MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE

FOLLOWUP RESPONSES TO PRESENTATION and
NDDH REQUEST FOR ADDITIONAL INFORMATION
SUPPLEMENTAL NOx BACT ANALYSIS STUDY
MILTON R. YOUNG STATION UNIT 1 and UNIT 2
REGARDING SCR ECONOMIC FEASIBILITY

February 11, 2010

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has requested[1] that Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") provide additional information clarifying the written response submitted December 11, 2009[2] that provided detailed and comprehensive cost data following the NDDH's and U.S. EPA's reviews of the Best Available Control Technology (BACT) Analysis Study – Supplemental Reports[3] submitted on November 12, 2009 for control of nitrogen oxides (NO_X) emissions from existing Unit 1 and Unit 2 at Milton R. Young Station (MRYS).

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced 2006 NO_X BACT Analysis Study[4] of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station in accordance with the requirements of a Consent Decree (CD)[5]. Burns & McDonnell also performed the November 2009 Supplemental NO_X BACT Analysis Study and generated the referenced reports for each MRYS boiler in response to the NDDH's request[6] to see Steps 3 and 4 of the BACT analysis process[7] include low-dust and tail end SCR alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has recently advised[8].

Information supplementing the previously-provided detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives, and their subsequent presentation to NDDH, are attached.

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[1] See Reference number 1, January 11, 2010.
[2] See Reference number 2, December 11, 2009.
[3] See Reference number 3, November 12, 2009.
[4] See Reference number 4, October 2006.
[5] See Reference number 5, April 24, 2006.
[6] See Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.
[7] See Reference number 7, October 1990.
[8] Ibid Reference number 6, July 15, 2009. SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT Analysis Study report and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports.

<u>NOx BACT Analysis Study Supplemental Reports</u>:

NDDH Request #1: How were the SCR reactors sized and the catalyst volume determined and what target NOx control efficiency was used to size the catalyst? How was the cost of the catalyst determined?

BMcD Response:

The same SCR system supplier that is providing the low-dust SCR equipment for the WE Energies South Oak Creek project in Wisconsin was asked to provide a budgetary equipment proposal for both low-dust and tail end SCR arrangements for each unit at MRYS. A lignite coal analysis (proximate, ultimate, and coal ash) and process design basis (boiler fuel heat input rates, excess air percentages, flue gas volumetric flows, temperatures and gas species contents) were included with the request. An assumed inlet and outlet NOx concentration was also provided, with a nominal 85% reduction from 0.5 lb/mmBtu requested. This SCR system supplier sized the SCR reactor, the SCR gas-to-gas heat exchange equipment (SCR GGH), and related ductwork. The initial catalyst charge for each reactor was included in the lump-sum equipment price proposal. The SCR system supplier did not disclose the specific volume of catalyst to be provided nor the specific manufacturer or type of catalyst (i.e. honeycomb, plate, etc.). Due to the proprietary nature of this SCR conceptual design and budgetary equipment pricing effort, this work was performed by the SCR system supplier with the understanding that it was confidential. Refer to Burns & McDonnell's response to NDDH Request #7 for additional information.

Two SCR catalyst suppliers provided budgetary replacement catalyst quotes, including catalyst volume, catalyst pitch, catalyst type, and arrangement of catalyst modules, based on preliminary process design provided by an SCR process design consultant. The design used for these catalyst supplier proposals was based on 90% overall NOx reduction across the SCR system. The catalyst suppliers also provided cost proposals for the replacement catalyst. One supplier provided a cost of replacement catalysts in terms of $/m^3. Due to the proprietary nature of this SCR reactor sizing and budgetary catalyst pricing effort, this work was performed by the SCR catalyst suppliers with the understanding that it was confidential. Refer to Burns & McDonnell's response to NDDH Request #7 for additional information.

NDDH Request #2: Anhydrous ammonia appears to be a less expensive reagent than urea for the SCR system due to local availability. A justification must be supplied for electing urea over anhydrous ammonia.

BMcD Response:

Aqueous urea solution was selected because of health and safety issues related to the use of ammonia, including site constraints involving over-the-road transport, on-site unloading and storage. MRYS does not have rail access, and is adjacent to a lake used for condenser cooling water and process water supplies. Public access to the lake is allowed. Anhydrous ammonia and aqueous ammonia are classified as hazardous chemicals per Clean Air Act Section 112 (r). This requires extensive emergency planning. Transport and handling of ammonia is restricted by the United States Department of Homeland Security and the Department of Transportation through the Rail Security Act. The U.S. EPA has determined that a toxic radius of a spill to be between 5 and 7 miles for anhydrous ammonia and 1 to 2 miles for aqueous ammonia[9].

NDDH Request #3: Support must be provided for the catalyst cleaning/replacement outage periods. This should include an explanation of the method used to estimate the outage time and clarification whether the outage time includes the regular outage period.

BMcD Response:

Burns & McDonnell and Minnkota queried SCR catalyst suppliers, process design consultants, utility construction and maintenance contractors, and utility personnel at U.S. coal-fired plants with operating SCRs to provide input into the estimation of time associated with catalyst installation into the empty (spare) layer of the reactor, and to remove dirty catalyst and install fresh catalyst in its place. The responses indicated that there is a broad range of experiences based on limited amounts of user and vendor data on this issue. The range of experience is due to the site-specific conditions and design-specific features of the reactor catalyst access doors' locations and sizes, module arrangement, hoisting equipment, staging areas and platforms, labor availability and familiarity. The general lack of data is due to the relative newness of many SCR installations currently operating at coal-fired powerplants in the United States that have not accumulated significant operating time and so have not required significant numbers of catalyst changeouts.

Catalyst replacement activities by current coal-fired powerplant users are typically scheduled during major boiler outages that are 18-36 months apart. The SCR catalyst changeout is usually not a schedule-critical activity during such outages. The catalyst changeout time required depends on how many modules are involved, and whether a single shift of personnel or multiple shifts per day are engaged in the work.

For the hypothetical application of low-dust and tail end SCR technologies at MRYS, most of the catalyst changeouts were assumed to coincide with boiler fireside cleaning outages, which are historically approximately 4 days in duration, three or four times per year, depending on the boiler involved. Because of the use of high pressure water to remove boiler deposits during these cleanings, the air exhausted from the boilers through the flue gas ductwork to the chimneys during these times contains moisture and particulate.

[9] See Reference 8.

Catalyst vendors have advised that this air stream is not suitable for passing through an SCR reactor filled with catalyst. This will require an SCR reactor bypass to be provided for use during these outages.

Before catalyst changeout operations can begin, the large volume of catalyst and supporting structural steel must be cooled down sufficiently to allow personnel to safely enter the reactor to gain access to remove any ash accumulations. The means and equipment required to remove the catalyst depends on the specific reactor design and module arrangements. The specific time and equipment requirements for catalyst changeouts are normally developed after the specific reactor and module details are established.

The SCR Cost Estimate study assumed that reactor isolation dampers and reactor maintenance bypass ductwork dampers would be required to avoid contamination of the catalyst by the air/water/particulate stream, and allow the reactors to be cooled while being isolated from the normal flue gas path to the chimney. The time estimated for catalyst installation into the empty (spare) layer of the reactor was 16 shifts, which, assuming two shifts per day, would be 8 days. The time estimated to remove dirty catalyst and install fresh catalyst in its place was 24 shifts, which, assuming two shifts per day, would be 12 days. The time assumed for reactor cooldown was previously estimated as 48-60 hours, which would elapse during the first half of the boiler cleaning process[10]. After the fresh catalyst is in place, and the reactor access doors closed, the entire volume of fresh and dirty catalyst remaining in the reactor must then be heated to above the moisture dewpoint to avoid possible moisture condensation during boiler startup. This would involve use of the supplemental catalyst outage heating system, not the flue gas reheat system nor flue gas from the boiler. Burns & McDonnell estimated that post catalyst changeout outage time will extend approximately 36-48 hours until the boilers are ready to begin the startup process to return to service.

The November 2009 Supplemental NOx BACT Analysis study assumed 1168 total hours and 1126 total hours of outage time per year associated with MRYS Unit 1's hypothetical application of low-dust and tail end SCR technologies (Scenario "B"), respectively. This is 980 hours and 938 hours of outage time in addition to the 188 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming three catalyst layer changeout outages per year for Unit 1, this works out to be approximately 13 extra days per outage. Unit 2's Scenario "B" assumed 1415 total hours of outage time for either hypothetical application of low-dust and tail end SCR technologies. This is 1234 hours of outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming four catalyst changeout outages per year for Unit 2, this works out to be approximately 13 extra days per outage.

[10] See Reference 9, March 15, 2007, pages 12-14.

The November 2009 Supplemental NOx BACT Analysis study assumed 401 total hours and 443 total hours of outage time per year associated with MRYS Unit 1's, and 387 total hours and 428 total hours of outage time per year for Unit 2's, hypothetical application of tail end and low-dust SCR technologies (Scenario "A"), respectively. This is 213 or 256 hours of Unit 1 outage time and 206 or 247 hours of Unit 2 outage time in addition to the 181 hours of outage time per year assumed for advanced separated overfire air alternative. Assuming one catalyst changeout outage every two years for each Unit 1 and Unit 2, this works out to be approximately between 8.6 and 10.7 extra days per outage, depending on the boiler and SCR technology studied.

The catalyst changeout outage times assumed in the November 2009 Supplemental NOx BACT Analysis study for MRYS Unit 1 and the similar study for MRYS Unit 2 are expected to be extensions to the boiler cleaning outages. Note that the estimated annual number of days for catalyst changeout outages is in addition to outage times included in the Advanced Separated Overfire Air alternative, which is also relative to baseline operation which include downtime for boiler cleanings. We believe the outage durations and frequency are reasonable assumptions to use for the purposes of showing possible economic outcomes that could result from the hypothetical application of low-dust and tail end SCR technologies at MRYS.

NDDH Request #4: The indirect capital costs associated with the project appear to be high. A detailed explanation of the estimation method must be supplied.

BMcD Response:

Burns & McDonnell used standard estimating practices to estimate direct, installation, and indirect capital costs for MRYS Unit 1's and Unit 2's hypothetical application of low-dust and tail end SCR technologies. To establish the context of estimated indirect costs, we note that several major assumptions were used by Burns & McDonnell in developing the capital cost estimates of the hypothetical applications of low-dust and tail end SCRs at Milton R. Young Station. These assumptions include the following:

- A multiple (parallel prime) contracting approach was selected (as opposed to single "turnkey" or Engineer-Procure-Construct contract). Although this approach may increase the project execution risk to the Owner, the execution risk is considered manageable. This contracting approach was recommended because it allows early award of major equipment procurements to allow detailed design engineering to proceed expeditiously to meet the project schedule, and offers the greatest flexibility for the Owner (Minnkota) to be involved in key decisions regarding design.
- Project will be executed to achieve completion in 2016 for Unit 2 and 2017 for Unit 1. It was assumed that the project will be executed with skilled workforce resources sufficient to meet the target project execution schedule while minimizing overtime. No additional overtime is included to accommodate a compressed work schedule.

Indirect Costs:

- Escalation based on historical data and Burns & McDonnell experience was assumed to average 5% per year for equipment, 9% per year for materials and 5% per year for labor. See additional general description of escalation included below.
- Contingency was calculated at 20% overall (10% for pricing and 10% for scope). Contingency was applied to Total Direct Capital Costs plus Indirect Capital Costs such as Engineering and Field Support, Construction Management and related indirects, Startup Expenses, and Cost Escalation during Project Execution. Owner Contingency was estimated at 7%. See additional general description of contingency included below.
- A performance bond is included for all subcontract work at the rate of 1.5% of the estimated project contract costs.
- Sales tax on construction consumables is included. No other tax is included.
- Owner will provide a builder's risk policy for the project. Cost for this is included in the estimate of Owner's costs.
- Interest During Construction (IDC) is included in the Owner's costs at 6% per year, assuming project execution-based monthly expenditures.

Escalation:

An estimate for escalation of project costs has been included in the capital cost estimate. Escalation of construction labor, materials, and indirects was estimated based on historical data and Burns & McDonnell experience.

Escalation of construction labor was estimated to be approximately 5% annually throughout the project. This estimate of escalation was based on the average increase in craft labor costs for the United States combined with known union labor contract costs in the next few years. The average annual escalation of union contracts for skilled and common labor rates over the last ten years in North Dakota has been approximately 5.0% per year.

Escalation of equipment and materials is included in the project estimate at a rate of 5% per year for equipment and 9% per year for materials. Since January 2004, steel pricing experienced rapid escalation equating to a nearly a 100% increase in rebar and structural steel costs, then dropped in late 2008 and early 2009. Within the past 6 months, steel prices have again started to rise. Pipe and electrical commodities have also seen a high overall escalation during this time, followed by a decline in late 2008. Due to this volatility, equipment and material suppliers have been providing pricing with short bid validity.

Contingency:

This project involves a significant amount of retrofit work in the existing plant. The SCR Cost Estimate study did not perform a thorough review of existing conditions and interfaces with the new work. It is anticipated that the scope of work will increase as unknown conditions are discovered during project execution. A contingency of 20% of the overall project costs is included in the project cost. Of this 20%, 10% covers accuracy of the pricing of the equipment and materials (commodities), and 10% covers omissions from the defined project scope. This contingency is not intended to cover changes in the general project scope (i.e. addition of buildings, addition of redundant equipment, addition of systems, etc.) nor major shifts in market conditions that could result in significant increases in contractor margins, major shortages of qualified labor, significant increases in escalation, or major changes in the cost of money (interest rate on loans).

In addition to the project contingency, an additional owner contingency is included to cover owner general project scope additions. Based upon the amount of preliminary design and project definition completed, a 7% scope contingency to cover such potential changes is included. However, this contingency level depends on the probability of additional scope and is typically determined by the Owner (Minnkota).

NDDH Request #5: Support must be supplied for the cost of natural gas and electricity.

BMcD Response:
Burns & McDonnell used estimated long-term average natural gas unit cost for the economics of conventional and fuel-lean gas reburn alternatives' annual operating costs included in the 2006 NOx BACT Analysis Study reports for MRYS Unit 1 and Unit 2. The annual cost of auxiliary power consumed by air pollution control equipment and the value of electric generator output not able to be sold ("lost") due to inability to produce electricity during outages related to the air pollution control equipment associated with particular control alternatives were also calculated. The long-term average unit costs for natural gas and electricity were provided by Minnkota. Burns & McDonnell's recent review of the forecast power industry's natural gas unit cost forecasts from 2006 confirm that the number used in the original NOx BACT Analysis Study calculations and reports submitted in October 2006 are reasonable, given the uncertainty and variability that is common with such forecasts.

In the November 2009 Supplemental NOx BACT Analysis study reports, Burns & McDonnell assumed the economics of hypothetical application of low-dust and tail end SCR technologies at MRYS should be also based on the same unit costs used for the 2006 NOx BACT Analysis study reports.

NDDH Request #6: More details, including calculations, must be supplied to justify the pressure drops and parasitic loads associated with the SCR configurations.

BMcD Response:

Burns & McDonnell used estimated flue gas pressure drops provided by the SCR supplier for the SCR reactor, and gas-to-gas heat exchangers (GGH), in the development of new induced draft booster fans' performance requirements and the alternatives' economics of hypothetical application of low-dust and tail end SCR technologies at MRYS for Unit 1 and Unit 2 in the November 2009 Supplemental NOx BACT Analysis study reports. The estimated flue gas pressure drops of the flue gas ductwork, which would be incurred upstream and downstream of the low-dust and tail end SCR reactors and GGHs, were calculated using a proprietary spreadsheet.

For low dust SCR cases, new ductwork would be connected downstream of the existing induced draft fans' outlets and a new booster fan for each reactor would follow the GGH outlet after the SCR reactor, discharging to the existing flue gas desulfurization (FGD) system absorber inlet duct[11].

In tail end SCR cases, new duct connections downstream of the existing induced draft fans' outlets would divert flue gas before the FGD absorbers' inlet ducts, through the hot side of the FGD GGH then back to the FGD absorber inlet duct. Additional duct connections downstream of the existing FGD absorbers' outlet ducts would reroute flue gas through the cold side of the FGD GGH, then to the cold side of the main (SCR) GGH upstream of the flue gas reheat section in the SCR reactor. After the reactor, flue gas would pass through the hot side of the main (SCR) GGH, continue to the new induced draft booster fans, and be discharged back to new duct connections near the existing inlets to the chimneys[12].

Horsepower required to drive the fans to produce pressure needed to overcome the cumulative ductwork and SCR equipment pressure losses for full load (maximum continuous rating) and "test block" flue gas flows was calculated from budgetary booster fan equipment quotes, which included preliminary pressure rise versus flow and mechanical efficiency curves, from two fan vendors. The horsepower required for the volumetric gas flow and pressure rise was then converted into electrical kilovolt-amperes (kVA) and kilowatts (kW) in order to calculate auxiliary power loads. An annual average load factor was applied, which was then multiplied by the assumed hours of annual operation to determine the annual megawatt-hours (MW-h) of consumed auxiliary power due to the SCRs' induced draft booster fans.

[11] See attached sketch for low-dust SCR equipment and ductwork conceptual arrangement.
[12] See attached sketch for tail end SCR equipment and ductwork conceptual arrangement.

The parasitic loads associated with the SCR alternatives studied were determined by identifying known power-consuming auxiliary equipment serving the new air pollution control equipment. Estimates of design horsepower or kVA, based on vendor quotes or similar projects where information is available, were generated. Conversion to kW along with application of an annual average load factor resulted in estimated average annual auxiliary power loads, which were summed together to establish the total parasitic load. Annual megawatt-hours (MW-h) of consumed auxiliary power due to the various SCR cases studied were calculated by multiplying the total parasitic load by the assumed hours of annual operation.

The table below provides the results of these calculations.

Pressure Drop and Fan Power Calculation Results

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) pressure drop, in. w.g.	--	2.7	--	1.87
FGD GGH (cold side) pressure drop, in. w.g.	--	2.7	--	1.87
SCR GGH (cold side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR reactor/catalyst press. drop, in. w.g.	2.0	2.0	2.0	2.0
SCR GGH (hot side) pressure drop, in. w.g.	2.3	2.7	1.74	1.98
SCR flue gas ducts/dampers/connections pressure drop, in. w.g.	5.4	6.2	4.5	6.3
Booster Fan Static Pressure Rise / Total Pressure[1] (Inches W.G.)	12.0 / 13.51	19.0 / 21.33	10.0 / 11.50	16.0 / 18.23
Booster Fan Motor Horsepower[2]	5000	7000	3500	5000
Load kVA / Demand kVA[3]	5000 /4500	7000 /6300	3500 /3150	5000 /4500
Quantity of Fans, capacity per fan, each case	One (1) x 100%		Two (2) x 50%	

1- Booster fan static pressure rise is the sum of the duct and SCR equipment pressure drops. Total fan pressure includes fan static pressure rise plus additional pressure rise required to overcome pressure drops within the fan equipment. These numbers do not include additional fan capacity (margin) above the amount required for full load (maximum continuous rating or MCR) operation, which allows for factors that reduce actual performance over sustained periods of running. Static pressure rise and Total pressure numbers are preliminary; final design may require values higher or lower than those shown.

2- Motor horsepower is greater than fan mechanical horsepower, and is based on available size larger than "Test Block" horsepower. Mechanical horsepower takes into account fan mechanical efficiency at the stated operating condition. Fans are sized based on mechanical efficiency and additional capacity (margin) above the MCR condition, referred to as "Test Block". The test block flow margin is 15% per fan, the test block pressure rise margin is 32.25% (1.15^2) above MCR values stated above. Test block fan mechanical efficiency is approximately 0.8. Fan Mechanical Horsepower = flue gas volumetric flow (actual cubic feet per minute) multiplied by pressure rise in inches w.g. divided by (6536 x efficiency). Fan efficiency varies with flow and pressure rise; values based on estimates/vendor quotes for full load (maximum continuous rating or MCR) conditions.

3- Horsepower (motor rating) is approximately equal to Connected Load kVA; Connected Load kVA x Estimated Annual Average Demand factor = Demand Load kVA.

Hypothetical applications of low-dust and tail end SCR technologies included estimates of auxiliary electrical power usage. It is important to note that some alternatives identified between 88 and 109 electricity-consuming items supplying or serving each SCR reactor system. Several pieces of auxiliary equipment with significant electrical power loads were included. These are: sootblowing air compressors with dryers; instrument/service air compressors with dryers; seal air fans for SCR reactor inlet and outlet flue gas isolation dampers; SCR flue gas reheat burner combustion air fans; drive gearboxes for rotary gas/gas heat exchangers; urea-to-ammonia dilution air/combustion air fans; auxiliary equipment service building ventilation/heating/lighting; and urea feed pumps. The instrument/service air and sootblowing air compressors are significant but necessary to supply dry compressed air used by equipment dedicated to control, maintain, and provide catalyst cleaning media for the SCR systems.

NDDH Request #7: All vendor correspondence related to SCR reactor sizing, catalyst volume, NOx control efficiency, catalyst cost, catalyst replacement schedule, and catalyst guarantees should be provided. This includes the original requests submitted to vendors and analyst [catalyst] suppliers by Minnkota and its consultants. This must also include the description of the gas stream that was supplied to the vendors.

BMcD Response:

Information responsive to this request by Minnkota, Burns & McDonnell and the SCR system supplier and SCR process design consultant, catalyst vendors, and flue gas particulate characterization consultant is being submitted (see Enclosures). Documents that include information considered as "trade secrets" per the NDDH's Air Pollution Control rules are being submitted and marked "confidential" (see Enclosures).

Minnkota developed agreements with the catalyst suppliers and flue gas particulate characterization consultant engaged in this effort, and has a general services agreement with Burns & McDonnell, which covers work done by the SCR system supplier and SCR process design consultant. Information provided under Enclosure C is considered non-confidential, and includes information for which no claim is being made for confidentiality, along with an index and summary of the information submitted which is suitable for release to the public. Enclosure D includes documents claimed to contain trade secrets which are requested to be treated as confidential, along with an affidavit stating how and why the information fulfills the conditions of confidentiality per the NDDH's Air Pollution Control rules describing this confidentiality procedure.

NDDH Request #8: Data must be provided for the temperature gradient of the regenerative heat exchanger to justify the reheat calculations. This must be provided for the both LDSCR and TESCR. The 600ºF temperature for the reheated flue gas must be justified.

BMcD Response:

The preliminary design temperatures for the hypothetical applications of low-dust and tail end SCR technologies shown in the table below were calculated by the SCR process consultant. The temperature data tabulated below for the Unit 1 low dust (LD) case include corrections identified by the SCR process consultant as described further in the response to NDDH Request #11.b. The SCR system supplier, which provided pricing of SCR equipment, including GGHs for low-dust and tail end SCRs, did not provide estimates of the GGHs' process performance.

SCR Process Design Temperatures

Parameter	U1 LD	U1 TE	U2 LD	U2 TE
FGD GGH (hot side) inlet temperature, ºF	--	335	--	331
FGD GGH (hot side) outlet / FGD Absorber Inlet temperature, ºF	--	(1)	--	(1)
FGD GGH (cold side) inlet/ FGD Absorber Outlet temperature, ºF	--	142	--	143
FGD GGH (cold side) outlet temperature, ºF	--	150	--	151
SCR GGH (cold side) inlet temperature, ºF	335	150	331	151
SCR GGH (cold side) outlet temperature, ºF	535	520	535	520
Flue Gas Reheat Burner outlet / SCR Ammonia Injection Grid/Reactor inlet temperature, ºF	580	563	580	563
SCR GGH (hot side) outlet temperature, ºF	380	199	380	197
FGD Absorber Outlet temperature, ºF	142	142	143	143

1- The temperature of the FGD GGH hot side outlet (discharges to FGD Absorber Inlet) was not provided by the SCR process consultant. It would be less than 330ºF.

As can be seen in the table above, the flue gas is reheated by natural gas to either 580ºF for low-dust SCR cases or 563ºF for tail end SCR cases. Natural gas heat input rates used in the November 2009 Supplemental NOx BACT Analysis study reports assumed these flue gas temperatures. These preliminary process design temperatures have not been confirmed pending final design by the gas/gas heat exchanger manufacturer. The catalyst vendors recommended that the catalyst be designed for (able to withstand continuous exposure to) 600ºF service operating temperature. The capacity of the reheat burner equipment was not specifically provided by the SCR system supplier, but was expected to be capable of raising the flue gas up to the recommended service temperature.

NDDH Request #9: A comparison of the SCR costs at M.R.Young Station versus PSE&G Mercer Station and We Energies Oak Creek Station should be provided or an explanation why such a comparison is not possible or inappropriate. We recognize that each plant has unique characteristics and there will be some design differences from plant-to-plant, but those differences should not necessarily dismiss making general comparison of costs unless there are unique or extenuating circumstances which would preclude a general cost comparison.

BMcD Response:

A BACT analysis is performed on a case-by-case, site-specific basis. It is inappropriate to compare the capital costs associated with the low-dust SCR installation at Mercer Station, or at South Oak Creek Station, against those developed for the hypothetical applications of low-dust and tail end SCR technologies at MRYS. Site conditions, boiler firing type, type and characteristics of fuels burned and resulting flue gas emissions and ash produced, and the limited amount of NOx reduction required for those referenced low-dust SCR cases that were not required to represent BACT, make the comparison not relevant to MRYS.

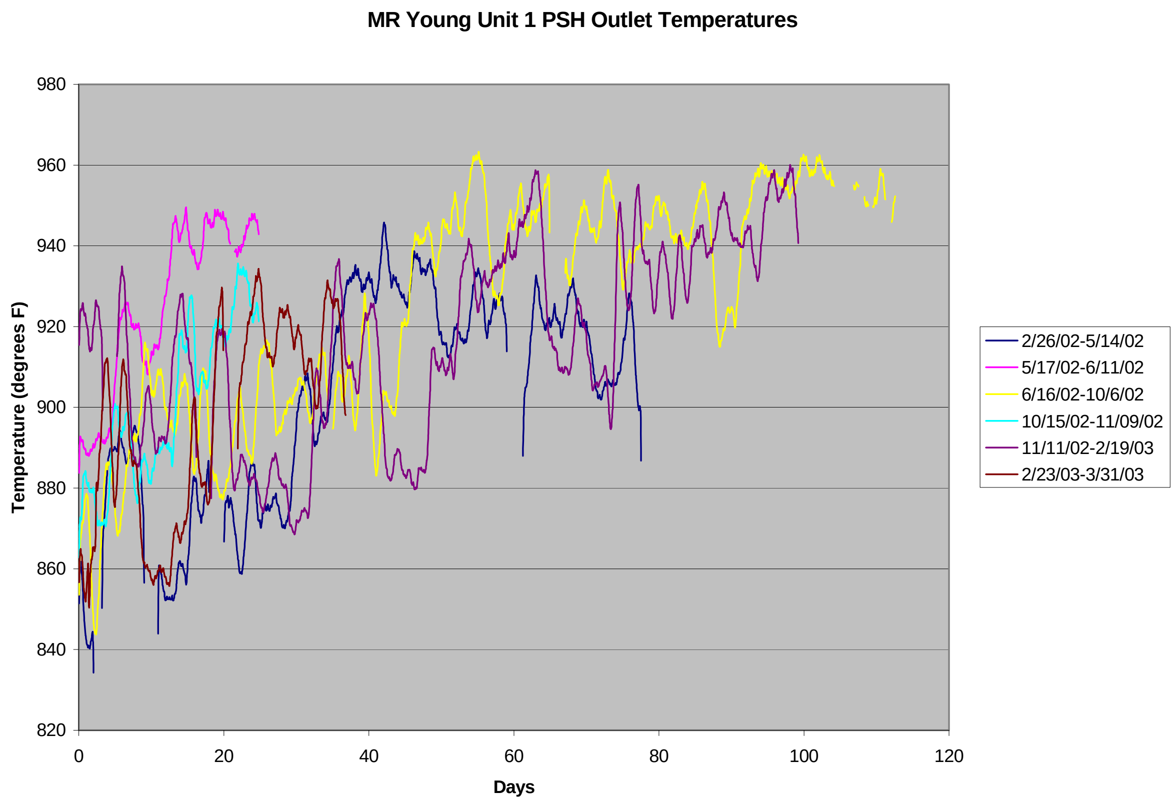
NDDH Request #10: Provide additional clarification and technical justification regarding Minnkota's determination that the units at MRYS are boiler limited and cannot generate additional steam for flue gas reheating purposes.

BMcD Response:

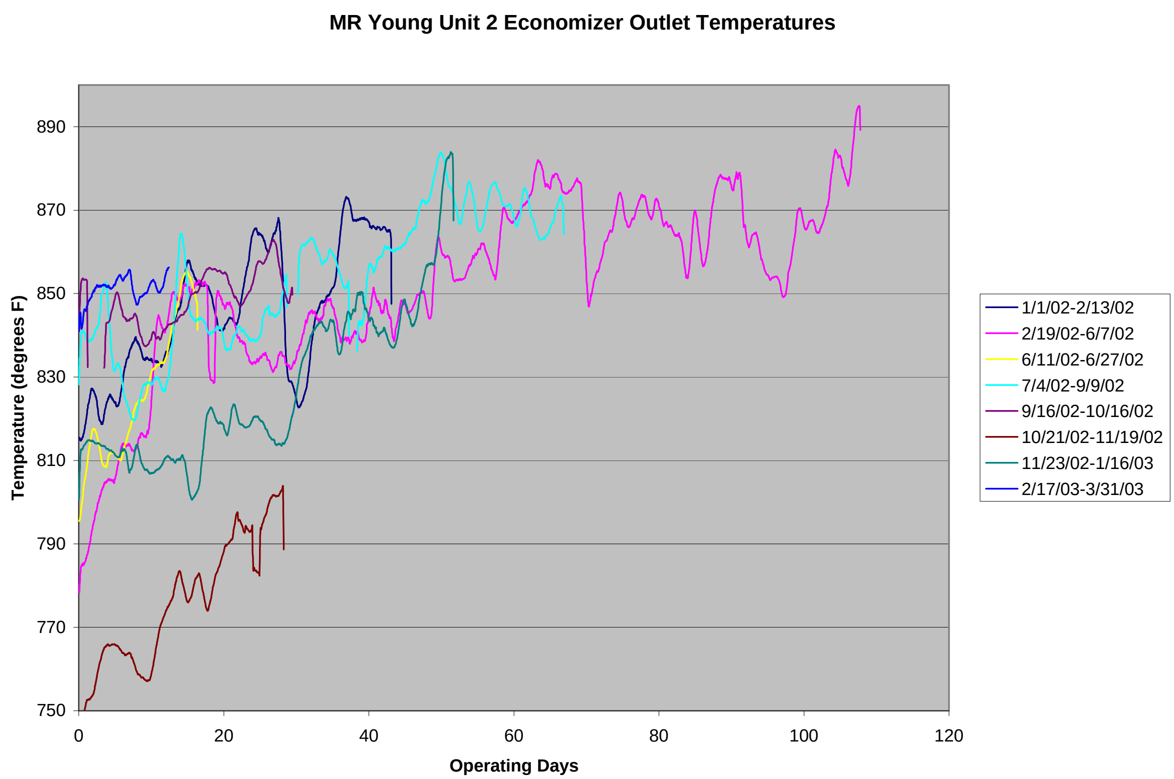
The steam turbine-generators at MRYS have a given output (gross megawatts) based on steam pressures, temperatures and flow rates related to the boilers. Removing high pressure/high temperature steam to use for flue gas reheating will directly cause a reduction in electrical output. This output reduction cannot be compensated for by increased boiler steam generation without unreasonable consequences. The boilers generate steam based upon their fuel heat input (firing) rates and capacities to absorb the heat created from the fuel combustion. The efficiency of converting fuel heat to steam to megawatts (heat rate or Btu per gross kilowatt) is limited by many factors. Fuel characteristics and boiler capacity are factors that impact heat rate (efficiency) that are not easily changed in the positive direction. The current fuel quality coming from the adjacent mine is not within the original design parameters of the boilers.

Because of the firing type (cyclone) and characteristics of North Dakota lignite burned and resulting flue gas emissions and ash produced at MRYS, the amount of fouling of the heat-absorbing surfaces within the boiler system is severe. These fouling conditions cause high exit flue gas temperatures that eventually reach the maximum limit recommended for maintaining the integrity of the air preheaters. This is indicated by the time-temperature graphs previously provided[13] and repeated below. The rate of boiler surface fouling increases significantly as more coal is fired, especially at maximum sustainable firing rates.

Due to the sticky character of the ash deposits, an "arsenal" of sootblower and water lance equipment is employed by Minnkota in an attempt to reduce the rate of fouling accumulations during boiler operations and remove these deposits during frequent boiler outages. These boiler cleaning outages occur every three to four months depending on the specific unit and the fuel quality delivered during the period. If the firing rate is increased to generate more steam for other heating purposes, the frequency of the cleaning outages must be increased. If the accumulated deposits are not removed, the frequency of the cleaning outages must be increased or the firing rates must be reduced and thus reduce the steam and electrical output of the boilers and steam turbine-generators. There is not "excess steam available for flue gas reheating" that would allow Minnkota to avoid reduced annual power generation.



[13] See Reference number 11, April 18, 2007, pages 13-17.


MR Young Unit 2 Economizer Outlet Temperatures
Temperature (degrees F)
890
870
850
830
810
790
770
750
0
20
40
60
80
100
120
Operating Days
1/1/02-2/13/02
2/19/02-6/7/02
6/11/02-6/27/02
7/4/02-9/9/02
9/16/02-10/16/02
10/21/02-11/19/02
11/23/02-1/16/03
2/17/03-3/31/03

NDDH Request #11: There appear to be several discrepancies in the documents that must be addressed including:

a. **The catalyst volume for Unit 2 (p. 4-23) is listed as 256 m^3 per reactor or 512 m^3 per layer. This is 4-5 times more than Unit 1 yet Unit 2 is not twice as large. Please verify the Unit 2 catalyst volume.**

At page 4-23, the words "per reactor" should be deleted from the sentence describing Unit 2's catalyst volume. This will be shown on an "Errata Sheet" attached to this document.

For Unit 2, the total initial volume was 768 cubic meters for three layers, or 256 cubic meters per layer, based on catalyst vendor input. Subsequent installation of 342 cubic meters for the fourth layer was assumed, also based on catalyst vendor input. Total initial volume plus first fill of spare layer equaling 1110 cubic meters is for two SCR reactors for each case studied for Unit 2. The correct catalyst volumes were used in the annual operating and maintenance cost calculations that are a portion of the levelized total annual costs for NOx control alternatives provided in the referenced November 2009 Supplemental NOx BACT Analysis study reports.

The conceptual design of Unit 1 Low-Dust SCR Reactor, and Tail End SCR Reactor as provided by the catalyst supplier included in each layer a total of 104 catalyst modules (8 x 13 arrangement). There is one SCR reactor for each case studied for Unit 1. The conceptual design of Unit 2 Low-Dust SCR Reactor, and Tail End SCR Reactor included in each layer a total of 91 catalyst modules per reactor (7 x 13 arrangement). There are two SCR reactors for each case studied for Unit 2.

b. **The reheat for Unit 2 for TESCR is listed as 48.11 MMBtu/hr per reactor and for LDSCR is 45.55 MMBtu/hr per reactor. The differential between TESCR and LDSCR is much less than for Unit 1 (60.3 MMBtu/hr and 31 MMBtu/hr). Please explain this difference.**

The preliminary process design calculations were reviewed for the hypothetical applications of low-dust and tail end SCR technologies for Unit 1 and Unit 2. It was determined from this review that the temperature rise for the Unit 1 LDSCR flue gas reheat system was incorrectly assumed to be 25 degrees F instead of 25 degrees C (equivalent to 45 degrees F). The corrected 45 degrees F temperature rise for the Unit 1 LDSCR flue gas reheat system is shown in the table included with the response to NDDH Request #8. The correct natural gas heat input rate for Unit 1's low-dust SCR cases is 54.5 MMBtu/hr (instead of 31 MMBtu/hr).

The discovery of the underestimate of Unit 1's low-dust SCR flue gas reheat fuel requires revision to the MRYS Unit 1 November 2009 Supplemental NOx BACT Analysis study report for "Scenario A" and "Scenario B" cases. A revised version of the referenced November 2009 MRYS Unit 1 Supplemental NOx BACT Analysis Study report document and the December 2009 response document is being submitted with the corrected numbers and recalculated control costs (see Enclosures). The flue gas reheat fuel rates and costs assumed for the hypothetical applications of Unit 1's tail end and Unit 2's low-dust and tail end SCR alternatives included in the November 2009 Supplemental NOx BACT Analysis study reports will not change.

The temperature rise for the Unit 1 TESCR, Unit 2 LDSCR, and Unit 2 TESCR flue gas reheat systems are also shown in the table included with the response to NDDH Request #8. These are all preliminary numbers that would require confirmation after final cold-side outlet design temperatures are established by the FGD and SCR gas/gas heat exchanger manufacturer.

c. The capital costs for the "stand alone" SCR (p.3 of attachments to December 11, 2009 submittal) do not total correctly. Please check the numbers and revise the documents as necessary.

The numbers for "Pricing Contingency" shown in the table that provided "Estimates of Total Capital Investment for Low Dust and Tail End Selective Catalytic Reduction Alternatives Best Available Control Technology – Supplemental Analysis Stand Alone" cases submitted on December 11, 2009 were incorrect. They should match the "Scope Contingency" numbers above the "Pricing Contingency" line in the table. A revised version of the referenced document is being submitted containing the table with corrected data (see Enclosures).

d. The flue gas reheat burners and fans appear to be included in both "SCR system equipment" and "Auxiliaries" cost estimates (see p.4 of attachments to December 11, 2009 submittal, footnotes 1 and 3). Please check this and revise the documents as necessary.

There are two systems of natural gas-fired burners associated with each alternative studied for hypothetical application of low-dust and tail end SCR technologies in the November 2009 Supplemental NOx BACT Analysis study reports. The "flue gas reheat burner equipment" is correctly included as part of the "Purchased Capital Equipment SCR System Equipment" item (1) (a) under "Direct Capital Costs" denoted by footnote number1 in both tables of "Estimates of Total Capital Investment" for "Shared Facilities" and "Stand Alone" as submitted on December 11, 2009. Item (1) (b) "Auxiliaries/Balance of Plant" of both tables has footnote number 3. This footnote should be revised to read as follows: "Includes service air and sootblower air compressors, induced draft booster fan(s) and dampers, urea-to-ammonia conversion ~~flue gas reheat~~ equipment with natural gas-firing burners and fan(s), SCR bypass ducts and isolation dampers, interconnecting ductwork, equipment for active coal yard storage modifications, and catalyst standby heating auxiliary equipment costs as well as mechanical setting of this equipment". A revised version of the referenced document with the corrected footnotes is being submitted (see Enclosures).

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REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter from Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: SCR Cost Estimate,* January 11, 2010.

2. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009.

3. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_X BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009.

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

5. Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.

6. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.

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

8. Technical Information (brochure) FT-9200-AP involving anhydrous and aqueous ammonia versus urea for SCRs available from Fuel Tech's website www.ftek.com, dated November 17, 2008.

9. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to EPA Comments NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Technical Feasibility, March 15, 2007. [with regard to two documents: ERG Memorandum to EPA Region 8 and EPA Office of Regulatory Enforcement, *Review and Critique of the Burns & McDonnell NO_X BACT Analysis for the Milton R. Young Station Operated by Minnkota Power (October 2006),* written by Roger Christman, Eastern Research Group, Inc., January 8, 2007, faxed by North Dakota Department of Health to Minnkota, January 9, 2007. *EPA Region 8 Preliminary Analysis of Burns & McDonnell*

BACT Analysis For Nitrogen Oxide at Milton R. Young Station, Units 1 and 2 January 8, 2007 faxed by North Dakota Department of Health to Minnkota, January 9, 2007.]

10. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns, Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study, April 18, 2007. [with regard to two documents: North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Determination Milton R. Young Station*, dated February 1, 2007, with enclosure from United States Environmental Protection Agency Region 8, letter to Terry O'Clair, North Dakota Department of Health Division of Air Quality, *Re: Transmittal of EPA Non-SCR concerns and additional information required for Minnkota BACT Analysis Study*, dated January 26, 2007.]

ATTACHMENTS

1. Conceptual design sketch, for hypothetical application of Low Dust SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

2. Conceptual design sketch, for hypothetical application of Tail End SCR technology to MRYS Unit 1 and Unit 2, Burns & McDonnell, 2009.

3. ERRATA Sheet:

    a. Corrections to Reference number 3 of this document "NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 2, Minnkota Power Cooperative, Inc. Operating Agent for Square Butte Electric Cooperative, Owner" November, 2009; (February, 2010).

ENCLOSURES:

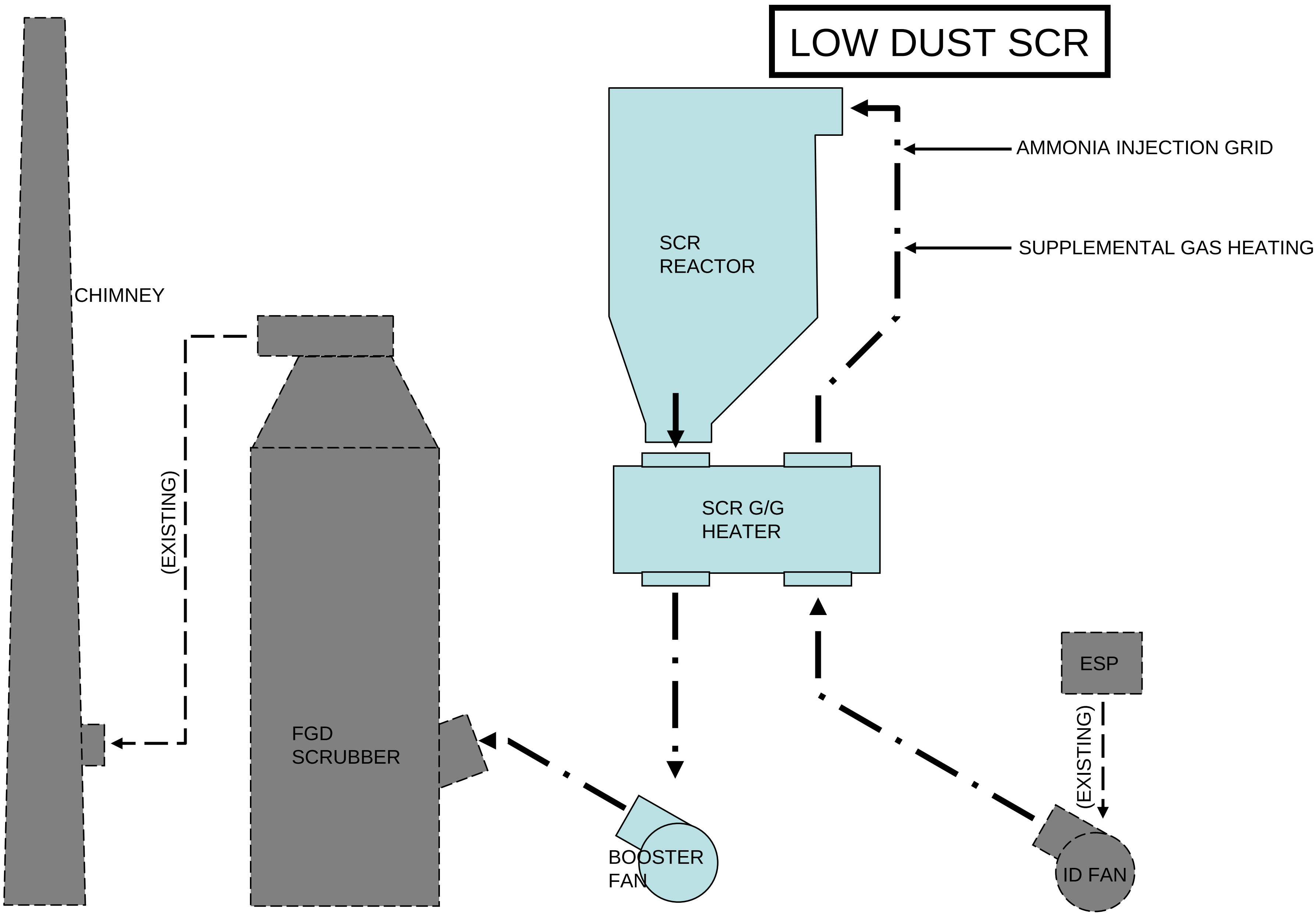
A. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, December 2009, submitted by Minnkota to North Dakota Department of Health on December 11, 2009, revised February, 2010.

B. NO_X Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009, submitted by Minnkota to North Dakota Department of Health on November 12, 2009, revised February, 2010.

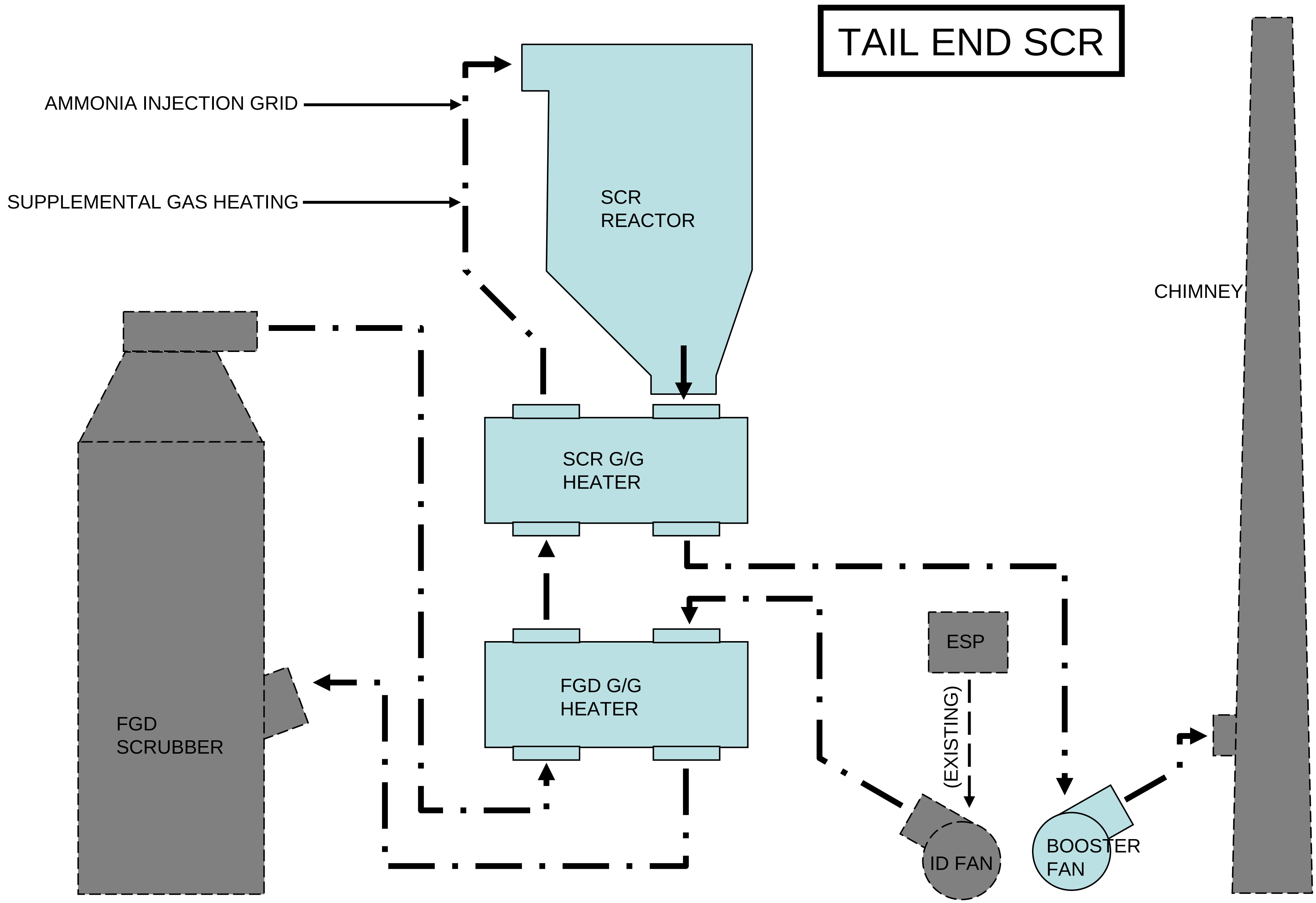
C. Non-confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

D. Confidential information related to response to NDDH Request #7 of this document (Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NOx BACT Analysis Study, Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility, February 2010).

SKETCH SK - FD1



SKETCH SK – FD2



ERRATA – MRYS Unit 2 Supplemental NOx BACT Analysis Study Report (November 2009)

Unit 2 Supplemental NOx BACT Analysis Study Report November 2009, page 4-23:

The second sentence of the paragraph should be revised to delete the words "per reactor":

> SCR catalyst replacements are additive to the general annual hypothetically-applied low-dust and tail end SCR equipment maintenance. Catalyst replacement costs are based on catalyst vendor quotation of volume of catalyst, estimated to be three layers initially (top, middle-upper and middle-lower) at 256 cubic meters per layer ~~per reactor~~ for two reactors in parallel. A fourth (bottom) layer at 342 cubic meters is expected to be required after initial operation of hypothetically-applied full-time tail end or low-dust SCR alternatives, as part of the catalyst replacement program. Catalyst replacement costs for the hypothetical application of SCR alternatives were estimated for the two different catalyst management scenarios described above.