the annual electricity generation reduction (kW-hrs/yr) resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual unit running plant capacity factors shown for hypothetically-applied SCR systems are based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-3 includes estimated unit gross and net electrical power demands (kilowatts) and annual usage (kW-hrs per year) used to calculate unit generation reductions and replacement electrical power costs due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix C3 of the initial NO_X BACT Analysis Study report[32]. These numbers assume that the reductions of annual operating time and capacity associated with the control alternatives are also applied.

[32] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

TABLE C.4-3 – Expected Auxiliary Electrical Power Demand Changes for MRYS Unit 1 NO_X Controls

Alt. Label[1]	NOx Control Alternative	Estimated Annual Average APC NOx Equipment Auxiliary Electrical Power Demand and Usage				
		Gross Demand[2] kW	Credit[3] kW	Total Net Demand[4] kW	Power Usage[5] kW-hrs/yr	Power Usage Cost[6], 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[7]	9,685	0	9,685	73,768,605	2,582
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[7]	9,685	0	9,685	67,189,753	2,352
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[7]	8,012	0	8,012	61,018,532	2,136
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[7]	8,012	0	8,012	55,548,184	1,944
E	SNCR w/ ASOFA	73.1	0	73.1	582,411	20
D	Gas Reburn w/ ASOFA	1	133	(132)	(1,054,343)	(37)
C	Lignite Reburn w/ ASOFA	4,666	261	4,405	11,905,082	1,217
B	FLGR w/ ASOFA	1	73	(72)	(578,744)	(20)
A	Advanced SOFA (ASOFA)	1	0	1	8,058	0.3

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The APC NOx equipment gross auxiliary electrical power demand of alternatives is the sum of the demand for individual technologies combined by simple addition. Actual power demands may differ from this due to positive or negative synergistic effects. Coal reburn includes 1,507 kW for feed preparation and conveying equipment demand plus 3,158 kW for the COHPAC system addition for PM control.
(3) - The APC NOx equipment auxiliary electrical power demand credit of coal reburn alternatives is the estimated result of lower cyclone coal preparation and feeder power demand due to lower boiler cyclone coal equipment loading. Actual power demands may differ from this due to accuracy of estimates for assumed amount of operating horsepower reduction.
(4) - The total net auxiliary electrical power demand is the sum of the gross demand and credit.
(5) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(6) - The annual change in APC NOx equipment auxiliary electrical power demand electricity cost is the annual change in kW-hrs/yr for these alternatives resulting from the implementation of the individual NOx control technique multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated power demands shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Table C.4-4 includes estimated net unit electrical annual power usage (kW-hrs per year) and expected reductions in annual operating time to calculate unit generation reductions due to the four hypothetically-applied SCR cases, along with the ASOFA numbers from the referenced Appendix C3 of the initial NO_X

BACT Analysis Study report[33]. These numbers assume the reduction in annual plant output is a combination of a reduction of net unit generation because of electrical power usage and reductions in annual operating time and capacity associated with the control alternatives.

TABLE C.4-4 – Expected Auxiliary Electrical Power Demand and Generation Reduction Cost Changes for MRY Unit 1 NO_X Controls

Alt. Label[(1)]	NOx Control Alternative	Estimated Annual Change in Unit Generation Due to APC NOx Equipment Auxiliary Power Electricity Demand and Generation Reduction			
		APC Electrical Power Usage[(2)] kW-hrs/yr	Unit Generation Reduction[(3)] kW-hrs/yr	Total Unit Electrical Power Generation Change[(4)] kW-hrs/yr	Total Unit Electrical Power Generation Change Cost[(5)] 1000$/yr
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[(6)]	73,768,605	97,976,764	171,745,369	6,011
T1	Hypothetical Tail End SCR w/ ASOFA –Scenario B[(6)]	67,189,753	275,168,784	342,358,537	11,983
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[(6)]	61,018,532	108,399,824	169,418,356	5,930
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[(6)]	55,548,184	285,591,844	341,140,028	11,940
E	SNCR w/ ASOFA	582,411	67,660,606	68,243,017	2,389
D	Gas Reburn w/ ASOFA	(1,054,343)	46,120,681	45,066,338	1,577
C	Lignite Reburn w/ ASOFA	11,905,082	77,958,350	89,863,432	3,946
B	FLGR w/ ASOFA	(578,744)	46,400,200	45,821,456	1,604
A	Advanced SOFA (ASOFA)	8,058	46,586,546	46,594,605	1,631

(1) - Alternative designation has been previously assigned from least removal to highest removal percentage.
(2) - The annual change in APC NOx equipment auxiliary electrical power demand electricity usage in kW-hrs/yr for these alternatives is the net power demand multiplied by the estimated annual operating time and running plant capacity ratio which reflects the adjustment for any expected availability and capacity impacts from the implementation of the control technique.
(3) - Annual electricity generation reduction is annual operating time reduction multiplied by the 12-month average gross output of 244.4 MW.
(4) - The total unit electrical power generation change is the sum of the annual change in APC NOx equipment auxiliary electrical power demand electricity usage plus the annual electricity generation reduction resulting from the implementation of the individual NOx control alternative.
(5) - The total unit electrical power generation change cost is the total generation change (kw-hrs/yr) multiplied by the incremental value of electricity generation, assumed to be $35.00/MW-hr. All cost figures in 2006 dollars.
(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated power demand shown for hypothetically-applied SCR systems are based on Burns & McDonnell estimates developed from preliminary equipment and ductwork sizing and designs with vendor budgetary proposals. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

[33] Ibid Reference number 3, October 2006, pages C3-1 through C3-11.

4.2.1.3 LEVELIZED TOTAL ANNUAL COST ESTIMATES FOR MRY STATION NO_X CONTROLS

A comparison of the control versus cost-effectiveness of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 1 was made. This is summarized as shown in Tables 4-7SA and 4-7SF, Figures 4-1SA and 4-1SF, and Figures 4-2SA and 4-2SF for MRY Station Unit 1.

TABLE 4-7SA – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Annual NOx Emissions(2) Tons/yr	Annual NOx Emissions Reduction(3) Tons/yr	Levelized Total Annual Cost(4) $1,000	Average Control Cost(5) $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(6)	589	9,345	44,465	4,758
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(6)	536	9,398	56,095	5,969
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(6)	586	9,348	36,872	3,944
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(6)	533	9,401	50,575	5,380
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334(7)	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388(8)	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990(7)	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

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

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 9,934 (= 0.973*8760*2,330/2000) was assumed for the baseline case.

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

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SA and 4-6SA for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate.

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

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specifically for MRYS Unit 1 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this

information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SA.

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

TABLE 4-7SF – Estimated Annual Emissions and Levelized Total Annual Cost for NO_X Control Alternatives - MRY Station Unit 1 - Shared Facilities SCR Projects

Alt. Label[1]	NOx Control Alternative	Annual NOx Emissions[2] Tons/yr	Annual NOx Emissions Reduction[3] Tons/yr	Levelized Total Annual Cost[4] $1,000	Average Control Cost[5] $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[6]	589	9,345	39,307	4,206
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[6]	536	9,398	50,937	5,420
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[6]	586	9,348	31,749	3,396
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[6]	533	9,401	45,452	4,835
E	SNCR w/ ASOFA	4,025	5,909	7,472	1,265
D	Gas Reburn w/ ASOFA	4,275	5,659	37,334[7]	6,597
C	Lignite Reburn w/ ASOFA	4,343	5,591	11,388[8]	2,037
B	FLGR w/ ASOFA	5,260	4,674	16,990[7]	3,635
A	Advanced SOFA (ASOFA)	5,874	4,060	2,489	613
	Baseline	9,934	0	0	

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

(2) - Estimated annual emission tons assume an annual unit uptime availability factor specific to each alternative; 9,934 (= 0.973*8760*2,330/2000) was assumed for the baseline case.

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

(4) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. See note 3 from Tables 4-4SF and 4-6SF for annualized cost factors. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline emissions based on annual operation at baseline pre-control NOx emission rate.

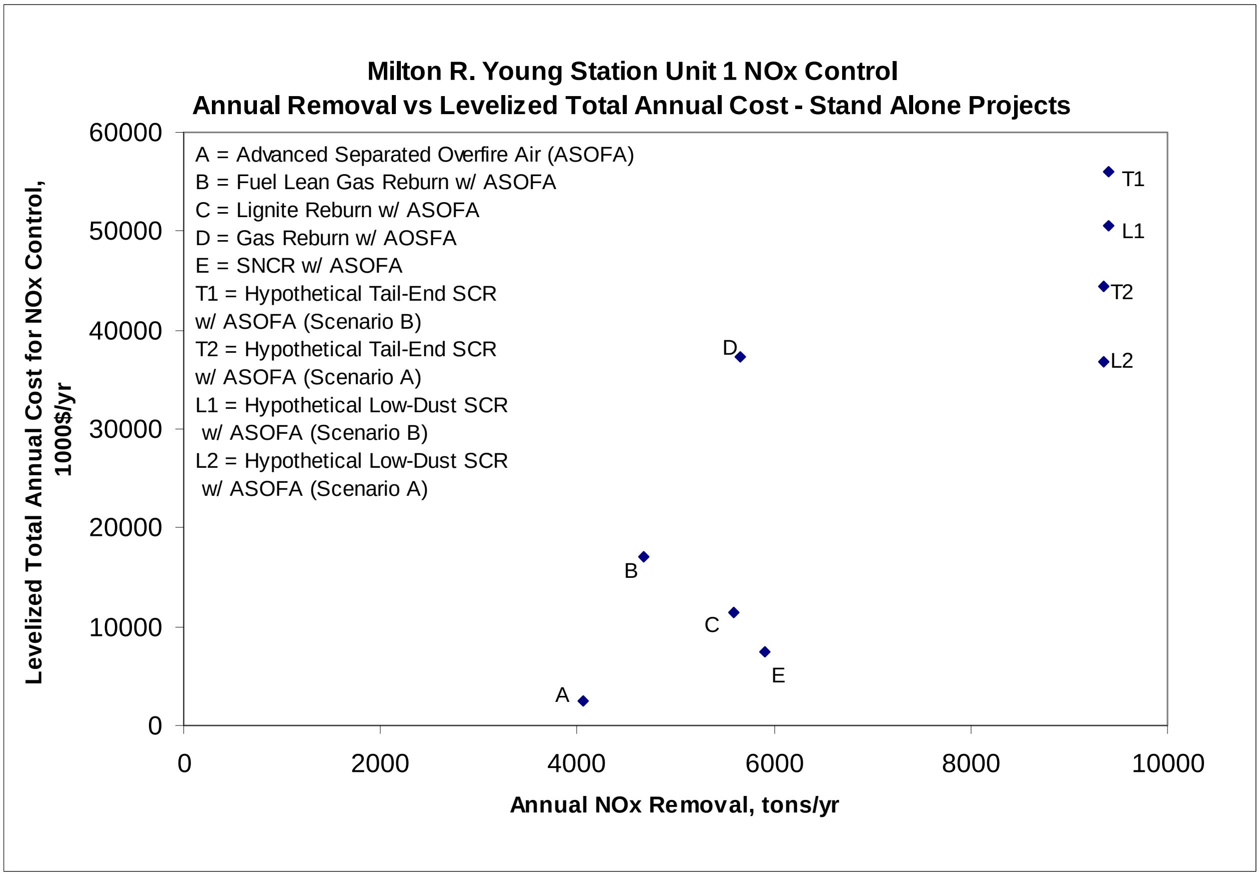
(5) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.

(6) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. Costs are derived from Burns & McDonnell internal database and cost estimates specifically for MRYS Unit 1 in 2006 dollars. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(7) - LTAC for gas reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR. See footnote number 8 under Table 4-3SF.

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

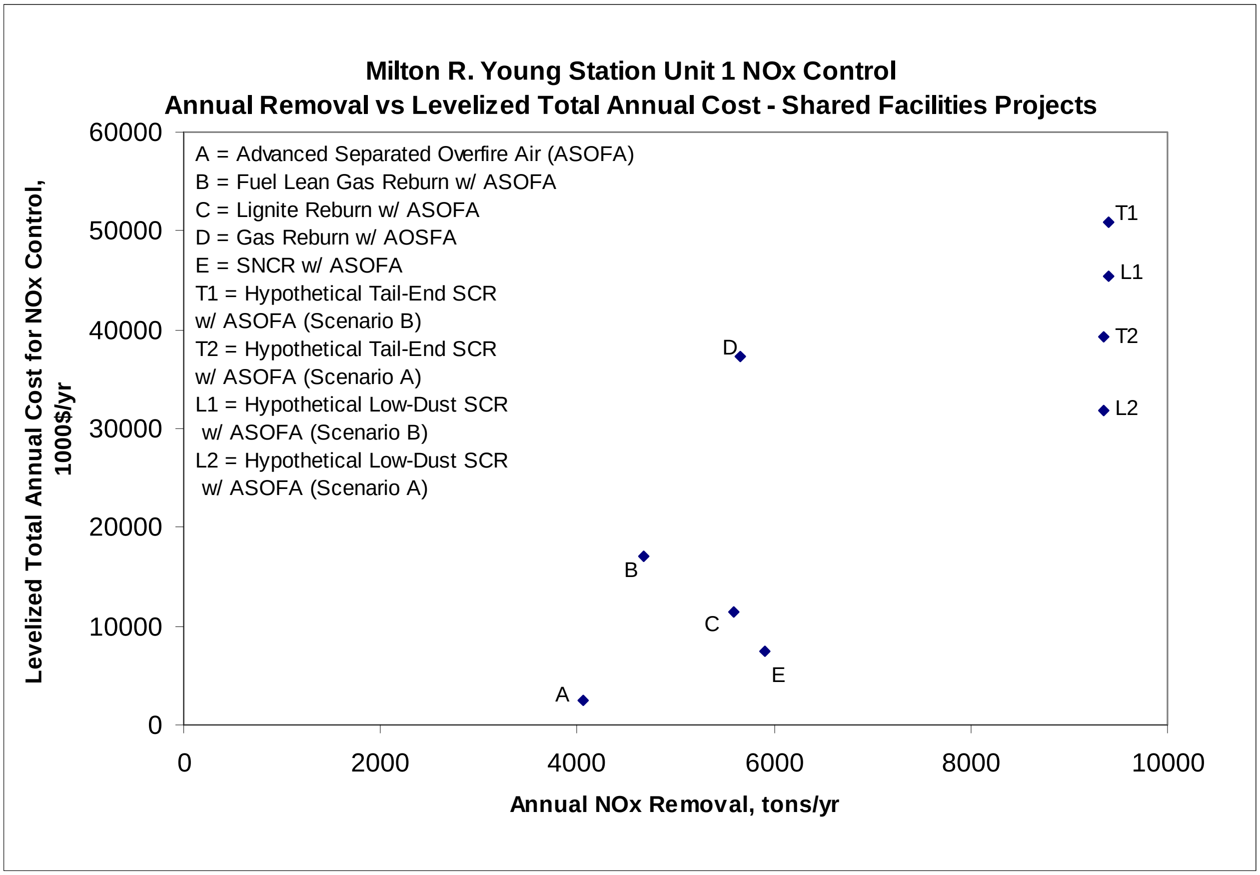
Figure 4-1SA – NO_X Control Cost Effectiveness - MRY Station Unit 1[(1)] Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SA.

(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-1SF – NO_X Control Cost Effectiveness - MRY Station Unit 1(1) Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-7SF.
(2) - The inclusion of tail-end and low-dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

The purpose of Figures 4-1SA and 4-1SF is to show the range of control and cost for four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives on Milton R. Young Unit 1 alternatives evaluated.

Data points for conventional gas reburn (Point D) and fuel-lean gas reburn (Point B) with advanced separated overfire air, and lignite reburn with ASOFA (Point C), in Figures 4-1SA and 4-1SF are inferior and therefore were eliminated from further control cost-effectiveness analysis.

A dominant set of control alternatives was determined by generating what is called the "envelope of least-cost alternatives". The dominant controls cost curve is the best fit line through the points forming the rightmost boundary of the data zone on a scatter plot of the annual NO_X removal tonnage versus LTAC for the various remaining BACT alternatives. Average and incremental annual costs and NO_X emission reductions for the dominant least-cost control alternatives remaining after the elimination of the obviously inferior options are listed in Tables 4-8SA and 4-8SF.

TABLE 4-8SA – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Alt. Label(1)	NOx Control Alternative	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	44,465	9,345	36,993	3,437	10,765
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	56,095	9,398	48,623	3,489	13,936
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	36,872	9,348	29,400	3,440	8,547
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	50,575	9,401	43,103	3,492	12,343
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA – 16,000 hrs) are labeled the same as in Table 4-7SA, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars.

(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-8SF – Dominant Controls Cost Curve Points for NO_X Control Alternatives - MRY Station Unit 1 - Shared Facilities SCR Projects

Alt. Label(1)	NOx Control Alternative	Levelized Total Annual Cost(2),(3) ($1,000/yr)	Annual Emission Reduction(3) (tpy)	Incremental Levelized Total Annual Cost(2),(4) ($1,000/yr)	Incremental Annual Emission Reduction(4) (tpy)	Incremental Control Cost Effectiveness ($/ton)(2),(4)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	39,307	9,345	31,835	3,437	9,264
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	50,937	9,398	43,465	3,489	12,458
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	31,749	9,348	24,277	3,440	7,058
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(5)	45,452	9,401	37,980	3,492	10,876
E	SNCR w/ ASOFA	7,472	5,909	4,982	1,849	2,694
A	Advanced SOFA (ASOFA)	2,489	4,060	2,489	4,060	613

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Dominant controls cost curve points from lowest (ASOFA) to highest (TESCR w/ ASOFA – 16,000 hrs) are labeled the same as in Table 4-7SF, and on the graphs that accompany this table (Points B, C, and D were eliminated).

(2) - All cost figures in 2006 dollars.

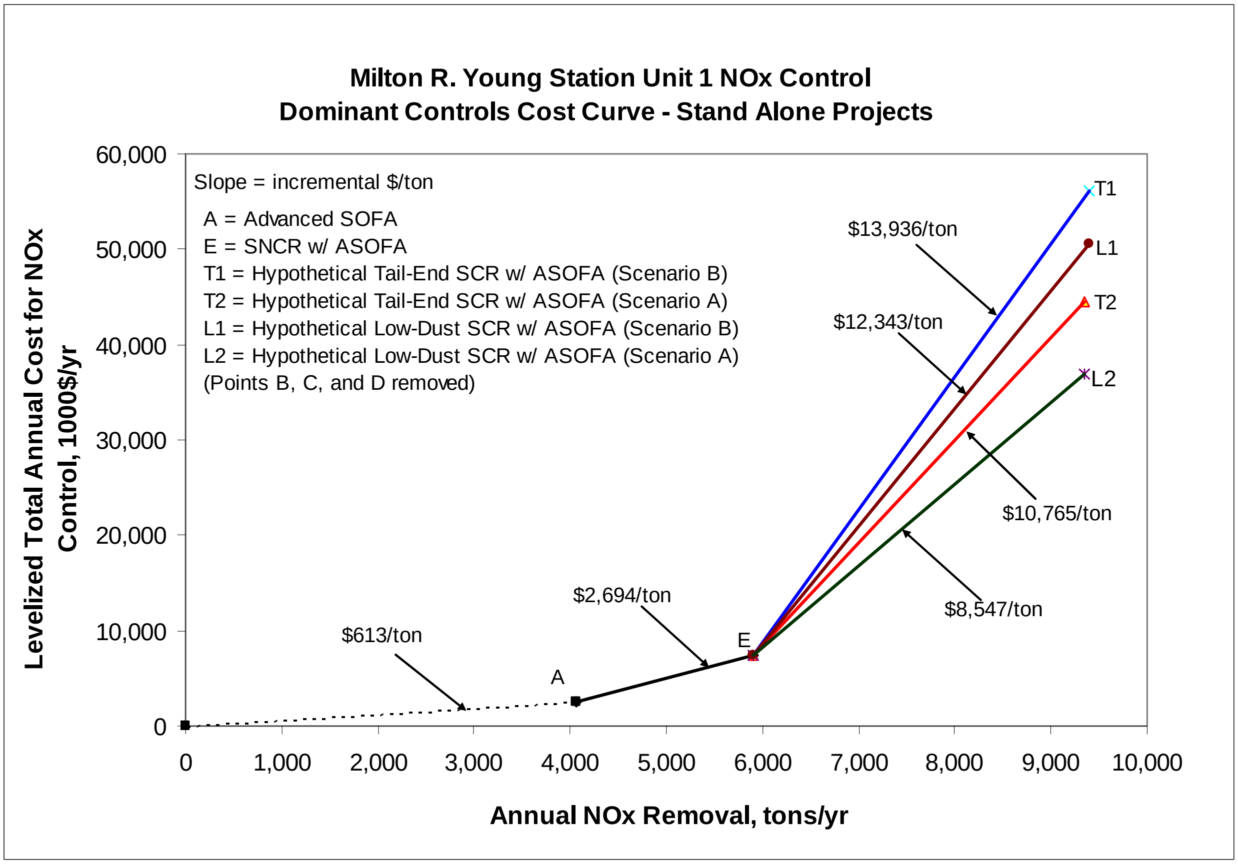
(3) - Annual emission reduction and levelized control cost of these alternatives is relative to current costs and pre-control unit MCR baseline emission rate.

(4) - Increment based upon comparison between consecutive alternatives (points) from lowest to highest.

(5) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figures 4-2SA and 4-2SF contains a repetition of the levelized total annual cost and NO_X control information from Figures 4-1SA and 4-1SF for MRY Station Unit 1, with Point B (FLGR™ with ASOFA) , Point C (Lignite Reburn with ASOFA) and Point D (conventional gas reburn with ASOFA) removed. This is the dominant controls cost curve for MRY Station Unit 1 NO_X emissions alternatives.

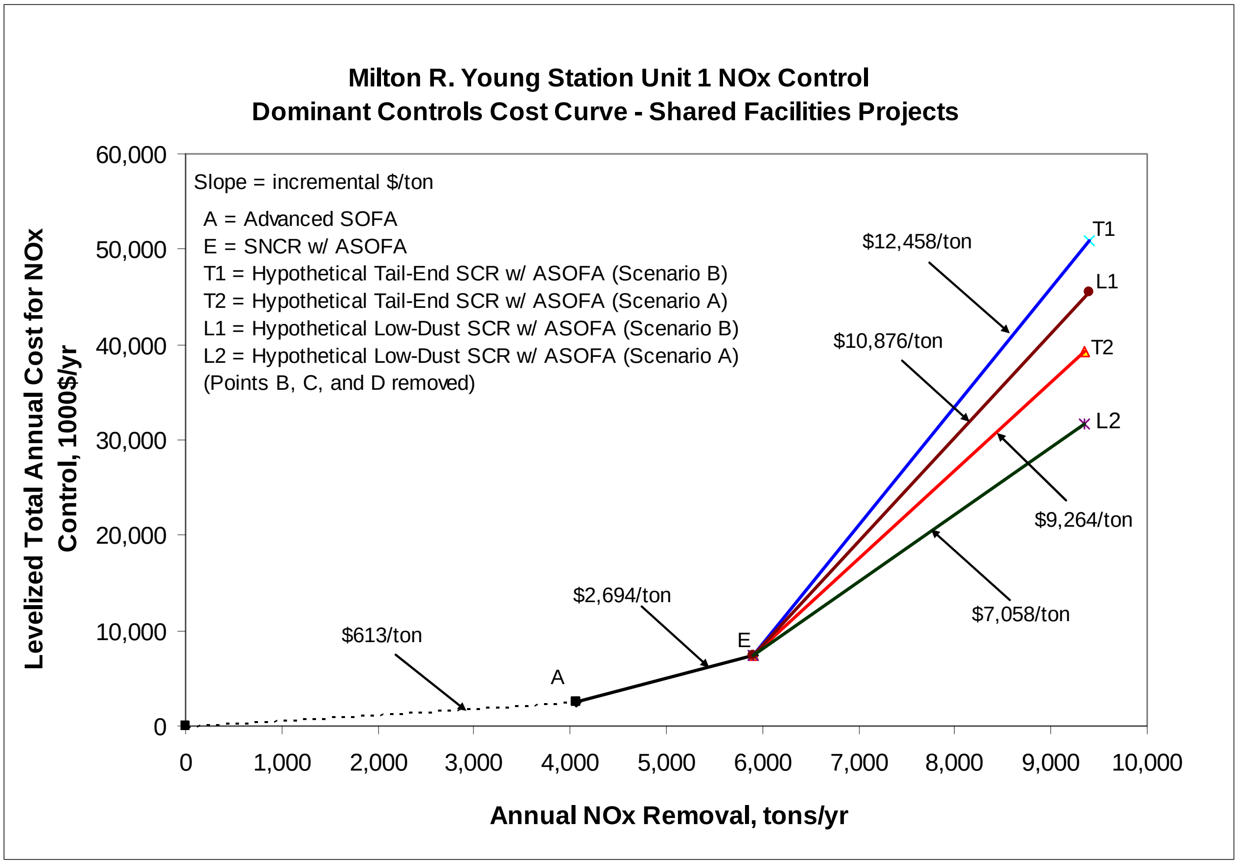
Figure 4-2SA – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve[1] - Stand Alone SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SA.

(2) - The inclusion of tail-end and low dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

Figure 4-2SF – MRY Station Unit 1 NO_X Control Alternatives BACT Dominant Controls Cost Curve(1) – Shared Facilities SCR Projects



(1) - All cost figures in 2006 dollars. Numbers are listed and qualifiers are noted in Table 4-8SF.
(2) - The inclusion of tail-end and low dust SCR technologies in this figure does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

As can be seen from a review of Tables 4-7SA and 4-7SF, the average levelized control cost effectiveness (called the unit control cost in this report) ranges from approximately $613/ton to $6,597/ton of MRYS Unit 1's NO_X emissions removed. The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,758/ton and for the hypothetically-applied Scenario B Tail End SCR w/ ASOFA case was $5,969/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $3,944/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $5,380/ton (stand alone projects). The unit control cost for the hypothetically-applied Scenario A Tail End SCR w/ ASOFA case was $4,206/ton and for the hypothetically-applied

Scenario B Tail End SCR w/ ASOFA case was $5,420/ton (shared facilities projects). The unit control cost for the hypothetically-applied Scenario A Low-Dust SCR w/ ASOFA case was $3,396/ton and for the hypothetically-applied Scenario B Low-Dust SCR w/ ASOFA case was $4,835/ton (shared facilities projects). Unit control costs for SNCR w/ ASOFA was $1,265/ton, more than twice that of ASOFA ($613/ton). It should be noted, however, that the very high estimated average control costs involve fuel lean gas reburn ($3,635/ton) and conventional gas reburn ($6,597/ton) technologies that were shown to be inferior options (not on the dominant controls cost curve) and thus were eliminated from further impacts analysis.

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 1 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was $613/ton; the incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,694/ton for MRYS Unit 1. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied low-dust SCR case (Point L2, Scenario A) was $8,547/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied tail end SCR case (Point T2, Scenario A) was $10,765/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied low-dust SCR case (Point L1, Scenario B) was $12,343/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied tail end SCR case (Point T1, Scenario B) was $13,936/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetically-applied SCR cases were $7,058/ton (low-dust Point L2, Scenario A) and $9,264/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetically-applied SCR cases were $10,876/ton (low-dust, Point L1, Scenario B) and $12,458/ton (tail end Point T1, Scenario B).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances,

> including the cost or other analyses, that show what is significantly different about the proposed source."[34]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to MRYS Unit 1 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines estimated an average control cost for SCR applied to MRYS Unit 1 of $549 per ton[35]. The unadjusted unit capital cost versus capacity factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[36] was $100/kW. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton"[37]. The site-specific control costs estimated for hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

Also, the use of incremental cost effectiveness is warranted per the final 2005 RHR/BART Guidelines, which state "the greater the number of possible control options that exist, the more weight should be given to the incremental costs vs. average costs". Also in the final 2005 RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[38]

[34] Ibid Reference number 2, Section IV.D.2.c.
[35] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[36] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[37] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[38] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

TABLE 4-9SA – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

Summary of Estimated Annual Emissions and Economics for NOx Control Alternatives Evaluated for Milton R. Young Station Unit 1 – Stand Alone SCR Projects

Alt. Label[1]	NOx Control Alternative	EMISSIONS[2] Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency[2] %	ECONOMIC IMPACTS Installed Capital Cost[3] $1,000	Annual O & M Cost[4] $1,000	Levelized Total Annualized Cost[5] $1,000	Average Control Cost[6] $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[7]	0.053	145	589	9,345	93.8[8]	222,864	20,048	44,465	4,758
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[7]	0.053	145	536	9,398	93.8[8]	222,864	29,361	56,095	5,969
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[7]	0.053	145	586	9,348	93.8[8]	180,739	16,908	36,872	3,944
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[7]	0.053	145	533	9,401	93.8[8]	180,739	27,882	50,575	5,380
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334[9]	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388[9]	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990[9]	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.45 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.45 MWg and assumes a 96.6% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.
(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.
(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.
(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

TABLE 4-9SF – Estimated Emissions and Economic Impacts Summary for NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

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

Alt. Label[1]	NOx Control Alternative	EMISSIONS[2] Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	NOx Removal Efficiency[2] %	ECONOMIC IMPACTS Installed Capital Cost[3] $1,000	Annual O & M Cost[4] $1,000	Levelized Total Annualized Cost[5] $1,000	Average Control Cost[6] $/ton
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[7]	0.053	145	589	9,345	93.8[8]	181,484	18,806	39,307	4,206
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[7]	0.053	145	536	9,398	93.8[8]	181,484	28,120	50,937	5,420
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[7]	0.053	145	586	9,348	93.8[8]	139,639	15,675	31,749	3,396
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[7]	0.053	145	533	9,401	93.8[8]	139,639	26,649	45,452	4,835
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	58.1	8,113	5,417	7,472	1,265
D	Gas Reburn w/ ASOFA	0.374	1,025	4,275	5,659	56.0	18,006	28,641	37,334[9]	6,597
C	Lignite Reburn w/ ASOFA	0.385	1,058	4,343	5,591	54.6	46,656	5,862	11,388[9]	2,037
B	FLGR w/ ASOFA	0.460	1,261	5,260	4,674	45.9	10,639	12,863	16,990[9]	3,635
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	39.5	4,277	1,695	2,489	613
	Baseline	0.849	2,330	9,934	0	0.0	0	0	0	

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual unit emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr MCR heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.45 MWg and assumes a 97.3% average annual availability. Values from reported emission data for the 12 month operating period during 2001-2005 with the highest rolling summation of NOx pounds.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars. Costs for gas reburn options include high-pressure natural gas supply pipeline installed capital cost of $8,075,000 for CGR and $4,038,000 for FLGR. Costs for increased PM collection capacity included in lignite reburn option are $23,561,000 for installed capital cost.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.45 MWg and assumes a 96.6% average running plant capacity ratio compared to nominal unit gross electrical output capacity of 253 MWg. All cost figures in 2006 dollars. Costs for increased PM collection capacity included in lignite reburn option are $1,909,000/yr for annual O&M cost.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons). All cost figures in 2006 dollars.
(7) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.
(8) - The stated overall control percentage includes the anticipated long-term emission reduction of 90% design removal from a baseline of 0.51 lb/mmBtu resulting from an advanced separated overfire air system, with air-staged low-NO_X cyclone combustion. Without a separated overfire air system operation or any other technique employed, the assumed emission rate would be 0.085 lb/mmBtu, for an overall reduction of 90 percent from a baseline of 0.849 lb/mmBtu.
(9) - LTAC for reburn options include high-pressure natural gas supply pipeline annualized capital cost of $704,000/yr for CGR and $352,000 for FLGR; LTAC for increased PM collection capacity included in lignite reburn option are $2,054,000 for annualized capital cost plus $2,384,000/yr for annualized O&M cost, for a total of $4,438,000/yr.

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

(1) The energy impacts.

(2) The environmental impacts.

4.2.2 ENERGY IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station impose direct impacts on the consumption of energy required for the production of electric power at the facility. The details of estimated energy usage and costs for the previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.2 and Appendix C3 of the October 2006 NOx BACT Analysis Study report[39].

The hypothetical application of Tail End and Low-Dust SCR w/ ASOFA alternatives involve higher energy consumption compared with the existing operation of MRYS Unit 1. New induced draft booster fan electrical power demand is needed due to the estimated additional flue gas pressure drop resulting from hypothetical application of SCR reactor, ductwork, and gas-to-gas heat exchangers. The additional auxiliary electric power demand for the hypothetical application of TESCR and LDSCR equipment were calculated to be 9.7 MW and 8.0 MW, respectively, using estimated annual average electrical loads of the booster fan, urea-to-ammonia conversion fired heater combustion/dilution air fan, direct-fired flue gas reheat burner combustion air fan, and service and sootblowing air compressor equipment and related auxiliary equipment.

Preliminary conceptual design details were developed for these alternatives. An estimated additional 12 inches w.c. of flue gas pressure drop was assumed for each hypothetical application of low-dust SCR system, and an estimated additional 19 inches w.c. of flue gas pressure drop was assumed for the hypothetical application of tail end SCR system. Equipment and ductwork arrangements and expected fouling of the catalyst for the hypothetical application of SCR system ductwork, reactor, and gas-gas reheater changes may cause significantly more restrictive flow paths. Thus the electrical power usage estimated here may be too low.

[39] Ibid Reference number 3, October 2006, pages 3-31 through 3-35, and Appendix pages C3-7 through C3-10.

The expected loss of electrical power generation from these reductions in net output was included as a cost, assuming $35 per megawatt-hour for replacement electrical power. Energy impacts of installing hypothetical application of low-dust and tail end SCR alternatives for NO_X control were included in the O&M cost section (4.2.1.2.1) of this supplemental analysis as Tables C.4-2 through C.4-4.

Aqueous urea solution was assumed to be the preferred, readily available and transportable source of the amine reagent needed to supply ammonia to the SCR reactor catalyst for the low-dust and tail-end SCR alternatives. A urea-to-ammonia conversion system dedicated for each SCR reactor was also assumed. This conversion process will use a natural gas-fired burner that mixes the combustion products at high temperature with the injected aqueous urea solution to thermally decompose the urea, producing gaseous ammonia to supply to the reactors' ammonia injection grids. Gaseous ammonia is the required amine reagent that the catalyst in the SCR reactors uses to convert nitrogen oxides to elemental nitrogen and water vapor. Ammonia (from urea conversion) is supplied and consumed continuously on demand while the SCR NO_X reduction process is in operation. Natural gas is fired continuously during the urea-to-ammonia conversion system operation.

Final reactor inlet flue gas reheat systems are required for the hypothetical application of tail end and low-dust SCR with ASOFA alternatives. A natural gas-fired duct burner that injects high temperature combustion products directly into the flue gas discharged from each SCR gas/gas heat exchanger was assumed for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in each SCR reactor. Natural gas is fired continuously for flue gas reheating during SCR system operation.

TABLE 4-10 – Energy Impacts for NO_X Control Alternatives - MRY Station Unit 1

Alt. Label(1)	NOx Control Alternative(2)	Estimated Annual Natural Gas Usage for Urea-to-Ammonia Conversion(3) (mmBtu/yr)	Estimated Annual Natural Gas Usage for SCR Inlet Reheat(4) (mmBtu/yr)	Estimated Annual Natural Gas Usage for Reburn Fuel(5) (mmBtu/yr)	Estimated Additional Annual Coal Burned for Urea Solution Dilution Water(6) (mmBtu/yr)	Estimated Total Annual Natural Gas Usage and Additional Annual Coal Burned (7) (mmBtu/yr)
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(5)	32,580	460,090	0	0	492,670
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(5)	29,674	419,054	0	0	448,728
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	32,409	235,290	0	0	267,699
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(5)	29,503	214,193	0	0	243,696
E	SNCR w/ ASOFA	0	0	0	54,315	54,315
D	Gas Reburn w/ ASOFA	0	0	3,721,806	0	3,721,806
C	Lignite Reburn w/ ASOFA	0	0	0	0	0
B	FLGR w/ ASOFA	0	0	1,541,796	0	1,541,796
A	Advanced SOFA (ASOFA)	0	0	0	0	0

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate. Alternatives are labeled the same as in Table 4-9.

(2) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1at Milton R. Young Station. The annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assumes replacement of SCR catalyst after a specified number of hours of unit operation.

(3) – Estimated annual natural gas usage for urea-to-ammonia conversion based on adjustments to preliminary budgetary equipment vendor proposals and process calculations. TESCR and LDSCR rate = 4.27 mmBtu/hr for one reactor.

(4) – Estimated annual natural gas usage for flue gas final reheat based on adjustments to preliminary vendor process calculations. TESCR rate = 60.3 mmBtu/hr for one reactor; LDSCR rate = 31 mmBtu/hr for one reactor.

(5) – Natural gas burned for reburn alternatives is assumed to replace coal, no boiler heat rate penalty assumed. Lignite reburn is assumed to burn the same total amount of coal in the boiler as without coal reburn.

(6) - Additional coal burned is due to the urea dilution water injected directly into the boiler's upper furnace, decreasing heat available for steam production and electricity generation, at a net loss of 900 Btu/lb of water for evaporation. See Appendix C3 in the 2006 NO_X BACT Analysis Study report for additional details.

(7) - Annual O&M costs include these values multiplied by the number of hours per year of operation and assume $7.98 per mmBtu for natural gas and $0.71 per mmBtu for coal.

4.2.3 ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

Operation of the NO_X control technologies on the dominant controls cost curve for potential application at the Milton R. Young Station would impose direct and indirect impacts on the environment. The most pronounced direct environmental impact expected from operation of any of the NO_X control options considered is the reduction of ozone and improvement in atmospheric visibility (i.e., reduced visibility impairment) downwind of the facility. Environmental impacts of previously-evaluated NO_X control alternatives were described and summarized in Section 3.4.3 of the October 2006 NOx BACT Analysis Study report.[40]

There would be a favorable environmental impact from potential reduction of annual unit operating time by approximately two percent due to cyclone slag issues associated with air-staged cyclones/ASOFA system operation and by between five percent and 17 percent due to catalyst management and SCR equipment maintenance-related issues for the various low-dust and tail end SCR alternatives. The impact of fewer annual hours of operation will be to decrease the annual amount (tons) of nitrogen oxides emitted, by between approximately 0.2 percent and one percent overall compared to baseline operation. However, generation of replacement electrical power at other powerplants will negate most of these emission reductions.

Operation of the hypothetical application of SCR systems is not expected to significantly impact emissions of carbon monoxide (CO) or volatile organic compounds (VOCs). Emissions from the urea-to-ammonia conversion and flue gas reheat natural gas-fired burners are additive and included in the flue gas entering the SCR reactor in each hypothetical application of SCR case.

Operation of any SCR system will normally cause a small amount of unreacted ammonia to be emitted. The amount of ammonia slip produced by an SCR depends on the reagent utilization and the location of the injection points. Higher SCR NO_X reduction performance involves greater amounts of reagent usage and ammonia slip. This is typically controlled to less than 2 ppmvd, especially when the possible formation of sulfates such as ammonium sulfate [$(NH_4)_2SO_4$] and ammonium bisulfate [NH_4HSO_4] will be more problematic at higher slip levels. Sulfur trioxide (SO_3) formed during combustion in the boiler can combine with ammonia during passage through the catalyst to form the sulfates downstream.

[40] Ibid Reference number 3, October 2006, pages 3-35 through 3-37.

Unreacted ammonia (“slip”) from SCR operation will not be collected downstream of the tail end SCR reactor. The wet flue gas desulfurization absorber downstream of the low-dust SCR reactor may reduce ammonia slip. Any remaining ammonia slip that is not collected or condensed in the air pollution control system will be emitted from the stack as an aerosol or condensable particulate. This has the potential to increase atmospheric visibility impairment downwind of the facility compared with a pristine condition.

Sulfur dioxide (SO_2) formed during combustion in the boiler can combine with oxygen during passage through the hypothetical application of tail end and low-dust SCR catalyst to form additional sulfur trioxide (SO_3) emissions. SO_3 can subsequently combine with water (H_2O) to form sulfuric acid (H_2SO_4), usually in the form of a mist. Wet flue gas scrubbing to remove SO_2 is not highly effective in removing SO_3 created in an upstream low-dust SCR, so higher sulfate emissions will result unless a precipitating reaction with ammonia or condensation in the downstream gas-gas reheater or ductwork occurs. SO_3 and H_2SO_4 can have significant negative far-field impairment impacts on atmospheric visibility if they are above threshold concentrations and not controlled. Tail end SCRs can also cause a small amount of SO_3 to be created as the remaining SO_2 not removed by the wet lime flue gas desulfurization systems will pass through the catalyst and some will be oxidized. It is not known whether the high concentration of alkalinity in the form of sodium aerosol particles will effectively eliminate the remaining SO_3 downstream of the low-dust and tail end SCR systems.

Catalyst from the hypothetical application of SCR reactors will require regular replacement, requiring disposal of the spent catalyst materials or chemical cleaning to remove deposits to allow reuse or regeneration. Hauling spent catalyst to a catalyst rejuvenation facility or an authorized landfill may be required, producing additional liquid and solid wastes and vehicle exhaust emissions.

Because railroad service is not available to MRYS, shipments of amine reagent (concentrated urea solution) for consumption by the hypothetical application of SCR reactors will require additional truck traffic between the supply facility and plant, producing more emissions from vehicle exhaust.

4.2.4 SUMMARY OF ECONOMIC, ENERGY AND ENVIRONMENTAL IMPACTS OF HYPOTHETICALLY-APPLIED SCR NO_X CONTROL ALTERNATIVES FOR MRY STATION UNIT 1

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application at the Milton R. Young Station evaluated for this study are summarized in this Section. Table 3-18 summarized the various impacts discussed in Sections 3.4.1 through 3.4.3 of the October 2006 NO_X BACT Analysis Study report[41]. This supplemental economic analysis examined the estimated capital cost of four hypothetically-applied SCR cases and previously-analyzed feasible NO_X control alternatives and any other powerplant upgrade costs necessary to implement the alternatives. In addition, the economic analysis examined the operating and maintenance costs associated with each NO_X control technology evaluated. These costs were then combined into the levelized total annual cost for a comparative assessment of the total implementation cost of each alternative. Finally, as part of the top-down analysis, a dominant controls cost curve was plotted and the unit control cost for each remaining alternative was evaluated. Four hypothetically-applied SCR cases and two previously-analyzed feasible alternatives were on the dominant controls cost curve and the latter were identified as the more cost effective alternatives. The four hypothetically-applied SCR cases and two previously-analyzed feasible BACT NO_X control alternatives were evaluated for incremental cost, energy, and environmental impacts applicable to Milton R. Young Station Unit 1. The results are summarized in Tables 4-11SA and 4-11SF.

The unit control cost for the hypothetical application of Scenario A Tail End SCR w/ ASOFA case was \$4,758/ton and was \$5,969/ton for the hypothetical application of Scenario B Tail End SCR w/ ASOFA case (stand alone projects). The unit control cost for the hypothetical application of Scenario A Low-Dust SCR w/ ASOFA case was \$3,944/ton and was \$5,380/ton for the hypothetical application of Scenario B Low-Dust SCR w/ ASOFA case (stand alone projects). The unit control cost for the hypothetical application of Scenario A Tail End SCR w/ ASOFA case was \$4,206/ton and was \$5,420/ton for the hypothetical application of Scenario B Tail End SCR w/ ASOFA case (shared facilities projects). The unit control cost for the hypothetical application of Scenario A Low-Dust SCR w/ ASOFA case was \$3,396/ton and was \$4,835/ton for the hypothetical application of Scenario B Low-Dust SCR w/ ASOFA case (shared facilities projects). Unit control cost for SNCR w/ ASOFA was \$1,265/ton, more than twice that of ASOFA (\$613/ton). The UCCs for the hypothetical application of SCR are approximately 270 to 470 percent of the UCC for SNCR w/ ASOFA (\$1,265/ton), and approximately 550 to 970 percent of ASOFA's UCC (\$613/ton).

The incremental cost analysis indicates that from a cost effectiveness viewpoint, the SNCR with ASOFA alternative for MRYS Unit 1 incurs a significant annual (levelized) incremental cost compared to the ASOFA NO_X control technique. The slope from zero (baseline) to ASOFA (Point A) was \$613/ton; the

[41] Ibid Reference number 3, October 2006, pages 3-20 through 3-38.

incremental cost per ton (slope) from ASOFA (Point A) to SNCR with ASOFA (Point E) was $2,694/ton for MRYS Unit 1. The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of low-dust SCR case (Point L2, Scenario A) was $8,547/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of tail end SCR case (Point T2, Scenario A) was $10,765/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of low-dust SCR case (Point L1, Scenario B) was $12,343/ton (stand alone projects). The incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of tail end SCR case (Point T1, Scenario B) was $13,936/ton (stand alone projects). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the top hypothetical application of SCR cases were $7,058/ton (low-dust Point L2, Scenario A) and $9,264/ton (tail end Point T2, Scenario A). For shared projects, the incremental cost per ton (slope) from SNCR with ASOFA (Point E) to the second hypothetical application of SCR cases were $10,876/ton (low-dust, Point L1, Scenario B) and $12,458/ton (tail end Point T1, Scenario B).

The incremental unit control cost per ton (slope) from SNCR with ASOFA to the hypothetical application of SCR with ASOFA cases are approximately 260 to 520 percent of the incremental UCC per ton (slope) between ASOFA and SNCR with ASOFA ($2,694/ton). The incremental UCCs from SNCR with ASOFA to the hypothetical application of SCR with ASOFA cases is between 11 and 23 times the incremental UCC for ASOFA from the pre-control baseline ($613/ton).

In the U.S. EPA's NSR Manual, the EPA does not specify acceptable or unacceptable ranges for average (unit control costs) and incremental cost effectiveness values. EPA's NSR Manual however, does specifically address the standard to be used when rejecting a candidate technology on the basis of adverse economic impact:

> "Consequently, where unusual factors exist that result in cost/economic impacts beyond the range normally incurred by other sources in that category, the technology can be eliminated provided the applicant has adequately identified the circumstances, including the cost or other analyses, that show what is significantly different about the proposed source."[42]

This supplemental report for the MRYS NOx BACT Analysis has clearly established the circumstances, including the economic impacts, which would make the hypothetical application of TESCR or LDSCR to

[42] Ibid Reference number 2, Section IV.D.2.c.

MRYS Unit 1 significantly more expensive than SCR costs normally incurred by other coal-fired steam electric generating units. The following information further supports EPA's own statements regarding the costs "normally incurred by other sources". The EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines was considered relevant for control cost-effectiveness comparison. The EPA's cost-effectiveness analysis used for establishing presumptive BART stated that "applying SCR for coal-fired cyclone units is typically less than $1500 a ton, and that the average cost-effectiveness is $900 per ton" [43]. EPA's technical support document estimated an average control cost for SCR applied to MRYS Unit 1 of $549 per ton[44]. The unadjusted unit capital cost factor assumed by the EPA for SCR retrofits applied to cyclone boilers in the cost-effectiveness analysis used for establishing presumptive BART[45] was $100/kW. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetical application of Low-Dust SCR w/ ASOFA cases at MRYS Unit 1 are $543 to $703/kW, which is more than 500 percent of the EPA's number. The estimated "stand alone" and "shared facilities" installed capital costs for the hypothetical application of Tail End SCR w/ ASOFA cases are $706 to $867/kW, which is more than 700 percent of the EPA's number. Also stated in the final RHR/BART Guidelines, "the average cost for each [of two options, A and B]… may be deemed to be reasonable. However, the incremental cost…of the additional emissions reductions to be achieved by control B may be very great. In such an instance, it may be inappropriate to chose control B, based on its higher incremental costs, even though its average cost may be considered reasonable".[46]

4.2.5 CONCLUSIONS

The site-specific control costs estimated for application of hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines discussed above.

The expected severity of catalyst blinding and pluggage from particulate matter and flue gases emitted from cyclone-fired boilers burning North Dakota lignite precludes the technical feasibility for successful application of such SCR technologies on the electric generating units (EGUs) at the Milton R. Young Station. Not withstanding the technical discussion of SCR technology infeasibility and technical details

[43] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[44] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.
[45] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 209.
[46] Ibid Reference number 11, July 2005, FR Vol. 70 No. 128, page 39168.

previously provided in Appendix A1 and Appendix B[47] of the initial NO_X BACT Analysis report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, this supplemental analysis concludes that the estimated capital and O&M costs for four variations of hypothetically-applied tail-end and low-dust SCR technology alternatives are significantly beyond the normal range of costs incurred, as compared to cost analysis values included in EPA's technical support document issued with the final Regional Haze Regulations and BART Guidelines[48,49]. Average control cost effectiveness for each hypothetical application of SCR control technology case is a minimum of approximately three times the unit control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 1 (SNCR with ASOFA). Incremental control cost effectiveness for each hypothetical application of SCR control technology case is a minimum of approximately three times the incremental control costs of the previously-analyzed highest-performing feasible control alternative recommended as BACT for MRYS Unit 1 (SNCR with ASOFA).

There is an expected decrease in capacity and availability to generate electrical power due to the hypothetical application of low-dust and tail end SCR alternatives. A five to 17 percent decrease in the number of hours of annual operation, and approximately 3% drop in annual plant capacity (net electrical output or MW_n) during operation of the MRYS Unit 1 system are expected if the hypothetical application of low-dust or tail end SCR alternatives were installed. There are also substantial expected negative energy impacts for each hypothetical application of SCR control technology case. Additional auxiliary electrical power demands of approximately 8 to 10 MW will result. This estimate of electrical power usage may be too low. This higher electrical power consumption and lower electrical power generation by MRYS Unit 1 will require additional replacement electrical power to be generated elsewhere.

Natural gas is fired continuously during the urea-to-ammonia conversion system operation for the hypothetical application of Tail End and Low-Dust SCR with ASOFA alternatives.

Final reactor inlet flue gas reheat systems are required for the hypothetical application of Tail End and Low-Dust SCR with ASOFA alternatives. Natural gas is fired continuously for flue gas reheating during SCR system operation for raising the reactor inlet temperature to 600ºF before ammonia injection and NOx reduction can occur in the SCR reactor.

[47] Ibid Reference number 3, October 2006.
[48] See Reference number 11, July 2005, FR Vol. 70 No. 128, pages 39135 and 39136.
[49] Ibid Reference number 4, June 2005, Excel Spreadsheet OAR-2002-0076-0446, page 215.

The site-specific control costs estimated for application of hypothetical application of tail-end and low-dust SCR alternatives to MRYS Unit 1 are significantly higher than the EPA's cost-effectiveness analysis for conventional SCR technologies included in the technical support document issued with the final Regional Haze Regulations and BART Guidelines[50]. SCR technologies of all three types identified in the October 2006 NO_X BACT Analysis Study report should be excluded from consideration for NO_X control at MRYS due to unacceptably high average and incremental cost per ton of pollutant removal based on the supplemental analysis provided herein. Therefore the conclusions regarding NOx BACT as expressed in the original October 2006 BACT Analysis for MRYS Unit 1 are confirmed.

The economic, energy, and environmental impacts of each NO_X control technology on the dominant controls cost curve for potential application to Unit 1 at the Milton R. Young Station evaluated for this study are summarized in Tables 4-11SA and 4-11SF.

[50] See Reference number 4, July, 2005.

TABLE 4-11SA – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 1 - Stand Alone SCR Projects

		EMISSIONS(2)				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS(9)	
Alt. Label(1)	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost(3) $1,000	Annual O & M Cost(4) $1,000	Levelized Total Annualized Cost(5) $1,000	Average Control Cost(6) $/ton	Incremental Control Cost(7) $/ton	Incremental Aux. Power Demand(8), kW	Incremental Annual Aux. Power Usage + Generation Reduction(8), kW-hrs/yr	Non-Air Increase	Toxic Air Increase
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A(10)	0.053	145	589	9,345	222,864	20,048	44,465	4,758	10,765	9,685	171,745,369	Flyash UBC, catalyst disposal	CO, NH_3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B(10)	0.053	145	536	9,398	222,864	29,361	56,095	5,969	13,936	9,685	342,358,537	Flyash UBC, catalyst disposal	CO, NH_3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A(10)	0.053	145	586	9,348	180,739	16,908	36,872	3,944	8,547	8,012	169,418,356	Flyash UBC, catalyst disposal	CO, NH_3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B(10)	0.053	145	533	9,401	180,739	27,882	50,575	5,380	12,343	8,012	341,140,028	Flyash UBC, catalyst disposal	CO, NH_3
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.
(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.
(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.
(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetical application of SCR technology cases.
(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

TABLE 4-11SF – Summary of Supplemental BACT Analysis Impact Results for Dominant NO_X Control Alternatives - MRY Station Unit 1 – Shared Facilities SCR Projects

		EMISSIONS[2]				ECONOMIC IMPACTS					ENERGY IMPACTS		ENVIRONMENTAL IMPACTS[9]	
Alt. Label[1]	NOx Control Alternative	Emission Rate lb/mmBtu	Hourly Emission lbs/hr	Annual Emission tons/yr	Emission Reduction tons/yr	Installed Capital Cost[3] $1,000	Annual O & M Cost[4] $1,000	Levelized Total Annualized Cost[5] $1,000	Average Control Cost[6] $/ton	Incremental Control Cost[7] $/ton	Incremental Aux. Power Demand[8], kW	Incremental Annual Aux. Power Usage + Generation Reduction[8], kW-hrs/yr	Non-Air Increase	Toxic Air Increase
T2	Hypothetical Tail End SCR w/ ASOFA – Scenario A[10]	0.053	145	589	9,345	181,484	18,806	39,307	4,206	9,264	9,685	171,745,369	Flyash UBC, catalyst disposal	CO, NH_3
T1	Hypothetical Tail End SCR w/ ASOFA – Scenario B[10]	0.053	145	536	9,398	181,484	28,120	50,937	5,420	12,458	9,685	342,358,537	Flyash UBC, catalyst disposal	CO, NH_3
L2	Hypothetical Low-Dust SCR w/ ASOFA – Scenario A[10]	0.053	145	586	9,348	139,639	15,675	31,749	3,396	7,058	8,012	169,418,356	Flyash UBC, catalyst disposal	CO, NH_3
L1	Hypothetical Low-Dust SCR w/ ASOFA – Scenario B[10]	0.053	145	533	9,401	139,639	26,649	45,452	4,835	10,876	8,012	341,140,028	Flyash UBC, catalyst disposal	CO, NH_3
E	SNCR w/ ASOFA	0.355	975	4,025	5,909	8,113	5,417	7,472	1,265	2,694	73	68,243,017	Flyash UBC	CO, NH_3
A	Advanced SOFA (ASOFA)	0.513	1,409	5,874	4,060	4,277	1,695	2,489	613	613	1	46,594,605	Flyash UBC	CO
	Baseline	0.849	2,330	9,934	0	0	0	0						

(1) - Alternative label has been assigned from highest to lowest unit NOx emission rate.
(2) - Estimated NO_X control level reductions relative to average annual emission baseline of 0.849 lb/mmBtu at 2,744 mmBtu/hr heat input. Emissions are calculated from unit emission rates, control percentage, hourly heat input, and annual hrs/yr operation compared to pre-control baseline based on annual operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability.
(3) - Installed capital cost is estimated for determination of total capital cost for a particular technology or combination, assuming 257 MWg unit capacity rating. All cost figures in 2006 dollars.
(4) - Annual operating and maintenance cost for a particular technology or combination is compared to unit baseline operation at a gross unit electrical output of 244.5 MWg and assumes a 97.3% average annual availability, which is the highest consecutive 12-months of operation from 2001-2005. All cost figures in 2006 dollars.
(5) - Levelized Total Annual Cost = Annualized Installed Capital Cost + Levelized Annual O&M cost. Annualized capital cost = Installed capital cost x 0.08718 annualized capital cost factor. Levelized annual O&M cost = Annual O&M cost x 1.24873 annualized O&M cost factor.
(6) - Average Control Cost Effectiveness ($/ton) is the Levelized Total Annual Cost ($/yr) divided by Annual Emission Reduction (tons/yr). All cost figures in 2006 dollars.
(7) - Incremental Control Cost Effectiveness ($/ton) is the difference in LTAC between the next most stringent alternative divided by the emissions reduction. All cost figures in 2006 dollars.
(8) - Energy impacts are incremental auxiliary electrical power demand (kW) and annual power usage plus generation lost due to negative unit reliability (fewer hours per year of operation) resulting from each control alternative (kW-hrs/yr) compared to the pre-control baseline.
(9) - Environmental impacts summarize expected non-air effects and potential toxic air emissions resulting from control alternative compared to the pre-control baseline. Flyash unburned carbon content may increase with air-staging cyclones; carbon monoxide concentrations may increase an insignificant amount with air-staging cyclones. Excess unreacted ammonia (slip) expected from SNCR technology and the hypothetical application of SCR cases.
(10) - The inclusion of tail-end and low-dust SCR technologies in this table does not constitute agreement that it is technically feasible to install these technologies on Unit 1 at Milton R. Young Station. The estimated annual NOx removal and LTAC shown for a hypothetically-applied SCR system is based on assumptions that known or expected reasons for technical infeasibility for installation and operation and maintenance of the SCR equipment on this boiler are solvable. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_X BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, so this information for the hypothetical application of SCR alternatives is included for comparative purposes only. See Section 4.2.1.2.1 for details of Scenario A and Scenario B that assume replacement of SCR catalyst after a specified number of hours of unit operation.

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

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

3. "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.

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

5. Comment & Response to EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station, submitted by Minnkota to NDDH, November 9, 2007.

6. EPA Report "Multipollutant Emission Control Technology Options for Coal-fired Power Plants", EPA-600/R-05/034, dated March, 2005, posted at their website: http://www.epa.gov/airmarkets/articles/multireport2005.pdf.

7. "Assessment of Control Technology Options for BART-Eligible Sources, Steam Electric Boilers, Industrial Boilers, Cement Plants and Paper and Pulp Facilities", dated March 2005, prepared by Northeast States for Coordinated Air Use Management (NESCAUM) in partnership with the Mid-Atlantic/Northeast Visibility Union, posted at the website: http://bronze.nescaum.org/committees/haze/BART_Control_Assessment.pdf.

8. "Analysis of Combustion Controls for Reducing NO_X Emissions From Coal-fired EGU's in the WRAP Region, Draft Report", prepared for the Western Regional Air Partnership by Eastern Research Group, Inc., ERG Contract Number 30204-101, dated April 26, 2005, available at: http://www.wrapair.org/forums/ssjf/documents/eictts/NOxEGU/050426Coal-fired%20EGUs_in_WRAP_Region-draft.pdf

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

10. EPA Office of Air Quality Planning and Standards (OAQPS) publication EPA/452/B-02-001, Section 4.2, NOx Controls – NOx Post-Combustion, Chapter 2 - Selective Catalytic Reduction, dated October 2000, posted at their website: http://www.epa.gov/ttn/catc/dir1/cs4-2 ch2.pdf

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